2021 PSE Integrated Resource Plan

Appendix A

April 2021

FINAL

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PSE PUGET SOUND ENERGY

A Public Participation

This appendix describes public involvement in the development of the 2021 PSE IRP.

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1. OVERVIEW

Public engagement is both a required and essential part of developing PSE's Integrated Resource Plan. For this IRP, PSE adopted guidelines from the International Association of Public Participation (IAP2), expanded its outreach to stakeholders, and developed a structure to increase PSE's accountability to stakeholders and clearly demonstrate how stakeholder feedback was incorporated in the IRP.

This engagement generated valuable constructive feedback, and the suggestions and practical information received from organizations and individuals helped to guide both the public participation process and inform key components of the 2021 IRP analysis. We thank those who took part for both the time and energy they invested, and we encourage their continued participation.

By the time the 2021 IRP is filed with the WUTC, PSE will have held 13 public meetings, as well as dozens of informal meetings, phone and email communications in which more than 212 individuals representing 93 advocacy groups, regulators, industries, customers and interested members of the public participated. In addition, the WUTC will have held a Recessed Open Meeting for PSE to present the draft IRP and ongoing analysis and to provide a forum for questions from the Commissioners and public comments.

All materials related to the 2021 PSE IRP public participation process can be found at pse.com/irp. This includes meeting agendas; presentations and datasets; meeting recordings, attendance and chat transcripts; Feedback Reports; and Consultation Updates. In addition, the meeting agendas, presentation materials, chat transcripts, Feedback Reports and Consultation Updates are also presented in Section 7 of this Appendix.

PSE hired stakeholder engagement specialists to help develop the Public Participation Plan, provide independent meeting facilitation, develop meeting and public comment guidelines, assist with meeting documentation, and suggest adjustments to the meetings to promote communication and stakeholder engagement. The consultant supporting the 2021 IRP public participation process was EnviroIssues.

2. 2021 PSE IRP PUBLIC PARTICIPATION PLAN

The IAP2 public participation framework was introduced to PSE by stakeholders during the 2019 IRP public engagement process and adopted by PSE for the 2021 IRP. The IAP2 framework, along with various public participation techniques, allowed PSE to design and implement an effective process that allowed stakeholders to clearly understand where they could influence components of key inputs, assumptions and decisions. All meetings were open to all people and there were no exclusions to participation in any topic. Due to COVID-19, all stakeholder engagement was virtual, using various online platforms. Although online platforms are no replacement for in-person meetings and discussions, we believe this resulted in increased participation by a more diverse group of stakeholders from our service territory compared to past IRPs.

IAP2 Framework

IAP2 uses a framework for the level of influence stakeholders can have in a public process called the Spectrum of Public Participation (Spectrum). To identify the role of stakeholders on this spectrum, the IRP project team considered how stakeholder input will be used, what stakeholder input can change, and how stakeholder input will affect the subsequent planning processes in the long term. PSE identified three types of engagement on the spectrum that were most important in its planning for public participation. They were:

To inform: To provide the public with balanced and objective information to assist them in understanding the problem, alternatives and/or solutions

To consult: To obtain public feedback on analysis, alternatives and/or decisions

To involve: To work directly with the public throughout the process to ensure that public concerns and aspirations are consistently understood and considered.

Given the time constraints for the 2021 IRP, the remote nature of participation due to COVID-19, and the use of established technical methodology to complete the 2021 IRP, the team elected to *inform* stakeholders of IRP progress at key decision points, and to *consult and involve* groups of stakeholders to provide input on certain IRP components throughout the process.

During the 2021 IRP, PSE promised to:

- Keep stakeholders informed of the IRP process, draft and filings to assist them in understanding the IRP.
- Listen to and acknowledge concerns and aspirations from highly impacted stakeholders and to demonstrate how public feedback influenced decisions.

Key Messages

During the 2021 IRP process, PSE focused on the following key messages:

- PSE is developing a plan that identifies how we provide cost-effective electricity and natural gas to our customers for the next twenty years. The plan helps guide investments in acquiring energy to ensure customer needs are met, while also considering social, equity and environmental concerns.
- PSE believes stakeholder input can and should improve the 2021 IRP and will clearly identify where and how stakeholder input can inform the plan.
- Requirements in the Washington State Clean Energy Transformation Act will be reflected in the 2021 IRP, including development of a 10-year Clean Energy Action Plan.
- The IRP will carefully consider the impacts of various conservation and energy resources against the needs and barriers faced by low-income and other vulnerable communities.
- Informing, involving and consulting stakeholders will help ensure that a comprehensive set of elements are considered in developing the IRP.
- PSE is working to integrate the IRP process with the Delivery System Planning process so stakeholders understand the interconnection and can easily participate in both.
- PSE will seek input on how to improve stakeholder involvement in future plans.

IRP Milestones, Public Participation Techniques and Objectives

Setting IRP Milestones

The IAP2 framework for effective public participation identifies the need for strong linkages and integration of public participation and technical work. In order to identify the key project milestones and decision points where stakeholders should be informed, or where PSE should work with stakeholders to receive input on project components, EnviroIssues worked with the IRP technical team in a workshop to align technical work with specific participation objectives and place them on the IRP development timeline.

Clear objectives then led to selection of participation techniques to promote PSE meeting those objectives. The goal was for PSE technical staff to work with stakeholders on the coordination of project milestones by aligning participation objectives and techniques, and clearly communicating when stakeholders have the opportunity to provide input and feedback to specific IRP topics.

Participation Techniques and Objectives

WEBSITE IMPROVEMENTS. The project website was redesigned in early 2020 to facilitate pubic involvement. All webinar registration information, agendas, presentation materials and technical documents, Feedback Reports and Consultation Updates were posted to pse.com/irp. An online Feedback Form invited stakeholders to provide input, suggestions and comments. To evaluate this participation technique, the website was monitored for time spent on site, pages visited and trends in visits over time.

PUBLIC WEBINARS. PSE was not able to conduct in-person meetings due to COVID-19 restrictions, and as a result online webinars replaced in-person meetings. These webinars were designed to inform, consult and involve stakeholders on key milestones and topics involved in the development of the IRP. During each webinar, stakeholders were able to ask questions and provide feedback verbally or through the online chat feature. Participation was facilitated by EnviroIssues to allow PSE to focus on the technical content of the presentations. If a question was not answered during the meeting, it was added to the meeting Feedback Report and PSE responded in writing. **One week before each webinar**, meeting reminders were emailed to alert stakeholders that the meeting materials had been posted to pse.com/irp and Feedback Forms were open. **One day after each meeting**, PSE posted the webinar recordings and chat transcripts to pse.com/irp.

WEBINAR RECORDINGS. All webinars were recorded and posted online **one day after the meeting**. The recordings included a voice recording, thumbnail versions of the slides used to support the meeting discussion and a written transcript for easy searching. Speakers' names are included in the transcript. The webinar recordings were used to promote participation by stakeholders who could not attend but wanted to stay involved and provide feedback. PSE accepted all stakeholder feedback, whether a stakeholder attended the webinar or not.

WEBINAR Q&A (chat) LOG. GoToMeeting was the primary online platform used to support the Webinars. All comments and questions received through the online chat were documented in the Webinar Q&A Log and posted online **one day after each meeting**. The chat log documentation includes a list of all attendees along with a name, timestamp and the comment made by each participant. Questions asked via the chat or verbally were answered by PSE verbally and are captured on the webinar recording. Any questions not answered during the webinar were added to the Feedback Report and answered by PSE in writing.

FEEDBACK FORMS. An online Feedback Form at pse.com/irp was designed to promote topic-specific suggestions and questions related to each public webinar. The feedback form was opened one week before the webinar and feedback was due one week after the meeting. Stakeholders used the Feedback Form to submit questions regarding the webinar presentation in advance of the meeting, and PSE typically answered those questions during the meeting. Following the webinar, stakeholders used the Feedback Form to provide specific input to PSE regarding the IRP analysis and materials presented. **At all times** stakeholders could submit questions and comments at pse.com/irp through a general comment form.

FEEDBACK REPORTS were posted to pse.com/irp **two weeks after each meeting.** These reports included all input, questions and comments received from stakeholders and written PSE responses to all feedback. The goal was to promote PSE accountability and foster two-way communication. When PSE did not have sufficient time to respond to all stakeholder feedback and/or if follow-up meetings were necessary to clarify input, PSE provided a response in the Consultation Update.

FOLLOW-UP MEETINGS. Follow-up meetings to the Feedback Reports allowed PSE to engage with stakeholders to clarify their input and/or engage in dialog. These gatherings were organized on an as-needed basis and helped to further develop PSE's Consultation Updates.

CONSULTATION UPDATES were posted to pse.com/irp **three weeks after each meeting**. These summaries of the consultation activity (follow-up calls and meetings, etc.) and feedback received reported on how PSE responded to feedback and documented how PSE incorporated the feedback into the IRP.

OTHER COMMUNICATION TOOLS. In addition to the techniques described above, PSE also used the following communications tools.

- PSE conducted Interviews with stakeholders to discuss key concerns and explore process improvements.
- Email was used for reminders about upcoming deadlines, webinars and registration information, and invitations to submit Feedback Forms and participate in surveys.
- Periodic email newsletters reminded stakeholders about upcoming webinars and deadlines and included summaries of stakeholder feedback and updates on the status of the IRP's development.

Dozens of informal meetings, phone and email communications supplemented these communications.

3. ADDITIONAL CONSIDERATIONS

Increasing Engagement

To begin planning for IRP public participation, the project team participated in a workshop led by EnviroIssues, a public participation consulting firm. At the workshop, the project team identified possible audiences and stakeholders who may be interested in or impacted by the IRP. The team then brainstormed possible issues, concerns and aspirations that the various audiences may have regarding the IRP and its implementation. The technical team and EnviroIssues then worked to correlate those audiences and issues, tracking which issues could be most important to each audience.

This correlation was used to identify the level of impact the IRP could have on each audience. The audiences were then sorted into categories and prioritized by their relative level of impact and/or interest. This assessment resulted in three tiers of stakeholders: primary, secondary and tertiary. The team was careful to recognize that the assessment was only a snapshot and that ongoing adjustments and clarifications would be necessary throughout the process as more was learned from different audiences and as audiences became more or less interested throughout the process. The stakeholder prioritization tiers determined by the IRP team are described below.

PRIMARY STAKEHOLDERS

- Internal PSE groups whose work is directly impacted by IRP results
- Energy regulatory groups
- Government representatives
- Highly vulnerable populations and their advocates
- Energy sector developers and producers
- Energy councils and coalitions directly impacted by IRP results
- Environmental groups previously involved in stakeholder processes
- Community groups previously involved in stakeholder processes
- PSE ratepayers

SECONDARY STAKEHOLDERS

- Internal PSE groups that experience fewer impacts from IRP results
- Environmental groups not previously involved in stakeholder processes
- Community groups not previously involved in stakeholder processes
- Energy sector organizations indirectly impacted by IRP results
- Labor organizations in energy industries

TERTIARY STAKEHOLDERS

Internal PSE groups that do not experience direct impacts from IRP results
Community groups with an indirect interest in IRP results
Land use interest groups
Customer groups with indirect impacts from IRP results

The following principles of participation were applied to the stakeholder tiers:

All stakeholders (primary, secondary and tertiary) are informed about all participation opportunities (information techniques)

All stakeholders (primary, secondary and tertiary) are welcome to participate in all participation opportunities

Primary stakeholders are specifically invited to participate in engagement opportunities

Once the stakeholder groups were identified, PSE developed an IRP participation list of more than 1,500 possible interested participants with input from regulators, stakeholders and PSE community outreach specialists. PSE provided targeted IRP information and maintained ongoing communication throughout the process with the three tiers of stakeholders. All stakeholders were welcome to participate in all aspects of the IRP process, join the webinars and provide feedback to PSE.

STAKEHOLDER INTERVIEWS. In April and May 2020, the project team conducted interviews with 15 stakeholders who had participated in the 2019 IRP Process. The full summary is available here:
https://oohpseirp.blob.core.windows.net/media/Default/documents/2020_0513_StakeholderInterviewSummary_Final.pdf

Key take-aways from the interviews included identifying the topics of greatest interest to stakeholders, the importance of inclusive stakeholder engagement, preserving effective participation strategies and suggestions for building trust and transparency.

Greatest topics of interest in May 2020:

- Load and price forecasting
- Implementation of CETA (Clean Energy Transformation Act)
- Social cost of carbon
- Electrification and renewables

- Demand response planning
- Electric and gas transmission

Stakeholders also suggested additional participants to increase the diversity of participation in the 2021 IRP, and PSE used these suggestions in developing its expanded email distribution list.

ATTENDANCE AND FEEDBACK PARTICIPATION. Webinar meeting attendance ranged from 61 to 81, with 68 being the average. The lowest attendance recorded was at Webinar 1 and the highest at Webinars 7 and 10, demonstrating increased engagement throughout the process. The number of separate Feedback Form questions and comments per webinar ranged from 23 to 114 with 58 being the average. A total of 683 individual questions and comments were addressed by PSE in written responses in the 13 Feedback Reports.

PSE provided responses to all questions, comments and feedback as documented in the Feedback Reports or Consultation Updates.

Greater Integration of Delivery System Planning

Public engagement and participation in delivery system planning is becoming increasingly important, and over time, the goal is for the IRP and delivery system planning stakeholder engagement processes to become closely integrated. The 2021 IRP begins this process by integrating delivery system planning into the public participation process more intentionally than in previous cycles. Discussion of delivery system and grid modernization issues was featured in four of PSE's 13 public meetings (webinars) held during this cycle.

- The July 14, 2020 Demand-side Resources and Demand Response meeting included discussion of efforts to reduce energy use by reducing the voltage of specific delivery system circuits while remaining within required tolerances.
- The August 11, 2020 Portfolio Sensitivities and CETA meeting included a presentation on distributed energy resources (DERs), PSE's first DER Forecast and non-wires analyses, and DER pilots and enablement activities.
- The November 16, 2020 meeting on the Clean Energy Action Plan, 10-year Distribution and Transmission Plan, and Economic, Health and Environmental Benefits Assessment included discussion of integrating delivery system planning and the IRP, current system needs that may be solved by DERs, and the modernization necessary to support large-scale DERs in the local system.
- The February 10, 2021, webinar included preliminary solutions to identified needs and 10-Year Distribution System plan details.

PSE is also working to integrate the new stakeholder requirements regarding regional transmission into the IRP Public Participation Plan, as described in the regional transmission planning process in Attachment K of PSE's OATT (Open Access Transmission Tariff). The stakeholder engagement process for transmission has historically been a process separate from the IRP; in this IRP cycle, transmission was addressed in the February 10, 2021 public meeting, as mentioned previously.

DER Planning and Delivery System Planning

RCW 19.280.100, Distributed Energy Resources Planning, recommends the distribution system investment planning process should utilize a transparent approach that involves opportunities for stakeholder input and feedback. This recommendation is initially met through integration in the 2021 IRP Public Participation Plan.

In 2019, PSE began planning for the establishment of an external technical panel to provide input on specific distributed energy issues. This group would monitor approaches implemented in jurisdictions like California and Hawaii that have more mature experience in implementing non-traditional solutions for both resource and delivery system planning; build a common understanding of the challenges, opportunities and trade-offs involved in modernizing the grid to better serve customers; promote collaboration and the best delivery system solutions; and help to further the public participation recommendations set forth by RCW 19.280.100. The input from these specific, focused, technical conversations will inform the IRP stakeholder process in the future. To date, PSE has engaged several consultants to investigate potential public engagement frameworks and engaged the WUTC for input and feedback in early 2019. Currently, PSE is identifying expert members to be part of the technical panel. COVID-19 slowed this effort, but we expect to launch the technical panel in 2021.

In the meantime, PSE has led in gathering a group of Washington utilities, called the Washington Utility Symposium, to share and learn from each other as each utility develops DER and non-wire approaches. On July 23, 2020, the planning kickoff meeting was held to gather interest and topics. On September 9, 2020, the first topic meeting discussed how utilities were organized around DER and non-wire processes. On October 29, 2020 the second topic meeting discussed tools, models and data management. Each utility participant is actively engaged in growing its processes, and the opportunity to learn from each other and share best practices will benefit all members of the group.

PSE continues its strong stakeholder engagement process for location-specific projects as they are implemented, leveraging community advisory groups, interactive websites and any and all permitting public processes.

4. PARTICIPANTS

93 organizations and 212 unique individuals participated in development of the 2021 PSE IRP. The participating organizations include the following.

350 Seattle

A
Absaroka Energy LLC
Alliance of Western Energy Consumers
Armada Power
ARUP
Avangrid Renewables
Avista

B
Bridle Trails
Broadreach Power

C
Cascade Natural Gas
City of Arlington
City of Bellevue
City of Kenmore
City of Mercer Island
City of Puyallup
City of Seattle, Office of Sustainability and Environment
Climate Reality Project
Climate Solutions
Coalition of Eastside Neighborhoods for Sensible Energy (CENSE)
Convergent Energy + Power

D
DNV GL

E
Eagle Cap Consulting
Enbala
Eos Energy Enterprises
Evergreen University
Energy Solutions

F
FISH (Friends of the Issaquah Salmon Hatchery)
Flex Charging
FortisBC
Franklin Energy

G
General Electric

H
Halmark
Hardy Energy Consulting
Hecate Energy

I
ICF
Impact Bioenergy
Invenergy

J
John Handcock
juwi Inc.

K
King County

L
LBNL; LBNL Consultant to UTC
League of Women Voters
Longroad Energy

M
Markell & Company LLC
Monolith Energy Consulting

N
National Grid Ventures
NextEra Energy Resources
Northwest Gas Association
Northwest Independent Power Producers Coalition (NIPPC)
Northwest Pipeline
Northwest Power and Conservation Council
Northwest Power Consulting
NW Energy Coalition (NWEC)

O
Obsidian Renewables, LLC
Office of the Attorney General Public Counsel Unit
Optimum Building Consultants
Orion Renewable Energy Group

P
PA Consulting Group
Pacific Northwest Utilities Conference Committee (PNUCC)
Panamint Capital LLC
Pasco Energy
Pete Stoppani Consulting LLC
Port of Olympia
Port of Tacoma
Prisma Energy

R
Renewable Energy Coalition
Renewable Northwest
Rye Development

S
Sapere Consulting
Shifted Energy
SLR International Corporation
Smart Wires
Solar Horizon
SSVP
Sun2oPartners
Sunenergy Systems Inc
The Sierra Club

T
Thurston County League of Women Voters
Town of La Conner
TransAlta
TrasAlta Renewables (RNW)
Triangle Associates
Twenty First Century Utilities

U
UniEnergy Technologies, LLC
Union of Concerned Scientists
United States Postal Service (USPS)

V
Vashon Climate Action Group

W
Wartsila
Western Solar
Washington Environmental Council
Washington State Department of Commerce
Washington State Office of the Attorney General, Office of the Attorney General Public Counsel Unit
Western Grid Group (WGG)
Western Solar
Washington Utilities and Transportation Commission policy staff and advocacy staff

5. SUMMARY OF PUBLIC COMMENTS

No.	Theme	Summary of PSE Action	IRP Documentation
1	Generic resource costs and assumptions	Adopted stakeholder recommended resource cost data from public sources including NREL.	Appendix A - Webinar 1 Consultation Update 1
2	Electric price forecast	Included stakeholder recommended natural gas price forecast and regional demand forecast updates as well as CETA renewable need requirement for Washington state electric utilities.	Appendix A – Webinar 2 Consultation Update 2
3	Transmission constraints	Included stakeholder recommended sensitivity to model firm transmission as a portion of the nameplate capacity. Adjusted transmission constraint assumptions.	Appendix A – Webinar 3 Consultation Update 3 Chapter 8, Electric Analysis
4	Social cost of Greenhouse Gases modeling approach	In addition to modeling SCGHG as a cost adder in the portfolio model, PSE also modeled other stakeholder requested SCGHG methods to evaluate the impact on conservation, resource additions and retirements.	Appendix A – Webinar 5 Consultation Update 5 Chapter 3, Resource Plan Decisions Chapter 8, Electric Analysis
5	Upstream emissions	PSE assumed upstream emission content consistent with Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (AR4) in all portfolio modeling. Some stakeholders suggested the IPCC Fifth Assessment Report (AR5) should be used. In response, PSE evaluated a sensitivity with upstream emissions consistent with IPCC Fifth Assessment Report (AR5).	Appendix A – Webinar 5 Consultation Update 5 Chapter 3, Resource Plan Decisions Chapter 8, Electric Analysis
6	Portfolio scenarios and sensitivities	PSE partnered with stakeholders to develop a list of possible scenarios and sensitivities and then allowed stakeholders to prioritize the sensitivities. PSE modeled many stakeholder selected sensitivities and documented the ones that were not modeled.	Appendix A Chapter 8, Electric Analysis Chapter 9, Natural Gas Analysis

7	Historical temperature years	Some stakeholders suggested that PSE should use an alternate temperature data set than the 30 years currently used. PSE conducted a temperature sensitivity where stakeholders could select to use a shorter data set or rely on the work of the Northwest Power and Conservation Council (NPCC). Stakeholders selected NPCC and PSE completed the sensitivity analysis.	Chapter 6, Demand Forecast Chapter 7, Resource Adequacy Analysis Chapter 8, Electric Analysis Appendix L, Temperature Trend Study
8	Peak Capacity Credit of Resources	Stakeholders suggested that some of the peak capacity credit of certain resources is lower than what other utilities are using. Peak capacity credit is unique to each utility and dependent on the load shape and supply availability.	Chapter 7, Resource Adequacy Analysis
9	Alternative fuels	Stakeholders wanted PSE to explore the use of alternative fuels such as hydrogen, RNG and biodiesel. PSE was able to analyze the use of biodiesel and the results of the biodiesel analysis helped shape the preferred portfolio.	Chapter 3, Resource Plan Decisions
10	Alternative compliance	PSE utilized the California carbon price as a proxy cost for 20 percent of load not met by renewable generation starting in 2030 and decreasing linearly to zero in 2045. PSE asked stakeholders for alternative assumptions but none were provided.	Chapter 2, Clean Energy Action Plan Chapter 5, Key Analytical Assumptions
11	No new natural gas resources	To ensure that PSE has a complete portfolio sensitivity analysis, natural gas combustion turbines were included in the modeling. However, PSE's preferred portfolio does not include natural gas combustion turbines. PSE found that a CETA-compliant fuel (biodiesel) combustion turbine along with renewable and distributed resources is the best mix of resources to meet CETA.	Chapter 1, Executive Summary Chapter 3, Resource Plan Decisions

12	Data availability	PSE provided various data sets along with the webinar slide decks to support the webinar discussions. With the final IRP, PSE is providing Excel workbooks which contain all the modeling inputs and outputs for both the electric and natural gas IRPs, including the conservation potential assessment underlying data.	Appendix H, Electric Analysis Inputs and Results Appendix I, Natural Gas Analysis Results
13	Colstrip	The portfolio model is able to select economic retirement of all existing resources, including Colstrip. PSE did not find any portfolio sensitivities where the model chose to retire Colstrip prior to 2025. In order to comply with CETA requirements, Colstrip is removed from PSE's electric supply by the end of 2025.	Chapter 8, Electric Analysis
14	Public process	Some stakeholders indicated that parts of the analysis were provided too late in the process. PSE continued to provide materials one week in advance with the analysis available at that time, but acknowledged this IRP cycle has been more iterative than desired and the final stages of the analysis, in light of the timeline, did not allow for optimum stakeholder engagement. PSE is taking steps to address this for the next IRP process.	Appendix A PSE IRP website: www.pse.com/irp
15	Incremental cost of compliance (2% cost cap)	As a result of stakeholder feedback, the 2021 IRP preferred portfolio has not been adjusted by the 2% cost cap. The incremental cost of compliance calculation is provided for informational purposes only and will be considered more fully in the Clean Energy Implementation Plan.	Chapter 8 Electric Analysis

6. TIMELINE, MEETINGS AND TOPICS

All meetings for the 2021 IRP public participation process were conducted remotely because of COVID-19 restrictions. Each meeting was opened with an orientation that explained how to participate using the electronic platform. Section 7 of this appendix presents the documentation for each of PSE's 13 webinars and the WUTC Recessed Open Meeting on the draft IRP filing.

January 2020	
	Week-long IAP2 training (Foundations and Public Participation) for PSE IRP Stakeholder Manager.
February 2020	
	Two-day IAP2 training for PSE IRP project team and selected PSE staff.
March 2020	
	Stakeholder interviews, development of broader participant list, exploration of process improvements. Development of the public participation plan.
April 2020	
	2021 IRP Work Plan and Public Participation Plan filed with the WUTC and published on the IRP website. All changes to the public participation plan were filed with the WUTC and communicated via the website and meeting announcements.
May 2020	
May 12	Invitation emailed to expanded list of 1,500 individuals that described the public participation process, explained "What is an IRP?", encouraged participation, provided a registration link to the first meeting and a sign-up or opt out option for notifications concerning the process.
May 21	Reminder emailed for May 28 Webinar 1, Generic Resource Assumptions. Meeting materials posted to pse.com/irp and Feedback Form opened. Registration encouraged and information and registration link for June 10 Webinar 2 also included.

May 28	**Webinar 1** **Generic Resource Assumptions** **Stakeholder role:** Consult **Meeting platform:** GoToWebinar **Attendance:** 61 participants and the IRP project team Orientation included the role of the IAP2 public participation process in the 2021 IRP and how to use the Feedback Form. The PSE IRP team presented an overview of IRP modeling and the schedule; described changes made to generic resource assumptions since the 2019 IRP Process; and posted a spreadsheet summarizing the generic resource assumptions for the 2021 IRP. Feedback Forms were used for the first time at this meeting. *Stakeholders shared their input on generic resource costs.*
May 29	Webinar 1 recording and chat posted to pse.com/irp.
June 2020	
June 4	Newsletter and reminder for the June 10 Webinar 2, Electric Price Forecasting, plus a reminder about the deadline for Webinar 1 feedback, and a “save the date” notice for Webinar 3. Webinar 2 materials posted to pse.com/irp and Feedback Form opened.
June 4	Feedback Forms due for Webinar 1, Generic Resource Costs; 18 individuals responded with questions and comments.
June 9	Second reminder emailed for Webinar 2, Electric Price Forecast.
June 10	**Webinar 2** **Electric Price Forecast** **Stakeholder role:** Inform **Meeting platform:** GoTo Meeting, in response to stakeholder concerns about the limitations of GoToWebinar. **Attendance:** 68 participants and the IRP project team The PSE team explained how the electric price forecast is used in the IRP to complete scenarios; described the modeling process; reviewed the electric price forecasts from the 2017 IRP and 2019 IRP Process and results of the draft 2021 IRP electric price forecast; reviewed CETA regulation assumptions; and reviewed 2021 IRP electric price scenarios. *Stakeholders*

	shared their input on incorporating clean energy policies in baseline assumptions to inform the electric price forecast.
June 11	Webinar 2 recording and chat posted to pse.com/irp.
June 11	Feedback Report for Webinar 1, Generic Resource Costs, posted to pse.com/irp with PSE responses to 54 questions and comments received from stakeholders.
June 17	Feedback Forms due for Webinar 2, Electric Price Forecast; 7 individuals responded.
June 18	Consultation Update on Webinar 1, Generic Resource Costs, posted to pse.com. The IRP team reported decisions on what costs to use and supplied the documentation used to make the decisions. *Generic resource costs were adjusted based on stakeholder feedback and an updated file was posted to pse.com/irp.*
June 23	Reminder emailed for June 30 Webinar 3, Transmission Constraints. Meeting materials posted to pse.com/irp and Feedback Form opened.
June 24	Feedback Report for Webinar 2, Electric Price Forecast, posted to pse.com/irp with PSE responses to 64 questions and comments received from stakeholders.
June 29	Second reminder emailed for Webinar 3, Transmission Constraints.
June 30	**Webinar 3** **Transmission Constraints** **Stakeholder role:** Consult **Meeting platform:** Zoom was tested as another meeting platform option. **Attendance:** 74 participants and the IRP project team The IRP project team presented background concerning transmission constraints and discussed transmission capacity constraints with participants (modeling methodology, capacity magnitudes and capacity uncertainty). A transmission cost assumption presentation included transmission rates and losses in the 2021 IRP. *Stakeholders shared their feedback on how to account for transmission availability with restricting resource builds.*

July 2020	
July 1	Webinar 3 recording and chat posted to pse.com/irp.
July 1	Consultation Update on Webinar 2, Electric Price Forecast, posted to pse.com/IRP. The IRP team reported its decisions on what prices to use and the documentation used to arrive at the decisions.
July 7	Feedback Forms due for Webinar 3, Transmission Constraints; 12 individuals responded.
July 8	Reminder email for July 14 Webinar 4, Demand-side Resources and Demand Response. Meeting materials posted to pse.com/irp and Feedback Form opened.
July 13	Second reminder emailed for Webinar 4, Demand-side Resources and Demand Response.
July 14	Feedback Report for Webinar 3, Transmission Constraints, posted on pse.com/irp with PSE responses to 68 questions and comments.
July 14	**Webinar 4** **Demand-side Resources and Demand Response** **Stakeholder role:** Inform and Consult **Meeting platform:** GoToWebinar was chosen as the platform for the remaining meetings based on stakeholder and PSE experience. **Attendance:** 69 participants and the IRP project team The IRP project team explained how the Conservation Potential Assessment (CPA) and Demand-Side Response Assessment is used in the IRP and described the methodology used in that assessment; explained electric DSR potential, natural gas DSR potential and distribution efficiency; and described how the CPA results are input into IRP modeling. In addition to PSE staff presentations, a representative of Cadmus presented the results of the CPA draft report. *Stakeholders learned about and shared their feedback on demand response programs and the costs and saving assumptions to be included in the conservation measures.*
July 15	Webinar 4 recording and chat posted to pse.com/irp.
July 15	Reminder email for July 21 Webinar 5, SCGHG and Natural Gas Upstream

	Emissions. Meeting materials posted to pse.com/irp and Feedback Form opened.
July 20	Second reminder email for July 21 Webinar 5, SCGHG and Natural Gas Upstream Emissions.
July 21	Consultation Update on Webinar 3, Transmission Constraints, posted to pse.com/irp. PSE reported decisions on what transmission constraints to use in the analysis.
July 21	Feedback Forms due for Webinar 4, Demand-side Resources and Demand Response; 17 individuals responded.
July 21	**Webinar 5** **Social Cost of Greenhouse Gases (SCGHG) and Natural Gas Upstream Emissions** **Stakeholder role:** Consult and Inform **Attendance:** 54 participants and the IRP project team Note: PSE views the terms social cost of greenhouse gases (SCGHG) and social cost of carbon (SCC) as interchangeable and therefore referenced them as SCC/SCGHG in the IRP models and in this meeting. In this webinar, PSE explained the SCC/ SCGHG according to CETA regulations, and presented the implications of modeling SCC/SCGHG as a cost adder vs. a tax, giving examples of the applications of each approach and the methodology. Background concerning the conclusions developed during the 2019 IRP Process was also provided for context, and SCC/SCGHG integration in the scenarios and portfolio sensitivities was described. *Stakeholders shared their input on why PSE should be utilizing the high social cost of carbon and learned about PSE's upstream emissions calculations.*
July 22	Webinar 5 recording and chat posted to pse.com/irp.
July 28	Feedback Report posted for Webinar 4, Demand-side Resources and Demand Response, with PSE responses to 114 questions and comments.
July 28	Feedback Forms due for Webinar 5, SCGHG and Natural Gas Upstream Emissions; 11 individuals responded.

August 2020	
Aug. 4	Consultation Report on Webinar 4, Demand-side Resources and Demand Response posted to pse.com/irp.
Aug. 4	Feedback Report posted for Webinar 5, SCGHG and Natural Gas Upstream Emissions, with PSE responses to 38 questions and comments. On August 25, an addendum to this Feedback Report was posted with PSE responses to an additional 8 questions and comments from NWEC's feedback. A total of 46 questions and comments were responded to on this topic.
Aug. 5	Reminder email for August 11 Webinar 6, Portfolio Sensitivities, CETA Assumptions and Distributed Energy Resources. Meeting materials posted to pse.com/irp and Feedback Form opened.
Aug. 10	Second reminder emailed for August 11 Webinar 6, Portfolio Sensitivities, CETA Assumptions and Distributed Energy Resources.
Aug. 11	Consultation Update on Webinar 5, SCGHG and Natural Gas Upstream Emissions, posted on pse.com.
Aug. 11	**Webinar 6** **Portfolio Sensitivities Development, CETA Assumptions and Distributed Energy Resources** **Stakeholder role:** Involve and Inform **Attendance:** 69 participants and the IRP project team The meeting content included portfolio scenarios and sensitivities, CETA assumptions, distributed energy resource integration, and a consultation update briefing on how stakeholder feedback has been included in the 2021 electric price forecast. *Stakeholders provided their thoughts and aspirations about what portfolio sensitivities PSE should consider modeling and learned that PSE will model 80 percent and 100 percent renewable portfolio targets.*
Aug. 12	Webinar 6 recording and chat posted to pse.com/irp.
Aug. 18	Feedback Forms due for Webinar 6, Portfolio Sensitivities, CETA Assumptions and Distributed Energy Resources; 8 individuals responded.
Aug. 25	Feedback Report on Webinar 6, Portfolio Sensitivities, CETA Assumptions and Distributed Energy Resources, posted on pse.com/irp with PSE responses to

	38 questions and comments.
Aug. 26	Reminder email for Sept. 1 Webinar 7, CETA Assumptions, Resource Adequacy, Electric Resource Need. Meeting materials posted to pse.com/irp and Feedback Form opened.
Aug. 31	Second reminder emailed for Sept. 1 Webinar 7, CETA Assumptions, Resource Adequacy, Electric Resource Need.
September 2020	
Sept. 1	Consultation Update on Webinar 6, Portfolio Sensitivities, CETA Assumptions and Distributed Energy Resources, posted on pse.com/irp, including an updated list of scenarios and sensitivities based on stakeholder feedback.
Sept. 1	**Webinar 7** **CETA Assumptions, Resource Adequacy, Electric Resource Need** **Stakeholder role:** Inform and Consult **Attendance:** 81 participants and the IRP project team At this meeting, stakeholders learned about PSE's 2021 IRP gas and electric demand forecasts, the resource adequacy analysis and draft resource adequacy results. *Stakeholders also had an opportunity to give feedback and suggestions on CETA alternative compliance.*
Sept. 2	Webinar 7 recording and chat posted to pse.com/irp.
Sept. 8	Feedback Forms due for Webinar *7,* CETA Assumptions, Resource Adequacy, Electric Resource Need; 5 individuals responded.
Sept. 15	Feedback Report on for Webinar 7, CETA Assumptions, Resource Adequacy, Electric Resource Need, posted on pse.com/irp with PSE responses to 23 questions and comments.
Sept. 22	Consultation Update for Webinar 7, CETA Assumptions, Resource Adequacy, Electric Resource Need, posted to pse.com/irp.
Sept 30	Newsletter emailed communicating the launch of Delivery System Planning process on pse.com/irp. A review of the status of the 2021 IRP process was provided, with a link to a survey to determine interest in PSE providing an

	introduction to the IRP or "IRP 101" seminar. *PSE received interest from six individuals and therefore concluded to revisit this proposal for the next IRP.*
October 2020	
Oct. 9	Reminder email for Oct. 14 Webinar 8, Natural Gas IRP. Meeting materials posted to pse.com/irp and Feedback Form opened.
Oct. 14	**Webinar 8** **Natural Gas IRP: Design Peak Day, Resource Alternatives, Portfolio Modeling and Sensitivities, Draft Results** **Stakeholder role**: Involve and Inform **Attendance**: 51 participants attended in addition to the PSE project team Stakeholders learned about PSE's natural gas peak day planning standard, natural gas resource alternatives and draft natural gas portfolio results. *Stakeholders had the opportunity to give feedback and suggestions on natural gas scenarios and portfolio sensitivities.*
Oct. 15	Webinar 8 recording and chat posted to pse.com/irp.
Oct. 19	Emailed invitation to participate via survey in selecting the electric portfolio sensitivities to be analyzed in the 2021 IRP.
Oct. 20	**Webinar 9** **Electric Portfolio Modeling Process, Final Electric Power Prices, Electric Sensitivities, Inputs and Observations from Draft Results** **Stakeholder role:** Involve and Inform **Attendance:** 62 participants and the PSE project team The IRP team explained the electric IRP analysis process (portfolio modeling, final resource adequacy analysis, final resource need, final electric price forecast, planning assumptions and resource alternatives) and electric portfolio sensitivities. S*takeholders learned about PSE's final electric price forecast, shared their thoughts and aspirations about PSE's draft electric portfolio results, and provided input on the electric portfolio and sensitivities.*
Oct. 19	To gain greater understanding of stakeholder priorities for the IRP, PSE invited

through Oct. 27	stakeholders to participate in selecting electric sensitivities via a Sensitivity Prioritization Survey fielded from October 20 to October 27. The survey link was distributed via email and made available online. Survey results are reported in Section 6 of this appendix.
Oct. 21	Webinar 9 recording and chat posted to pse.com/irp.
Oct. 21	Feedback Forms due for Webinar 8, Natural Gas Analysis; 13 individuals responded.
Oct. 27	Newsletter alert: last day to participate in the survey to select the portfolio sensitivities for analysis in the 2021 IRP.
Oct. 27	Feedback Forms due for Webinar 9, Electric Portfolio Modeling, Final Electric Power Prices, Electric Sensitivities, Inputs and Observations from Draft Results; 11 individuals responded.
Oct. 28	Feedback Report on Webinar 8, Natural Gas Analysis, posted to pse.com/irp with PSE responses to 52 questions and comments.
November 2020	
Nov. 3	Feedback Report on Webinar 9, Electric Portfolio Modeling, Final Electric Power Prices, Electric Sensitivities, Inputs and Observations from Draft Results, posted to pse.com/irp with PSE responses to 71 questions and comments.
Nov. 4	Consultation Update on Webinar 8, Natural Gas Analysis, posted on pse.com/irp.
Nov. 10	Consultation Update on Webinar 9, Electric Portfolio Modeling, Final Electric Power Prices, Electric Sensitivities, Inputs and Observations from Draft Results, posted on pse.com/irp.
Nov. 13	Reminder emailed for Nov. 16 Webinar 10, CEAP, CEIP, EHEB, Delivery System and Grid Modernization. Meeting materials posted to pse.com/irp and Feedback Form opened.

Nov. 16	**Webinar 10** **Clean Energy Action Plan (CEAP), Clean Energy Implementation Plan (CEIP), Economic, Health and Environmental Benefits Assessment (EHEB), Delivery System and Grid Modernization Needs** **Stakeholder role:** Consult, Involve and Inform **Attendance:** 81 participants and the IRP project team. The IRP team delivered an overview of the 2021 IRP modeling process and timeline, the Clean Energy Action Plan and Clean Energy Implementation Plan; discussed the PSE's desire and stakeholders' request to give input on initial metrics for the Economic, Health and Environmental Benefits Assessments; gave a CETA rulemaking update; proposed a methodology for assessing current conditions; and presented the delivery system and grid modernization needs for the 10-year transmission and distribution plan. *Stakeholders gave feedback and suggestions on the Clean Energy Action Plan and the Clean Energy Implementation Plan; provided their thoughts and aspirations concerning the Economic, Health and Environmental Benefits Assessment of Current Conditions; and learned about PSE's 2021 delivery system and grid modernization needs.*
Nov. 17	Webinar 10 recording and chat posted to pse.com/irp.
Nov. 20	Email communication thanking stakeholders for participating in the November 16 meeting and asking stakeholders to provide feedback on the Economic, Health and Environmental Benefits Assessment of Current Conditions, along with specific input PSE is seeking to better inform draft and final IRP.
Nov. 30	Second reminder email asking stakeholders to provide feedback on the on the Economic, Health and Environmental Benefits Assessment of Current Conditions, along with specific input PSE is seeking to better inform draft and final IRP.
Nov. 30	Feedback Forms due for Webinar 10, CETA, CEAP, CEIP, EHEB, Delivery System and Grid Modernization; 10 individuals responded.
December 2020	
Dec. 7	Feedback Report on Meeting 10, CEAP, CEIP, EHEB, Delivery System and Grid Modernization, posted to pse.com/irp with PSE responses to 34

	questions and comments.
Dec. 8	Reminder emailed for Dec. 15 Webinar 11, Flexibility Analysis and Portfolio Draft Results. Meeting materials posted to pse.com/irp and Feedback Form opened.
Dec. 14	Consultation Update on Webinar 10, CETA, CEAP, CEIP, EHEB, Delivery System and Grid Modernization, posted to pse.com/irp.
Dec. 14	Second reminder email for Dec. 15 Webinar 11, Flexibility Analysis and Portfolio Draft Results.
Dec. 15	Additional reminder email for Dec 15 Webinar 11, Flexibility Analysis and Portfolio Draft Results. Link attached to webinar materials posted on pse.com/irp.
Dec. 15	**Webinar 11** **Flexibility Analysis and Portfolio Draft Results (electric & natural gas)** **Stakeholder role:** Consult and Involve **Attendance:** 88 individuals and the IRP project team. The meeting content included draft conservation results (electric and gas), draft electric and natural gas results, and flexibility analysis. *At this meeting, stakeholders had an opportunity to give feedback and suggestions on the flexibility analysis. Stakeholders provided their thoughts and aspirations concerning the portfolio draft results.*
Dec. 16	Webinar 11 recording and chat posted to pse.com/irp.
Dec. 28	Feedback Forms due for Meeting 11, Flexibility Analysis and Portfolio Draft Results; 7 individuals responded.
January 2021	
Jan. 4	Draft 2021 PSE Integrated Resource Plan filed with the Washington Utilities and Transportation Commission.
Jan. 11	Feedback Report on Webinar 11, Flexibility Analysis and Portfolio Draft Results, posted to pse.com/irp with 69 PSE responses to questions and comments.

Jan. 19	Consultation Update on Webinar 11, Flexibility Analysis and Portfolio Draft Results, posted to pse.com/irp.
February 2021	
Feb. 4	Reminder emailed for Dec. 15 Webinar 12, Electric Portfolio Draft Results, Delivery System and Grid Modernization Solutions, Flexibility Analysis Results and Economic, Health and Environmental Benefits Assessment. Agenda posted to pse.com/irp and Feedback Form opened.
Feb. 9	Second reminder emailed for Dec. 15 Webinar 12. All meeting materials posted to pse.com/irp.
Feb. 10	**Webinar 12** **Electric Portfolio Draft Results, Delivery System and Grid Modernization Solutions, Flexibility Analysis Results, and Economic, Health and Environmental Benefits Assessment** **Stakeholder role:** Consult and Inform **Attendance:** 75 and the IRP project team. The IRP team delivered an overview of the 2021 IRP portfolio draft results and the System Planning team presented on the 10-year plan. Flexibility results were reported, and a status update was provided for the Health and Environmental Benefits Assessment. PSE's desire and stakeholders' request for input on the updated metrics and indicators for the Economic, Health and Environmental Benefits Assessments was discussed. S*takeholders gave feedback and suggestions on the results presented; provided their thoughts and aspirations concerning the Economic, Health and Environmental Benefits Assessment of Current Conditions; and learned about PSE's 2021 delivery system and grid modernization needs.*
Feb. 11	Webinar 12 recording and chat posted to pse.com/irp.
Feb 17	Feedback Forms due for Webinar 12, Electric Portfolio Draft Results, Delivery System and Grid Modernization Solutions, Flexibility Analysis Results and Economic, Health and Environmental Benefits Assessment; 5 individuals responded.

Feb. 24	Feedback Report on Webinar 12, Electric Portfolio Draft Results, Delivery System and Grid Modernization Solutions, Flexibility Analysis Results and Economic, Health and Environmental Benefits Assessment, posted to pse.com/irp with 37 PSE responses to questions and comments.
Feb.23	Reminder emailed for February 26 WUTC Recessed Open Meeting with information for public comment sign-up. Meeting presentation filed with WUTC on February 19, 2021.
Feb. 25	Reminder emailed for March 5 Webinar 13, Market Risk Assessment, Stochastic Analysis, Preferred Portfolio, CEAP, CEIP Overview. Agenda posted to pse.com/irp and Feedback Form opened.
Feb. 26	**WUTC Recessed Open Meeting** PSE presented draft 2021 IRP results and results of ongoing analysis. Opportunity for Commissioners to ask questions and members of the public to express their views to the Commissioners, WUTC Staff and PSE staff during the public comment portion of the virtual meeting.
March 2021	
Mar. 3	Consultation Update on Webinar 12, Electric Portfolio Draft Results, Delivery System and Grid Modernization Solutions, Flexibility Analysis Results and Economic, Health and Environmental Benefits Assessment, posted to pse.com/irp.
Mar. 4	Second reminder emailed for March 5 Webinar 13, Market Risk Assessment, Stochastic Analysis, Preferred Portfolio, CEAP, Overview of the CEIP Implementation Plan and Public Participation.
Mar. 5	**Webinar 13** **Market Risk Assessment, Electric and Natural Gas Stochastic Analysis, Preferred Portfolio, Clean Energy Action Plan, Overview of the Clean Energy Implementation Plan and Public Participation** **Stakeholder role:** Inform and Consult **Attendance:** 75 and the IRP project team. In this webinar, PSE explained the market risk assessment and results of the stochastic analysis. The preferred portfolio was presented, along with

	background concerning the approach and methodology. An overview of the Clean Energy Implementation Plan was provided, along with the current status of the development of the CEIP Public Participation. *Stakeholders learned about PSE's market risk assessment, stochastic analysis and preferred portfolio, and shared their input on PSE's development to date on the Clean Energy Implementation Plan and Public Participation.*
Mar. 12	Feedback Forms due for Webinar 13, Market Risk Assessment, Stochastic Analysis, Preferred Portfolio, CEAP, Overview of the CEIP Implementation Plan and Public Participation; 12 individuals responded.
Mar. 19	Feedback Report on Webinar 13, Market Risk Assessment, Stochastic Analysis, Preferred Portfolio, CEAP, Overview of the CEIP Implementation Plan and Public Participation, posted to pse.com/irp with 40 PSE responses to questions and comments.
Mar. 23	Consultation Update on Webinar 13, Market Risk Assessment, Stochastic Analysis, Preferred Portfolio, CEAP, Overview of the CEIP Implementation Plan and Public Participation, posted to pse.com/irp.

7. SENSITIVITY PRIORITIZATION SURVEY RESULTS

To gain greater understanding of stakeholder priorities for the IRP, PSE invited stakeholders to participate in selecting electric sensitivities via a Sensitivity Prioritization Survey fielded from October 19 to October 27. The survey link was distributed via email and made available online.

Sensitivities are important for determining the reasonableness of the portfolio. PSE uses a mathematical model that optimizes the portfolio to the lowest reasonable cost for a given set of assumptions, but there are many possible futures. Sensitivities make it possible to analyze how different regulations or conditions would impact the mix of resources. For example: Does the mix of new resources change? Does the portfolio cost change? Do portfolio emissions change?

In addition to prioritizing various sensitivity analyses, the survey gathered feedback on two specific sensitivity assumptions: 1) which alternative fuel they thought would be most interesting to model for peaking plants, hydrogen or biodiesel, and 2) which methodology to use to model temperature changes into the future; three options were offered and were discussed at the October 20 webinar.

The survey results were reported to stakeholders in the Webinar 9 Consultation Update on November 10, 2020. Over 140 individuals participated. Figure A-1 summarizes the sensitivity prioritization results and how the results were applied to the 2021 IRP modeling process. PSE completed 34 sensitivities for this IRP. Additional sensitivities were added throughout the portfolio modeling process. As a result, Figure A-1 only includes the sensitivities developed at the time of the survey. Please refer to Chapter 5, Key Assumptions, for the complete list of sensitivities included in the 2021 IRP.

Figure A-1: Sensitivity Prioritization Results and Application

Rank	Votes	Survey Number	Sensitivity Name	Sensitivity Description	Application
1	132	35	EV battery to grid	Include an electric vehicle-to-grid resource as a generic resource	For IRP modeling, electric vehicle-to-grid resource will have similar attributes to generic distributed storage resources. A forecast of distributed storage resources has been included as a 'must-take' resource in all portfolio scenarios and sensitivities. As a result, PSE decided not to model this as a stand-alone sensitivity.
2	129	21	Use AR5 to model upstream emissions	Quantify upstream emissions using AR5 methodology rather than AR4 methodology	Modeled as Sensitivity K.
3	126	14	6-yr ramp rate	Reduce the ramp rate for conservation measures from 10 years to 6 years	Modeled as Sensitivity F.
4	126	32	Add 185 MW Colstrip Trans-mission	Model additional transmission from the Colstrip substation to PSE service territory	PSE presented an upper transmission capacity limit of 565 MW to Montana in the June 30 and Oct. 20 Webinars. At that time, these values represented the most-likely transmission capacity available to PSE in the region. Since then, negotiations for sale of PSE's portion of Colstrip Unit 4 and its accompanying transmission have ceased, such that PSE can now model 750 MW of available transmission capacity to Montana for all scenarios and sensitivities, making this sensitivity no longer necessary.
5	124	17	Social discount rate for DSR	Reduce the discount rate of demand-side resources from 6.8% to 2.5%	Modeled as Sensitivity H.

Rank	Votes	Survey Number	Sensitivity Name	Sensitivity Description	Application
6	122	39	SCGHG only (dispatch cost)	Model the social cost of greenhouse gases as a dispatch cost in the absence of other CETA targets	Sensitivity S models the SCGHG in the absence of other CETA targets. However, the SCGHG is modeled as a fixed cost adder to align with SCGHG accounting used in Scenario 1, Mid Economic Conditions. The SCGHG will be modeled as a dispatch cost in sensitivities I and J.
7	121	36	Time-of-use pricing	Include time-of-use pricing for conservation and demand response programs	Critical Peak Pricing (CPP) is an alternative rate, and it is modeled as a demand response program. PSE is developing a plan for other alternative rates that will be filed with WUTC later in 2021, However, further research determined modeling constraints do not allow for optimization modeling of time-of-use pricing.
8	121	41	Private solar input testing	Model inclusion of subsidy for solar and electric storage resources	This sensitivity is not explicitly modeled for the 2021 IRP; however, results from Sensitivity C, Distributed Transmission/Build Constraints at Tier 2, will shed light on costs and benefits associated with higher adoption of distributed solar PV resources.
9	120	42	Equity-focused portfolio	A minimum of 50% of new resources must be located in WA state and expansion of community solar programs	In the draft IRP portfolio results, more than 50% of resources are located in WA state in all scenarios and sensitivities. Also, all include increased amounts of conservation and demand response. Given that the Mid Scenario portfolio has already selected conservation in the upper limits of the supply curve, PSE cannot add 150% of cost-effective conservation to the portfolio. PSE has contacted the stakeholder and will work with them to re-define this sensitivity.
10	116	46	Virtual Power Plants (VPP)	VPPs are used to manage distributed energy resources	Virtual power plants are included in a comprehensive discussion of grid modernization efforts in Appendix M along with other components of grid modernization.

Rank	Votes	Survey Number	Sensitivity Name	Sensitivity Description	Application
11	24	26	100% renewable resources by 2030	More aggressive renewable resource adoption; all gas plants retired by 2030	Modeled as Sensitivity N.
12	22	28	Carbon reduction	All natural gas plants retired by 2045 and run-time limits are imposed to meet carbon emission targets	Modeled as sensitivity O; however, run-time limits were not imposed prior to 2045. Instead, alternative compliance measures were used to reach carbon neutrality.
13	18	18	High SCGHG	Higher social cost of greenhouse gases than specified by CETA	Given that CETA's renewable requirements are already pushing the portfolio builds, PSE decided to model the CO_2 tax portfolio that received fewer votes.
14	17	9	"Highly Distributed" Trans-mission/ build constraints, Tier 1	Model a significantly transmission constrained system	Sensitivity C models the Tier 2 transmission constraints level, and Sensitivity D models time-delayed transmission. PSE feels these two sensitivities will give enough information to help inform the resource plan, but if time allows, this may be included in the final IRP.
15	13	11	"Highly Centralized" Trans-mission/ build constraints, Tier 3	Model a lightly transmission constrained system	Sensitivity C models the Tier 2 transmission level and Sensitivity D models the time-delayed transmission. PSE feels these two sensitivities will give enough information to help inform the resource plan, but if time allows, this may be included in the final IRP.
16	13	12	Trans-mission/ build constraints, time-delayed (option 2)	Model an expanding transmission system over time	Modeled as Sensitivity D.

Rank	Votes	Survey Number	Sensitivity Name	Sensitivity Description	Application
17	13	47	Alternative fuel #2 for peakers	Model a must-run sensitivity of either biodiesel OR hydrogen as an alternative fuel for peaker plants. This sensitivity is a vote to model BOTH biodiesel and hydrogen.	Sensitivity M models biodiesel as an alternative fuel source for new peaker plants. PSE did not have sufficient hydrogen pricing at the time of this IRP to model hydrogen as an alternative fuel source.
18	12	20	Mid economic conditions with SCGHG as dispatch cost in electric price and portfolio model	Model the social cost of greenhouse gases as a dispatch cost in both the power price and portfolio models	Modeled as sensitivity J.
19	12	33	Fuel switching from electric to gas	Decreases demand in electric portfolio and increases demand in gas portfolio	Given low interest, this will not be modeled in the IRP.
20	11	5	Mid economic conditions plus increased renewable build	Economic conditions and power price forecast adjusted to model 100% renewable energy goal in Oregon	Given low interest, this will not be modeled in the IRP.
21	11	16	Non-energy Impacts	Increase the value of non-energy impacts from adoption of conservation and demand response measures	Modeled as Sensitivity G. Given that non-energy impacts are part of CETA, PSE has prioritized this sensitivity.

Rank	Votes	Survey Number	Sensitivity Name	Sensitivity Description	Application
22	10	24	SCGHG as a tax in WA, OR, CA	Models the social cost of greenhouse gases plus a regional CO_2 tax of $15/ton (adjusted for inflation over time) in WA, OR and CA	Sensitivity L models impacts associated with carbon pricing across all states in the WECC. During the 2017 IRP, PSE modeled a carbon tax in Washington only. This led carbon emissions to shift to other states in the western interconnect and increase WECC-wide emissions. PSE recommends modeling the CO_2 tax as a federal tax across all states to prevent this shift of dispatch and emissions.
23	10	37	Holistic conser-vation approach	Additional information needed to complete this sensitivity	Given low interest, this will not be modeled in the IRP.
24	8	22	Mid economic conditions with SCGHG as a fixed cost plus a federal CO_2 tax	Models the social cost of greenhouse gases plus a federal CO_2 tax	Modeled as Sensitivity L.
25	6	6	Low demand with mid gas prices	Low demand in both power price and demand forecasts and “most-likely” gas price forecast	Given low interest, this will not be modeled in the IRP.
26	6	15	8-yr ramp rate	Reduces the conservation measures ramp from 10 years to 8 years	Given low interest, this will not be modeled in the IRP.
27	6	44	Must-take Battery or Pumped Hydro Storage and Demand Response	Must-take DR and Battery storage before other builds are optimized. Resource additions are constrained to the CETA 2% cost cap, must build demand response and battery storage before gas plants	Sensitivity P models the must-take energy storage. This sensitivity can be compared to the 2% of annual revenue requirement. Sensitivity U looks at the resource plan as compared to the 2% threshold and adjusts the portfolio as necessary.

Rank	Votes	Survey Number	Sensitivity Name	Sensitivity Description	Application
28	5	4	Low demand with a very high gas price	Mix of low demand and very high gas price forecasts	Given low interest, this will not be modeled in the IRP.
29	5	45	2% cost threshold, renewable over-generation test	Resource additions are constrained to the CETA 2% cost cap, PSE market sales are prohibited	Sensitivity A models renewable overgeneration. This sensitivity can be compared to the 2% of annual revenue requirement. Sensitivity U looks at the resource plan as compared to the 2% threshold and adjusts the portfolio as necessary.
30	2	23	High economic conditions with SCGHG as a dispatch cost in electric prices and portfolio model	The social cost of greenhouse gases as a dispatch cost, with higher-than-expected power price, demand and gas price forecasts	Given low interest, this will not be modeled in the IRP.
31	2	34	High economic conditions with SCGHG as a dispatch cost in portfolio model only	The social cost of greenhouse gases as a dispatch cost, under higher-than-expected power price, demand and gas price forecasts	Given low interest, this will not be modeled in the IRP.
32	2	40	Tweaks to resource cost assump-tions	Alter resource cost assumptions for generic resources (further detail forthcoming from WUTC staff)	Given low interest, this will not be modeled in the IRP.

Figure A-2 provides the results of the alternative fuel poll.

Figure A-2: Alternative Fuels Poll Results

Rank	Alternate Fuel Option	Number of Responses
1	Hydrogen	140
2	Biodiesel	16

Figure A-3 provides the results of the temperature sensitivity methodology poll.

Figure A-3: Temperature Sensitivity Methodology Poll Results

Rank	Temperature Methodology	Number of Responses
1	3. Northwest Power and Conservation Council's climate model temperature assumption	93
2	2. Temperature normal based on most recent 15 years of temperature data	43
3	1. Trended normal based on historical observed trends (trended normal analysis completed by Itron Inc., Appendix L)	20

8. MEETING DOCUMENTATION

The materials for each Webinar completed for the 2021 Electric and Natural Gas IRPs are included here and posted on pse.com/irp. Presentation materials for the WUTC Recessed Open Meeting on the draft IRP filing are also included.

The contents for each meeting includes:

- **Agenda**
- **Presentation Materials**
- **Excel Data Spreadsheets:** When provided.
- **Webinar Chat Box Transcript/Q&A Log**: A verbatim report of the questions submitted during the webinar and a record of meeting participants. Answers were usually provided verbally by IRP staff during the webinar in order of relevance to the topic being discussed. Questions on other topics were answered at the end of the webinar. Visit the project website to view a recording of the webinar and to hear PSE staff responses. Timestamps are available for tracking.
- **Feedback Report**: Feedback Reports were posted to pse.com/irp two weeks after each meeting. These reports included all input, questions and comments received from stakeholders on the webinar topic and written PSE responses to all feedback.
- **Additional Feedback:** When received by correspondence.
- **Consultation Update**: Consultation Updates were posted to pse.com/irp three weeks after each meeting. These summaries of the consultation activity (follow-up calls and meetings, etc.) and feedback received reported on how PSE responded to feedback and documented how PSE incorporated the feedback into the IRP.

Webinar 1, May 28, 2020

Generic Resource Assumptions

Webinar #1: Generic Resource Assumptions
May 28, 2020 from 1:30 p.m. to 4:00 p.m. PST

Virtual webinar link: https://attendee.gotowebinar.com/register/4112488354960834319

Webinar ID: 537-409-243

Call-in telephone number (audio only): 1-877-309-2074

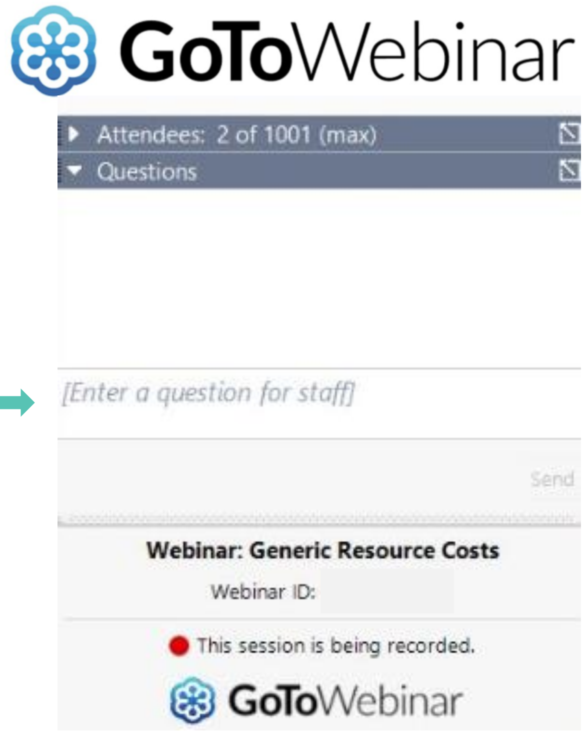
Topic	Lead
Welcome **Agenda review**	EnviroIssues
Safety moment **Team introductions**	Irena Netik, Director, Energy Supply Planning & Analytics
Public participation approach	EnviroIssues
An introduction to the 2021 IRP	Irena Netik, Director, Energy Supply Planning & Analytics
IRP models overview	Elizabeth Hossner, Manager, Resource Planning, PSE
Electric generic resource costs presentation • Generic resource operating characteristics • Review of the generic resource costs • PSE recommended costs • Stakeholders share feedback on generic resource costs	Elizabeth Hossner, Manager, Resource Planning PSE
Question & answer • Webinar participant questions	Facilitated by EnviroIssues
Wrap up • Thank you’s • What’s coming next	EnviroIssues

2021 IRP Webinar #1: Generic Resource Assumptions

Planning Assumptions & Resource Alternatives
Electric Portfolio Model

May 28, 2020

Welcome to the webinar and thank you for participating!



How to ask a question or submit a comment

- Expand the Questions window on your control panel
- Type in your question
- Staff are on hand to keep track of questions on generic resource costs
- We will also take a Q&A break at several points during the presentation
- If there's more time available at the end of the presentation, we'll take more questions

Virtual webinar link:
https://attendee.gotowebinar.com/register/4112488354960834319

Webinar ID: 537-409-243

Call-in telephone number: 1-877-309-2074

Agenda

- Safety moment
- PSE IRP team introduction
- Public participation plan overview
- Introduction to the 2021 IRP
- Electric IRP models overview
- Electric generic resource assumptions

Safety moment: Call 811 before you dig

Dial 811 at least **two full business days** (not including the day you call) before you plan to dig, no matter the size of your project. It's not only smart, **it's the law**.

- It's important to have the locations of underground utilities verified and clearly marked
- Striking a natural gas or electric line may result in service disruptions, bodily harm, fines and/or repair costs

pse.com/pages/know-whats-below

PSE IRP Team

Irena Netik
Director, Energy Supply Planning & Analytics

Elizabeth Hossner
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Charles Inman
Associate Energy Resources Planning Analyst

Public participation approach

Public participation in the 2021 IRP

Tools for public participation

To keep you informed...

- Website postings
- Email notifications
- Briefings
- Feedback Reports
- Consultation Updates
- E-Newsletters
- Topical fact sheets

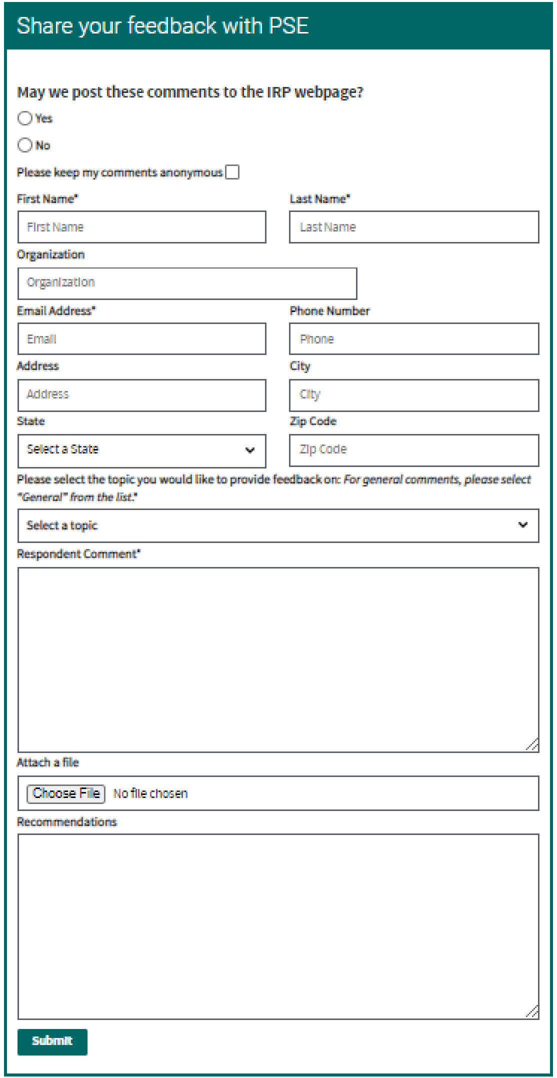
To seek your thoughts, ideas, concerns...

- Stakeholder interviews - *completed*
- Feedback webinars
- Online meetings
- Feedback forms

Feedback Form

- An important way to share your input
- Available on the website 24/7
- Comments, questions and data can be submitted throughout the year, but timely feedback supports the technical process
- Please submit your Feedback Form <u>within a week of the meeting topic</u>

Feedback Form → **Feedback Report** → **Consultation Update**


Share your feedback with PSE

May we post these comments to the IRP webpage?

- Yes
- No

Please keep my comments anonymous

First Name* — First Name

Last Name* — Last Name

Organization — Organization

Email Address* — Email

Phone Number — Phone

Address — Address

City — City

State — Select a State

Zip Code — Zip Code

Please select the topic you would like to provide feedback on: *For general comments, please select "General" from the list.*

Select a topic

Respondent Comment*

Attach a file

Choose File No file chosen

Recommendations

Submit

Feedback cycle

Action	Timing
Stakeholders can submit questions and feedback via the Feedback Form.	**Anytime, 24/7 online access**
PSE will share the meeting agenda, presentation slides and any supporting materials on the website.	**One week before each meeting**
A recording of the webinar and the transcript of the chat will be posted to the website so those who were unable to attend can review.	**One day after each meeting**
Feedback Forms related to the specific meeting topic are due.	**One week after each meeting**
A Feedback Report of all comments collected from the Feedback Form, along with PSE's responses, will be shared with stakeholders via the website.	**Two weeks after each meeting**
A Consultation Update, where PSE demonstrates how stakeholder feedback was applied, will be posted to the website.	**Three weeks after each meeting**

An introduction to the 2021 IRP

What has happened since the 2019 IRP process?

- The 2019 IRP resulted in a Progress Report filed in November 2019
- In December 2019, PSE hosted a webinar comparing different methods for applying social cost of carbon
- The 2021 IRP Work Plan, including a Public Participation Plan, were filed in April 2020 and recently updated (see Docket No: UE-200304 and UG-200305)
- A new website pse.com/irp has launched and provides a robust platform for engagement
- The Washington Utilities and Transportation Commission (WUTC) is progressing on several rulemakings:
  - Integrated Resource Planning Rulemaking – UE-190698
  - Clean Energy Implementation Plans and Compliance with the Clean Energy Transportation Act Rulemaking, UE-191023
  - Purchase of Electricity Rulemaking – UE-190837

2021 Electric IRP Priorities

The IRP is a long-term forecast of demand side resources and supply side resources that appear to be cost effective to meet the growing needs of our customers.

The study period for electric planning is 2022-2045.

The 2021 IRP will

- Transition to a carbon free electricity supply by 2045.
- Remove coal generation from the portfolio of resources.
- Reinforce our commitment to reliability as we transition to a cleaner electricity supply.

CETA timeline

- **2025:** Elimination of coal-fired resources from electric power supply
- **2030:** Carbon neutral energy supply
  - 80% non-emitting and renewable resources
  - 20% can be met with alternative compliance
- **2045:** 100 percent non-emitting electricity supply

2021 IRP modeling process

The 2021 IRP will follow a 6-step process for analysis:

1. Establish peak capacity, energy and renewable energy need
2. Determine planning assumptions and identify supply-side and demand-side resource alternatives
3. Analyze scenarios and sensitivities using deterministic and stochastic risk analysis
4. Analyze results
5. Develop resource plan
6. Develop 10-year Clean Energy Action Plan

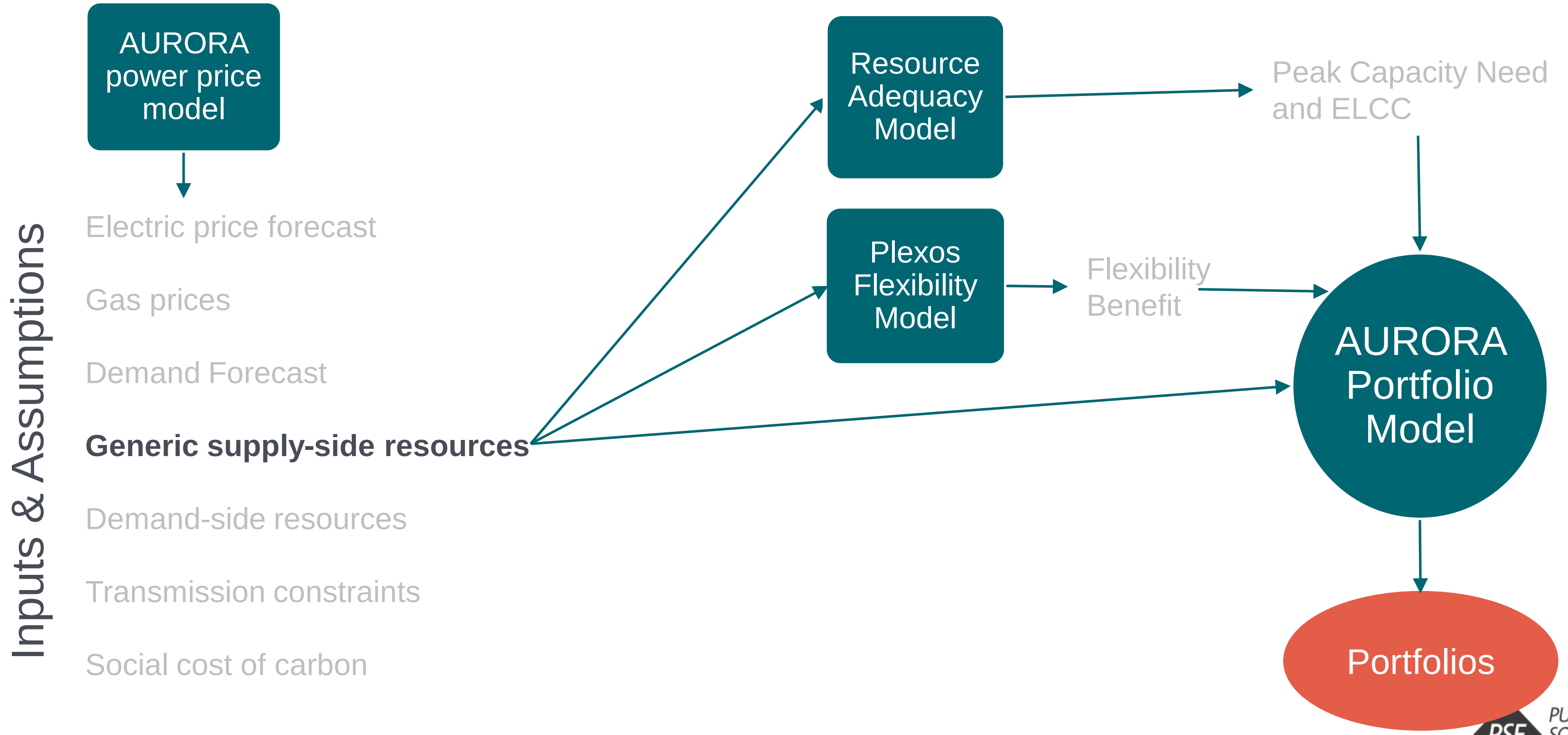
2021 IRP process timeline

Meeting dates are available on pse.com/irp and will be updated throughout the process. This is a tentative timeline subject to revision.

PUGET SOUND ENERGY

IRP modeling process

Electric IRP Models



Electric generic resource assumptions

Participation Objective

- Stakeholders share input on generic resource costs for the electric portfolio

The purpose of generic resources

- What are the generic resources used for?
  - Generic resources are used for planning purposes only. They are a stand-in to build portfolios of potential new resources
  - Generic Resources give us an idea of what new resources might cost in the future and how different resources can fit into PSE’s needs
  - During an acquisition process, the generic resources are replaced with actual resources

We heard you…

- As part of the 2019 IRP process, PSE received feedback from stakeholders about generic resource assumptions. As a result, PSE has researched and revised aspects of our generic resource assumptions.

- What we've changed:
  - Greater reliance on publicly available data sources
  - New renewable resource options
  - Generating resource capital costs have been updated
  - Aspects of operations and maintenance costs have been updated

- What we've retained:
  - PSE will continue to use the HDR report from the 2019 IRP for the operating characteristics of thermal and energy storage resources

- Data available online as an excel spreadsheet that provides all the costs that we will review in the slides. This is all the data that PSE has collected on capital costs, fixed costs, and variable costs.
  - Generic Resource Assumptions Workbook Summary

Generic resource assumptions

Generic resource assumptions are made up of different components

1. Operating characteristics
2. Ongoing costs for fuel and maintenance
3. Capital cost to build the plant

1 Operating characteristics – Thermal Plants

	CCCT	Frame Peaker	Recip Peaker
Nameplate (MW)	336	225	18.7
Heat Rate (Btu/kWh)	6,624	9,904	8,445
Min up (minutes)	60	60	35
Min Down (minutes)	15	15	15
Ramp Rate (MW/minute)	40	40	16
Start time (warm, minutes)	60	21	5
Forced outage rate (%)	3.88	2.38	3.30
Min capacity (%)	38	30	30

Where does this data go?

This data goes to the AURORA portfolio model, Plexos flexibility model and the Resource Adequacy Model

1 Operating characteristics – Energy Storage

	Pumped Storage Hydro	Battery
Nameplate (MW)	300	25
Round Trip Efficiency (%)	80	87
Discharge rate (hours)	8	4
Degradation (%/yr)	near zero	near zero
Operating Range (%)	37.5 - 100	2 - 100
Forced outage rate (%)	1	2

Where does this data go?

This data goes to the AURORA portfolio model, Plexos flexibility model and the Resource Adequacy Model

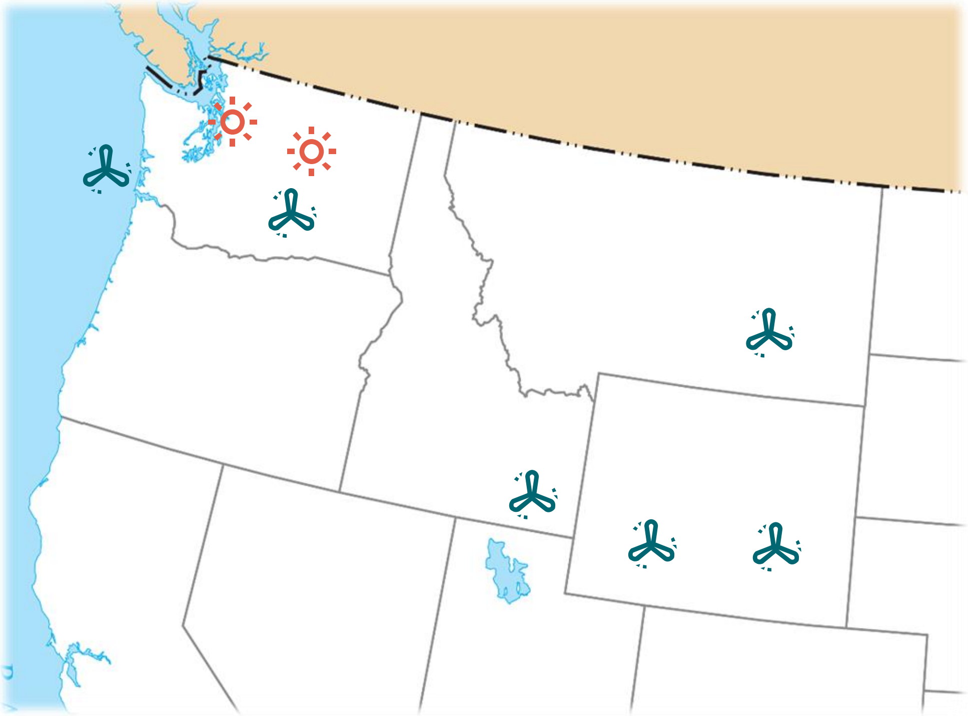
PSE PUGET SOUND ENERGY

1 Operating characteristics – Renewable resources

Annual Average Capacity Factor (%)	
Washington Wind	28.6
Montana Wind	49.1
☆Wyoming-East Wind	48.2
☆Wyoming-West Wind	39.4
☆Idaho Wind	32.3
Offshore Wind	34.8
☆Washington-West Distributed Solar	12.9
Washington-East Utility Solar	27.7

☆Indicates new resource added for 2021 IRP

Capacity factor data is from NREL database and DNV GL. This data reflects the total energy not the peak capacity



Location is a key driver of renewable resource characteristics

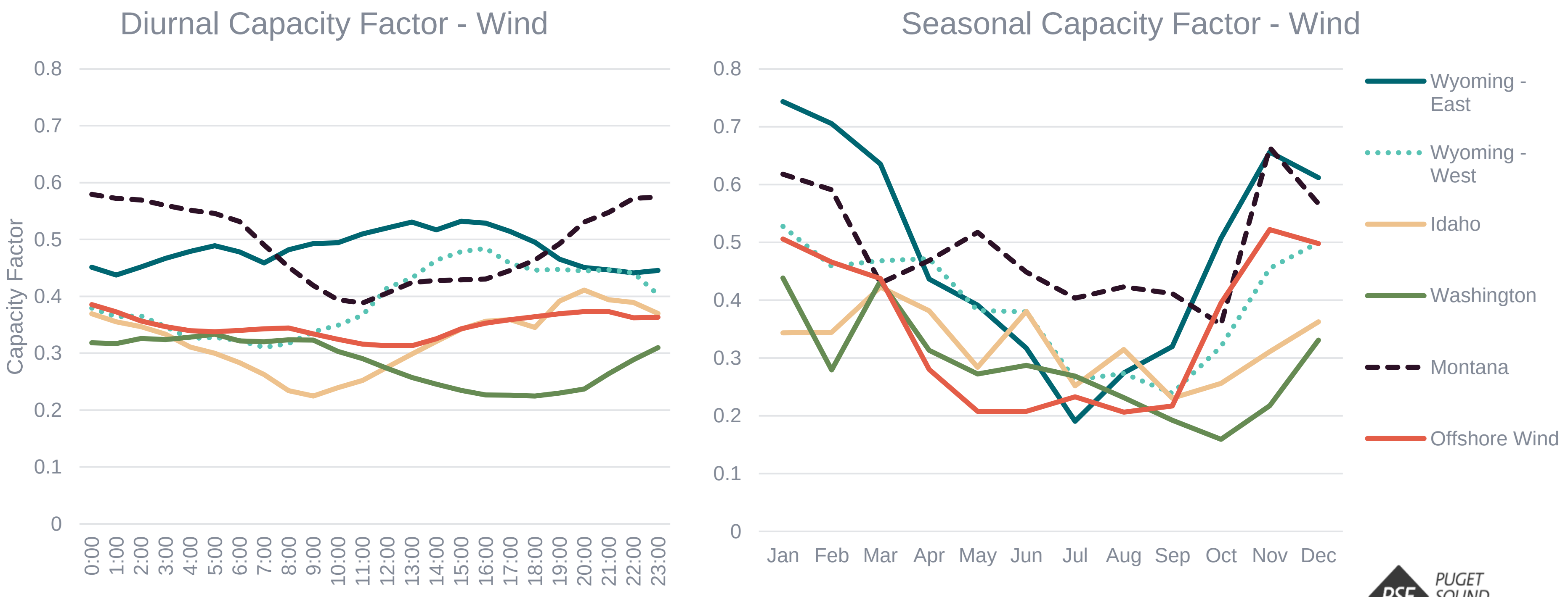
PSE PUGET SOUND ENERGY

1 Operating characteristics – Renewable resources

- Renewable resource data sources include:
  - NREL (WY Wind, ID Wind and W WA Solar)
  - DNV GL (WA Wind, MT Wind and E WA Solar)

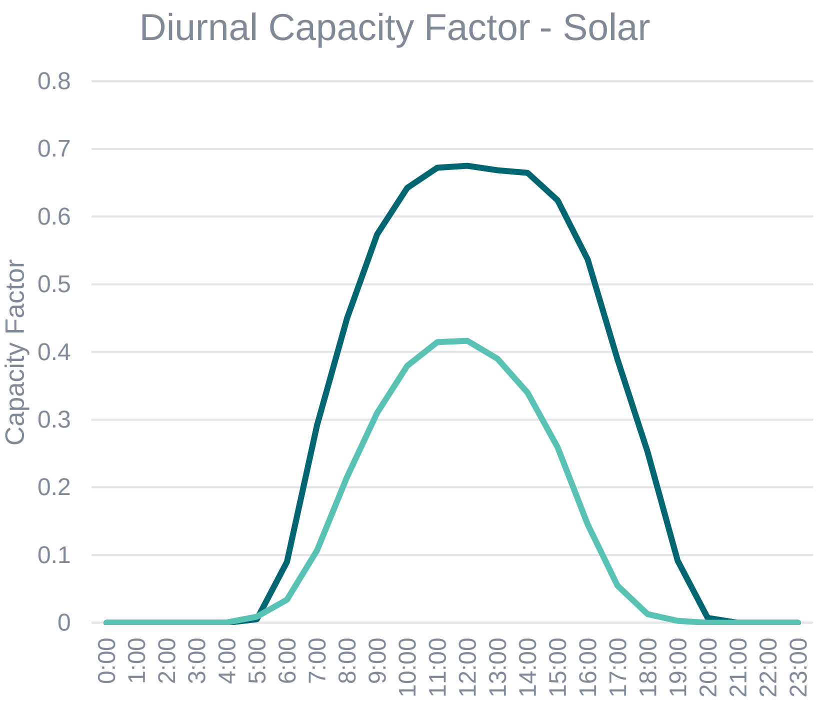
- Deterministic renewable resource shapes were selected as the most-representative annual capacity factor (P50) value out of 250 draws
  - The 250 draws are used in the resource adequacy model and in the stochastic model.
  - The most-representative shape is used in the deterministic portfolio model.

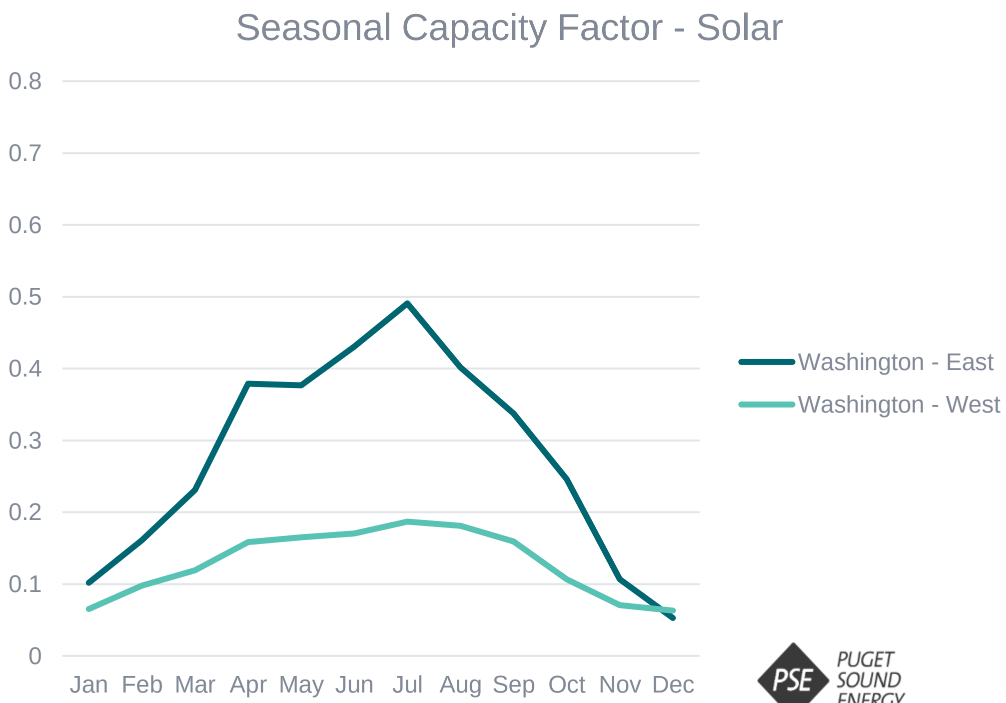
Operating characteristics – Renewable resources - Wind



Renewable resource capacity is often a function of both time of day and time of year

1 Operating characteristics – Renewable resources - Solar





WEBINAR 1 - 5/28/20 - 30

Renewable resource capacity is often a function of both time of day and time of year

PUGET SOUND ENERGY

2 Ongoing costs

Ongoing costs are divided into two categories

1. **Variable costs** – these are costs that are dependent on the energy produced by the plant

2. **Fixed costs** – these are costs that must be paid regardless if the plant runs or not

PSE PUGET SOUND ENERGY

2

Ongoing Costs – Variable – Operations and maintenance costs

- Includes fuel, waste disposal and other costs dependent upon the quantity of energy produced
- Renewable resources typically have very low to zero Variable Operations and Maintenance costs
- Publically available data sources have been compiled for comparison and will be presented for discussion shortly

Where does this data go?

This data goes to the AURORA portfolio model, and the Plexos flexibility model

PUGET SOUND ENERGY

2 Ongoing Costs – Variable – Start-up Costs

- Thermal resources require additional resources during start-up procedures as compared to normal operation
- PSE assumes a start-up cost of **$6,502 per start** for frame peaker generators.
  - Source: 2019 HDR report on Generic Resource Costs, in 2018 US dollars

Where does this data go?

This data goes to the AURORA portfolio model, and the Plexos flexibility model

2 Ongoing Costs – Fixed – Operations and Maintenance

- Includes annual maintenance, labor, materials, site leasing, gas pipeline capacity cost and other recurring costs not dependent on quantity of energy produced
- Publically available data sources have been compiled for comparison and will be presented for discussion shortly

2

Ongoing Costs – Gas Transport and Transmission

- **Gas Transport Costs**
  - Gas transport costs are costs associated with moving gas from the source to the generator
  - Gas transport cost values and assumptions will be discussed with the natural gas resource alternatives that will be released by June 30, 2020

- **Transmission Costs**
  - Transmission costs are costs associated with moving power from a generator onto PSE's distribution network
  - Transmission cost values and assumptions will be discussed during the Transmission Constraints Webinar to be held on June 30, 2020

3 Capital Costs

- Capital costs represent the upfront cost to construct a new generating resource.
  - PSE has elected to represent capital costs as an ‘Overnight Capital Cost’ which includes Engineering, Procurement and Construction costs plus Financing costs for ‘overnight’ construction of a project
  - What is not included in Overnight Capital Costs?
    - Extra costs incurred during construction such as AFUDC (Allowance for Funds During Construction)
    - The cost of interconnection – the cost of the substation along with the transmission lines or gas pipelines to connect to the system

- The Northwest Power and Conservation Council has compiled capital, VOM and FOM costs for their Generic Resource Reference Plants for the updated Power Plan. PSE has utilized this dataset to present a range of resource costs
- Data sources include:

National Renewable Energy Laboratory (NREL)	U.S. Energy Information Administration (EIA)	Lazard
Northwest Power and Conservation Council (NPCC)	Lawrence Berkeley National Laboratory (LBNL)	Regional IRPs

3 PSE recommended costs

- PSE recommended costs are the average of the costs from the different resources reviewed.
  - Each resource vintage year for averaging varies depending on the most available data

- PSE applied the EIA Annual Energy Outlook (AEO) cost curves for future years to the recommended costs

- All costs in 2016 real dollars

- Additional information and charts provided in Excel file

- All capital costs are overnight costs only, they do not include AFUDC or interconnection costs

PSE recommended costs – CCCT, F-Class

Data Source (2019 Vintage, 2016 U.S. Dollars)	Overnight Capital Cost ($/kW)	Fixed Operating and Maintenance ($/kW-yr)	Variable Operating and Maintenance ($/MWh)
GTW (+ 20% owner's cost) 1x1 GE 7F.05 - 372MW	812	--	--
2019 Idaho Power 1x1 300MW F-Class Frame	1,138	--	--
2019 Avista draft 1x1 413MW GE 7F.06 Adv CCCT	918	--	3.62
2019 Avista draft 1x1 480MW SGT6-5000F Adv CCCT	849	12.56	3.62
2019 Avista draft 1x1 424MW MHI-501F1 Adv CCCT	899	12.56	3.38
2019 Avista draft 1x1 308MW GE 7F.04 Conv CCCT	987	13.53	2.90
Lazard High	1,235	12.82	3.56
Lazard Low	665	10.45	2.85
EIA AEO Generic Conv CCCT - 702 MW F-class	965	10.95	3.49
NREL ATB - average of adv. H-class and conv. F-class	878	10.38	2.72
PSE 2019 IRP HDR 1x1 348MW F-Class Frame	1,006	13.68	2.44
Average (PSE 2021 IRP Reference Plant)	**941**	**12.12**	**3.18**

PSE recommended costs – Frame Peaker, F-Class

Data Source (2019 Vintage, 2016 U.S. Dollars)	Overnight Capital Cost ($/kW)	Fixed Operating and Maintenance ($/kW-yr)	Variable Operating and Maintenance ($/MWh)
GTW GE 7F.05 - 239 MW Frame (+20% owners cost)	497	--	--
Lazard - Generic Gas Peaker - Frame	665	5.22	4.51
EIA 2019 AEO - Adv CT - 1x237MW F-class Frame	668	6.77	10.65
NREL ATB - average of H-class (frame) and LM-6000 (aero)	881	12.02	7.02
PSE 2019 IRP HDR 1x237 F-Class Frame	625	3.80	6.34
Average (PSE 2021 IRP Reference Plant)	**667**	**6.95**	**7.12**

PSE recommended costs – Recip Peaker

Data Source (2018 Vintage, 2016 U.S. Dollars)	Overnight Capital Cost ($/kW)	Fixed Operating and Maintenance ($/kW-yr)	Variable Operating and Maintenance ($/MWh)
Wartsila 220MW recip	1,061	--	--
Seventh Plan 12x 18V50SG 220MW Wartsila Recip	1,382	10.63	9.57
Seventh Plan MTA 12x 18V50SG 220MW Wartsila Recip (Low)	1,250	--	--
Seventh Plan MTA 12x 18V50SG 220MW Wartsila Recip (High)	1,450	--	--
2019 PGE 6x18MW Wartsila 18V50SG Recip	1,222	4.98	5.24
2019 PGE 6x18MW Wartsila 18V50SG Recip - Low Est.	893	--	--
2019 PGE 6x18MW Wartsila 18V50SG Recip - High Est.	1,552	--	--
2019 NorthWestern draft 2019 IRP 1x18MW Recip	1,771	--	--
E3 Gen WECC Recip	1,305	--	--
2019 PSE pre-IRP HDR 12x18MW Recip	943	3.61	5.12
PSE 2019 IRP HDR 12x18MW Recip - Dual Fuel	1,081	3.98	5.60
Average (PSE 2021 IRP Reference Plant)	**1,265**	**5.80**	**6.38**

PSE recommended costs – Residential Solar

Data Source (2018 Vintage, 2016 U.S. Dollars)	Overnight Capital Cost ($/kW)	Fixed Operating and Maintenance ($/kW-yr)	Variable Operating and Maintenance ($/MWh)
Lazard High (AC)	3,141	--	--
Lazard Low (AC)	2,851	--	--
NREL ATB 2019 Mid (AC)	3,373	--	--
NREL ATB 2018 Mid (AC)	3,271	--	--
NREL US PV Benchmark 2018 (AC)	3,000	--	--
E3 2019 (AC)	3,141	--	--
Average (PSE 2021 IRP Reference Plant)	**3,129**	**--**	**--**

This is a new resource added for 2021 IRP, so there is no 2019 IRP comparison

PSE recommended costs – Utility Solar

Data Source (2018 Vintage, 2016 U.S. Dollars)	**Overnight Capital Cost ($/kW)**	**Fixed Operating and Maintenance ($/kW-yr)**	**Variable Operating and Maintenance ($/MWh)**
Lazard High (AC)	1,208	--	--
Lazard Low (AC)	918	--	--
NREL ATB 2019 Mid (AC)	1,425	17.64	0.00
NREL ATB 2018 Mid (AC)	1,278	11.04	0.00
NREL US PV Benchmark 2018 (AC)	1,420	--	--
E3 2019 (AC)	1,401	--	--
PGE 2016 IRP Update (AC)	1,471	8.57	--
PGE 2019 IRP (AC)	1,459	21.16	--
Avista 2017 IRP (AC)	1,119	20.58	--
Idaho Power 2017 IRP (AC)	1,493	--	--
Mid-Term, Low (AC)	1,350	--	--
Mid-Term, High (AC)	1,500	--	--
PSE 2019 IRP HDR 100 MW (AC)	1,422	21.16	--
Average (PSE 2021 IRP Reference Plant)	**1,347**	**15.77**	**0.00**

PSE recommended costs – Onshore Wind

Data Source (2018 Vintage, 2016 U.S. Dollars)	Overnight Capital Cost ($/kW)	Fixed Operating and Maintenance ($/kW-yr)	Variable Operating and Maintenance ($/MWh)
PGE 2016 IRP Update	1,425	43.37	0.84
Avista 2017 IRP	1,737	--	--
NWPCC Mid-Term - Low	1,500	--	--
NWPCC Mid-Term - High	1,700	--	--
NREL ATB 2019 Mid	1,556	42.47	0.00
Lazard High	1,498	35.27	0.00
Lazard Low	1,111	27.06	0.00
LBNL 2018	1,419	--	--
E3 2019	1,594	--	--
PSE 2019 IRP HDR-WA	1,452	35.75	--
Average (PSE 2021 IRP Reference Plant)	**1,499**	**36.79**	**0.00**

Public sources do not identify different capital cost by region, so one cost will be used for each onshore wind option and the transmission costs will vary depending on location

PSE recommended costs – Offshore Wind

Data Source (2018 Vintage, 2016 U.S. Dollars)	Overnight Capital Cost ($/kW)	Fixed Operating and Maintenance ($/kW-yr)	Variable Operating and Maintenance ($/MWh)
NREL ATB 2019 TRG6, Depth: 144m, Landfall: 38km, Floating	4,211	83.50	--
PSE 2019 IRP, Depth: 18 - 121m, Landfall: 5 - 24km, Floating	5,730	115.96	--
Average (PSE 2021 IRP Reference Plant)	**4,971**	**99.73**	**0.00**

PSE recommended costs – Pumped Storage

Data Source (2020 Vintage, 2016 U.S. Dollars)	Overnight Capital Cost ($/kW)	Fixed Operating and Maintenance ($/kW-yr)	Variable Operating and Maintenance ($/MWh)
Swan Lake - 393 MW/9hr, COD 2025	2,093	--	--
Badger Mountain - 300 MW/8hr, COD 2025	2,137	--	--
2019 PAC Draft IRP - 400MW/9.5hr, COD 2025	2,991	16.20	--
2019 Avista Draft IRP - 100MW/16hr share, COD 2025	2,754	14.50	--
2019 NWE Draft IRP (Low) - 500MW/9hr, COD 2025	1,971	14.06	--
2019 NWE Draft IRP (High) - 500MW/9hr, COD 2025	3,479	14.06	--
US DOE HydroWire 2019 Avg	--	15.36	--
2019 PSE Draft IRP - 500MW/8hr, COD 2025	2,176	14.06	--
Average (PSE 2021 IRP Reference Plant)	**2,515**	**14.84**	**0.00**

PSE recommended costs – Battery Storage, 4hr Li-Ion

Data Source (2020 Vintage, 2016 U.S. Dollars)	Overnight Capital Cost ($/kW)	Fixed Operating and Maintenance ($/kW-yr)	Variable Operating and Maintenance ($/MWh)
NREL ATB 2019 Mid	1,262	31.56	0.00
PGE 2019 IRP 4 hour	1,485	--	--
Avista 2019 IRP 4 hour	1,390	48.61	--
PAC 2019 pre-IRP 4 hour	3,297	54.34	--
PAC 2019 pre-IRP 4 hour large	1,707	31.53	--
PSE 2019 IRP HDR 4 hour	2,472	31.08	--
Average (PSE 2021 IRP Reference Plant)	**1,935**	**39.42**	**0.00**

For the 2019 IRP process, PSE modeled 2-hr Li-Ion, 4-hr Li-Ion, 4-hr Flow, and 6-hr Flow. Public sources only have 4-hr Li-Ion assumptions.

Should PSE use HDR report for other battery options or just model the 4-hr Li-Ion?

PSE recommended costs – Biomass

Data Source (2019 Vintage, 2016 U.S. Dollars)	Overnight Capital Cost ($/kW)	Fixed Operating and Maintenance ($/kW-yr)	Variable Operating and Maintenance ($/MWh)
NREL ATB 2019 Dedicated Mid	3,713	110.10	5.90
EIA – AEO 2019	3,899	118.92	4.57
PSE 2019 IRP 15MW Woodfired Biomass	7,744	333.58	6.38
Average (PSE 2021 IRP Reference Plant)	**5,119**	**187.53**	**5.62**

PSE recommended costs

- Challenging to work with different data sources with varying vintage year
- The final cost summary is for vintage year 2021
- All costs are in 2016 real U.S. dollars
- Capital costs represent overnight costs only. PSE will add AFUDC and interconnection costs as well

3 PSE recommended costs - Summary

(2021 Vintage, 2016 U.S. Dollars)	Overnight Capital Cost ($/kW)		Fixed Operating and Maintenance ($/kW-yr)		Variable Operating and Maintenance ($/MWh)	
	2019 IRP	2021 IRP	2019 IRP	2021 IRP	2019 IRP	2021 IRP
CCCT	991	927	13.68	12.12	2.44	3.18
Frame Peaker	618	660	3.80	6.95	6.34	7.12
Recip Peaker	931	1,248	3.61	5.80	5.12	6.38
Solar Utility	1,422	1,226	21.16	15.77	0.00	0.00
Solar Residential	--	2,848	--	--	--	--
Onshore Wind	1,438	1,484	35.75	36.79	0.00	0.00
Offshore Wind	5,730	4,971	115.96	99.73	0.00	0.00
Pumped Storage	2,176	2,515	14.06	14.84	0.00	0.00
Battery (4hr, Li-Ion)	2,427	1,900	31.08	39.42	0.00	0.00
Biomass	7,744	5,119	333.58	187.53	6.38	5.62

Next steps

- Submit Feedback Form to PSE by **June 4, 2020**
- A recording from today's webinar will be posted to the website **tomorrow**
- PSE will compile all the feedback in the Feedback Report and post all the questions by **June 11**
- By **June 18**, PSE will make a decision on what costs to use. The documentation for the decision made will be released in a Consultation Update that will be posted to the website

Upcoming meetings

- Stakeholders can register for upcoming meetings on the website
- Agendas and meeting materials will be posted one week prior to each meeting
- Meetings will be added as the IRP technical work progresses

Date	Topic
June 10	Electric Price Forecast
June 30	Transmission Constraints
July 14	Demand Side Resources
July 21	Social Cost of Carbon
August 11	Develop Portfolio Sensitivities

Thank you for your attention and input.

Please complete
your Feedback Form by June 4, 2020

We look forward to your attendance at PSE's next public participation webinar:

Electric Price Forecast

June 10, 2020

Appendix

Capital Costs – Context for excel file available online

- PSE has curated the data compiled by NPCC into a spreadsheet for quick and easy comparison
- How to interpret this data:
  - Data is organized by resource type
  - **"Raw"** sheets contain **all** of the data compiled by NPCC (e.g. mix of F- and H-Class CTs at various nameplate capacities)
  - **"Clean"** sheets represent only data **meaningful** to PSE's portfolio (e.g. only F-Class CTs with nameplate capacity near 200 MW)
  - Costs are color coded with GREEN prices being the LOWEST and RED prices being the HIGHEST
  - Costs are 'most-representative' and do not reflect variability of real-world construction
  - Costs are in 2016 U.S. Dollars
  - PSE 2021 IRP Reference Plant – is PSE's recommendation for the given generator cost, generally an average of the presented costs

GENERIC RESOURCE COST SUMMARY

EXCEL SPREADSHEET

Click this link to download the spreadsheet:

https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/May_28_Webinar/Generic_Resource_Cost_Summary_PSE%202021%20IRP_052020.xlsx

Webinar #1: Generic Resource Assumptions Q&A

5/29/2020

Overview

On May 28, 2020 Puget Sound Energy hosted a webinar on generic resource assumptions as part of the 2021 Integrated Resource Plan. At this webinar, stakeholders shared their input on generic resource costs. Participants were able to submit feedback on the webinar and materials prior to and after the webinar occurred. Additionally, participants were able to ask questions using a Q&A chat box provided by the GoToWebinar platform.

Below is a verbatim report of the questions submitted to the Q&A chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Timestamps for questions are available for tracking. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 61 people attended the meeting.

Attendees included:

Jessica Ackerman, James Adcock, Eleanor Bastian, Larry Becker, Charlie Black, Joni Bosh, Robert Briggs, Rachel Brombaugh, Peter Brown, Stephanie Chase, Vincent Ching, Colin Crowley, Weimin Dang, Cody Duncan, Kara Durbin, Molly Emerson, Ben Farrow, Tom Flynn, Max Greene, Steve Greenleaf, Brian Grunkemeyer, Vladimir Gutman-Britten, Daniel Handal, Fred Heutte, Mike Hopkins, Doug Howell, Laurie Hutchinson, Cameron Janacek, Richard Johnson, Kevin Jones, Eric Kang, Dan Kirschner, Michele Kvam, Sarah Laycock, Virginia Lohr, Jenny Lybeck, Kate Maracas, Kassie Markos, Don Marsh, Sheri Maynard, Jennifer Mersing, David Meyer, Margaret Miller, Valerie O’Halloran, John Ollis, Court Olson, Anthony O'Rourke, Bill Pascoe, David Perk, Nathan Sandvig, Kathi Scanlan, Cindy Song, Steve Johnson Steve Johnson, Rahul Venkatesh, Katie Ware, Charles Weschler, Willard (Bill) Westre, Kendra White, Bob Williams, Scott Williams and Zacarias Yanez.

Questions Received

Questions are posted in the order in which they were received. The webinar began at 1:30 PM PDT and ended at 4:00 PM PDT.

Responses from staff in the chat box were only provided to assist with webinar troubleshooting. They have not been included for brevity.

Time Asked	Name	Question Asked
01:32:44 PM PDT	Doug Howell	Who is speaking?
01:33:28 PM PDT	Doug Howell	Request that questions can be seen by all participants, not just staff.
01:33:34 PM PDT	Virginia Lohr	Have you started?
01:37:32 PM PDT	Doug Howell	May we see who is participating?
01:38:59 PM PDT	Virginia Lohr	We had no audio, but it's working now.
01:40:04 PM PDT	Doug Howell	It is much better to have questions and participants available in real time. This is key to transparency.
01:42:23 PM PDT	Doug Howell	FYI, King County did this very successfully with 70 participants for their climate plan webinar.
01:44:33 PM PDT	James Adcock	I feel PSE IRP's in the past have been more successful when questions can be asked and answered more-or-less in real time, not delayed "until the end" -- when questions are delayed "until the end" they never get answered in a meaningful way.
01:47:26 PM PDT	David Perk	In the 2019 IRP cycle there were a couple of IRPAG meetings that were opportunities for the general public to make comments. Apparently that format won't be available in the 2021 cycle?
01:49:06 PM PDT	James Adcock	I am concerned that the "chat moderator" is "editing" the questions/chat I am posting in a way which does not necessarily accurately represent that which I am actually saying.
01:49:13 PM PDT	Don Marsh	Q&A's on a particular slide must be near real-time to have a good record for the webinar. Otherwise, the continuity is lost for viewers.
01:50:55 PM PDT	Virginia Lohr	What is the difference between QUESTIONS and CHAT?
01:51:53 PM PDT	James Adcock	I was surprised that PSE "canceled" the 2019 IRP Process without even a "Closure Meeting."
01:53:13 PM PDT	David Perk	+1 on James' comment
01:54:41 PM PDT	James Adcock	Will the 2021 IRP meet the 2030 "80/20" requirements?

Time Asked	Name	Question Asked
01:55:39 PM PDT	Virginia Lohr	When are the "On-line Meetings"?
01:56:44 PM PDT	Kevin Jones	WAC 480-100-620 states "The utility must inform, consult, and involve stakeholders in the development of its IRP..." What IAP2 level are you applying to this meeting?
01:58:03 PM PDT	James Adcock	If meeting dates change or are canceled how many weeks notice will we have about those changes? It is very disruptive to our schedules and other commitments to have meeting dates changed or moved with little notice.
02:01:24 PM PDT	James Adcock	Was that a "Yes" committment to meeting the 2030 "80/20" requirements? I did not hear Irena say that in so many words.
02:01:30 PM PDT	Joni Bosh	Did the 2019 progress report include estimated resource need?
02:02:26 PM PDT	Kevin Jones	Since WAC 480-100-620 uses "and", not "or", wouldn't it be more appropriate to apply the "involve" level of public participation to this meeting? If not, why not?
02:02:28 PM PDT	David Perk	Welcome Elizabeth!
02:02:31 PM PDT	Kate Maracas	Will there be phases of the IRP process for which the IAP2 "collaborate" level will be utilized?
02:04:05 PM PDT	Virginia Lohr	You make a distinction between webinars and on-line meetings. When are the on-line meetings and who is invited to them and where can I find information on them? I do not see the distinction on your web site.
02:04:12 PM PDT	Don Marsh	When will the Demand Forecast assumption be discussed? This has been a weak point in previous IRPs, so we want to concentrate on these assumptions.
02:05:14 PM PDT	James Adcock	Can we get access to the input data used for stochastic modeling?
02:06:20 PM PDT	Charlie Black	Elizabeth mentioned PSE's existing resources. How will PSE develop assumptons about costs, availabilities, remaining lives, etc. for PSE's existing generating resources?
02:07:17 PM PDT	Doug Howell	Agree with Jim. We need access to the input files for Plexos, Aurora and the Resource Adequacy models. We will sign NDAs as necessary.
02:09:17 PM PDT	Kate Maracas	Does PSE's capacity expansion model optimize strictly on least cost, or is it configurable to optimize on other parameters associated with particular resources (such as value of flexibility, voltage support, and other ancillary services)?
02:10:55 PM PDT	Nathan Sandvig	How does this upcoming RFP interface with this IRP process?
02:10:56 PM PDT	Charlie Black	Supplement to my question on assumptions about PSE's existing resources: what assumptions are being made about need and costs for reburbishments, other investment costs in the existing resources?
02:14:36 PM PDT	Don Marsh	The location of resources is important. Costs of a resource should include transmission costs, transmission losses, transmission reliability and resiliency, and risks (fires).

Time Asked	Name	Question Asked
02:15:07 PM PDT	Kevin Jones	Hi Alison. WIll you post my follow-on question regarding WAC 480-100-620 posted 12 minutes ago? Thanks!
02:17:51 PM PDT	Doug Howell	To build off of what Elizabeth just said, and you "must" put in the social cost of carbon in the baseline assumption.
02:18:43 PM PDT	Fred Heutte	Just a thought -- we used GoToWebinar for a test run and the limitation of only "organizers" seeing the actual entries in the chat is a significant limitation, so you may want to consider GoToMeeting next time.
02:19:18 PM PDT	David Perk	But will the Social Cost of Carbon be part of the baseline assumptions?
02:19:52 PM PDT	Fred Heutte	Also to note -- I hosted a webinar on resource adequacy on Tuesday with GoToMeeting and the chat is a lot better with everyone seeing the interaction.
02:21:07 PM PDT	James Adcock	I don't feel it is fair to blame "technology" for the very limited amount of real and meaningful active "public participation" in this meeting. These kinds of "technology" related meeting problems have been going on for more than a decade now.
02:21:28 PM PDT	David Perk	+1 to Fred's comment on using GoToMeeting for better interaction and transparency.
02:22:32 PM PDT	Joni Bosh	How recent is the HDR data? My recollection is this study was completed in 2018?
02:25:55 PM PDT	James Adcock	I will ask my "NREL" question again: Can we get a pointer to the web address of the "NREL [Wind] database" mentioned on page 25 of this meeting?
02:26:02 PM PDT	Fred Heutte	I'm not understanding the 37.5-100 operating range for pumped storage. The Absaroka Gordon Butte project anticipates a full operating range from -400 to +400 with very little interruption and very fast (20MW/sec) ramp rates based on a European design with at least one plant in service using that configuration.
02:26:10 PM PDT	Doug Howell	What is winter peaking for Montana wind?
02:26:56 PM PDT	Kate Maracas	Section 13(3) of CETA requires Commerce and the UTC to adopt rules defining analysis and reporting requirements for "Retail electric load met with market purchases and the western energy imbalance market or other centralized market administered by a market operator" (among other things). How does the IRP evaluate the role of market resources (energy prices)? The generic resource cost data on PSE's website only includes capital and O&M costs.
02:26:59 PM PDT	Fred Heutte	Offshore wind is way above the indicated value for the "sweet spot" area from southern Oregon to northern California -- well above 50%.
02:28:54 PM PDT	Fred Heutte	Could you explain a bit more on using wind/solar P50 values for the resource adequacy assessment? Maybe I'm missing something but where a deterministic value may be ok for some modeling, for RA it really needs to represent daily, seasonal and interannual variability.
02:29:33 PM PDT	Robert Briggs	Please tell us where the offshore wind is located.

Time Asked	Name	Question Asked
02:31:34 PM PDT	Kevin Jones	If I heard Irena correctly, let me say, for the record, that PSE appears to not be implementing WAC 480-100-620 regarding public participation.
02:32:53 PM PDT	Kevin Jones	Regarding offshore wind - how far off the coast?
02:37:10 PM PDT	James Adcock	Thank you for the NREL ref -- can you also repeat the assumed Wind Turbine model number which is being used?
02:39:07 PM PDT	James Adcock	There are many different Wind Turbine models and blade designs matching "3 Megawatt 100 Meters" can you please give me more detailed technical information about what exactly you are assuming?
02:43:40 PM PDT	Doug Howell	Do gas costs include social cost of carbon and upstream emissions?
02:46:08 PM PDT	James Adcock	Why not include interconnect costs?
02:46:38 PM PDT	Don Marsh	I don't understand excluding the cost of interconnection. Does that get included somewhere else?
02:48:50 PM PDT	Kevin Jones	How does PSE evaluate the cost risk of having to move offshore wind more than 3 miles offshore in the IRP? Is this a revision to the model when you complete your research, or does the model include a cost variation parameter?
02:49:04 PM PDT	Mike Hopkins	for thermal generation, was there any consideration of using biofuels or renewable gas as fuel instead of traditional nat gas?
02:52:29 PM PDT	Fred Heutte	here's a number of comments compressed into one submission -- * thanks for an well structured breakout on new resource costs and for providing full detail - big progress already in the 2021 IRP! * we disagree very strongly with using AEO future cost curves, they are using an obsolete approach and the ATB method is much better * we recommend converting to discounted present value instead of nominal value, not only for generation costs but across the board in the IRP * future cost decline most important to get right for fast innovation resources including solar, battery, hybrid and offshore wind * very important to model hybrids (solar+storage, wind+storage) in this IRP!
02:52:57 PM PDT	Fred Heutte	sorry about the formatting on that one! I will also have a couple comments on the specific details when that's appropriate
02:53:15 PM PDT	James Adcock	I am concerned about the possibility of triggering large-scale gas pipeline upgrade needs without fairly including those costs in NG Peaker costs analysis.
02:54:23 PM PDT	Kevin Jones	Does the PSE model include cost risks in general? If not, how to you consider cost risks?

Time Asked	Name	Question Asked
02:54:49 PM PDT	Bill Pascoe	Where can we find information about assumed lives for the various resurces?
02:56:10 PM PDT	Don Marsh	+1 on Fred's recommendation to model hybrids (renewables + storage). We have seen costs of 2 cents / kWh for solar + storage in El Paso, TX. Might not be quite so cheap in the Northwest, but we would like to have accurate accounting of those technologies in our region.
02:56:16 PM PDT	Robert Briggs	There are two recent studies that show that renewable hydrogen can play an important role in enabling transitioning to 100% carbon-free energy at reduced cost. The two studies of great relevance to this IRP are: Path to 100% Renewables for California, WÄRTSILÄ®, <https://www.wartsila.com/docs/default-source/power-plants-documents/downloads/white-papers/americas/path-to-100-renewables-for-california.pdf>. Hydrogen Opportunities in a Low-Carbon Future: An assessment of long-term market potential for hydrogen in the Western United States, Energy+Enviromental Economics, May 2020. It seems that it would be financially imprudent for PSE to add any thermal plants that are not designed to allow them to operate on 100% hydrogen, otherwise they will be at risk of being taken out of service before the end of their service life. Your comment?
02:56:42 PM PDT	Doug Howell	How is PSE dealing with the risk of stranded assets for new gas plants given likelihood they will no longer be "used and useful" but the debt will continue?
02:58:08 PM PDT	Fred Heutte	question on solar+battery hybrid -- will you be using combo cost rather than adding one to the other?
02:59:43 PM PDT	Fred Heutte	We are seeing costs for combo solar+hybrid that are much less than adding them together for several reasons -- colocation costs and some factors that appear to relate to project finance and investor risk appetite
03:01:19 PM PDT	Kevin Jones	Has PSE looked at the available market for "alternate fuels"? Both capacity and cost?
03:01:50 PM PDT	Robert Briggs	Yes, purchase only equipment that can run on 100% hydrogen. Also, add renewable hyrdogen as a storage resource.
03:03:36 PM PDT	Valerie O'Halloran	I may have missed this, but will PSE be looking at HydroPower as well.
03:05:32 PM PDT	James Adcock	Again, under WA law it only "works" to use renewable fuel on NG plants IF you directly use that renewable fuel in the NG plant. If you simply inject renewable gas into the gas pipeline in general you are only qualifying for the "20%" part of the 2030 "80/20" requirements. And again, you have not yet clearly stated for the record whether: "Yes PSE will meet the 2030 '80/20' requirements" -- or alternatively

Time Asked	Name	Question Asked
		maybe PSE is saying: "We don't believe we have a requirement to meet 2030 '80/20' requirements" -- we need to understand what PSE's position is on this issue so that we can understand what PSE is trying to accomplish in this IRP.
03:05:40 PM PDT	Fred Heutte	Info on the Absaroka Gordon Butte project: https://gordonbuttepumpedstorage.com/wp-content/uploads/2020/03/3.04.2020_BriefingDoc_Final.pdf and their NW Council presentation https://nwcouncil.app.box.com/s/xfuiz4fzn0yw6zzmu61djsxc7pt5b3z7
03:06:36 PM PDT	Brian Grunkemeyer	Follow-up: should the value of energy produced in out years be reduced by the discount rate?
03:08:22 PM PDT	Bill Pascoe	When and how will PSE look at flexible capacity needs in this IRP?
03:10:05 PM PDT	Brian Grunkemeyer	If you apply a discount rate to the operating costs, but don't provide a discount rate to the value of energy produced, isn't that inconsistent?
03:10:50 PM PDT	Willard (Bill) Westre	The Variable costs do not seem to include fuel cost. Is this separate?
03:14:21 PM PDT	James Adcock	In previously IRP's there were concerns about required diesel start-ups on the Recips -- not able to meet air quality requirements?
03:16:15 PM PDT	Fred Heutte	On the specific details (referring to the XLS data, for which many thanks) -- * we recommend using only the most recent cost estimates per source for the "clean" averages, and removing previous estimates such as the earlier ATB and PSE IRP values * we also suggest completely excluding the ATB "constant" values which are only intended as a constant baseline for NREL internal modeling
03:18:03 PM PDT	Fred Heutte	One more on the details -- we recommend averaging the ATB low and mid values because they represent the lower and higher bound of their modeling and especially for solar we believe the average between ATB low and mid is the most likely case based on our own modeling
03:19:07 PM PDT	Court Olson	Utility solar doesn't have to be tracking. Have you compared the cost of non-tracking?
03:19:07 PM PDT	Fred Heutte	On offshore wind, there is significant new cost data showing much lower capital cost but it is still basically proprietary -- I will try and connect PSE to some sources
03:21:18 PM PDT	Fred Heutte	If I might respond to Court -- the vast majority of utility scale PV is now single axis tracking, with effectively no incremental capital cost but better overall output, especially with properly sized inverters (as measured for example by the inverter loading ratio or ILR)
03:31:58 PM PDT	Don Marsh	I still have a question about when we will discuss the Load Forecast.
03:33:49 PM PDT	Doug Howell	More than just stochastic modeling, we need input files for Aurora, Plexos, Resource Adequacy and Load Forecast

Time Asked	Name	Question Asked
03:34:18 PM PDT	Don Marsh	I'm disappointed that the Demand Forecast is designated as an "inform" item. This group has good questions and good information that could "inform" PSE's modeling. We are hoping the Demand Forecast will be much more accurate than it has in previous IRPs.
03:35:57 PM PDT	David Perk	+1 Don's comment re Demand Forecast's "inform" designation
03:36:33 PM PDT	Joni Bosh	I think the reference is to the current DR RFP and the all source RFP that is underway?
03:36:50 PM PDT	David Perk	+1 Doug's request for additional input files to be made available
03:38:38 PM PDT	Don Marsh	+1 Doug's request for input files
03:38:39 PM PDT	Joni Bosh	Yes.
03:40:18 PM PDT	Fred Heutte	if I understand correctly, you automatically get GoToMeeting with the GoToWebinar subscription
03:40:24 PM PDT	Kate Maracas	Can PSE provide anonymyzed bid data in the form of median values by project type?
03:40:45 PM PDT	Doug Howell	Why aren't questions made available to everyone?
03:41:03 PM PDT	Fred Heutte	we are all learning about this new all-webinar-all-the-time world!
03:41:14 PM PDT	Willard (Bill)Westre	How have the responses (PPA's) to the 2017 RFP's, indicating market costs effected the cost data.
03:41:31 PM PDT	Doug Howell	It is must different to see questions in real time.
03:41:39 PM PDT	Doug Howell	It is *much different
03:44:07 PM PDT	Don Marsh	We learn a lot from anonymized RFP data from utilities in other states. It would be wonderful if PSE took this step for increased transparency and accountability. It's appropriate for such a technologically and ecologically advanced region as the Puget Sound.
03:45:56 PM PDT	David Perk	Will there be a general public comment opportunity during the 2021 IRP cycle?
03:46:01 PM PDT	Brian Grunkemeyer	FYI - we saw a drop in EV driving (and charging) by about 75% as a result of COVID shelter-in-place and stay-at-home orders. I'll send some pictures for your information.
03:46:14 PM PDT	Kate Maracas	Will PSE consider using bid data to inform future IRPs once they have been fully negotiated? Note that I'm not suggesting making the data public.

Time Asked	Name	Question Asked
03:46:22 PM PDT	Bill Pascoe	Have the meeting times been established?
03:46:24 PM PDT	Kevin Jones	Do all these meetings start at 1:30PM?
03:46:30 PM PDT	Joni Bosh	Could you post the link to the website again:
03:47:48 PM PDT	Virginia Lohr	Didn't UTC (David Nightingale) ask for anonymous RFP data in one of the early 2029 IRP meetings?
03:48:20 PM PDT	Virginia Lohr	2019 IRP, I meant
03:48:30 PM PDT	Don Marsh	We have seen COVID impacts on electric demand from around the country, but very little information from the Northwest. When will PSE tell us what is happening in its service area?
03:51:09 PM PDT	Court Olson	In future meetings, would you please schedule a five minute "bio" break after 90 minutes?
03:51:15 PM PDT	Kevin Jones	Could you post your website link in the chat?
03:51:30 PM PDT	Kevin Jones	Sorry - I see you did. Thanks.
03:52:43 PM PDT	Kate Maracas	It's https://pse-irp.participate.online
03:56:15 PM PDT	David Perk	hank you -- wishing you good health

HDR GENERIC RESOURCE COSTS REPORT

Click this link to access the report:

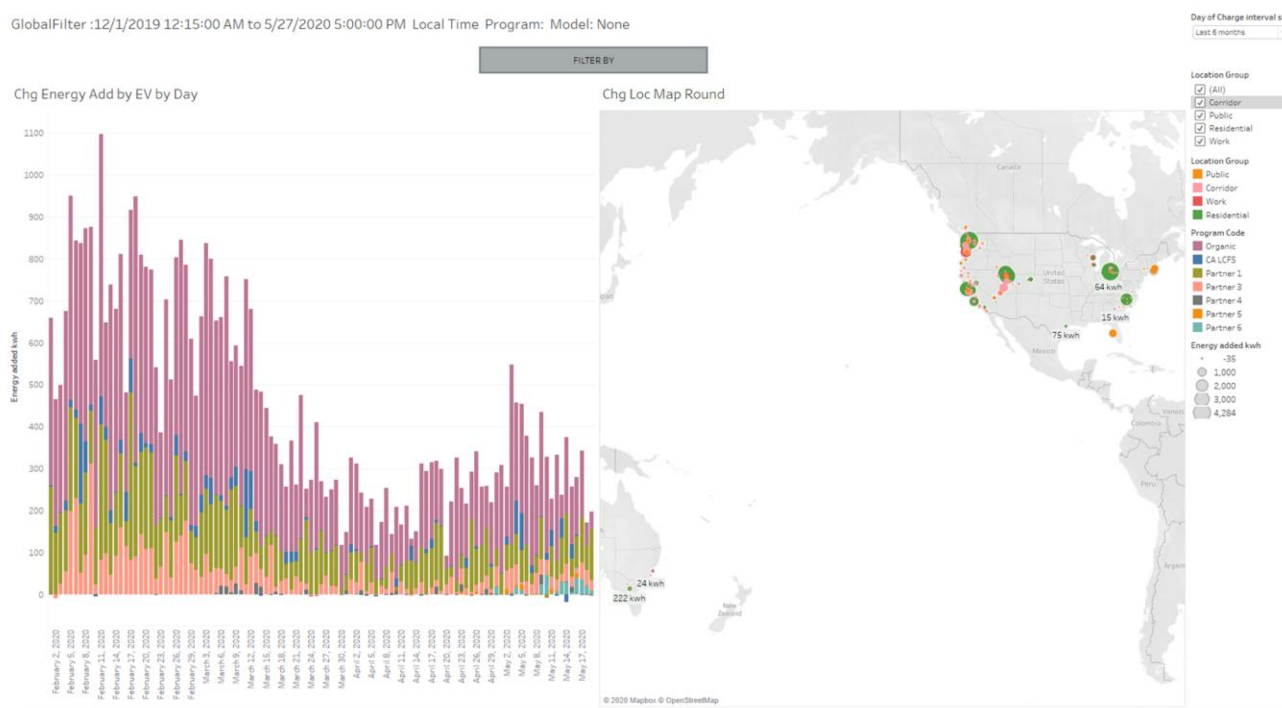
https://oohpseirp.blob.core.windows.net/media/Default/PDFs/HDR_Report_10111615-0ZR-P0001_PSE%20IRP_Rev4%20-%2020190123).pdf

The following stakeholder input was gathered through the online Feedback Form, from May 13 through June 4, 2020. PSE's response to the feedback can be found in the far-right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on June 18, 2020.

2021 IRP Generic Resource Assumptions Workshop Feedback Report			
Feedback Form Date	**Stakeholder**	**Comment**	**PSE Response**
5/13/20	James Adcock	I am concerned that while I received an email "invite" to join the 2021 IRP process, when I tried to use the provided automated method of responding to that "invite" PSE's automated system instead logged an error message, rather than correctly "signing me up" for the IRP process. I then sent an email to PSE IRP leader Irena Netik, telling her about this problem, asking her to sign me up for the 2021 IRP, and asking her to acknowledge this email. She has not responded.	An acknowledgement email was sent on 5/13/20 at 2:20 pm. A copy of the message is included below: **From:** Netik, Irena **Sent:** Wednesday, May 13, 2020 2:20 PM **To:** 'jimad@msn.com' <jimad@msn.com> **Subject:** RE: Welcome to PSE's 2021 IRP Process Hello Jim, Thank you for your continued involvement and interest in the 2021 IRP process. I am confirming that we did in fact receive your response to the poll in the MailChimp email indicating that you do want to be engaged in the 2021 IRP process. Thank you for your feedback on the usability of that poll and we will work to make responding clearer. PSE is committed to engagement throughout the 2021 IRP process, and I appreciate interested stakeholders like yourself. I hope you are available to attend the first webinar on May 28, 2020 from 1:30 p.m. to 4:00 p.m. Thank you, Irena Netik Director, Resource Planning **From:** James Adcock <jimad@msn.com> **Sent:** Wednesday, May 13, 2020 6:15 AM **To:** IRP -- mail -- **Subject:** Re: Welcome to PSE's 2021 IRP Process **CAUTION - EXTERNAL EMAIL** Phishing? Click the PhishAlarm **"Report Phish"** button. For mobile - forward to **abuse@pse.com** Could you acknowledge this email please, so that I know you received it? Thank you,
5/21/20	James Adcock	This question relates to the May 28 2020 IRP Presentation, Page 25 -- -- "Operating characteristics" of Wind Resources. The source of this information is given as "NREL Database." Can you please give us a pointer to the exact "NREL Database" and information therein being used? IE a web address, etc.? As you know, in recent years the Wind Industry has advanced their technology, both in designing new windfoils with greater availability at lower wind speeds, which might benefit "Washington Wind Annual Average Capacity Factor" and also in improving power conversion, such that high wind generation limits have been lifted, so that more power can be generated in high-wind conditions. I want to make sure that your data source "NREL Database" is recent enough to capture these new Wind technological developments. Please answer the question asked so that we can determine whether or not your modeling assumptions include recent Wind Industry innovations that may affect resource costs, and relative resource costs, including affecting whether Wind resources are better built in Washington vs. Other States.	The NREL database refers to the 5-min wind speed data obtained from NREL's Wind Toolkit database: https://www.nrel.gov/grid/wind-toolkit.html. The NREL Wind Toolkit data contains mesoscale modeled data from 2007 to 2013. Only wind speed data was used from the NREL database, capacity factors were calculated by PSE analysts with experience in wind energy assessment in order to employ up-to-date wind technology and methods. The raw, 100m above ground level wind speed data was processed using industry-informed methods to calculate hourly net production shapes. Processing steps include: • Re-average 5-min wind speed data to hourly wind speed data • Calculate gross production using the air density adjusted, power curve for a GE3.03-140 as a model turbine • Apply loss factors including estimated wake impacts, stochastic availability losses, turbine performance losses, environmental losses (stochastic icing shutdown, high/low temperature shutdown) and electrical line losses to calculate a final net production shape. • Validate net production calculation against existing NREL Wind Tool Kit net capacity factor estimates and DNV GL production calculations for select sites.

			This process was repeated for 250 unique locations surrounding the point of interest, then the most representative shape was selected for the deterministic Portfolio model. The described process has only been performed for the wind resources added to the 2021 IRP (Wyoming and Idaho wind resources). 2019 IRP wind resource characteristics (Washington, Montana, Offshore) were obtained from HDR and DNV GL 3rd party analysis. The HDR report is available for review on the PSE IRP website (pse.com/irp). Documentation for the DNV GL wind shapes is not available at this time.
5/28/20	Brian Grunkemeyer, FlexCharging	When evaluating resources, do you apply a discount rate to the value of energy produced? This article below in Utility Dive makes an argument that the Levelized Cost of Energy hurts renewables because the math is wrong. The author observes that LCOE doesn't apply a discount rate to the value of energy produced in the out years. The claim is LCOE overprices wind & solar by 18% and 27% respectively compared to natural gas. The author is pushing a slightly corrected metric, the "present value of the cost of energy" instead of LCOE. https://www.utilitydive.com/news/lcoe-is-not-the-metric-you-think-it-is/578360/ It's possible PSE doesn't use LCOE at all in its resource evaluation. But it may be useful to understand whether discount rates apply to the value of energy produced as well as operating costs. This same thought process could apply to conservation as well, correct? Please inform the IRPAG about whether it is reasonable to apply a discount rate to the value of energy when valuing resources & conservation measures, and whether you do so.	Resources are evaluating on an annual basis for the life of the plant, we do not use the levelized cost of energy in the models. The discount rate is only applied at the end to levelize the costs for charts and tables that are used for comparison.
5/28/20	Virginia Lohr, Citizens' Climate Lobby	The emails I received before the May 28 meeting had links to this form and to a general PSE IRP page, but the link to the specific page where the materials for the webinar would be was not included. I had to send time searching through your IRP pages to find them. In the future, I suggest you send copies of the materials for a webinar to all people who have expressed interest in the IRP process. If that is not possible, then at least share the url of the actual web page where you are posting the materials.	Thank you for the suggestion. PSE will plan to send direct links to materials in future email updates.
5/28/20	James Adcock	This is feedback in regards to the chosen PSE "technology" for the meeting, namely "GoToWebinar" and the need to submit questions indirectly by keyboard as opposed to directly by microphone. I have participated in other large meetings including by Commerce and UTC which did successfully allow direct communication and interaction with the presenters by microphone. By using the "raise hand first" protocol this worked out very well in these other forums. But, in regards to today's "GoToWebinar" format where one has to type in questions via keyboard -- it really didn't work for me. What I see happening in practice over and over again is that Irena or Elizabeth interpret a question not as coming from an technological expert, but rather as-if it were coming from a kindergartener, and then give either a dismissive answer, or no-answer-at-all but rather an answer to a different question that the presenter made up in their mind. For example often a technology expert participant asks a question -- in context -- "But what about ABC?" and Elisabeth simply answers a different question "As I told you earlier, we are not doing ABC, we are doing XYZ." OK, but the participant didn't misunderstand what you were doing [which was XYZ], rather they asked you a specific question, which you chose to ignore by answering an entirely different question. And the problem with having to use a keyboard and chat -- as PSE knows perfectly well -- is that gives no opportunity for the technology expert participant to say "Wait a second -- that is not the question I asked you!" In summary "GoToWebinar" is simply yet-another PSE ploy, in a long series of PSE ploys, over a decade-plus of IRP meetings, to prevent real and meaningful public participation, allowing the public to actually ask real and meaningful technological questions, and receiving real and meaningful technological answers. The reason that these question are being asked is very simple: Participants want to be able to ensure that PSE is making the best resource acquisitions -- and retirements -- possible, at BOTH the lowest ratepayers costs AND the lowest environmental damage costs. And the reason the PSE continually avoids giving meaningful answers is that PSE does not want to be held accountable to actually making the best possible resource acquisitions -- meaning that PSE will be making resource acquisitions which are more expensive to ratepayers, AND more damaging to the environment.	For the June 10, 2020 meeting, PSE transferred the meeting platform from GoToWebinar to GoToMeeting in part due to your and other participants' feedback. PSE will make best efforts to more clearly answer questions in all meetings.

		PSE, like Commerce and WUTC already do, needs to choose to use a "technological resource" that allows participants to ask questions of presenters by microphone "in more-or-less real time" after the participant "raises their hand". Further, PSE presenters should commit to giving real and meaningful answers to participant questions, which actually are responsive to the question, and not simply dismissive ploys just intended to "make the question go away." PSE needs to actually make a real commitment to PUBLIC PARTICIPATION in their IRP Process -- as required by law -- and not this continual PSE ploy of "We Talk and You Just Listen." PSE needs to design into meeting schedules enough time for participants to ask questions. I suggest that PSE design into their meetings the assumption that 1/2 of the time will be taken by PSE making presentations, and that 1/2 of the time will be used by participants asking questions and by PSE giving actual and real answers to those questions, rather than engaging in ploys to avoid given real answers.	
5/28/20	James Adcock	This is feedback you requested in terms of a more detailed understanding of what exact NREL Wind Data you are using, and what "generic 3 Meg 100 Meter" wind turbine you are assuming. My expressed concern is that your modeling may not include more recent Wind Turbine technological developments over recent years, where now wider blades are available making Wind Farms display better availability at lower wind speeds -- as may be more appropriate to Washington State Wind Farm modeling, and also higher output generators are now available which do not run into output upper limits until higher wind speeds -- which may be more appropriate for Montana Wind Farm modeling. Can you please tell me exactly what you are using in terms of Wind Turbine assumptions. What I see on the NREL site is the assumption of "Vestas V-90 3 MW" -- is this the wind turbine you are assuming for all your Wind Farm modeling? What I also see on the NREL site is various documentation and data creation dates from 2007 to 2015 -- meaning that any Wind Turbine technological developments in the last 5 to 13 years would not be included in your IRP modeling. Is this a correct assumption? Please clarify to me and other participants exactly what NREL wind data you are using and how, exactly that Wind Turbine(s) you are modeling, and from what calendar year your wind data, and wind turbine model(s) date from.	The NREL database refers to the 5-min wind speed data obtained from NREL's Wind Toolkit database: https://www.nrel.gov/grid/wind-toolkit.html. The NREL Wind Toolkit data contains mesoscale modeled data from 2007 to 2013. Only wind speed data was used from the NREL database, capacity factors were calculated by PSE analysts with experience in wind energy assessment in order to employ up-to-date wind technology and methods. The raw, 100m above ground level wind speed data was processed using industry-informed methods to calculate hourly net production shapes. Processing steps include: • Re-average 5-min wind speed data to hourly wind speed data • Calculate gross production using the air density adjusted, power curve for a GE3.03-140 as a model turbine • Apply loss factors including estimated wake impacts, stochastic availability losses, turbine performance losses, environmental losses (stochastic icing shutdown, high/low temperature shutdown) and electrical line losses to calculate a final net production shape. • Validate net production calculation against existing NREL Wind Tool Kit net capacity factor estimates and DNV GL production calculations for select sites. This process was repeated for 250 unique locations surrounding the point of interest, then the most representative shape was selected for the deterministic Portfolio model. The described process has only been performed for the wind resources added to the 2021 IRP (Wyoming and Idaho wind resources). 2019 IRP wind resource characteristics (Washington, Montana, Offshore) were obtained from HDR and DNV GL 3rd party analysis. The HDR report is available for review on the PSE IRP website. Documentation for the DNV GL wind shapes is not available at this time.
5/28/20	Nate Sandvig, National Grid Ventures	-This comment is in reference to slides 43 and 44- PSE IRP Team, Good webinar. Reviewing pumped storage slide/assumptions, would change Swan Lake COD to 2026. Would also add 1200-MW Goldendale and a COD of 2028. We have HDR as our quasi-owner's engineer for Goldendale, and they can follow-up with details (Carl Mannheim with HDR is copied). Presumably with scale in mind, Goldendale should be less capital cost on a $/kW basis. Also, by averaging data sources, Swan Lake (and Goldendale) is really at a disadvantage compared to batteries when that is not necessarily the case. As you've stated, pumped storage went up (2176→2515) and batteries went down (2427→1900). Just trying to keep a level playing field on cost for starters without getting into duration advantage, supply chain risk, degradation, recycling, waste, etc. that aren't factored into battery costs.	PSE is currently researching more information on pumped storage hydro and will have the results for the Consultation Update on June 18. PSE contacted Nate Sandvig on June 11 and discussed more detailed information on the Swan Lake and Goldendale projects. We look forward to receiving this information and incorporating it into the analysis.

		Thanks, Nate Sandvig	
5/28/20	Brian Grunkemeyer, FlexCharging	During today's IRPAG meeting, someone mentioned PSE was still working to understand demand changes after the impact of SARS-CoV-2. At FlexCharging, we do have a number of electric vehicles that we're monitoring, and we saw a ~75% drop in driving & charging. California issued a shelter-in-place order around March 15. WA high tech employers encouraged everyone to work from home around March 5th, then Gov. Inslee issued a stay-at-home order late the following week. This data is not limited to the US west coast. I've also included a map of the charging locations here. The number of charge sessions at public, workplace, and corridor chargers also dropped after the lockdowns. But it also looks like drivers got antsy in the first week of May. 	This information has been shared with PSE's load forecasting group and will be discussed further at the demand forecast meeting which will be scheduled in the next few weeks.
5/29/20	Don Marsh, CENSE	I participated in the Generic Resource Assumptions webinar on May 28. At a couple of points during the meeting, I asked questions about the Demand Forecast, but the answers were vague and unsatisfying. First, I asked when the Demand Forecast would be discussed. No specific date was given. PSE said the company was trying to evaluate the impacts of the COVID-19 crisis. Of course, we all understand the pandemic is having a significant negative effect on demand. However, PSE has a process for handling uncertain scenarios (like the future price of natural gas). The company can provide a range of outcomes (best case, worst case, and most likely), and then we can proceed cautiously with those scenarios in mind. Second, I asked how the public could participate in the development of the forecast. I was told that this part of the IRP would be "inform-only." This means that PSE will do all of its modeling in secret, and then "inform" us what the models predict. Without access to the data or the tools, we must trust PSE to come up with the right answers. However, this trust has been strained because PSE's forecasts have been significantly too high during the last decade, occasioning comment from the WUTC. For example, in previous IRPs, PSE has consistently projected substantial demand growth during the winter, but winter demand throughout PSE's service territory has actually declined since 2009. The Demand Forecast is at least as important to a successful IRP as the Generic Resource Assumptions. If the public doesn't have a good understanding of what customers' future needs will be, it's hard to know whether the IRP is a prudent plan to meet those needs. We should understand where there are likely to be "hot spots" of demand growth, and how vigorous that growth is expected to be. A forecast that covers PSE's entire service territory misses opportunities to target local needs with appropriate alternatives. For example,	The demand forecast for the 2021 IRP will be covered in an upcoming meeting. PSE is currently developing a schedule for the next set of meetings. We expect the website (pse.com/irp) to be updated and a schedule filed with the WUTC in the next few weeks.

		high growth in a small area might be an ideal scenario to deploy distributed resources and energy storage without over-building the entire grid. PSE's "Energize Eastside" project provides an instructive example. The company is using a five-year-old forecast of 2.4% annual demand growth to justify this project. Given the history of demand during the past decade, plus the realities of lower demand in the COVID age, this forecast is pure fantasy. Even before the outbreak of the virus, 2.4% growth seemed incongruous given falling winter demand throughout PSE's service area. PSE responded that the growth of the Eastside is unprecedented and is straining the Eastside grid. However, no proof has been provided that Eastside population and economic growth is actually producing increased demand, or that Eastside growth is significantly more vigorous than other areas served by the utility. Ratepayers worry that incorrect forecasts are used to justify unnecessary infrastructure investments that are costly to customers and harmful to the environment. We request four corrective steps be taken immediately: 1) Schedule a meeting specifically dedicated to the Demand Forecast. This meeting should occur as soon as possible, because the rest of the IRP is difficult to judge if participants don't have a clear understanding of the need PSE is trying to serve. 2) Provide individual summer and winter forecasts for each of the eight counties served by PSE (or finer geographic granularity, if warranted). 3) Provide full data and assumptions to IRP participants, and allow substantive feedback to shape the final forecasts. 4) To provide full context, demand forecasts should show at least ten years of peak demand history, including both actual and weather normalized trends. We also need to have a discussion about weather normalization procedures. There is no reason why this fundamental part of the IRP should remain secretive and obscure. To be legitimate, this IRP must demonstrate a significant improvement in the process and transparency of the Demand Forecast. Sincerely, Don Marsh	
6/1/20	Robert Briggs, Vashon Climate Action Group	There are two recent studies that show that renewable hydrogen can play an important role in enabling transitioning to 100% carbon-free energy at reduced cost. The two studies of great relevance to this IRP are: Path to 100% Renewables for California, WÄRTSILÄ®, https://www.wartsila.com/docs/default-source/power-plants-documents/downloads/white-papers/americas/path-to-100-renewables-for-california.pdf. And Hydrogen Opportunities in a Low-Carbon Future: An assessment of long-term market potential for hydrogen in the Western United States, Energy+Enviromental Economics, May 2020. [See Attached Executive Summary] It seems that it would be financially imprudent for PSE to add any thermal plants that are not designed to allow them to operate on 100% hydrogen, otherwise they will be at risk of being taken out of service before the end of their service life. Your comment?	Thank you for the reference material. We have reviewed through the Wartsila slides and are working on reviewing through the other documents that you have provided. The PSE IRP team has also scheduled a meeting with an industry expert to learn more about the commercial availability of renewable fuels for gas plants. PSE is currently researching more information on this topic and will have an update for the Consultation Update on June 18.
6/1/2020	Robert Briggs, Vashon Climate Action Group	Include electrolyzers and compressed hydrogen storage used in conjunction with H2-capable peaker plants as a measure in this IRP. Install a small (e.g., 5 MW) electrolyzer at one of your gas plants to evaluate its potential for long-term storage and the provision of other grid services.	The PSE IRP team has been in contact with the plant engineers to discuss this recommendation. The team is currently researching hydrogen as a fuel at the current gas plants and future gas plants and will have an update for the Consultation Update on June 18.
6/2/2020	Kevin Jones, Vashon Climate Action Group	REVISED: I participated in the 2021 PSE IRP Generic Resource Assumptions webinar on May 28, 2020. There are at least two concerns that I would like PSE to respond to.	Thank you for your questions. Responses below as you have numbered and labeled: 1. There are different risk factors when looking at new assets.

		1. It appears that PSE is not considering cost risk of potential assets being analyzed in the 2021 IRP. In some cases, the siting of offshore wind assets or the market cost of non-fossil based gas fuels, for example, these cost risks could be considerable. Yet it was clearly stated in the presentation that PSE does not consider asset cost risk in the IRP analysis. a. Why is cost risk not considered in the PSE IRP analysis? b. Where in the PSE portfolio analysis process is cost risk considered? c. Please also address how PSE's analysis process considers, or does not consider, asset acquisition schedule risk. 2. The IRP Draft WAC 480-100-620 states that "The utility must inform, consult and involve stakeholders in the development of its integrated resource plan and its two-year progress report" (emphasis added). When asked "What IAP2 level are you applying to this meeting?" Irena Netik responded "we are applying the consult level to this meeting" (ref time 31:33 in the meeting recording at https://register.gotowebinar.com/recording/3604364449812524812). When asked "Since WAC 480-100-620 uses "and", not "or", wouldn't it be more appropriate to apply the "involve" level of public participation to this meeting? If not, why not?" Irena Netik's answer was "PSE made the determination that we use involve as the appropriate level" (ref time 49:30 in the meeting recording at https://register.gotowebinar.com/recording/3604364449812524812) a. Please clarify PSE's position – will the May 28, 2020 meeting comply with the consult or involve IAP2 level? b. Please provide rationale for not conducting all 2021 PSE IRP meetings at the IAP2 "involve" level of public participation given the use of the word "and" in WAC 480-100-620 public participation directions. Please let me know where and when we can expect a reply. Please provide and post answers to the above questions on the PSE IRP website. Thank you, Kevin Jones kevinjonvash@gmail.com Vashon Climate Action Group	a. The risk of permitting. This is a factor used when assessing resources in the RFP, but not included in the IRP. b. The risk that resources will have different costs than projected. In the past PSE has not modeled this risk as part of the stochastic risk modeling, but we have discussed it several times and started developing information for the 2019 IRP. PSE will work to use a cost of resource as one of the variables to change in the stochastic analysis. The stochastic analysis work will begin later in the year. c. Asset acquisition schedule risk. This risk considers the operating start date for different resources. Since the 2021 IRP planning horizon starts in 2022, PSE considers the schedule for asset acquisition, permitting and building for the first year a resource is available. For example, a wind project can be built in 18 months, but you also have to consider permitting, acquisition of the turbines, and transportation to the side. This increases the process to 3 years lead time, so the first year available is 2024. 2. PSE reviewed stakeholder input from 2019 and considered the levels from the IAP2 spectrum that could be best supported. PSE determines the IAP2 spectrum for the public participation. The meeting on May 28 was at the "consult" level which is defined by IAP2 guidelines as "to obtain public feedback on analysis, alternatives and/or decision" and the promise is to "keep you informed, listen to and acknowledge concerns and aspirations, and provided feedback on how public input influenced the decision." Certain IRP subjects will be at the "involve" level but not all subjects meet that level of involvement.
6/3/2020	Willard (Bill) Westre, Union of Concerned Scientists	The Generic Resource Approach is no longer a reasonable method of analyzing generation costs for an IRP or a CEIP. It does not reflect the way PSE acquires resources so it cannot be accurate or transparent. Of the 97 responses to PSE's 2017 RFP's, the vast majority of generation resources proposed were Power Purchase Agreements (PPA). Of the 21 responses selected by PSE for further consideration 18 were PPA's for direct delivery of power at a defined price, only one was a PPA with a build-asset option and only two were PPA's with a buy-asset-option. The Generic Resource Approach data as presented leaves out the majority of generation resource costs – particularly finance cost, fuel cost, accurate performance data, national state and local subsidies, property and other ownership costs; local variations such as tax and labor rates, grandfathered requirements and other competitive advantages, construction transportation costs, etc. that are inherently included in PPA proposed costs. PPA proposals are a considerably more accurate source of data to use as the foundation for resource selection. Since PPA data is what PSE uses in resource selection, it is the data that should be used in the IRP including subsequent analysis processes such as resource adequacy. Adopt a Market Cost Approach using PPA data from previous solicitations. Confidential data can be protected in numerous ways e.g. presenting average data for 3 or more PPA proposals of the same type. This has been used by other utilities that have adopted this approach. PSE could begin by using data from the 2017 RFP responses received in 2018. The data is available already – just use it. Use of 6.97% as discount rates in General Resource Assumptions is unwarranted. The current Federal Fund Rate is 0.25% with the possibility of going negative. The current 30-year Corporate Bond Rate is 3.24%. It is not prudent for PSE to charge ratepayers any higher than market rates for asset purchases or use in determining capital costs for future assets. Secondly, use of high discount rates for cost estimates discriminates against renewable energy sources versus thermal resources - because renewable resources have high capital costs and zero fuel costs, whereas thermal resources have high fuel costs and lower capital costs.	The IRP models PSE-built resources as the generic resource, so a PPA is not directly comparable. PPAs are bids from third party developers and their financial structure is different from a utility, so they can offer prices that may be different from the cost for a utility to build and operate a generating resource. The generic resource cost webinar only presented the overnight costs. The Consultation Update will have the final costs that include the financing costs, PTC and ITC, taxes and insurance. PSE will continue to model generic resources as a PSE built and operated power plant. We can document the cost of materials and construction for a generic resources, but it is difficult to estimate future PPA costs, making it hard to model as a generic resource.

		Use the discount rate of 2% as suggested by the US Council of Economic Advisors in this policy brief: https://obamawhitehouse.archives.gov/sites/default/files/page/files/201701_cea_discounting_issue_brief.pdf Note: this does not apply to the discount rate specified for determination of the Social Cost of Carbon in the CETA regulation.	
6/4/2020	Bill Pascoe, Absaroka Energy and Pascoe Consulting	1. Pumped Storage Hydro (PSH) Nameplate Capacity (slide 24 from May 28, 2020 presentation) - The slide shows a 300 MW nameplate capacity. Please confirm that PSE will model shared ownership of a 300 MW PSH facility (PSE ownership share of less than 300 MW, say in 50 or 100 MW increments) in the IRP. 2. PSH Energy Storage Capability (slide 24) – The slide show an 8-hour discharge period, presumably at full (nameplate) capacity. Please confirm that this will be modeled in the IRP as 2,400 MWH of storage that can be called upon in various combinations of MW and hours (300 MW for 8 hours, 150 MW for 16 hours, 300 MW for 4 hours + 100 MW for 12 hours, etc.). 3. Energy Storage Recharge Parameters – What are the assumed recharge parameters for PSH and batteries? 4. PSH Operating Range (slide 24) – Gordon Butte PSH includes "quaternary" technology that allows the project to operate at any point from 0% to 100% generation and 0% to 100% pumping. This operating range should be modeled as a PSH option in the IRP. 5. Battery Degradation (slide 24) – The assumption that battery degradation is "near zero" is only reasonable if the capital costs on slide 44 include an allowance for future additions of new capacity to offset degradation of the initial installed capacity. If this is not the case, PSE should research and include a non-near-zero degradation rate for batteries. 6. Energy Storage Lives – What are the assumed lives for PSH and batteries?	PSE is currently researching more information on pumped storage hydro and will have the results for the Consultation Update on June 18.
6/4/2020	Stephanie Chase, Public Counsel Unit of the Washington State Attorney General's Office	During the last webinar, PSE staff mentioned that there would not be a general public listening session for this IRP. In light of that, what efforts are you making to inform customers or stakeholders about the IRP process and ways that they may become involved or offer feedback, outside of the technical webinars?	For the 2021 IRP, PSE expanded its outreach efforts and contacted more than 1,400 potential stakeholders from across PSE's service territory with an invitation to participate. As a result, new stakeholders have participated in the webinars. PSE continues to provide regular outreach and updates to the expanded stakeholder list. PSE is creating more stakeholder engagement opportunities through webinar recordings and feedback forms all through the process. Stakeholders can provide feedback to PSE at any point through the IRP process.
6/4/2020	Sarah Laycock, Public Counsel Unit of the Washington State Attorney General's Office	There had been a question regarding renewable gas. As a follow up, just wondering if and how RNG will be modeled in this IRP. I saw that PSE contracted to obtain a certain (seemingly large?) amount from Klickitat PUD for about three years, if I recall correctly. So, just trying to figure out why RNG doesn't appear to be listed as a renewable to model	PSE is currently researching more information on renewable fuels as an alternative fuel source and will have the results for the Consultation Update on June 18.
6/4/2020	Mike Hopkins, FortisBC	I think it would be useful to explore use of other fuels besides traditional natural gas in the thermal generation resource options - such as biofuels, renewable nat gas, hydrogen - to see if any would be viable in the future. While these fuels are likely more costly, they would reduce GHG emissions in valuable baseload or peaking plants. I think using the chat box to ask questions rather than having participants calling in was useful in keeping the meeting focused on the agenda topics and it was much easier to hear all the questions and answers.	PSE is currently researching more information on renewable fuels as an alternative fuel source and will have the results for the Consultation Update on June 18.
6/4/2020	Kathi Scanlan, WUTC, and WUTC staff	Commission Staff Feedback for Puget Sound Energy 2021 IRP: Webinar # 1 Generic Resource Assumptions (May 28, 2020) 1. This feedback, dated June 4, 2020, states the informal comments, questions, and recommendations of Washington Utilities and Transportation Commission Staff, Kathi Scanlan. Staff appreciates the continued work of PSE's IRP Team and the opportunity to participate. Timely feedback is offered as technical assistance and is not intended as legal advice. Staff reserves the right to	1. Thank you and noted. 2. PSE will provide an updated table in the Consultation Update on June 18. 3. Transmission costs will be covered in the June 30 webinar.

		amend these opinions should circumstances change or additional information be brought to our attention and are not binding on the commission. 2. Capital Costs—Beyond slides 34 and 35, staff requests more information on definitions used by PSE, including definition of overnight capital costs, capital cost, or all-in capital costs to build plant. It is staff's understanding the Northwest Power and Conservation Council capital cost estimates include EPC + owners costs, including interconnection costs, development costs, legal, land, and overnight costs do not include interest that would be incurred during construction (AFUDC). Defining these new columns in the slides presented for the PSE recommended costs, including differentiating overnight capital, capital, capital-all-in, etc., for slides 36-45, and providing additional discussion and rationale is requested. 3. Conceptual cost estimates for transmission and delivery for each technology—the Clean Energy Transformation Act (CETA), including provisions in the IRP statute (RCW 19.280.030(1)(d)), which requires each utility to perform a comparative evaluation of renewable and nonrenewable generating resources, including transmission and distribution delivery costs. PSE indicated public sources do not identify different capital cost by region, so one cost will be used for each onshore wind option and transmission costs will vary depending on location. PSE responded that it may utilize the, "HDR Report flat 5-mile transmission and gas pipeline to get to system, plus flat $/mile applied to resources." Staff requests more follow-up information related to estimating costs for infrastructure outside the fence. PSE states, by June 18, PSE will decide what costs to use (slide 48). Staff requests clarification on transmission and distribution delivery costs, and when they will be discussed. 4. Regarding request for proposals (RFPs) and generic resource cost assumptions, staff asks: Can recent RFPs help PSE true-up resource costs in the IRP? The PSE's 2021 IRP resource cost inputs need to be the best available as they are a stand-in for potential new resources—there is a connection with the RFP. RFP data can inform generic resource costs, while maintaining confidentiality, where and when appropriate. How will PSE's RFP data inform generic resource costs? Staff agrees with comments posed by several other stakeholders on this discussion topic and requests PSE provide additional clarification of how its RFP data can inform cost data in its 2021 IRP. 5. Energy Storage—PSE asks stakeholders if the company should use the HDR Report for other battery options or only model the 4-hr Li-Ion in the IRP? Staff recommends PSE should include other battery options in its IRP analysis. By analyzing only one type, PSE is likely limiting its capacity for future resources from the outset and may not give PSE a broad enough analysis of how different resources can fit into PSE's needs. Energy storage is a key enabling technology for utilities to accomplish the goals of the state's clean energy transformation. In 2017, the Commission issued a report and policy statement on the treatment of energy storage technologies in the integrated resource planning process (see Docket U-161024, Service Date 10/11/17), which staff strongly encourages PSE revisit. Further, staff recommends PSE compare alternative data, including PNNL's Energy Storage Technology and Cost Characterization Report (July 2019): https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf This report defines and evaluates cost and performance parameters of six battery energy storage technologies (BESS) (lithium-ion batteries, lead-acid batteries, redox flow batteries, sodium-sulfur batteries, sodium metal halide batteries, and zinc-hybrid cathode batteries) and four non-BESS storage technologies (pumped storage hydropower, flywheels, compressed air energy storage, and ultracapacitors). Data for combustion turbines are also presented. Detailed cost and performance estimates were presented for 2018 and projected out to 2025. 6. Solar—According to a new LBNL utility scale PV benchmarking report (June 2020), solar useful life expectations have substantially increased to 30 years or more. The report includes relevant operation expenditure data: https://emp.lbl.gov/publications/benchmarking-utility-scale-pv. As reported by LBNL, solar project developers, sponsors, long-term owners, and consultants have increased project-life assumptions over time, from an average of ~21.5 years in 2007 to ~32.5 years in 2019. PSE's HDR Report (and workbook) provides data 5 to 10 years less than. Also, staff appreciates the additional consideration and data and analysis for distributed-generation residential solar (slide 39). Did PSE consider commercial distributed-generation solar as a type to model for its electric generic resource assumptions? 7. Existing and Refurbishment of Resources (remaining useful life)—Staff requests additional details regarding how PSE models existing resources and refurbishment costs and echoes similar questions raised in real time during the webinar on this topic. Please explain how PSE determines budgets for O&M inputs and economic retirement in the IRP modeling process. Further, how is PSE modeling PPAs—existing PURPA and other supply resources (expiration)? 8. For the 2021 IRP, PSE expanded its data sources and revised its generic resource assumptions based on feedback received from stakeholders from the last IRP cycle, which staff also appreciates. For the 2021 IRP, PSE states that it intends to utilize	4. For the 2021 IRP, PSE is following stakeholder recommendations to utilize publicly available cost information and will not utilize confidential bid information from the last RFP process. 5. PSE is researching the PNNL report and will have an update in the Consultation Update on June 18. 6. PSE is researching operating life and will have an update in the Consultative Update on June 18. 7. The operations and maintenance costs at PSE's existing resources are based on the most current budget and escalated at 1.5% per year. The PSE IRP team plans to use the 2020 budget for the 2021 IRP portfolio model. Since the IRP model allows for economic retirements, a decommissioning cost is used to adjust the remaining revenue requirement at the plant if it retires before the end of its economic life. All contracts are modeled with the contractual end date. The one exception is the Mid-C hydro contracts. The IRP has an assumption that the Mid-C contracts will get renegotiated and extended. The assumption for the Mid-C contracts in the 2021 IRP is under review. 8. The HDR report referenced in the webinar was incorrectly posted to the "Work Plan" area of the IRP website. The HDR report is now correctly posted with the Generic Resource Cost webinar materials. 9. A meeting for natural gas portfolio modeling has not yet been scheduled. PSE is currently developing a schedule for the next set of meetings. We expect the website (www.pse.com/irp) to be updated and a schedule filed with the WUTC in the next few weeks. 10. The GoToWebinar does not have the capability for attendees to make their questions visible to all GoToWebinar participants. Unfortunately, PSE learned about this limiting capability a few days before the webinar. The PSE team found a workaround to make all questions/comments visible to participants in real-time by copying and pasting the questions. PSE plans to us the GoToMeeting platform for the next webinar which has the desired functionality. 11. The demand forecast will be covered in an upcoming meeting. PSE is currently developing a schedule for the next set of meetings. We expect the website (www.pse.com/irp) to be updated and a schedule filed with the WUTC in the next few weeks. 12. PSE plans to share the appropriate model data as it is developed to support the IRP process. PSE is currently developing a schedule for the next set of meetings, which will include flexibility modeling and ELCC contributions. We expect the website (www.pse.com/irp) to be updated and a schedule filed with the WUTC in the next few weeks. PSE is researching efficiency gains for hybrid or co-located projects and will have an update in the Consultation Update. 13. PSE is tracking Northwest Power and Conservation Council's climate change analysis and at this time the IRP team is still assessing the appropriate methods to incorporate a climate sensitivity in the 2021 IRP.

		select information from the "Generic Resource Costs for Integrated Resource Planning, Revision 4" report authored by consultant HDR to supplement information. The generic resource costs will be derived from publicly available data sources and stakeholder feedback, where public data sources do not provide detailed operational characteristics necessary for robust power system modeling. The generic resource operational characteristics will continue to be sourced from the HDR Report. As such, staff questions why PSE's Revision 4 Generic Resource Costs for IRPs (HDR Report), which was referenced numerous times in the webinar, was not initially posted under the first webinar and grouped with other Generic Resource Assumption Documents for review prior to the meeting. PSE's website shows generic resource assumptions will be discussed on May 28, 2020 and lists four meeting documents: Webinar 1: Generic Resource Assumptions presentation REVISED [PDF, 1.6 MB] Webinar 1: Generic Resource Assumptions agenda [PDF, 120 KB] Generic Resource Assumptions Workbook Summary [Excel, 879 KB] Generic Resource Assumptions Webinar Q&A Log [PDF, 158 kb] PSE instead provides a link to its HDR Report under the subheading "Work Plan" in a completely different area of the IRP website https://pse-irp.participate.online/2021-IRP . To ensure transparency in the public process, staff recommends relevant documents be grouped or linked together with the relevant webinars to allow for timely stakeholder review before and after the meeting. 9. Slide 14—PSE made comments regarding the action plan not pertaining to the gas IRP (referring to step 6 of PSE's 6-step process), please clarify if PSE intends to submit a short-term plan outlining the specific actions to be taken by the utility in implementing the gas long-range integrated resource plan? 10. Public Participation— Staff appreciates that PSE's IRP webinar web recording is available for stakeholders and others who are not able to attend the webinar during work hours. Consultations with commission staff and public participation are essential to the development of an effective IRP. The PSE copy/paste delay of comments and questions in Webinar #1 was perplexing. Looking ahead, as PSE transitions to the new platform for Webinar #2, staff requests to see questions and comments from stakeholders in real-time during future webinars. 11. Upcoming Webinar #2—Staff found PSE's comments regarding load forecasting as categorized as an "inform item" with no firm advisory group date around this topic surprising and requests further clarification and discussion. The demand forecast produced by PSE provides public insight into the future demand for power and gas in PSE's service area. The demand forecast is influenced by economic and population trends in the Pacific Northwest. As a forecast, and an input for hourly demand for PSE, it is the most important factor in determining resource need. Again, staff believes ongoing feedback is essential to the development of an effective IRP. 12. Increasing Transparency in IRP Modeling—Staff appreciates PSE updates to the new website content, including delineating models used and inputs throughout the six-step IRP development process. The new generic resource assumptions workbook is a very helpful first addition to the library of data inputs and encourages PSE to share Aurora data input files and tables to increase transparency, including but not limited to Plexos Electric Portfolio Model, Electric Resource Adequacy Model (RAM), and Sendout Gas Portfolio, and other models. In terms of specific model questions, how does PSE account for efficiency gains for hybrids or co-located projects as inputs into the model(s)? Further, please specify the date PSE intends to discuss flexibility modeling and ELCC contribution? 13. Planning for tomorrow, the Northwest Power and Conservation Council is likely incorporating the impact of climate change in its next Power Plan. Reviewing regional and electricity data for 2018, the Council's power planning staff reported in the fall of 2019 that the 2018 winter was warmer on average than the previous 91 winters. UTC staff requests additional information on how PSE intends to assess the climate sensitivity in future years of the utility's load-resource balance and potential effects from changes in temperature/streamflow. Does PSE intend to use projected temperatures or streamflow distribution rather than historic distributions? Further, will PSE model unplanned outages linked to climate change in its IRP analysis, such as wildfires or other extremes like floods, snow pack shortage, or concurrent weather-related events?	
6/4/2020	Katie Ware, Renewables Northwest	*See attached PDF for comments (2020-06-04 RNW Feedback PSE Generic Resource Assumptions.pdf)*	1. Thank you. 2. PSE is researching pumped storage hydro and will have an update in the consultation update. 3. PSE is reviewing the data sources provided and will have an update in the consultation update. 4. PSE is modeling solar + battery and wind + battery in the 2021 IRP. The consultation update will include these resources along with research that PSE is doing on efficiency gains for having co-located resources.

6/4/2020	Joni Bosh and Fred Huette, NW Energy Coalition	*See attached PDF for comments (2020-06-04 resource-cost feedback NWEC.pdf)*	1. PSE is researching pumped storage hydro and will have an update in the consultation update. 2. For this IRP PSE will model offshore wind off the coast of Washington State, but we will continue to research offshore wind and monitor any developments in technology and location. 3. Thank you for the feedback and we apologize for the confusion. PSE develops 250 stochastic draws for each wind and solar resource. These draws are used as part of the resource adequacy model to develop the peak capacity credit or ELCC. The P50 single hourly profile is used the deterministic portfolio model along with the ELCC that was developed in the resource adequacy mode. 4. Thank you for feedback. 5. a) PSE is modeling solar + battery and wind + battery in the 2021 IRP. The consultation update will include these resources along with research that PSE is doing on efficiency gains for having co-located resources. b) PSE is researching pumped storage hydro and will have an update in the consultation update c) PSE will research the data sources and make sure that we are including the latest information in the capital cost. An update will be available as part of the consultation update. 6. PSE is looking into using the ATB cost curves instead of the AEO cost curves. An update will be available as part of the consultation update.
6/4/2020	Vlad Gutman-Britten, Climate Solutions	*See attached PDF for comments (PSE IRP feedback 6_4 Climate Solutions.pdf)*	1. PSE is researching owner's costs and AFUDC and will have an update as part of the consultation update. 2. PSE is looking into using the ATB cost curves instead of the AEO cost curves. An update will be available as part of the consultation update. 3. PSE is researching the outlier costs for both battery storage and biomass to see if there is a good reason for the higher costs. Without knowing the assumptions behind the costs it is hard to determine if it is a reasonable data point or not. PSE will have an update as part of the consultation update. 4. PSE is researching pumped storage hydro and will have an update in the consultation update. 5. PSE is modeling solar + battery and wind + battery in the 2021 IRP. The consultation update will include these resources along with research that PSE is doing on efficiency gains for having co-located resources.
05/28/2020 (question not answered during webinar)	Bill Pascoe, Absaroka Energy and Pascoe Consulting]	When and how will PSE look at flexible capacity needs in this IRP?	PSE is currently developing a schedule for the next set of meetings which will include flexibility modeling. We expect the website (www.pse.com/irp) to be updated and a schedule filed with the WUTC in the next few weeks.
05/28/2020 (question not answered during webinar)	Virginia Lohr, Citizens' Climate Lobby	Did David Nightingale (WUTC) ask for anonymous RFP data in one of the early 2019 IRP meetings?	PSE checked the meeting summaries for the 2019 IRP process and did not locate this reference.
05/28/2020 (question not	Kate Maracas,	Can PSE provide anonymized bid data in the form of median values by project type?	Due to RFP bidder confidentiality agreements, PSE will not make bid data public in any format.

answered during webinar)	Western Grid Group (WGG)		
05/28/2020 (question not answered during webinar)	Kate Maracas, Western Grid Group (WGG)	Will PSE consider using big data to inform future IRP's once they have been fully negotiated? Note that I'm not suggesting making the data public.	Once a project has been selected through the RFP process, negotiated, constructed and added to PSE's resource portfolio, then PSE will use those costs for that resource only. Since the costs are negotiated, it is difficult to use that as a prediction for future resource costs.

June 4, 2020

Puget Sound Energy
IRP Team

RE: Feedback of Renewable Northwest, Generic Resource Assumptions
Puget Sound Energy's May 28, 2020, Feedback Webinar Relating to Generic Resource Assumptions for PSE's 2021 Integrated Resource Plan.

I. INTRODUCTION

Renewable Northwest thanks Puget Sound Energy ("PSE") for this opportunity to provide feedback as a stakeholder in PSE's 2021 Integrated Resource Plan ("IRP"). This feedback is a response to PSE's May 28, 2020, Feedback Webinar regarding the Generic Resource Assumptions ("Assumptions") of the 2021 IRP.

Renewable Northwest participated in the first hour of the Feedback Webinar and subsequently joined Climate Solutions in a separate meeting with PSE to address questions on the webinar's content. Below, we provide feedback based on 1) the materials provided by PSE for the webinar, including the revised Generic Resource Assumptions Presentation and the Generic Resource Assumptions Workbook Summary, and 2) the public discussion heretofore on the Assumptions for PSE's 2021 IRP.

II. FEEDBACK

1. Renewable Northwest appreciates the addition of new proxy renewable resources to PSE's IRP modeling. Other utilities throughout the Northwest are identifying significant value in adding geographically and technologically diverse renewable resources to their systems, especially as these resources continue to fall in cost. We appreciate PSE's commitment to sharing more information about how the new proxy resources were selected and the intersection between these resources and available transmission capacity, and we look forward to additional engagement on these topics.

2. Renewable Northwest has identified possible discrepancies in PSE's determination of cost values for the proxy pumped hydro storage resource. Slide 43 of PSE's revised May 28, 2020 slide deck regarding generic resource assumptions breaks out the values that PSE averaged to determine the cost for its PSE 2021 IRP Reference Plant. Among those values, three stand out:

- Swan Lake, which is listed as a 393 MW/9 hour project with overnight capital costs of $2,093/kW;
- 2019 PAC Draft IRP which is listed as a 400 MW/9.5 hour project with overnight capital costs of $2,991/kW; and
- 2019 NWE Draft IRP (High), which is listed as a 500 MW/9 hour project with overnight capital costs of $3,479/kW.

Considering Swan Lake and the generic 2019 PAC Draft IRP resource together, Appendix A of PacifiCorp's 2018 Renewable Resources Study Report used in PacifiCorp's 2019 IRP lists Swan Lake as a 400 MW/9.5 hour project with EPC project costs of $2,070/kW.[1] These figures appear to be a mix of PSE's Swan Lake attributes and PSE's "2019 PAC Draft IRP" attributes.

On the other hand, the $2,991/kW figure appears to come from Table 6.1 of PacifiCorp's 2019 IRP, but in that table it is attributed to a 300 MW x 1,800 MWh proxy project located in Utah.[2]

As for the 2019 NWE Draft IRP (High) value of $3,479/kW, Renewable Northwest had significant concerns with many of the cost inputs NorthWestern Energy used in their 2019 ESRPP and discussed these concerns in our comments to the Montana Public Service Commission (although we did not address pumped hydro storage specifically).[3] Following this general trend of higher-than-expected costs for renewable and non-emitting resources in NorthWestern's ESRPP, we note that the 2019 NWE Draft IRP (High) value stands out as an outlier on PSE's slide 43.

For additional perspective on how these values may have affected PSE's proxy pumped hydro storage resource, we note that slide 47 shows approximately a 15% increase in pumped hydro storage costs between PSE's 2019 IRP and its 2021 IRP. We are unaware of any real-world circumstances that would support this increase, and removing the high PacifiCorp and NorthWestern figures would yield a value slightly higher than but generally consistent with PSE's 2019 value. All in all, we encourage PSE to take a second look at their pumped hydro storage cost inputs.

3. Renewable Northwest appreciates PSE's decision to use values from Lazard's Levelized Cost of Energy report as inputs to inform its proxy generating resource costs. Lazard's Levelized Cost of Storage report provides similar value in tracking price trends and providing up-to-date costs

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[1] Available at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019-irp/2019-irp-support-and-studies/Renewable_Resources_Assessment_for_the_2019_Integrated_Resource_Plan.pdf.
[2] Available at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf.
[3] Renewable Northwest's January 15, 2020 Comments on NorthWestern Energy's 2019 ESRPP are available on the Montana Public Service Commission's EDDI website.

for storage resources. Version 5.0 of the Levelized Cost of Storage report, released in November 2019, shows a range of capital costs for 4-hour battery storage systems from $898/kW to $1,874/kW -- both lower than PSE's proposed cost for the proxy 4-hour battery system.[4] We encourage PSE to incorporate Lazard's values into its battery storage cost calculation.

4. Renewable Northwest encourages PSE to model hybrid resources as well as standalone renewable and storage resources. Hybrid resources can bring additional value and system benefits above the aggregate values of their component parts modeled as standalone resources, and the full benefits can be difficult to capture unless they are explored in a targeted manner. As an example, in developing its 2019 IRP, PacifiCorp identified significant cost savings when it modified its model to select solar-plus-storage rather than standalone solar.[5] This value was attributable to resource-adequacy benefits that PacifiCorp's initial model run was unable to capture when assessing resources separately. Meanwhile Portland General Electric's most recent Request for Proposals resulted in the selection of a hybrid wind-solar-storage project as a least-cost, least-risk resource to meet PGE's identified needs.[6]

III. CONCLUSION

Renewable Northwest thanks PSE for its consideration of this feedback. We look forward to continued engagement as a stakeholder in this 2021 IRP process.

Sincerely,

/s/ Katie Ware	*/s/ Max Greene*
Katie Ware	Max Greene
Washington Policy Manager	Regulatory & Policy Director
Renewable Northwest	Renewable Northwest
katie@renewablenw.org	max@renewablenw.org

[4] Available at https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf -- see slide 7 for capital cost information.

[5] See Slide 28 of PacifiCorp's 2019 Integrated Resource Plan (IRP) Public Input Meeting slide deck from September 5-6, 2019, available at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019-irp/2019-irp-presentations-and-schedule/2019-09-5-6%20-%20General%20Public%20Meeting.pdf.

[6] See Press Release, *Portland General Electric and NextEra Energy Resources to develop nation's first major energy facility co-locating wind, solar and battery storage* (Feb. 12, 2019), available at https://www.portlandgeneral.com/our-company/news-room/news-releases/2019/02-13-2019-portland-general-electric-and-nextera-energy-resources-to-develop-en.

NW Energy Coalition Comments on Costs for Generic Resources

June 4, 2020

1. **Pumped Storage [Slide 24]**

Please explain the operating range of 37.5-100% for pumped storage. Because this is hydro generation technology, it is our understanding that there is no minimum operating rate (Pmin) for pumped storage.

In addition, new technology is now improving the overall performance of pumped storage. The proposed Absaroka Gordon Butte project in Montana anticipates using a "quaternary" configuration, consisting of three pairs of 134 MW generators and pumps with a full operating range from -400 to +400 MW, that can switch from generation to pumping mode with very little interruption and very fast (20MW/sec) ramp rates, similar to the design of the KOPS II facility in Austria.

Further information:

https://gordonbuttepumpedstorage.com/wp-content/uploads/2020/03/3.04.2020_BriefingDoc_Final.pdf

https://nwcouncil.app.box.com/s/xfuiz4fzn0yw6zzmu61djsxc7pt5b3z7

2. **Offshore wind [Slide 25]**

Pacific offshore wind has a winter peaking seasonal profile that is very favorable to PSE winter peaking needs, as shown in slide 27. However, while the presentation indicates a 34.8% capacity factor for Washington offshore wind, much higher output is anticipated from potential offshore wind in southern Oregon and northern California, with capacity factors at the best southern Oregon sites of over 50%. See Musial et al., Oregon Offshore Wind Site Feasibility and Cost Study, 2019, nrel.gov/docs/fy20osti/74597.pdf. We urge PSE to constantly monitor technology improvements in offshore wind, as this resource may be particularly suited to meet westside winter needs in the future.

The Bureau of Ocean Energy Management is sponsoring ongoing technical workshops focusing on the southern Oregon region, including one scheduled for June 4, 2020.

3. **Resource adequacy – renewable resources (Slide 26)**

As we discussed during the workshop, the wording on Slide 26 is ambiguous. As we understand PSE's clarification, the resource adequacy assessment is stochastic using 250 draws to represent resource variability, and the P50 wind/solar values derived from that assessment are then used for the deterministic portfolio modeling. That should be clarified and explained on the slide.

4. **Ongoing and Capital Costs [Slides 29-47 and Generic Resource Cost Summary spreadsheet]**

We appreciate the well-structured breakout on new resource costs and the full detail provided in the accompanying spreadsheet. The derivation of the values is well documented and allows stakeholders to review the process and compare the results to other analyses. This is a major improvement for the 2021 IRP process.

5. **Current Capital Costs**

(a) Hybrid Solar+Storage and Wind+Storage. As discussed during the workshop, we understand that PSE will be modeling hybrid project costs taking into account the cost savings afforded by common site location, interconnection costs, etc., and not simply adding together the renewable and storage costs. We noted that the cost savings may also include additional factors such as financing structures that are attractive to investors. We encourage PSE to include the most current publicly available data and independent assessments, as cost trajectories are going down quickly during this formative period for hybrid resources. A recent California ISO presentation showed that in 2019, for new projects entering the CAISO transmission queue, 95% of solar projects are hybrids and 75% of wind projects.

(b) Pumped Storage. The Absaroka Gordon Butte project in Montana and the National Grid/Rye Development Goldendale project in Washington should be included in the resource list and cost assessment.

(c) As indicated in the Generic Resource Cost spreadsheet, we recommend using only the most recent cost estimates from any source to construct the average values for the years 2018 onward. Including older cost estimates will tend to bias the median and mean value per resource type upward as there has been consistent overestimation of future costs for resources undergoing rapid innovation and scale-up. In addition, as noted below, both the NREL ATB Low and Mid values should be included. For example, using the most recent cost estimates would change the Clean Solar-Utility sheet in the following way:

Line	Source
exclude	
9	NREL ATB 2018 Mid (AC)
15	PGE 2016 IRP Update (AC)
17	PSE 2017 IRP (AC)
19	Avista 2017 IRP (AC)
22	Pacificorp 2017 IRP (AC)
23	Pacificorp 2019 pre-IRP BMcD - 50 MW in ID (AC)
24	Pacificorp 2019 pre-IRP BMcD - 200 MW in ID (AC)
26	7P - Low Cost PV (AC)
27	Mid-Term, Low (AC)
28	Mid-Term, High (AC)

add NREL ATB 2019 Low (AC)
add PGE 2019 IRP
add PacifiCorp 2019 IRP
add NW Power and Conservation Council 2021 Plan initial inputs (GRAC)

Similar exclusions and additions should be applied to the “clean” worksheet for each resource category.

(d) In the Raw Resource sheets, the NREL ATB Constant values should be removed. The Constant scenarios set equal resource costs in all future years and are only used for NREL internal modeling purposes.

6. Future Capital Costs [Generic Resource Cost Summary spreadsheet]

We strongly disagree with the use of the Annual Energy Outlook (AEO) trajectories for future resource costs (Cost Curves tab of the spreadsheet). Instead, we recommend using the average of the NREL ATB Mid and Low estimates (which extend to 2050) to create the cost trajectories for each resource type. NREL does not have a High scenario, so the two provided basically equate to medium-low and medium-high values for future years. Our own independent estimates suggest the midpoint between those values is reasonable for assessing future resource cost trajectories.

For example, the AEO estimates solar utility PV (single axis tracker) costs as $1614/kW-ac in 2019 and $1309/kW-ac in 2030, a 19% decrease in 11 years. The midpoint of the ATB estimates are $1028/kW-dc in 2019 and $713/kW-dc in 2030; converting to ac values using an inverter loading ratio of 1.3, that is $1337/kW-ac in 2019 and $927/kW-ac in 2030, a 31% decrease.

The AEO uses an outmoded trending model and poorly documented methodology with stale data. The NREL ATB method includes more attributes with better balancing, much better documentation and a thorough assessment of the most current available data. While we do not agree with all of NREL’s method, it is clearly the most authoritative national source of current resource cost data and future projections, so as noted, we support use of an averaged approach for the NREL ATB Mid and Low-cost scenarios for future cost trajectories in the PSE IRP.

We hope that in the future there will be a way for participants in the feedback sessions to speak directly; there were often confusing gaps between presentation, follow up questions and eventual responses.

Cordially,

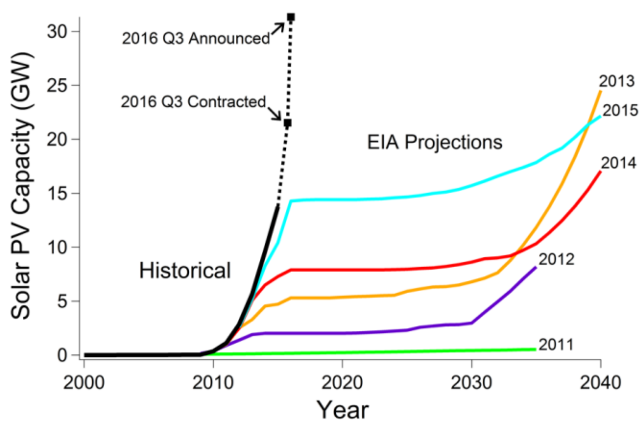
Joni Bosh, Senior Policy Associate
NW Energy Coalition

Fred Heutte, Senior Policy Associate
NW Energy Coalition

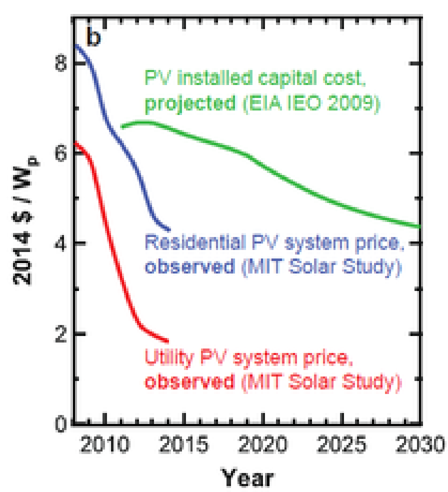
DATE: June 4, 2020
FROM: Climate Solutions
RE: Feedback on May 28 IRP Meeting

- **Owner's costs**
    - In the last IRP, PSE originally had 10% for RE and 30% for thermal, then ultimately used a blanket 30%.
    - We have requested from PSE a better understanding of what costs go into the owner's costs, and believe that those assumptions should be reflected in including owner's costs to the various resources.
- **EIA AEO learning curves**
    - AEO historically underestimates the installations of renewable energy capacity and therefore, the projected cost reductions of renewables.
    - We recommend using NREL's ATB instead of AEO.
    - A number of sources demonstrate EIA's poor track record projecting future deployment and costs:
        - Clean Technica - AEO Wildly Misses the Mark, Again

Figure 1. U.S. Utility-Scale Solar PV Capacity and EIA Projections



        - Clean Energy Action
        - Zenmo: PV growth



- **Averaging data for capital costs**
    - Averaging data for capital costs should not be based on so many utility IRP projections. Utility IRP projections also pull from data sources, so PSE should understand where the data comes from and use that data instead of utility IRPs.
    - Some of the IRPs that are being used are from 2016/2017, which is using information from outdated sources. PSE should only use the most up-to-date sources.
    - PSE should also be more consistent on where to average data from, and how many data sources they are using. For example, using the NREL report, which is already an average, and four IRP calculations will skew the average towards utility IRP projections.
- **Battery storage & biomass costs**
    - The batter storage and biomass costs are inflated by one single entry that is a substantial outlier from the others and we recommend deleting the outlier.
    - Storage costs should also incorporate Lazard's cost of storage.
- **Pumped hydro**
    - Pumped hydro costs appear to be high, and it appears in part due to Swan Lake being referenced twice from two different sources with different costs. PSE indicated that they are unaware of what is in PAC's pumped storage resource assumption, yet continues to use the assumption. We recommend only relying on reliable sources for these resource assumptions.
- **Support modeling hybrid resources**
    - The PSE spreadsheet includes a hybrid Solar + Storage resource, and we recommend incorporating this into the model. Additionally, we recommend looking at a hybrid Wind + Storage resource as well.

PSE IRP Consultation Update
Webinar 1: Generic Resources Assumptions
May 28, 2020

6/18/2020

The following consultion update is the result of stakeholder suggestions gathered through an online feedback form, collected between May 13 through June 4, 2020 and summarized in the June 11 feedback report. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

Pumped Storage Hydro

PSE received feedback from Nate Sandvig, National Grid Ventures, Bill Pascoe, Pascoe Energy representing Absoroka Energy & Orion Renewables, Katie Ware and Max Greene, Renewable Northwest; Fred Huette and Joni Bosh, Northest Energy Coalition (NWEC); Kathi Scanlan, WUTC staff; and Vlad Gutman-Britten, Climate Solutions, on the cost and operating assumptions of pumped storage hydro. This feeback included:

1. Overnight capital cost (cost that does not include interest/cost of capital)

   PSE has further reviewed other data sources for the capital cost of pumped storage hydro and has included the estimates from the Pacific Northwest National Laboratory (PNNL) report on energy storage. This estimate was already included as DOE Hydrowires 2019. Further, PSE has reviewed the assumptions for PacifiCorp's cost estimate (PacifiCorp, 2019 IRP) and concluded that it is very similar to the Swan Lake project and removed the PacifiCorp estimate so it is not double counted. The capital cost has been updated in the revised summary workbook Excel file for the generic resources assumptions available on PSE's IRP website under materials for Webinar 1 on pse.com/irp.

   Katie Ware, Renewable Northwest, notes that the PacifiCorp's draft IRP Pumped Storage Hydropower (PSH) generic resource looks to be based on Swan Lake. PSE read through PacifiCorp's generic resource assumptions and agrees, that their generic PSH resource appears to be the same as Swan Lake. PacifiCorp's draft IRP cost estimate was removed so that there isn't any double counting. Renewable Northwest also recommended additional review of the 2019 NWE Draft IRP (High) value. PSE reviewed NWE's costs and as a result will average NWE high and low cost estimates and then use the "mid" for the PSH capital cost average.

2. Operating characteristics

   PSE has reviewed the feedback received and contacted certain stakeholders (for example, Nathan Sandvig, National Grid Ventures; Bill Pascoe, Absaroka Energy & Orion Renewables, Fred Huette, Northwest Energy Coalition (NWEC)) to further discuss operating characteristics of pumped storage hydro.

   a. Nameplate capacity. The nameplate capacity will be reduced to 50 MW to assume a joint ownership and the ability to size to need.
   b. Operating range. The operating range will be updated to use 0% to 100% as supplied by Bill Pascoe and recommended by NWEC.
   c. Ramp rate. Newer technology allow the units to ramp at 20 MW/seconds. This is an input into the Plexos flexilibty model.
   d. Discharge rate. The input into the Aurora is the total energy of storage and the model will optimize the hours and energy used.

Battery Energy Storage System

PSE received feedback from Kathi Scanlan, WUTC staff, on using the Pacific Northwest National Labs (PNNL) report on energy storage. PSE reviewed the document and has included the cost estimates in the revised summary workbook Excel file for the generic resources assumptions available on PSE's IRP website under materials for Webinar 1 on pse.com/irp. PSE has also added the 2-hr Lithium Ion battery, and the 4-hr and 6-hr flow battery as resources options for the 2021 IRP.

Katie Ware, Renewable Northwest, and Vlad Gutman-Britten, Climate Solutions, provided feedback on using the Lazard levelized cost estimates. The discussion is provided below under captital costs, vintage year.

Vlad Gutman-Britten, Climate Solutions, provided feedback on on the PacifiCorp high battery storage capital cost. The high capital cost refers to a smaller 1 MW battery, so the cost was removed from the average and PSE will only use the cost estimate for the larger 15 MW battery.

PSE received feedback from Bill Pasco, Absoroka Energy & Orion Renewables, on battery degredation. The battery systems are assumed to have 0% degradation with an increased fixed O&M costs. This higher fixed costs are for maintenance over time to prevent the degredation.

Hybrid Resources

PSE received feedback from Fred Huette and Joni Bosh, NWEC; Kathi Scanlan, WUTC staff; Vlad Gutmen-Britten, Climate Solutions; Katie Ware and Max Greene, Renewable Northwest, on modeling hybrid or co-located resources such as solar + battery and wind + battery. In the 2019 IRP process, a 100 MW solar PV plus a 25 MW 2hr Lithium Ion battery was modeled with a 10% benefit to costs for co-locating the resource. The benefit represents that the battery can use the same substation and interconnection as the solar project. Also the battery received the benefit of the solar Investiment Tax Credit (ITC) since it was connected to the solar project. This same resource will be modeled in the 2021 IRP and a wind + battery resource will be added as well. PSE will model a 100 MW wind project located in Washington with a 25 MW 2hr Lithium Ion battery. The costs will be modeled with a 10% reduction for the benefit of co-location. The revised summary excel file has been updated to include these resources.

Capital Costs

Many stakeholders gave feedback on the data sources used for the capital cost average.

1. **Dated information.** PSE received feedback from Fred Huette and Joni Bosh, NWEC, and Vlad Gutman-Britten, Climate Solutions, about using dated sources. PSE has made sure that only the most current information is used for the cost averaging. The updated data is included in the revised summary Excel file. Older data from 2016/2017 is included in the file for comparison purposes, but is not used in the cost average cacluation.
2. **Other utilitiy cost estimates.** Vlad Gutman-Britten, Climate Solutions, suggested that averaging data for capital costs should not be based on so many utility IRP projections. We feel this in an important data point since utilities usually hire a consulting firm to develop this information, as it gives an important perspective from the utility point of view. PSE will keep the other utility cost estimates in the cost average including PSE's 2019 IRP process estimates from HDR (Generic Resource Costs of Integrated Planning, October 2018).
3. **ATB low cost estimate.** Fred Huette and Joni Bosh, NWEC, suggested to use both the low and mid National Renewable Energy Laboratory (NREL) ATB cost estimate. Per the NREL website, the mid case is the most likely scenario, so PSE will only include the mid cost estimate in the cost average and not add the low.

   > Three future scenarios (Constant, Mid, and Low technology cost) through 2050 to reflect a range of perspectives based on published literature:
   >
   > a. **Constant Technology Cost Scenario:** Base Year (or near-term estimates of projects under construction) equivalent through 2050 maintains current relative technology cost differences and assumes no further advancement in R&D.
   > b. **Mid Technology Cost Scenario:** Technology advances through continued industry growth, public and private R&D investments, and market conditions relative to current levels that may be characterized as "likely" or "not surprising."
   > c. **Low Technology Cost Scenario:** Technology advances that may occur with breakthroughs, increased public and private R&D investments, and/or other market conditions that lead to cost and performance levels that may be characterized as the "limit of surprise" but not necessarily the absolute low bound."

4. **Cost curves.** At the suggestion of Fred Huette and Joni Bosh, NWEC, and Vlad Gutman-Britten, Climate Soluations, PSE has compared the Annual Energy Outlook (AEO) cost curves and the NREL ATB (NREL, 2019 Annual Technology Baseline) cost curves. PSE will use the NREL cost curves for future capital costs. This update has been reflected in the revised summary Excel file.
5. **Owner's costs.** Vlad Gutman-Britten, Climate Solutions, requested additional information of the costs that go into owner's costs. Owner's costs are included in overnight costs and are different than Allowance for Funds Used During Construction (AFUDC). The capital costs shared with the IRP stakeholders on May 28 represent "Overnight Capital Costs" which estimate the cost of building the project "overnight" and therefore do not include extra costs incurred during construction. Capital costs are inclusive of the Engineering, Procurement and Construction (EPC) plus the Owner's costs (financing costs), but generally do not include interconnection costs.
6. **Allowance for Funds Used During Construction (AFUDC).** PSE will assume a generic assumption of 10% to the overnight cost to reflect AFUDC from the 2019 IRP process. The revised summary Excel file has been updated to include the total all-in costs that include AFUDC.
7. **Interconnection costs.** The the assumption from the 2019 IRP process will be used for the 2021 IRP. This includes to cost of a substation, 5 miles of transnsmission lines, and 5 miles of gas pipline for the natural gas (NG) . A full discussion of the assumption is included in the HDR report (Generic Resource Costs of Integrated Planning, October 2018) on the PSE's IRP website. The revised summary Excel file has been updated to include the total all-in costs that include interconnection costs.
8. **Vintage year for average**. Many of the data sources used provide costs for different vintage years. PSE used the year with the most data and averaged across data sources that provided costs for that particulat vintage year.This meant that certain data sources were left out because costs were provided for a different year. For example, the battery storage resource was averaged for the year 2020 since that had the most data points. But this meant that the costs for the Lazard report (2019 Levelized Cost of Energy) were left out since those were for a 2018 vintage plant. The different data sources did not provide any information on inflation to change the costs into a different vintage and PSE did not make any assumptions to change the vintage year. For the 2021 IRP, PSE will remain with this assumption, but is open to suggestions for how to handle it in future IRPs.

Economic Life

PSE received feedback from Kathi Sclanlan, WUTC staff, on the assumed economic life of resources stating the solar photovoltaics (PV) economic life has substatiantially increased. PSE has researched this and found that the current manufactors of solar PV will warranty the panels for up to 25 years. Given this information, PSE will update the economic life of solar from 20 to 25 years.

Bill Pascoe, Absaroka Energy & Orion Renewables, asked what is the assumed operating life for pumped stoage hydro (PSH) and battery storage. PSH is assumed to have a 30 year-life and batteries are assumed to have a 20-year life.

Hydrogen as a Fuel

Many stakeholders, including Kevin Jones and Rob Briggs of Vashon Climate Action Group and Doug Howell of the Sierra Club, gave feedback on using hydrogen as a fuel source for the natural gas generators. PSE has consulted with industry experts and thermal plant engineers. This is an emerging fuel source and PSE will continue to monitor the progress of the technology and applications in the US and abroad, as well as continue our involvement in the development as a member of Renewable Hydrogen Alliance. Many companies are developing hydrogen ready gas turbines that can start with a blended hydrogen to NG fuel and in future years retrofit the combustor to run on 100% hydrogen. Though the technology for turbine exists today, the supply for 100% hydrogen does not. The current gas transportation pipelines can only handle a 3% - 10% hydrogen mix. To move to a higher concentration of hydrogen would require new pipelines or electrolyzer and storage on site. The cost to create the hydrogen fuel is currently unknown. PSE is researching the cost of a hydrogen ready gas turbine and the cost for future retrofits to handle 100% hydrogen along with the costs for the fuel supply. PSE will provide an update on our findings as we begin the portfolio modeling and if there is enough iformation to include it as a resource option in the 2021 IRP. Even if there is not enough information to include it as a resource option, the 2021 IRP will include a discussion of hydrogen as a fuel and the technology need for the fuel supply.

Summary of all Updates

PSE appreciates the feedback provided by stakeholders. In summary, the Excel summary workbook includes the following changes:

- Pumped Storage Hydro overnight capital costs revised to include more data sources and averaging across vintage year 2021 instead of 2020.
- Pumped Storage Hydro size assumption has been revised to 50 MW. PSE will also update operating characteristics for PSH to reflect newer techonology.
- Considering hybrid resources, certain changes have been made in the summary Excel file. Wind + battery resource as been added. PSE will model a 100 MW wind project located in Washington with a 25 MW 2 hr Lithium Ion battery.
- PSE has adopted the NREL data to generate cost curves.
- AFUDC and interconnection costs have been added in a new tab to calculate the all-in capital costs that will be used in the models.
- PSE will update the economic life of solar from 20 to 25 years.
- PSE will further develop costs concerning hydrogen as a fuel for application in the 2021 IRP analysis or if that is not feasible, the 2021 IRP book will include a robust discussion of the state of the industry concerning hydrogen.
- Lithium Ion 2-hr battery and flow 4-hr and 6-hr battery added. PSE was able to collect some other data sources from the PNNL energy storage report and some other utility IRPs besides the HDR report (Generic Resource Costs of Integrated Planning, October 2018).

Figure 1 below is a table comparing the costs from the 2019 IRP, the draft 2021 IRP as presented on May 28, and the updated capital costs after stakeholder feedback. The following table is also located in the revised Excel summary file under the tab “summary” and available for stakeholders can track the costs and calculations.

Figure 1: Overnight capital costs

(2021 Vintage, 2016 U.S. Dollars)	**Overnight Capital Cost ($/kW)**		
	2019 IRP	2021 IRP draft	2021 IRP proposed
CCCT	991	927	943
Frame Peaker	618	660	664
Recip Peaker	931	1,248	1,256
Solar Utility	1,422	1,226	1,264
Solar Residential	--	2,848	2,957
Onshore Wind	1,438	1,484	1,421
Offshore Wind	5,730	4,971	4,377
Pumped Storage	2,176	2,515	2,145
Battery (4hr, Li-Ion)	2,427	1,900	1,542
Battery (2hr, Li-Ion)	1,455	--	849
Battery (4hr, Flow)	1,625	--	2,051
Battery (6hr, Flow)	2,244	--	2,860
Solar + Battery	2,698	--	1,901
Wind + Battery	--	--	2,043
Biomass	7,744	5,119	5,246

Figure 2 below is a table showing how the AFUDC and interconnection costs are added to the overnight for the final all-in costs that PSE will be using for portfolio modeling. The following table is also located in the revised Excel summary file under the tab “summary” and available for stakeholders can track the costs and calculations. The cost curve with costs by vintage year are also included with this table.

Figure 2: All-in capital costs

(2021 Vintage, 2016 U.S. Dollars)	Overnight Capital	AFUDC	Interconnection Costs	Total All-In Capital cost
CCCT	943	94	91	1,128
Frame Peaker	664	66	134	865
Recip Peaker	1,256	126	143	1,525
Solar Utility	1,264	126	100	1,489
Solar Residential	2,957	296	--	3,252
Onshore Wind	1,421	142	47	1,610
Offshore Wind	4,377	438	65	4,878
Pumped Storage	2,145	214	47	2,406
Battery (4hr, Li-Ion)	1,542	154	367	2,063
Battery (2hr, Li-Ion)	849	85	367	1,301
Battery (4hr, Flow)	2,051	205	367	2,624
Battery (6hr, Flow)	2,860	286	367	3,513
Solar + Battery	1,901	190	420	2,511
Wind + Battery	2,043	204	373	2,620
Biomass	5,246	525	607	6,378

Webinar 2, June 10, 2020

Electric Price Forecast

PUGET SOUND ENERGY

Webinar #2: Electric Price Forecast
June 10, 2020 from 1:30 p.m. to 4:30 p.m. PST

Virtual webinar link: https://global.gotomeeting.com/join/993123797

Meeting ID: 993-123-797

Call-in telephone number (audio only): +1 (224) 501-3412

Topic	Lead
Welcome • How to participate • Agenda review	EnviroIssues
Safety moment **Team introductions**	Irena Netik, Director, Energy Supply Planning & Analytics
Public participation approach	EnviroIssues
The 2021 IRP • IRP modeling process • Project timeline	Irena Netik, Director, Energy Supply Planning & Analytics
How is the electric price forecast used?	Elizabeth Hossner, Manager, Resource Planning
Electric price forecast presentation • Modeling overview • 2017 and 2019 IRP review • Results of 2021 draft electric price forecast	Elizabeth Hossner, Manager, Resource Planning Jennifer Magat, Senior Energy Resources Planning Analyst
5-minute break	
Electric price forecast presentation (continued) • Clean energy regulation assumptions • 2021 electric price scenarios	Elizabeth Hossner, Manager, Resource Planning
Question & answer • More participant questions • Using the Feedback Form	Facilitated by EnviroIssues
Wrap up • Next steps • Upcoming meeting schedule • Thank you's	Irena Netik, Director, Energy Supply Planning & Analytics

2021 IRP Webinar #2:
Draft Electric Price Forecast

Planning Assumptions & Resource Alternatives
Electric Portfolio Model

June 10, 2020

Agenda

- Safety moment
- How is the electric price forecast used?
- Modeling overview
- Review of 2017 IRP and 2019 IRP Progress Report electric price forecasts
- Results of draft 2021 IRP electric price forecast
- Clean energy regulation assumptions
- 2021 IRP electric price scenarios

Safety Moment

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Speakers

PUGET SOUND ENERGY

Public participation in the 2021 IRP

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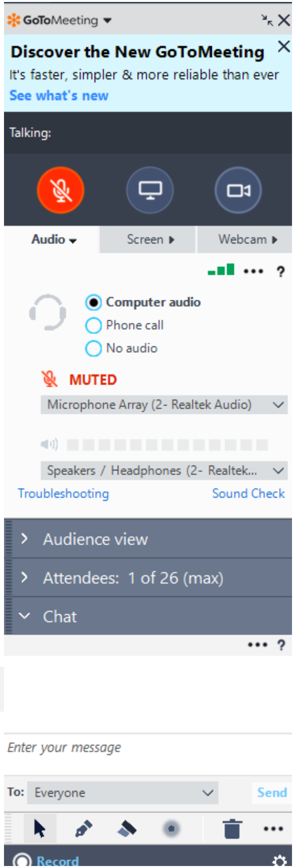
Welcome to the webinar and thank you for participating!



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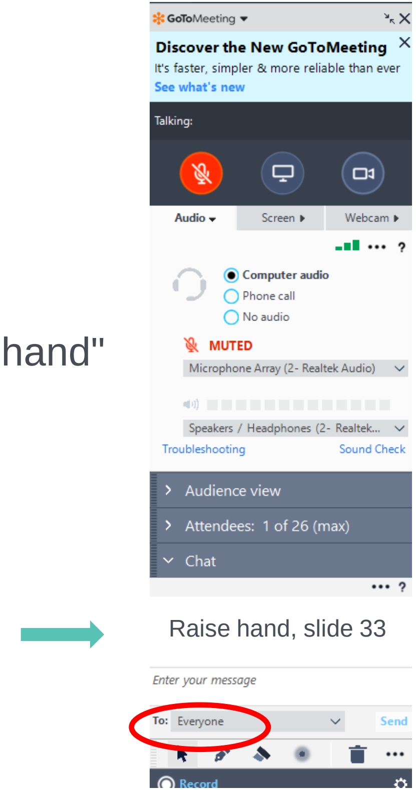
Presentation Do's

- Mute your mic during the presentation
- Ask clarifying questions using the Chat window
- Share your questions or comments with "Everyone"
- During question time, reference Slide # and type "Raise hand"
- Wait to be called on to ask your question



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2021 IRP modeling process

The 2021 IRP will follow a 6-step process for analysis:

1. Establish peak capacity, energy and renewable energy need
2. Determine planning assumptions and identify supply-side and demand-side resource alternatives
3. Analyze scenarios and sensitivities using deterministic and stochastic risk analysis
4. Analyze results
5. Develop resource plan
6. Develop 10-year Clean Energy Action Plan

2021 IRP process timeline

Meeting dates are available on pse.com/irp and will be updated throughout the process. This is a tentative timeline subject to revision.

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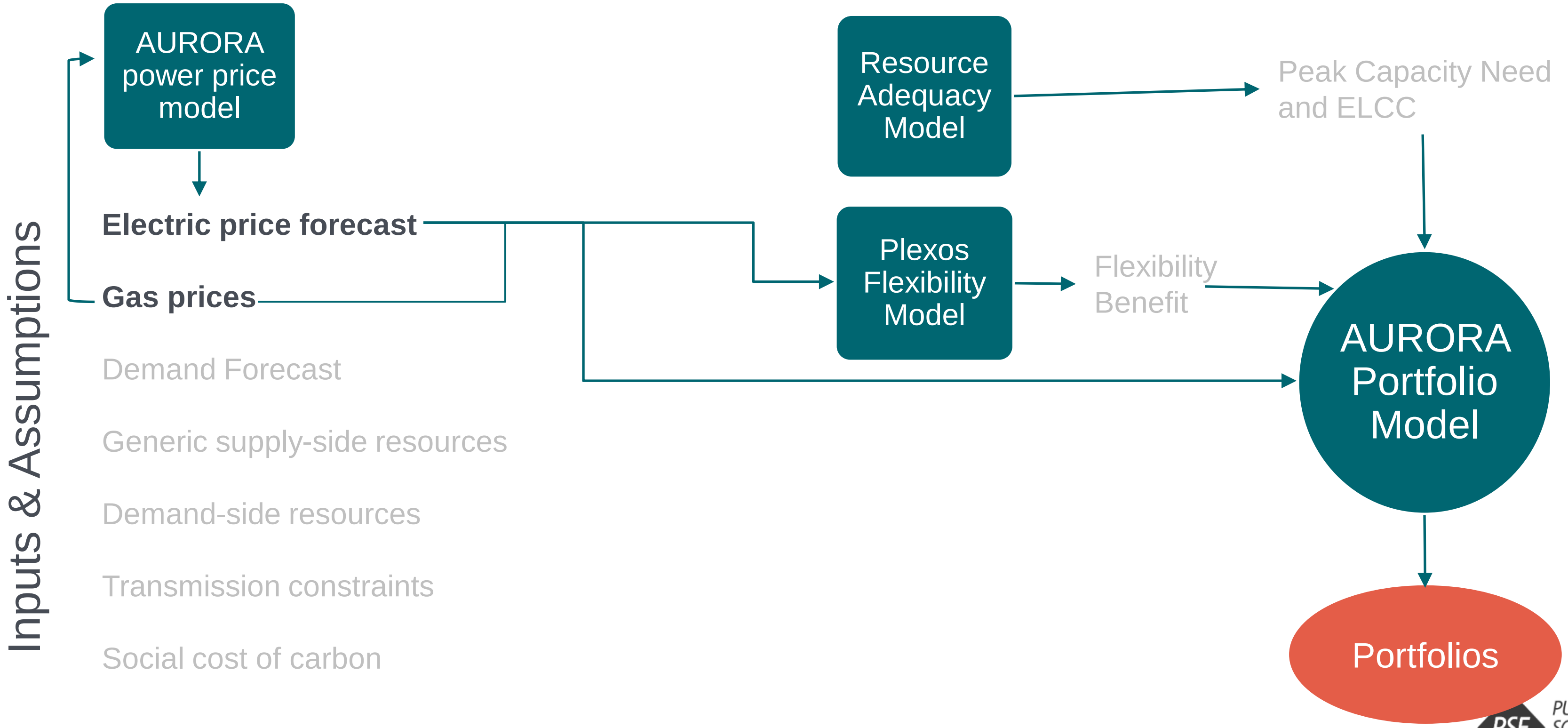
How is the electric price forecast used?

How is the electric price forecast used?

- IRP
  - The electric price forecast is used as the cost of wholesale market purchases and for economic dispatch of power plants in both the Plexos flexibility model and the AURORA portfolio model.
  - It is used to determine the value of the resource against the market.
- Analysis to support resource acquisitions
  - The acquisition analysis uses the same models as the IRP an the electric price forecast is used in the manner as the IRP.
  - The acquisition analysis also incudes CETA implementation and RPS incremental cost calculation evaluation.
- Avoided costs for Energy Efficiency Services (EES) measure evaluation
  - The electric price forecast is used to evaluate cost effective energy efficiency measures.
- Schedule 91 & 92 for PURPA resources - Public Utility Regulatory Policies Act (**PURPA**, Pub. L. 95–617, 92 Stat. 3117, enacted November 9, 1978)
  - Schedule 91 are the tariff rates for small renewables resources <5 MW
  - Schedule 92 are the avoided cost rates for large renewable resources 5-80 MW
- Other analysis as needed for the company

Modeling overview

Electric IRP Models

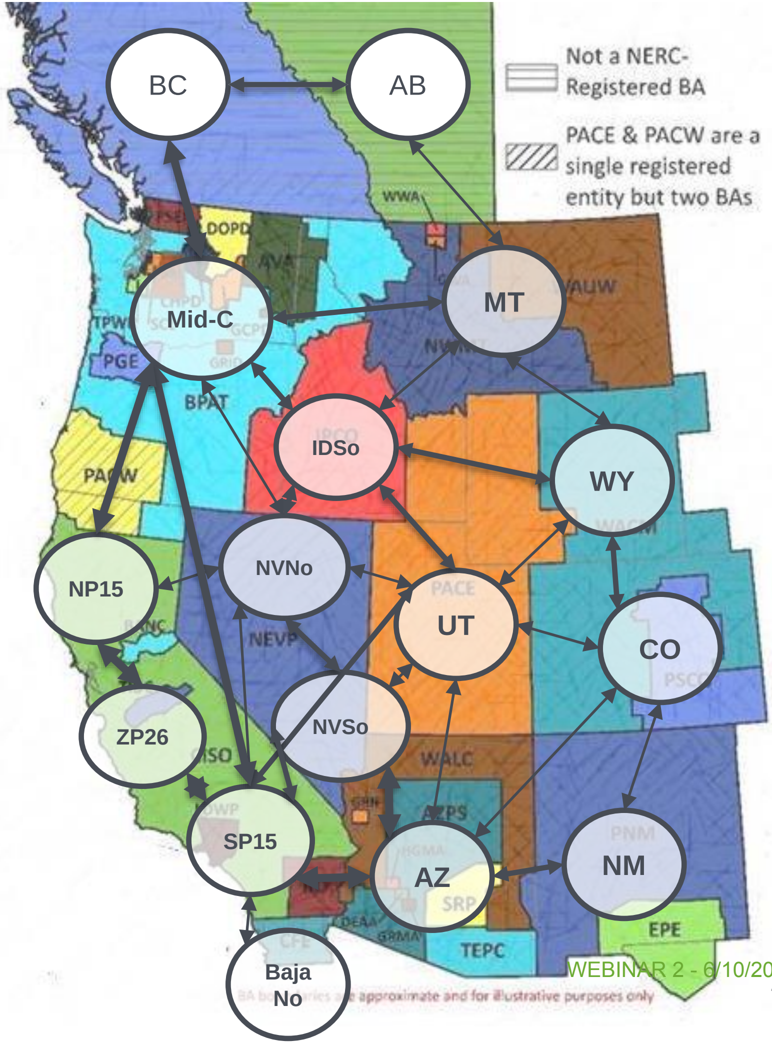


How does PSE create power prices?

- PSE uses a software model called AURORA.
  - Software for forecasting wholesale power market prices, long term capacity expansion, portfolio analysis and risk analysis
  - AURORA is a fundamentals-based model that employs a multi-area, transmission-constrained dispatch logic to simulate real market conditions
- PSE started using AURORA in 1999 for power costs then in 2003 for IRP and acquisitions.
- AURORA users include
  - Utilities, including investor-owned utilities (IOUs), publics, co-ops and municipalities
  - State public utility commissions, inter-state and federal agencies, system operators and other regional planning authorities
  - Traders, independent power producers (IPPs), developers and financial institutions
  - Consultants, universities and national labs

AURORA BY ENERGY EXEMPLAR

PSE PUGET SOUND ENERGY



AURORA system diagram for WECC

The WECC system diagram provides an object view of each zone definition system being modeled. A system diagram has been created for all delivered zone definition systems.

Legend – Transmission Links:
< 650 MW
650 – 2000 MW
> 2000 MW

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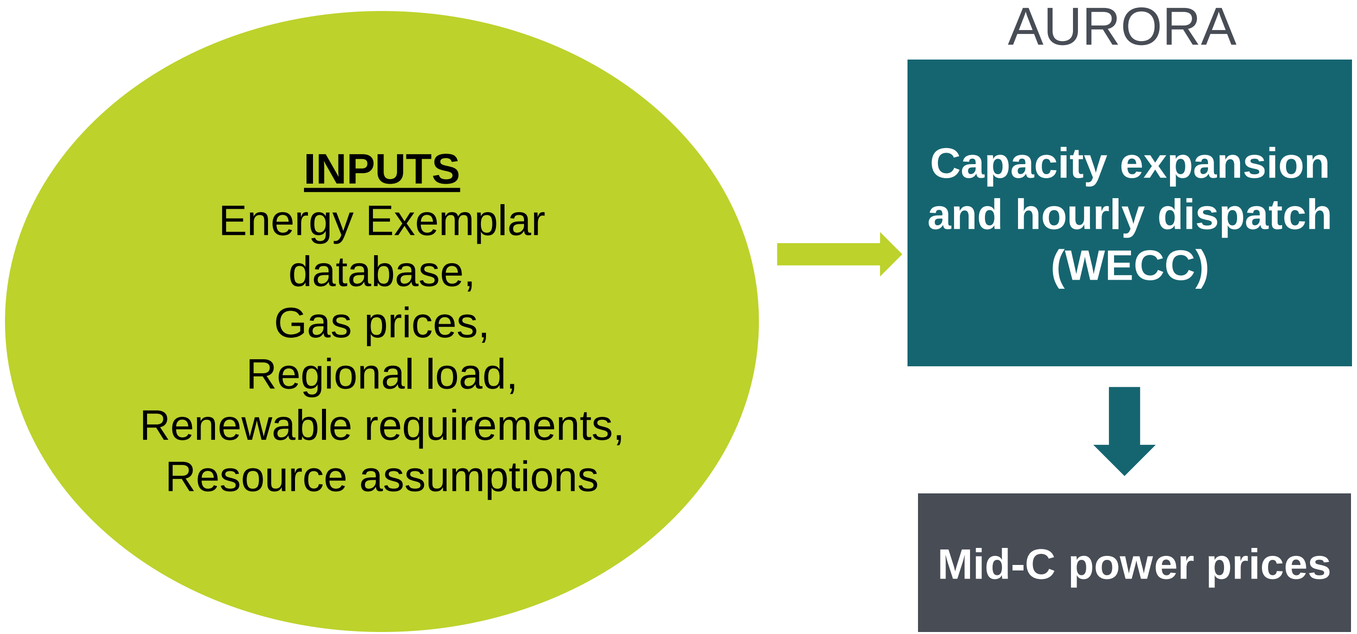
Electric price forecast model



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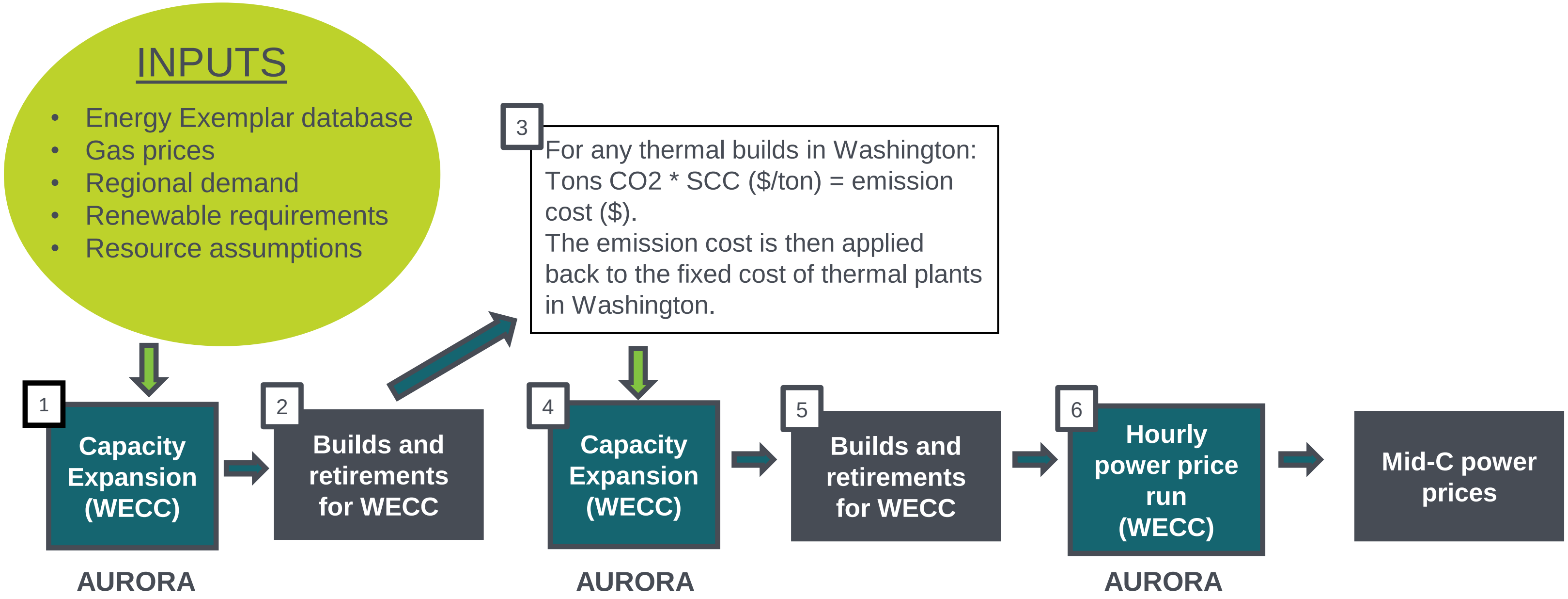
The social cost of carbon (SCC) is reflected as a planning adder in the electric price forecast



Notes:

1. This methodology is for the electric price forecast. The methodology for the portfolio model will be discussed at the July 21 webinar.
2. In the electric price model, no new thermal plants are built in Washington State.

Review of 2017 IRP and 2019 IRP Progress Report electric price forecasts

Changes in assumptions for electric price forecast from 2017 IRP to 2019 IRP Progress Report

- Lower regional load from the 7th Power Plan
- Lower gas prices using the Wood Mackenzie prices released in Spring 2018
- Adaptation of regional clean energy policies
  - Nevada renewable requirement increased from 25% to 50% by 2030 and 100% by 2050
  - New Mexico increased from 20% RPS to 100% zero carbon by 2045
  - California SB 100, renewable requirement increased from 50% RPS to 60% renewable resources by 2030 and 100% by 2045
  - Washington SB 5116 Clean Energy Transformation Act, increased from 15% renewable requirement to 80% renewable resources by 2030 and 100% by 2045

2019 IRP Progress Report clean energy policy assumption for electric price forecast

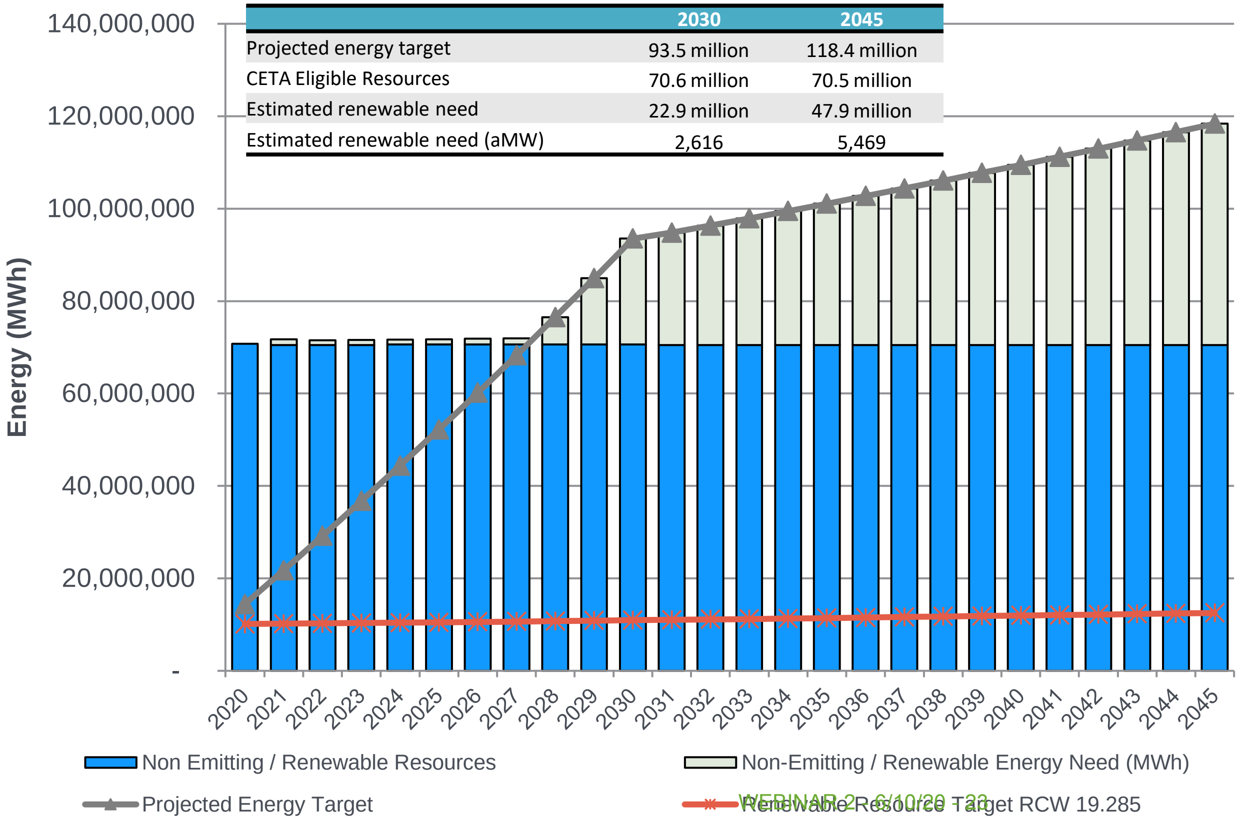
With stakeholder input, the 2019 IRP Progress Report electric price forecast assumed a renewable need of 22.9 million MWh in 2030, approximately 8,700 MW nameplate capacity of new renewable resources added in Washington state.

The renewable need assumption was based on the following:

- The utilities, that are currently more than 80% hydro, will reach 100% by 2030
- The utilities, that are less than 80% hydro, will reach 80% by 2030
- Applying the above assumptions to the 2018 Washington Department of Commerce fuel mix report provides:
    - 52% of sales in Washington by utilities will reach 100% by 2030
    - 48% of sales in Washington by utilities will reach 80% by 2030
    - This comes to an additional 22.9 million MWh (approx. 8,700 MW nameplate) of new renewable resources added in Washington State.

Renewable energy needed in Washington to support Clean Energy Transformation Act

	2030	2045
Projected energy target	93.5 million	118.4 million
CETA Eligible Resources	70.6 million	70.5 million
Estimated renewable need	22.9 million	47.9 million
Estimated renewable need (aMW)	2,616	5,469



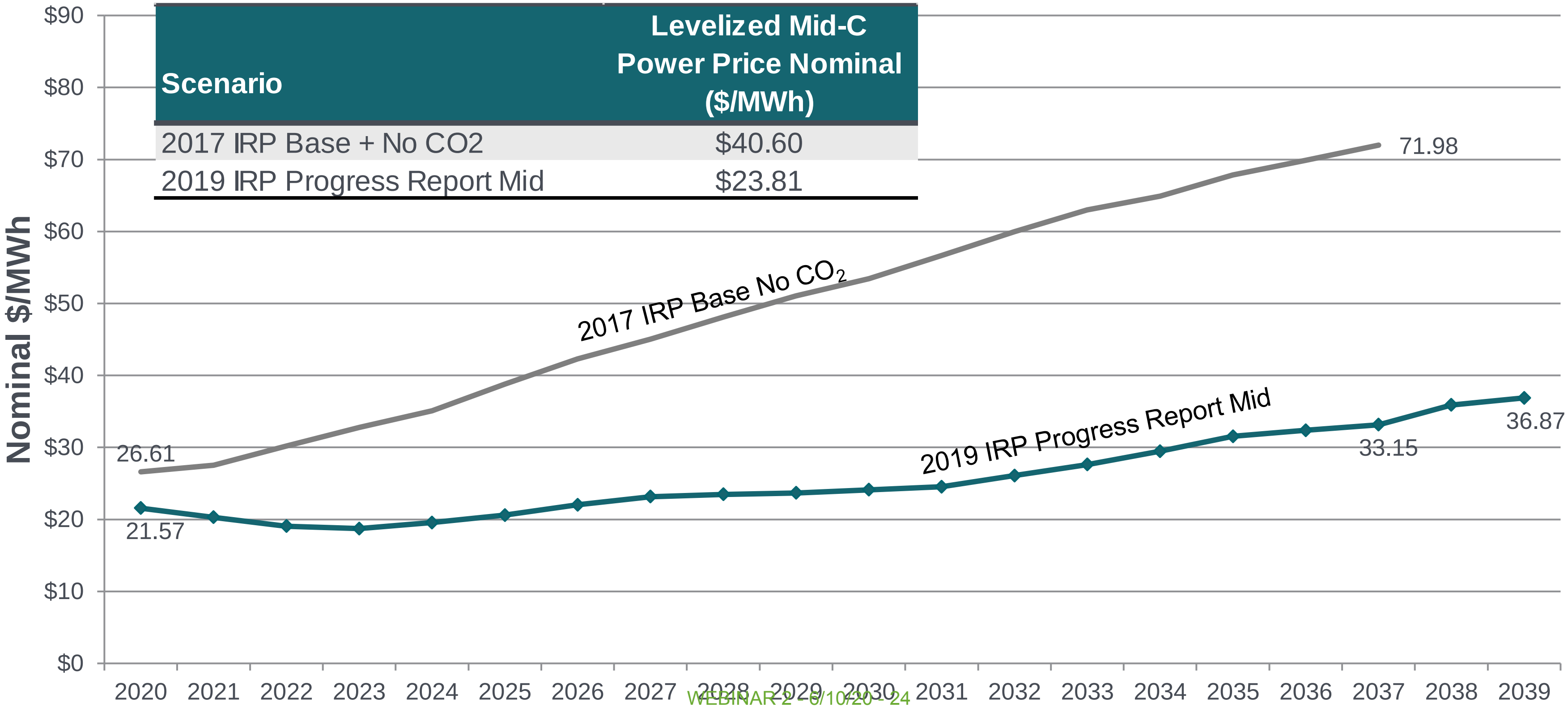
Renewable need for 2020 – 2028 is based on RCW 19.285. Starting in 2029, the incremental renewable need is higher to meet the requirement of 80% of sales under SB 5116 in 2030.

Non-emitting resources such as hydro and nuclear are eligible to meet the requirement. Washington State Electric Utilities Fuel Mix Report from 2000 – 2017 show the average hydro as 6,619 aMW and nuclear as 480 aMW. A total of 7,098 aMW will be used as a proxy annual contribution from hydro and nuclear when determining the incremental renewable need for Washington under SB 5116.

PSE PUGET SOUND ENERGY

2017 IRP vs 2019 IRP Progress Report Mid-C electric price forecast

Scenario	Levelized Mid-C Power Price Nominal ($/MWh)
2017 IRP Base + No CO2	$40.60
2019 IRP Progress Report Mid	$23.81



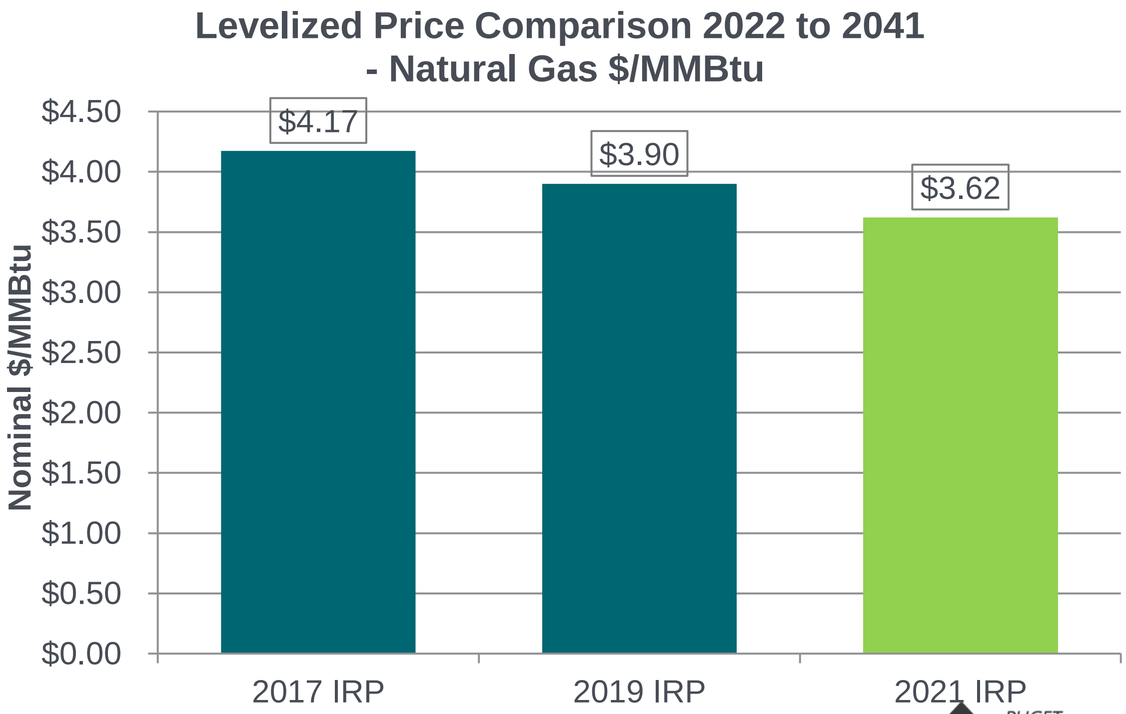
Results of draft 2021 IRP electric price forecast

2021 IRP electric price update

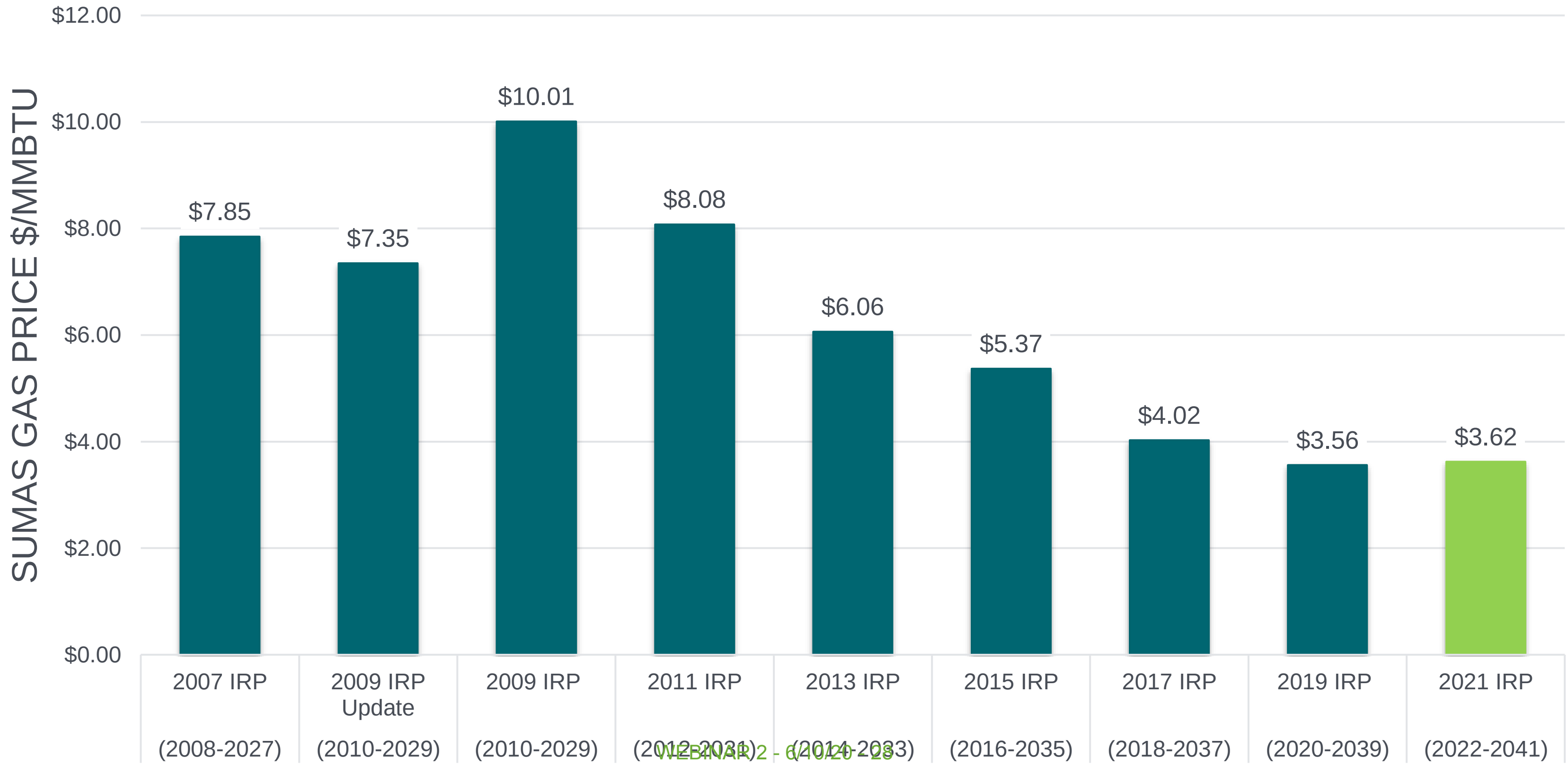
What didn't change?	What changed?
• North American Database v2018 in Aurora • Regional Demand from the 7th Power Plan • Clean energy policies adopted in the 2019 IRP process: Arizona decision 69127 California SB100 Nevada SB358 New Mexico SB489 Montana SB164 Oregon SB1547 Utah SB202 Washington SB5116	• Implemented the latest available Aurora Version 13.4 • Updated generating resource additions and retirements using S&P Global Data • Updated new regional renewable resources needs Colorado: 100% clean energy sources by 2050 for utilities serving 500,000 or more customers Reflected changes in need due to new renewable resources in construction phase • Included updated gas price forecast from Wood Mackenzie

2021 IRP gas price forecast is lower than the 2019 IRP

MID GAS PRICES. From 2022-2025, this IRP uses the three-month average of forward marks for the period ending Jan 31, 2020. Forward marks reflect the price of gas being purchased at a given point in time for future delivery. Beyond 2025, this IRP uses Wood Mackenzie long-run, fundamentals-based gas price forecasts that were published in Fall 2019.

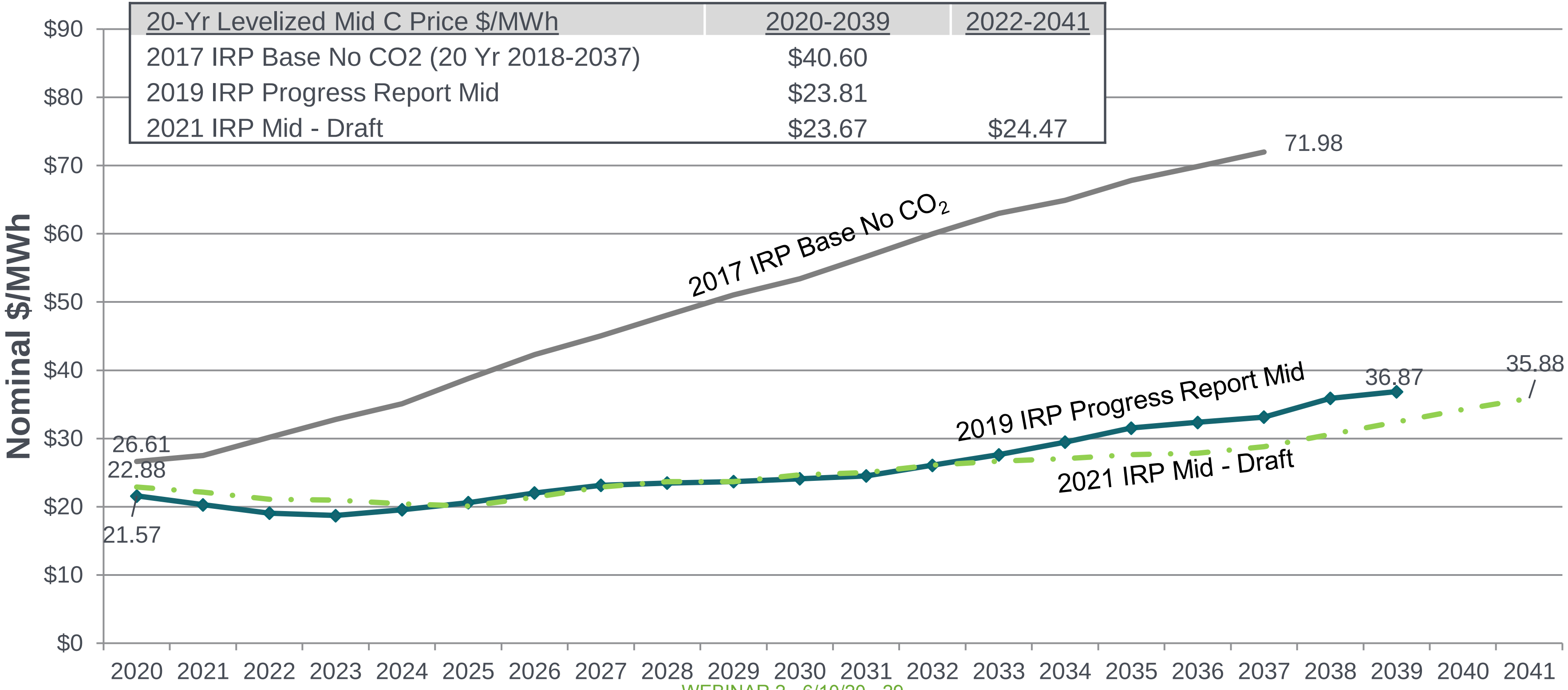


Comparison of gas price forecasts

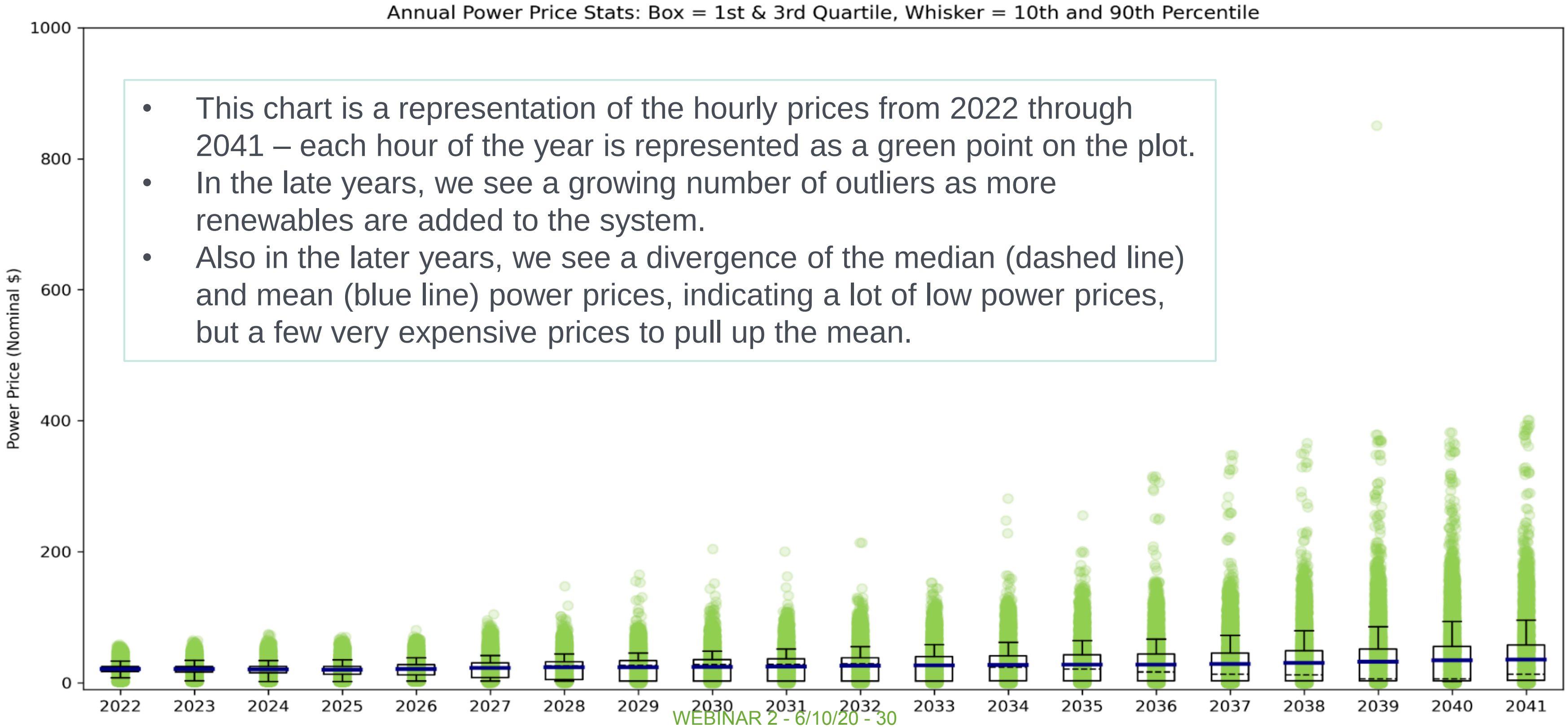


2021 IRP electric price update

20-Yr Levelized Mid C Price $/MWh	2020-2039	2022-2041
2017 IRP Base No CO2 (20 Yr 2018-2037)	$40.60	
2019 IRP Progress Report Mid	$23.81	
2021 IRP Mid - Draft	$23.67	$24.47



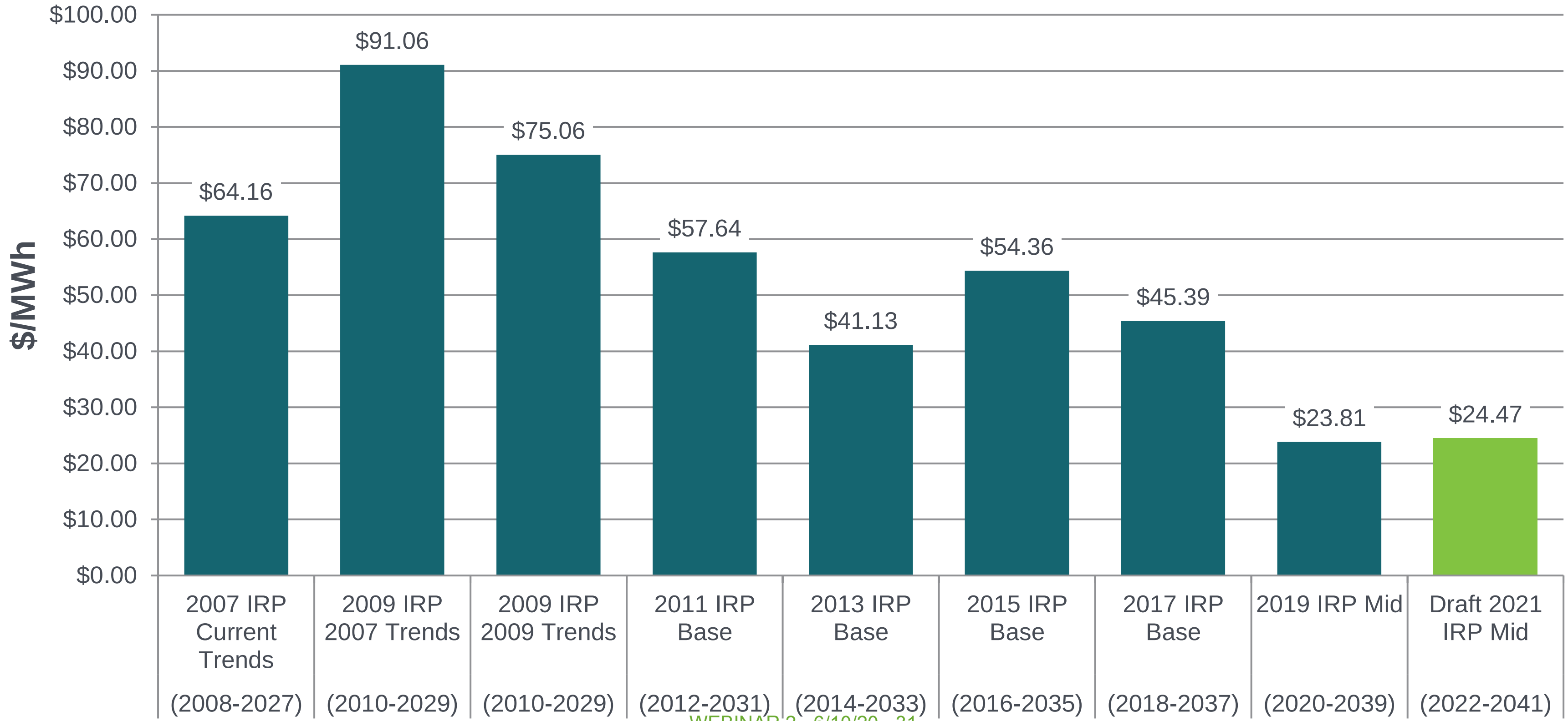
2021 IRP electric prices show increased variability over time



- This chart is a representation of the hourly prices from 2022 through 2041 – each hour of the year is represented as a green point on the plot.
- In the late years, we see a growing number of outliers as more renewables are added to the system.
- Also in the later years, we see a divergence of the median (dashed line) and mean (blue line) power prices, indicating a lot of low power prices, but a few very expensive prices to pull up the mean.

* Solid blue line: average power price; Dashed blue line: median power price

Comparison of electric price forecasts



5-minute break

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Participation Objective

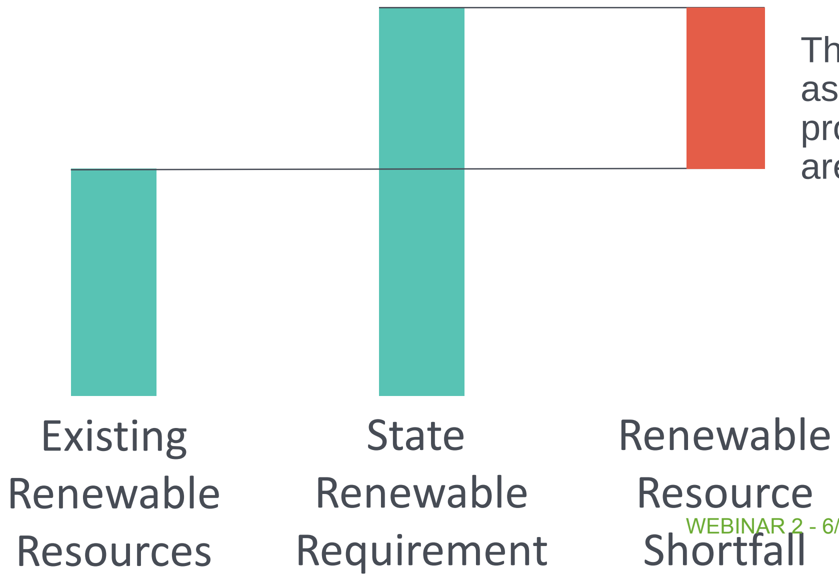
- Stakeholders share input on incorporating clean energy policies in baseline assumptions to inform the electric price forecast
- Stakeholders share input on alternative electric price scenarios that vary demand, gas prices, or clean energy implementation

PUGET SOUND ENERGY

Clean energy regulation assumptions

How PSE models clean energy regulation assumptions

- For each state, we must determine what amount of renewable resources must be built in order to meet renewable energy requirements in that state.
- By comparing the existing resource pool to the forecasted resource need, we determine how many renewable energy resources need to be added.



The resulting deficit of renewable resources is used as a constraint in the capacity expansion modeling process to ensure that enough renewable resources are built.

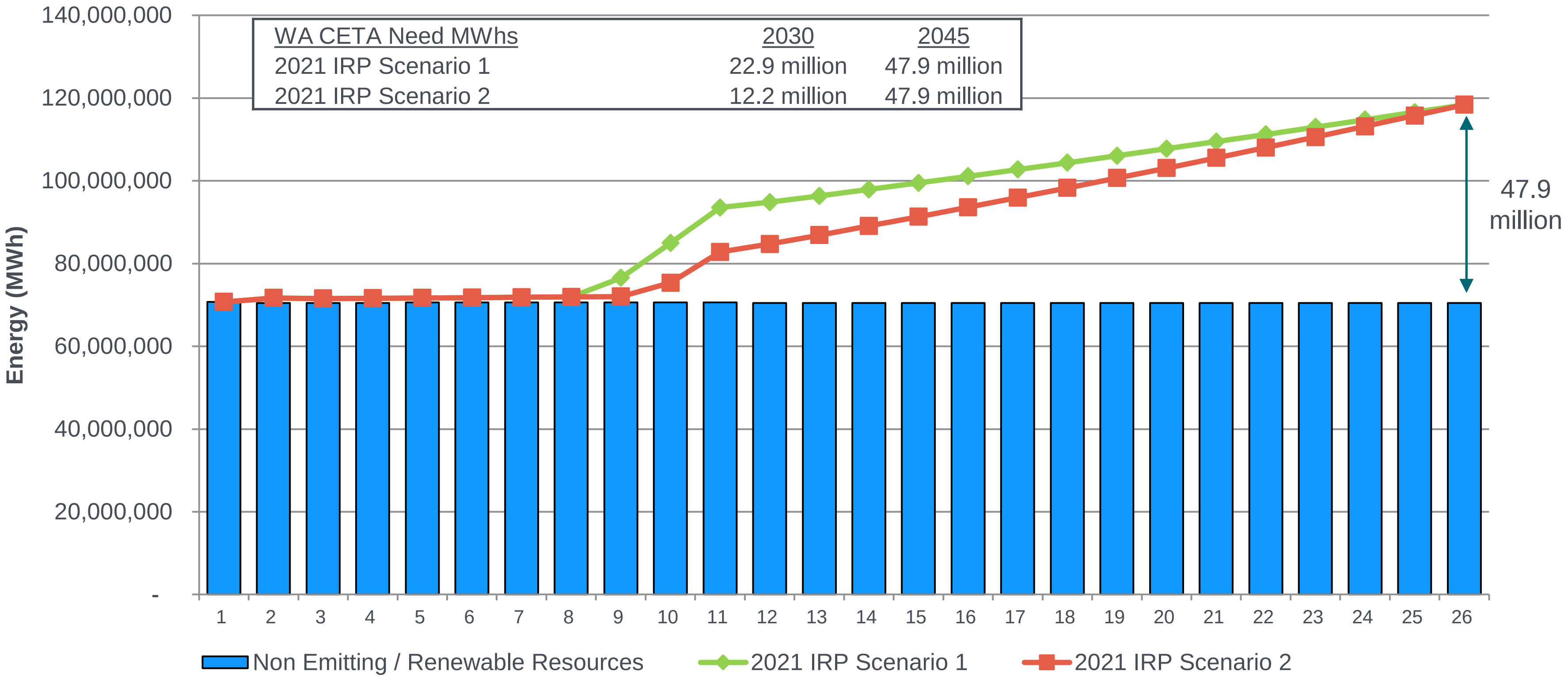
Clean energy regulation assumptions for electric prices

- With stakeholder input, the 2019 IRP Progress Report electric price forecast assumed that 90% of electric sales in Washington will be met by renewable resources by 2030.
  - This is a total of 22.9 Million MWh (approx. 8,700 MW) of new renewable resources added in Washington State by 2030.

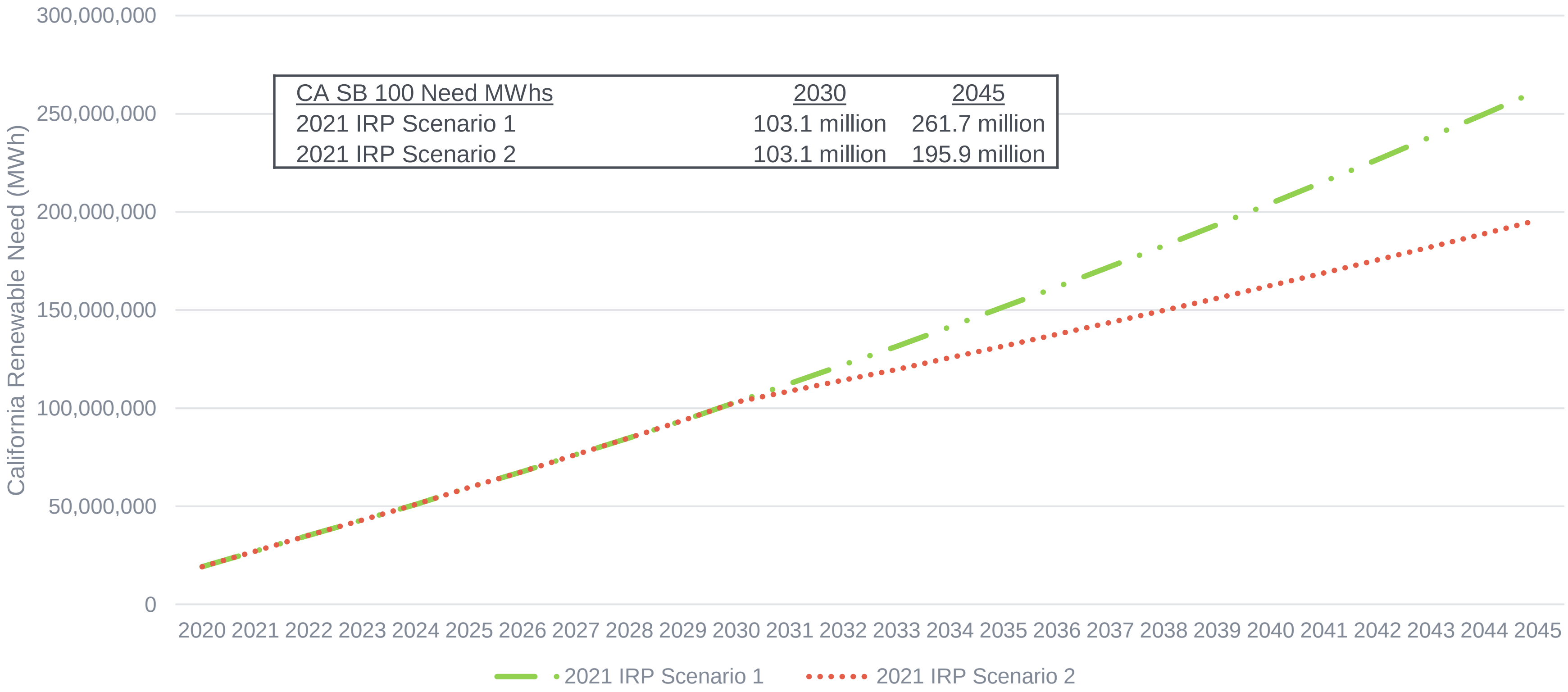
- California SB100 requires 60% renewable or carbon free resources by 2030 and a *goal* to get to 100% by 2045.
  - The 2019 IRP assumed that California would reach the 100% goal with all renewable resources, but the law allows for other non-renewable carbon free resources.

	Washington	**California**
Clean Energy Implementation Scenario 1	22.9 million MWh by 2030 47.9 million MWh by 2045	103.1 million MWh by 2030 261.7 million MWh by 2045
Clean Energy Implementation Scenario 2	12.2 million MWh by 2030 47.9 million MWh by 2045	103.1 million MWh by 2030 195.8 million MWh by 2045

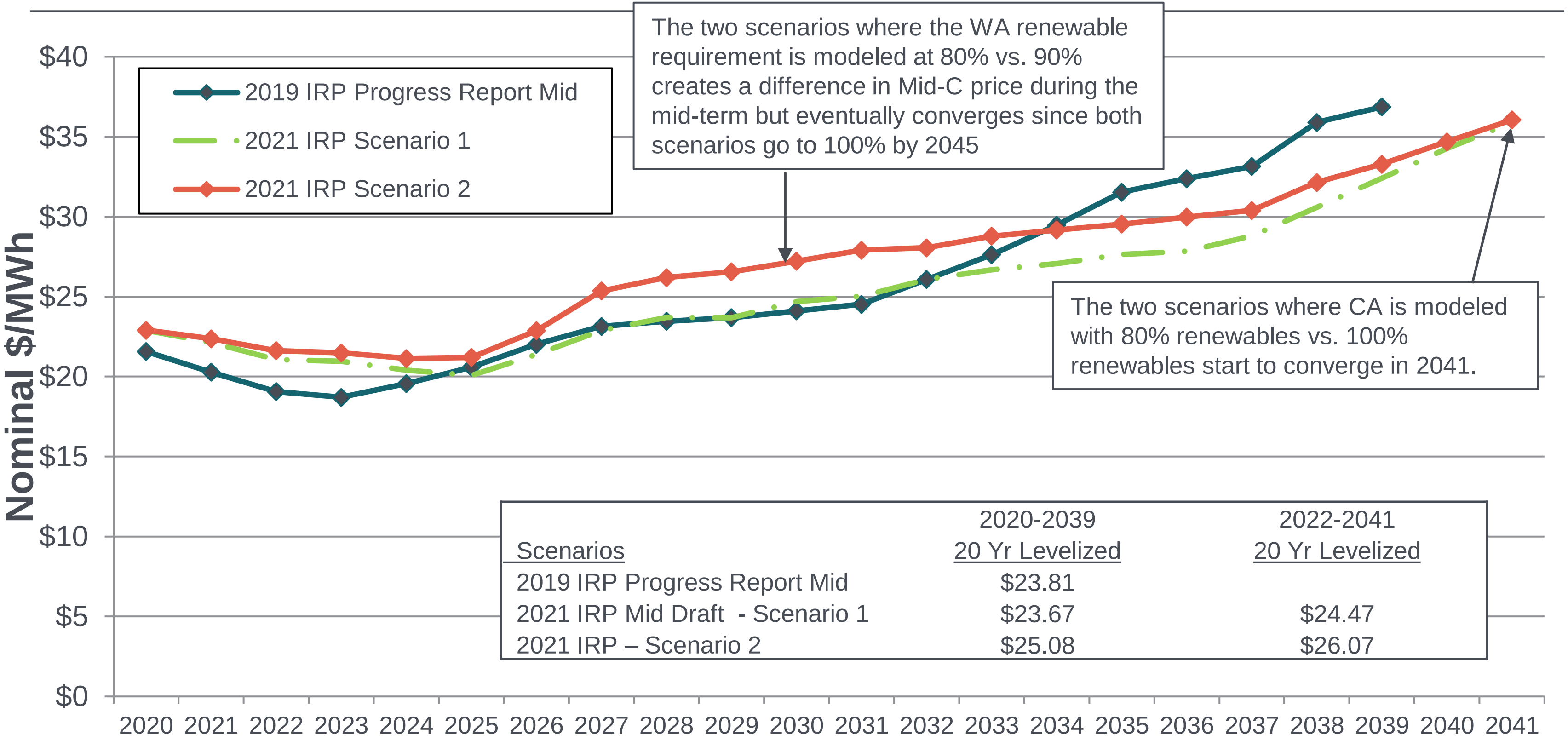
Washington CETA renewable need



California SB 100 renewable need



Clean Energy regulation sensitivities



Scenarios	2020-2039 20 Yr Levelized	2022-2041 20 Yr Levelized
2019 IRP Progress Report Mid	$23.81	
2021 IRP Mid Draft - Scenario 1	$23.67	$24.47
2021 IRP – Scenario 2	$25.08	$26.07

Stakeholder feedback

PSE is looking for feedback on which clean energy implementation scenario to use for the electric price forecast

- Should we use the higher renewable resource shortfall in 2030 of 22.9 million MWh or the lower 12.1 million MWh for Washington?
  - Note: the MWh need is based on the mid demand forecast and will adjust with the low and high demand forecast.
- This assumption can be modeled as
  1. The same RPS/clean energy regulation assumption that will be used in all the electric price scenarios modeled, or
  2. Varied by electric price scenario

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2021 IRP electric price scenarios

What is an electric price scenario?

Electric price scenarios are different sets of assumptions that create future electric market conditions.

- Gas prices, carbon regulation and regional loads create different wholesale electric prices, which affect the relative value of different resources.
- Wholesale electric price forecasts are developed using the AURORA model.
- This analysis models all major generators in the interconnected Western U.S., along with loads.

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Electric price scenarios vs. portfolio sensitivities

The purpose of a scenario is to create a 20-year electric price forecast.

The purpose of the sensitivity is to test different resources in PSE's portfolio.

Scenarios are about the market; sensitivities are about PSE's place in the market.

2021 IRP draft scenarios for electric price analysis

Scenario	Demand	Gas Price	CO_2 price/Regulation	RPS/Clean Energy Regulation
1. Mid	Mid	Mid	**CO_2 price:** CA AB32, and BC **CO_2 Regulation:** Social Cost of Carbon and upstream natural gas GHG in WA	WA CETA plus all other state regulations in the WECC
2. Low	Low	Low	**CO_2 price:** CA AB32, and BC **CO_2 Regulation:** Social Cost of Carbon and upstream natural gas GHG in WA	WA CETA plus all other state regulations in the WECC
3. High	High	High	**CO_2 price:** CA AB32, and BC **CO_2 Regulation:** Social Cost of Carbon and upstream natural gas GHG in WA	WA CETA plus all other state regulations in the WECC
4. No CETA	Mid	Mid	**CO_2 price:** CA AB32, and BC	WA 15% RPS plus all other state regulations in the WECC

Stakeholder feedback

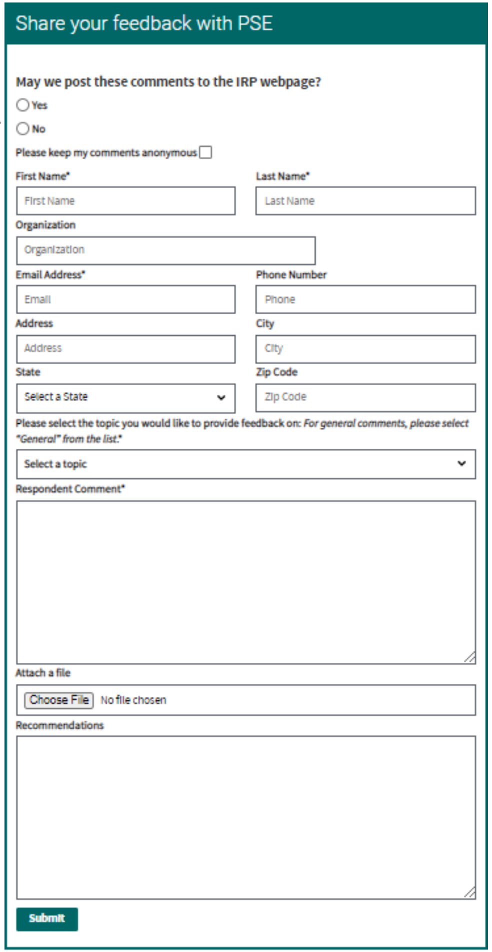
PSE is looking for feedback on other electric price scenarios that vary

- Demand,
- Gas prices, or
- Clean energy implementation

Scenario	Demand	Gas Price	CO_2 price/Regulation	RPS/Clean Energy Regulation
5. Stakeholder scenario	?	?	**CO_2 price:** CA AB32, and BC **CO_2 Regulation:** Social Cost of Carbon and upstream natural gas GHG in WA	?

Feedback Form

- An important way to share your input
- Available on the website 24/7
- Comments, questions and data can be submitted throughout the year, but timely feedback supports the technical process
- Please submit your Feedback Form <u>within a week of the meeting topic</u>


Share your feedback with PSE

May we post these comments to the IRP webpage?

Yes

No

Please keep my comments anonymous

First Name* | Last Name*

Organization

Email Address* | Phone Number

Address | City

State (Select a State) | Zip Code

Please select the topic you would like to provide feedback on: *For general comments, please select "General" from the list.*

Select a topic

Respondent Comment*

Attach a file

Choose File No file chosen

Recommendations

Submit

Feedback Form

Feedback Report

Consultation Update

Questions & Answers

Next steps

- Submit Feedback Form to PSE by **June 17, 2020**
- A recording and the chat from today's webinar will be posted to the website **tomorrow**
- The Feedback Report from the Generic Resource Assumptions webinar will also be posted **tomorrow.**
- PSE will compile all the feedback in the Feedback Report and post all the questions by **June 24**
- By **July 1**, PSE will make a decision on what costs to use. The documentation for the decision made will be released in a Consultation Update that will be posted to the website

Upcoming meetings

- Stakeholders can register for upcoming meetings on the website
- Agendas and meeting materials will be posted one week prior to each meeting
- Meetings will be added as the IRP technical work progresses

Date	Topic
June 30, 1:30 pm – 3:30 pm	Transmission Constraints
July 14, 1:30 pm – 4:30 pm	Demand Side Resources
July 21, 1:30 pm – 4:30 pm	Social Cost of Carbon
August 11, 9:30 am – 12:30 pm	Develop Portfolio Sensitivities

Thank you for your attention and input.

Please complete
your Feedback Form by June 17, 2020

We look forward to your attendance at PSE's next public participation webinar:

Transmission Constraints

June 30, 2020

PSE PUGET SOUND ENERGY

Webinar #2: Electric Price Forecast Q&A

DRAFT 6/11/2020

Overview

On June 10, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss the electric price forecast. Stakeholders shared their input on incorporating clean energy policies in baseline assumptions to inform the electric price forecast. Participants were able to submit feedback on the webinar and meeting materials prior to and after the webinar occurred. Additionally, participants were able to ask questions using a chat box provided by the GoToMeeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 68 people attended the meeting, including project staff and six attendees who only called into the meeting and did not identify themselves.

Attendees included:

James Adcock, Larry Becker, Charlie Black, Joni Bosh, Robert Briggs, Koch, Cathy, Stephanie Chase, Zhi Chen, Weimin Dang, Cody Duncan, Kara Durbin, Nancy Esteb, Spencer Gray, Brian Grunkemeyer, Vlad Gutman-Britten, Kelly Hall, Warren Halverson, Lori Hermanson, Fred Heutte, Mike Hopkins, “J”, Elizabeth Hossner, Brandon Houskeeper, David Howarth, Doug Howell, Charles Inman, Magat, Jennifer, Kevin Jones, Eric Kang, Dan Kirschner, Michele Kvam, Sarah Laycock, Virginia Lohr, Penny Mabie, Kate Maracas, Kassie Markos, Don Marsh, Sheri Maynard, Jennifer Mersing, David Meyer, Irena Netik, Valerie O'Halloran, Court Olson, Anthony O'Rourke, Bill Pascoe, David Perk, Alison Peters, Kathi Scanlan, Gurvinder Singh, Alexandra Streamer, Tyler Tobin, Rahul Venkatesh, Katie Ware, Eddie Webster, Elyette Weinstein, Willard (Bill) Westre, Bob Williams, John Williams, Scott Williams, and Zacarias Yanez.

Questions Received

Questions from attendees are posted in the order in which they were received. The first four rows represent questions submitted in advance through the Feedback Form. The webinar began at 1:30 PM PDT and ended at 4:30 PM PDT. A full verbatim chat log is available as an appendix.

Slide number	Question	Sent by
Intro	Can you please enumerate in detail all of the various types of historical data used anywhere in any of your modeling efforts, including the earliest calendar year and latest calendar year from which each of those historical data types was used.	James Adcock
24	On this page you state for the "2021 IRP electric price update" that the "Regional Demand from the 7th Power Plan" didn't change. Why didn't it change? Why would you not assume a downturn in demand due to the downturn in the economy due to COVID-19? Shouldn't your regional demand assumptions be updated to recognize the reality of the huge change in the regional economy, and thereby demand, caused by COVID-19? Economists are projecting that it will take a decade for the US Economy to recover from COVID-19.	James Adcock
28	Can you please list all of the assumptions, and all of the data used, including historical range of dates from which that data was collected, in generating this plot?	James Adcock
42	Given that CETA is now "the law of the land" why is it appropriate to develop a scenario where you assume that you do not have to meet the CETA requirements?	James Adcock
Welcome Slide	is this the link for go to meeting that will be used for the future meetings? ditto for the code?	Joni Bosh
Welcome Slide	Can everyone see questions and comments posted here?	Doug Howell
8	Slide 8-Staff requests when discussing IRP scenarios used to develop planning assumptions, including alternative scenarios and 'futures', PSE clearly define what it means by each case, including 'base case' and clearly label and reference what is meant for each case for the discussion today	Kathi Scanlan
11	Slide 11-what other analyses needed for the company (last bullet)?	Kathi Scanlan
11	Do avoided costs take into account both avoided generation and avoided T&D?	Don Marsh

Slide number	Question	Sent by
8	Slide Page 8 Raise Hand. But what *are* your "planning assumptions?" Whenever we ask you what is your input modeling data, including what range of calendar dates for each of those input datas, you refuse to answer us. And this has been going on for more than 10 years now. The input modeling data IS part of your "planning assumptions"	James Adcock
11	Slide Page 11 Raise Hand. How do you model the difference in "market prices" between emitting sources of electricity vs. non-emitting sources of electricity? Moving forward towards 2030 the great majority of your electricity needs to come from non-emitting sources.	James Adcock
11	Just to clarify, is the electric price forecast the same value for all the listed uses on slide 11?	Joni Bosh
13	Slide 13-Clarifying Question: When is PSE planning to discuss its resource adequacy and flexibility model(s) in greater detail? Dates of webinars/meetings?	Kathi Scanlan
13	Is Plexos a power flow model?	Kate Maracas
14	Bullet 2- what fundamentals are your referring to, specifically? (I am asking for examples of fundamentals on slide 14. Thanks)	Elyette Weinstein
14	S-14 What MW transmission Constraint numbers are you using for Mid-C and MT wind	Bill Westre
14	I hope James Adcock's statement that his question was not answered will be treated as a question and that Elizabeth will attempt to actually answer his original question.	Virginia Lohr
13	Second Kathi's question - interested in the assumptions and values in the RA model.	Joni Bosh
15	General question: If all resources are lumped into a broad energy price then how does your analysis drive a reasonable resource portfolio	John Williams
16	Do you count only those resources that are permitted, not those that are planned? Slide 16	Joni Bosh
16	What date is the data obtained from NWPCC (regional load)?	Kathi Scanlan
16	Slide 16. How do you in fact model "Regional Load" as an input? What data inputs do you use as inputs to your modeling of "Regional Load?" What range of dates of data inputs used as data to generate your "Regional Load" modeling do you use?	James Adcock
17	On slide 17, does "Resource Assumptions" incorporate any feedback PSE received from the May 28th webinar on Generic Resource Assumptions?	Katie Ware

Slide number	Question	Sent by
17	Slide 17 - PSE needs to assume social cost of carbon ($74/ton) for all thermal resources. Why isn't this being reflected?	Doug Howell
16	SLide 16 so Aurora is not used to determine the portfolio?	John Williams
17	Why is SCOC not added to box 6 as well	Bill Westre
17	Slide 17: why are there no new thermal plants built in WA? Is that a constraint on the model? Is SCC only applied to facilities built in Washington?	Kelly Hall
*****	I think I am directing my questions to specific issues that PSE is mentioning in passing on the page of the slides that PSE is presenting.	James Adcock
17	Slide 17 indicates that the Social Cost of Carbon (SCoC) is included for thermal builds in Washington. Is the SCoC used for dispatching existing thermal resources in Washington?	Charlie Black
16	the question of counting new resources is an important one -- we are already in a situation where most new resources across the west coming online in the next 5 years will not have commitments (contracts, under construction) much more than 2 or 3 years in advance	Fred Heutte
17	note that the NW Council's draft 2021 Plan load forecast is still being refined and will be based on a climate-adjusted baseline -- the initial model inputs will be available soon and PSE should consider using that as perhaps a model sensitivity for the 2021 IRP	Fred Heutte
17	No. SCC needs to apply to thermal power coming into WA	Doug Howell
17	Katie Ware's question was actually a yes/no question. I don't recall hearing if the answer was Yes or No. Please clarify for me.	Virginia Lohr
17	Follow up on slide 17: when you say SCC only on Washington as a result of CETA, do you mean energy delivered to Washington (but facility may be in another state) or only facilities physically located in Washington?	Kelly Hall
17	How PSE internalizes SCC should also be applied to price. You have to assume you are paying this price for planning purposes.	Doug Howell
17	Second Doug Howell's comment that out of state carbon resources need to have the social cost of carbon attached for correct modelling.	Court Olson
17	on the Council's planning process, we are hearing that early modeling results may be available in August or September, though the official draft plan won't be out until early next year	Fred Heutte

Slide number	Question	Sent by
19	will you incorporate other policies and commitments from utilities as well, such as Xcel, Idaho Power, and Avista that have committed to 100% as well. And CO's law that utilities consider SCC and make progress towards 90% carbon reduction by 2050? These will also impact price forecasts.	Kelly Hall
19	The Wood Mac gas price forecast is now two years old. Why isn't PSE using a more current forecast?	Charlie Black
19	To clarify Slide 19, these are changes (particularly WoodMac 2018 gas price) from 2017 IRP to 2019 Progres Report. Are these the assumotions to be used in this IRP?	Dan Kirschner
21	Slide 21-Please explain the light green slivers on top of the blue non-emitting/renewable resources 2021-2027.	Kathi Scanlan
21	s-21 Where is existing WA wind?	Bill Westre
21	Slide 21 Why would you assume that the "Renewable Needs Ramp" starts at the red line of about 10M? and not the blue bar at about 70M? CEIP requires a demonstration of "linear progress ramp."	James Adcock
17	Please answer Kelly Hall's question on slide 17: when you say SCC only on Washington as a result of CETA, do you mean energy delivered to Washington (but facility may be in another state) or only facilities physically located in Washington?	Kevin Jones
21	If the state has a sharp increase in need in 3 years, is it reasonable to assume that prices of new facilities will increase non-linearly due to a spike in demand for new projects? How do you model this effect?	Brian Grunkemeyer
21	Energy demand has not been rising at the rate indicated on this slide as "target". Please confirm that this "target" line is strictly reflecting the renewable energy ramp up needed to meet the law. If so, what future total energy demand is assumed for 2045?	Court Olson
24	Slide 24-What date is PSE for the consultant(s) gas price forecast? Is it one consultant or a blend of consultants gas forecast(s) used as input to Aurora?	Kathi Scanlan
24	Are those estimated MW builds for Solar and wind for the base year or over the 20 years? Sorry, I had interference and missed a bit of what you were saying.	Joni Bosh
25	Slide 25 Given that US economists are predicting that the COVID-ravaged US economy will not fully recover until the end of the decade, shouldn't the long-term gas prices be updated? And that gas price predictions made before the COVID-19 crash don't have relevancy anymore?	James Adcock

Slide number	Question	Sent by
28	Slide 28 What input data assumptions are you using when making this slide? How can we interpret this slide if you don't tell us what assumptions you made when creating this slide? For example, is this slide also based on the assumption of "No New Washington State NG Builds?"	James Adcock
28	my question on slide 28 is the impact of hybrids (solar/wind plus storage), standalone storage and flexible demand at scale on market prices as compared to renewables by themselves	Fred Heutte
28	The cost of gas to society has not gone down. The will of humanity is to eliminate all fossil fuels so that we have any hope of a future. I don't fully understand the things you are saying about social cost of carbon and how and when it will be incorporated, but we need to get off of "natural" gas immediately. Artificially low prices for gas, perhaps because of reduced demand, because more and more people know we need to get off of gas, should not be used to justify more gas. Will your modelling lead us to the future that is our only hope for survival?	Virginia Lohr
28	Will PSE make the hourly power price forecast results availalable to the IRPAG?	Charlie Black
28	Slide 28 follow-up -- Are you *seriously* suggesting that this is a reasonable prediction of future volutility???	James Adcock
28	Slide 28 Wouldn't people just build NG Peakers, Battery Storage, or Pumped Hydro to "arbitrage" these high price variability and differential???	James Adcock
29	Slide 29: why did electric price forecast increase on slide 29 when on slide 27 it appears to have declined slightly?	Kelly Hall
	Will you address Charlie Black's question about hourly price forecasts in the next part of the presentation?	Joni Bosh
Break	Why not allow more meeting time in the future so that there *is* enough time to answer questions?	James Adcock
33 - 34	How accurate historically is the demand forecasting you are using? How much demand can be reduced by extensive conservation? reduce the demand when you cannot meet the need with current resources	John Williams
38	Slide #38 - They can build renewables or "optimize their portfolios." Can you explain more concretely what you mean by optimizing a portfolio that can substitute for building renewables?	Robert Briggs

Slide number	Question	Sent by
34	Slide 34 - Have you given any thought as to how each of these modeled scenarios could affect CETA's incremental cost calculation?	Katie Ware
42	Question 1: What is PSE's base case scenario for electric price forecast - is PSE calling it "IRP Mid - Draft" in this presentation? Please clarify base case.	Kathi Scanlan
42	Question 2: Does PSE mean in the "No CETA" or absent those standards under CETA RCW 19.405.040(1) and 050(1) as well as implied cost of coal close-out in 2025? The "No CETA" scenario is not clear. For example, how does this scenario relate to the CETA incremental cost baseline and draft Clean Energy Implementation Plan (CEIP) draft rules? Staff requests a response to the connection to CETA requirements and CEIP draft rules.	Kathi Scanlan
42	Would you please refresh our memories on what year's data the 7th Power Plan was based on. Is there really no more recent data that could be used to update those projections?	Robert Briggs
Q&A	How is this recent demand data inputted into your modeling? Should more recent years be and climate warming be more highly weighted in your models?	Warren Halverson
Q&A	Will the wholesale power price forecasts be made available at the hourly price level of granularity?	Charlie Black
Q&A	In the context of the 2019 IRP Progress Report and changes compared to these 2021 draft numbers, would you discuss the three primary inputs that affect power prices and what you've seen in terms of changes in modeling and results thus far?	Kathi Scanlan
Q&A	Could you explain the rationale for the position that PSE does not apply the Social Cost of Carbon to electricity that comes in from other states when PSE calculates their IRP power price?	Kevin Jones
Q&A	I was puzzled by the comment made along with slide #26 that the 20-year low price for gas reflected delays in permitting LNG export facilities. Does this suggest that another 20 years of delays are anticipated in Kalama Methanol and Jordan Cove? Or did I mishear? In any case, it strikes me that a longer view on these prices is needed.	Robert Briggs

Slide number	Question	Sent by
Q&A	I know this meeting agenda does not include DR, but since we just completed the UTC DR Workshop, what issues and opportunities do you see for PSE to increase their adoption of DR in this IRP. I recall from the PSE SCC Workshop that little DR was adopted, leading one reviewer to say "there must be something wrong with your model". Do you think the model needs adjustment and was there any insights from the DR Workshop that suggests any specific adjustments?	Kevin Jones
Q&A	I look forward to that discussion My question - do you have any insights at this time?	Kevin Jones
Q&A	Let me rephrase with more content: Thanks for your reply on DR Elizabeth. My question - did PSE receive any insights on DR from the UTC DR Workshop?	Kevin Jones

Appendix

A full verbatim chat log from the meeting is available below. Questions sent only to the meeting organizers have not been included for brevity.

Name	Time sent	Comment
Doug Howell	1:44 PM	Can every one see questions and comments posted here?
John Williams	1:44 PM	yes
Alexandra Streamer	1:44 PM	Hi Doug - yes, all participants can see the questions and comments
Kathi Scanlan	1:44 PM	yes
Alison Peters	1:45 PM	Joni asked if today's meeting link will work for future meetings. No, there will be a new one each time. Thanks Joni. You can share any future comments or questions with "everyone" so everyone can see them. Thank you!
Kathi Scanlan	1:49 PM	Slide 8-Staff requests when discussing IRP scenarios used to develop planning assumptions, including alternative scenarios and 'futures', PSE clearly define what it means by each case, including 'base case' and clearly label and reference what is meant for each case for the discussion today
Kathi Scanlan	1:56 PM	Slide 11-what other analyses needed for the company (last bullet)?
Don Marsh	1:56 PM	Do avoided costs take into account both avoided generation and avoided T&D?
James Adcock	1:56 PM	Slide Page 8 Raise Hand. But what *are* your "planning assumptions?" Whenever we ask you what is your input modeling data, including what range of calendar dates for each of those input datas, you refuse to answer us. And this has been going on for more than 10 years now. The input modeling data IS part of your "planning assumptions" Slide Page 11 Raise Hand. How do you model the difference in "market prices" between emitting sources of electricity vs. non-emitting sources of electricity? Moving forward towards 2030 the great majority of your electricity needs to come from non-emitting sources.
Joni Bosh	1:56 PM	Just to clarify, is the electric price forecast the same value for all the listed uses on slide 11?
Joni Bosh	1:58 PM	Thanks
James Adcock	2:00 PM	That was not an answer.
Kathi Scanlan	2:01 PM	Slide 13-Clarifying Question: When is PSE planning to discuss its resource adequacy and flexibility model(s) in greater detail? Dates of webinars/meetings?
Kate Maracas	2:02 PM	Is Plexos a power flow model?
elyette weinstein	2:03 PM	Bullet 2- what fundamentals are your referring to, specifically?
Willard (Bill) Westre	2:03 PM	S-14 What MW transmission Constraint numbers are you using for Mid-C and MT wind

Name	Time sent	Comment
Virginia Lohr	2:04 PM	I hope James Adcock's statement that his question was not answered will be treated as a question and that Elizabeth will attempt to actually answer his original question.
Joni Bosh	2:04 PM	Second Kathi's question - interested in the assumptions and values in the RA model.
elyette weinstein	2:05 PM	I am asking for examples of fundamentals on slide 14. Thanks
John Williams	2:06 PM	General question: If all resources are lumped into a broad energy price then how does your analysis drive a reasonable resource portfolio
Alexandra Streamer	2:06 PM	Hi Bill - PSE will discuss transmission constraints in more detail during the June 30 webinar
Joni Bosh	2:08 PM	Do you count only those resources that are permitted, not those that are planned? Slide 16
Kathi Scanlan	2:08 PM	Slide 16-What date is the data obtained from NWPCC (regional load)?
James Adcock	2:09 PM	Slide 16. How do you in fact model "Regional Load" as an input? What data inputs do you use as inputs to your modeling of "Regional Load?" What range of dates of data inputs used as data to generate your "Regional Load" modeling do you use?
Katie Ware	2:09 PM	On slide 17, does "Resource Assumptions" incorporate any feedback PSE received from the May 28th webinar on Generic Resource Assumptions?
Doug Howell	2:09 PM	Slide 17 - PSE needs to assume social cost of carbon ($74/ton) for all thermal resources. Why isn't this being reflected?
John Williams	2:10 PM	SLide 16 so Aurora is not used to determine the portfolio?
Willard (Bill) Westre	2:10 PM	Why is SCOC not added to box 6 as well
Kelly Hall	2:11 PM	Slide 17: why are there no new thermal plants built in WA? Is that a constraint on the model? Is SCC only applied to facilities built in Washington?
John Williams	2:12 PM	Why are SCOS values not applied by each resource, since it is not uniform cross all resources.
James Adcock	2:13 PM	I think I am directing my questions to specific issues that PSE is mentioning in passing on the page of the slides that PSE is presenting.
Charlie Black	2:15 PM	Slide 17 indicates that the Social Cost of Carbon (SCoC) is included for thermal builds in Washington. Is the SCoC used for dispatching existing thermal resources in Washington?
Fred Heutte	2:18 PM	the question of counting new resources is an important one -- we are already in a situation where most new resources across the west coming online in the next 5 years will not have commitments (contracts, under construction) much more than 2 or 3 years in advance
Fred Heutte	2:20 PM	note that the NW Council's draft 2021 Plan load forecast is still being refined and will be based on a climate-adjusted baseline -- the initial model inputs will be available soon and PSE should consider using that as perhaps a model sensitivity for the 2021 IRP
Doug Howell	2:22 PM	No. SCC needs to apply to thermal power coming into WA

Name	Time sent	Comment
Virginia Lohr	2:23 PM	Katie Ware's question was actually a yes/no question. I don't recall hearing if the answer was Yes or No. Please clarify for me.
Kelly Hall	2:23 PM	Follow up on slide 17: when you say SCC only on Washington as a result of CETA, do you mean energy delivered to Washington (but facility may be in another state) or only facilities physically located in Washington?
Doug Howell	2:24 PM	How PSE internalizes SCC should also be applied to price. You have to assume you are paying this price for planning purposes.
Court Olson	2:25 PM	Second Doug Howell's comment that out of state carbon resources need to have the social cost of carbon attached for correct modelling.
Fred Heutte	2:27 PM	on the Council's planning process, we are hearing that early modeling results may be available in August or September, though the official draft plan won't be out until early next year
Kelly Hall	2:33 PM	Slide 19: will you incorporate other policies and commitments from utilities as well, such as Xcel, Idaho Power, and Avista that have committed to 100% as well. And CO's law that utilities consider SCC and make progress towards 90% carbon reduction by 2050? These will also impact price forecasts.
Charlie Black	2:33 PM	The Wood Mac gas price forecast is now two years old. Why isn't PSE using a more current forecast?
Dan Kirschner	2:34 PM	To clarify Slide 19, these are changes (particularly WoodMac 2018 gas price) from 2017 IRP to 2019 Progres Report. Are these the assumotions to be used in this IRP?
Kathi Scanlan	2:37 PM	Slide 21-Please explain the light green slivers on top of the blue non-emitting/renewable resources 2021-2027.
Willard (Bill) Westre	2:38 PM	s-21 Where is existing WA wind?
Kelly Hall	2:38 PM	Slide 21: Is this assuming that CETA investments occur in 2028 and beyond, or are you simply identifying a need? If you are projecting builds, do you expect any differences if you assume these investments occur earlier, starting in 2022 to demonstrate continuous progress as reuqired by CETA?
Irena Netik	2:39 PM	Response to Charlie Black and Dan Kirschner: Jennifer only covered the changes from 2017 IRP to 2019 IRP progress report. 2021 IRP assumptions will be covered next.
elyette weinstein	2:39 PM	Kathy the light green bars are nuclear.
Fred Heutte	2:39 PM	Gas price risk is a complex issue and I'm very wary of simply accepting any forecast especially my own. We're seeing a lot more short term variability right now but the big question for me is what gas prices will look like by 2025 and after and there, I am not satisfied by the conventional wisdom that it will be quite low -- that may be, but we need a sense of upside risk
James Adcock	2:39 PM	Slide 21 Why would you assume that the "Renewable Needs Ramp" starts at the red line of about 10M? and not the blue bar at about 70M?
Kevin Jones	2:40 PM	Please answer Kelly Hall's question on slide 17: when you say SCC only on Washington as a result of CETA, do you mean energy delivered to Washington (but facility may be in

Name	Time sent	Comment
		another state) or only facilities physically located in Washington?
James Adcock	2:41 PM	(continued) CEIP requires a demonstration of "linear progress ramp."
James Adcock	2:44 PM	You are not answering my question again, I was not asking about PSE, I was asking about THIS SLIDE about Washington State.
James Adcock	2:44 PM	PSE refused to answer my question again.
Brian Grunkemeyer	2:44 PM	If the state has a sharp increase in need in 3 years, is it reasonable to assume that prices of new facilities will increase non-linearly due to a spike in demand for new projects? How do you model this effect?
Court Olson	2:44 PM	Energy demand has not been rising at the rate indicated on this slide as "target". Please confirm that this "target" line is strictly reflecting the renewable energy ramp up needed to meet the law. If so, what future total energy demand is assumed for 2045?
Kathi Scanlan	2:47 PM	Slide 24-What date is PSE for the consultant(s) gas price forecast? Is it one consultant or a blend of consultants gas forecast(s) used as input to Aurora?
Fred Heutte	2:47 PM	a point on slide 22 I will want to do a Raise Hand discussion later -- nominal dollars vs real/discounted present value dollars
Don Marsh	2:49 PM	Court's question reflects our confusion because the Demand Forecast is presented so late in the assumptions portion of the IRP. We would really like to understand demand at the regional level and PSE's service area earlier in the IRP process.
Joni Bosh	2:51 PM	Are those estimated MW builds for Solar and wind for the base year or over the 20 years? Sorry, I had interference and missed a bit of what you were saying.
James Adcock	2:53 PM	Slide 25 Given that US economists are predicting that the COVID-ravaged US economy will not fully recover until the end of the decade, shouldn't the long-term gas prices be updated? And that gas price predictions made before the COVID-19 crash don't have relevancy anymore?
Dan Kirschner	2:54 PM	Slide 25: this appears to be a reasonable approach for gas prices given various sources/forecasts.
Irena Netik	2:56 PM	Response to Kevin Jones: for the electric power price forecast, SCC is applied to facilities physically located in WA state
James Adcock	2:56 PM	Slide 28 What input data assumptions are you using when making this slide? How can we interpret this slide if you don't tell us what assumptions you made when creating this slide? For example, is this slide also based on the assumption of "No New Washington State NG Builds?"
Fred Heutte	2:56 PM	my question on slide 28 is the impact of hybrids (solar/wind plus storage), standalone storage and flexible demand at scale on market prices as compared to renewables by themselves
Don Marsh	3:00 PM	Slide 28 growing price variability makes a great case for energy storage to alleviate high prices during outlier hours. I hope PSE will have some great analysis regarding the

Name	Time sent	Comment
		economic case for energy storage, especially as battery prices fall and capacities rise. Many utilities are incorporating more battery projects in their plans than PSE seems to be.
Virginia Lohr	3:02 PM	The cost of gas to society has not gone down. The will of humanity is to eliminate all fossil fuels so that we have any hope of a future. I don't fully understand the things you are saying about social cost of carbon and how and when it will be incorporated, but we need to get off of "natural" gas immediately. Artificially low prices for gas, perhaps because of reduced demand, because more and more people know we need to get off of gas, should not be used to justify more gas. Will your modelling lead us to the future that is our only hope for survival?
Fred Heutte	3:04 PM	let me add to my previous comment on slide 28, I would also include pumped storage not just battery
Charlie Black	3:04 PM	Will PSE make the hourly power price forecast results availalable to the IRPAG?
James Adcock	3:04 PM	Slide 28 follow-up -- Are you *seriously* suggesting that this is a reasonable prediction of future volutility???
Fred Heutte	3:06 PM	just to note, the California ISO says that of new entries to their transmission queue in 2019, 95% of the new solar is hybrid and 75% of wind
James Adcock	3:06 PM	Slide 28 Wouldn't people just build NG Peakers, Battery Storage, or Pumped Hydro to "arbitrage" these high price variability and differential???
Kelly Hall	3:07 PM	Slide 29: why did electric price forecast increase on slide 29 when on slide 27 it appears to have declined slightly?
Joni Bosh	3:11 PM	Will you address Charlie Black's question about hourly price forecasts in the next part of the presentation?
Irena Netik	3:12 PM	Response to Charlie Black: The hourly gas price forecast is confidential. PSE purchases it from Wood Mackenzie. Under our contract we are only able to publish the results provided here.
Fred Heutte	3:12 PM	Concerning slide 29, an important underlying assumption is that market prices are effectively heat rate based, that is, the marginal unit is usually a gas plant which must recover its fuel and start costs -- while true now (except in the spring runoff), I wonder how true that will be in the future as gas is displaced by clean supply and flexible demand -- just a thought
James Adcock	3:13 PM	Why not allow more meeting time in the future so that there *is* enough time to answer questions?
Don Marsh	3:15 PM	Feedback: a price forecast without some accounting of energy storage seems pretty sketchy, I'm sorry to say.
Fred Heutte	3:16 PM	also, market design (the potential EIM Enhanced Day Ahead Market) and the potential NW Power Pool resource adequacy program could have a significant benefit for reducing and stabilizing market prices, but neither of those is yet in place
Fred Heutte	3:18 PM	one of the disadvantages of a four-year IRP cycle is that policy and market changes are evolving at a faster pace than that
James Adcock	3:18 PM	Slide 33 Comment: This assumes that there is an "open" market where utilities share their renewable resources "as needed" [perhaps at a price] with other utilities. But there is

Name	Time sent	Comment
		no such "open market", AND we know historically, for a variety of reasons, there are "utilities" [and I include BPA in that category] who choose not to openly share their renewables with other utilities. If this continues to be the case, then WA-wide *more* new renewables would need to be built than you assume.
Kate Maracas	3:18 PM	To Fred and all - but EDAM and the NWPP RA program are very likely to be in place - in some form, during this planning horizon.
John Williams	3:22 PM	Slide 33 and 34 How accurate historically is the demand forecasting you are using? How much demand can be reduced by extensive conservation? reduce the demand when you cannot meet the need with current resources
Robert Briggs	3:28 PM	Slide #38 - They can build renewables or "optimize their portfolios." Can you explain more concretely what you mean by optimizing a portfolio that can substitute for building renewables?
James Adcock	3:28 PM	Slide 38 Feedback as you have requested: I personally put a very high priority on PSE *actually* meeting the 2030 "80/20" requiremens, including "linear progress towards that goal" until 2030. In order to make that more likely I would prefer that PSE assume the higher level of shortfall -- i.e. that other utilities may choose to NOT "fairly" make all of their renewables available to PSE.
Kevin Jones	3:28 PM	Penny - we are here donating our time. We expect dialogue. Please don't tell me you are protecting my time, which I am donating to this process. My time is wasted if we don't achieve dialogue, which we are again failing to achieve.
Fred Heutte	3:29 PM	Just want to underscore the importance of revisiting or perhaps adjusting from the Council's 7th Plan forecast which was basically locked down in mid-2015.
Katie Ware	3:29 PM	Slide 34 - Have you given any thought as to how each of these modeled scenarios could affect CETA's incremental cost calculation?
James Adcock	3:31 PM	Agree with Kevin Jones -- with the current format, where we cannot directly ask questions, and follow-up to clarify our questions and actually get meaningful answers -- this current choice of PSE meeting format where we are not actually allowed to talk to PSE presenters, and are not actually allowed to directly ask questions and clarifications -- which is "wasting my time."
Virginia Lohr	3:33 PM	Giving PSE time to get through their presentation clearly is simply "informing." People attending these meetings are not doing so simply to be informed, but clearly want to have meaningful input into the process. There appears still to be something broken in the system when the goal is for PSE to get through their presentation. This is no change or even a back-track from the last IRP process. Your feedback requested on slide 38 seems rather simplistic given the entire slide deck.
David Perk	3:34 PM	+1 to what Virginia Lohr writes about informing vs dialog.

Name	Time sent	Comment
Kathi Scanlan	3:34 PM	Question 1: What is PSE's base case scenario for electric price forecast - is PSE calling it "IRP Mid - Draft" in this presentation? Please clarify base case. Question 2: Does PSE mean in the "No CETA" or absent those standards under CETA RCW 19.405.040(1) and 050(1) as well as implied cost of coal close-out in 2025? The "No CETA" scenario is not clear. For example, how does this scenario relate to the CETA incremental cost baseline and draft Clean Energy Implementation Plan (CEIP) draft rules? Staff requests a response to the connection to CETA requirements and CEIP draft rules.
John Williams	3:35 PM	The sensitivity of multiple variable can be addressed by doing a linear regression (?). This may help to determine the "best answer" to the possible scenarios. You need a consulting statistian which I am obviously not.
James Adcock	3:36 PM	Slide 43: I'd like to see a "COVID-19 Crash" compatible scenario, which assumes Low Demand *and* Low Gas Prices, *and* CETA requirements, including "linear implementation ramp" from 2020 to 2030.
Robert Briggs	3:36 PM	Would you please refresh our memories on what year's data the 7th Power Plan was based on. Is there really no more recent data that could be used to update those projections?
Doug Howell	3:36 PM	Slide 42. CETA $74/ton is now an average or baseline, but certainly not a high case scenario. InterAgency Working Group has high of $123/ton (2007 dollars)
Robert Briggs	3:38 PM	The comment that the low gas prices were based on delays in approving LNG
Dan Kirschner	3:38 PM	7th Power Plan published in early 2016
Robert Briggs	3:39 PM	2016
Fred Heutte	3:39 PM	The 7th Plan was formally adopted in February 2016.
Fred Heutte	3:41 PM	raise hand -- slides 22 and 27
James Adcock	3:42 PM	Raise Hand.
James Adcock	3:42 PM	Can I use the microphone?
Robert Briggs	3:43 PM	I agree with Fred on the real dollar comment!
Warren Halverson	3:43 PM	In PSE's Docket UE190529 & UG 19530, January 2020, PSE requested a roughly 7% increase in electric and natural gas prices. Simultaneously, the WSJ had an article entitled "Glut pushes natural gas prices below $2 -- a drop of 61% in two years -- several factors were mentioned.
Robert Briggs	3:44 PM	Two part comment on slide #28.
Warren Halverson	3:45 PM	How is this recent demand data inputted into your modeling? Should more recent years be and climate warming be more highly weighted in your models?
Alexandra Streamer	3:46 PM	@Warren, would you like to verbally state those questions or would you prefer that we read it?
Katie Ware	3:46 PM	Raised hand

Name	Time sent	Comment
Don Marsh	3:48 PM	Raise hand (IAP2 process)
James Adcock	3:49 PM	7th Power Plan was begun in 2010, after the 6th Power Plan was published.
Charlie Black	3:52 PM	Will the wholesale power price forecasts be made available at the hourly price level of granularity?
James Adcock	3:54 PM	WAC regulations require IRP *Participation* NOT *Presentation* !
Kate Maracas	3:58 PM	Riase hand -
James Adcock	3:58 PM	Slide 28 Even "just" BPA hydro modulation -- BPA choosing to generate more when prices are high, and to generate less when prices are low -- since most hydro *is* a form of stored energy -- would *in practice* greatly compress the assume high variability in this slide.
Court Olson	3:59 PM	The response to the question from Don Marsh is not satisfactory. This problem of dialogue and interaction has been long standing with PSE TAG meetings in the past and it has been worsened in the webinar format. This is not because a webinar format prevents the level of interaction that we would like and have been requesting for years. It appears to clearly be the PSE preference to have condensed meetings that are largely in presentation form. Please reconsider your response voiced today by the meeting facilitator. Many of us are not feeling that these meetings are as interactive as they should be. If more time is needed, then make a little more time available for dialogue during presentations. That should not be difficult. We'll appreciate your consideration.
Robert Briggs	4:00 PM	Two part comment on slide #28: There are vertical scale problems on this slide. There may be a lot of valuable data on the slide but they are obscured by the presentation. A log scale or other technique could solve the problem. It does appear that there are significant numbers of VERY inexpensive power. What assumptions about storage are embedded in the graph?
Kathi Scanlan	4:00 PM	In the context of the 2019 IRP Progress Report and changes compared to these 2021 draft numbers, would you discuss the three primary inputs that affect power prices and what you've seen in terms of changes in modeling and results thus far?
Kevin Jones	4:01 PM	I agree with Don re: lack of improvement in exchange of info between the public and PSE and will add (1) TAG members raised this same issue - a lack of dialogue - in the 2019 IRP. I expect that is true from years past. PSE has not solved this problem, despite the IAP2 claims, the remote engagement and the point that there are 50 people on the call, and (2) Comments in response to the 2021 PSE IRP work plan stated: "To successfully address this concern (unresolved issues), we call upon PSE to ensure strong stakeholder engagement and allow sufficient Milestone B time to successfully resolve these issues to the satisfaction of the primary stakeholders" to which PSE responded "We are going to continue to update the meeting schedule as we develop the IRP technical work and receive stakeholder feedback on the specific technical topics". I appreciate your dedication to addressing public concerns by

Name	Time sent	Comment
		allowing sufficient time for dialogue. It appears that additional IRP work plan schedule adjustments are needed.
Fred Heutte	4:08 PM	raise hand for a comment on prices
James Adcock	4:08 PM	Raise Hand
Virginia Lohr	4:08 PM	Please read my comment from 3:33, which reinforces what toehrs ahve said.
Robert Briggs	4:09 PM	I was puzzled by the comment made along with slide #26 that the 20-year low price for gas reflected delays in permitting LNG export facilities. Does this suggest that another 20 years of delays are anticipated in Kalama Methanol and Jordan Cove? Or did I mishear? In any case, it strikes me that a longer view on these prices is needed.
Alexandra Streamer	4:09 PM	To confirm, Virginia, is this the comment: "Giving PSE time to get through their presentation clearly is simply "informing." People attending these meetings are not doing so simply to be informed, but clearly want to have meaningful input into the process. There appears still to be something broken in the system when the goal is for PSE to get through their presentation. This is no change or even a back-track from the last IRP process. Your feedback requested on slide 38 seems rather simplistic given the entire slide deck."
Kevin Jones	4:10 PM	Could you explain the rationale for the position that PSE does not apply the Social Cost of Carbon to electricity that comes in from other states when PSE calculates their IRP power price?
Kevin Jones	4:19 PM	Thanks Elizabeth. I'll give that more thought and see if I have a follow-up input.
Kate Maracas	4:19 PM	Raise hand.
Don Marsh	4:23 PM	I would love to feel that PSE is making a leading-edge effort to embrace smart and modern technologies like energy storage, demand response, distributed generation, and energy efficiency. We feel that many other utilities are doing a better job in these areas. A company serving a technologically advanced and environmentally aware customer base in the Puget Sound region should be providing a great example for the whole country. Stakeholders are trying to do our part.
Don Marsh	4:23 PM	Perhaps that can be demonstrated in the CEIP?
Kevin Jones	4:24 PM	I know this meeting agenda does not include DR, but since we just completed the UTC DR Workshop, what issues and opportunities do you see for PSE to increase their adoption of DR in this IRP. I recall from the PSE SCC Workshop that little DR was adopted, leading one reviewer to say "there must be something wrong with your model". Do you think the model needs adjustment and was there any insights from the DR Workshop that suggests any specific adjustments?
Kathi Scanlan	4:24 PM	Staff appreciates that we can see all questions asked in this GoToMeeting real time. Thank you for making this change.
Alexandra Streamer	4:24 PM	@Don and @Kevin, would you like to read that out or just submitting for comment?
Kevin Jones	4:24 PM	That is a question for PSE to address.

Name	Time sent	Comment
Don Marsh	4:24 PM	You can read mine. Thanks
James Adcock	4:26 PM	If PSE "Promises" to answer my question about what their data sources into their analsyses are, and what range of historical dates that data comes from, that would be a step forward after 10 years of waiting. For example PSE just "answered" my previous question about Wind data by referring me to a 5 Terabyte database, out of which PSE only actually uses about 5 Megabytes, which means that somewhere in there literally 1 part in a Million of where PSE pointed me to, is the actual answer. So PSE's "answer" is to send me off for literally a "Find One Needle in a Million Hay Haystack" -- Is This Seriously what you call "Answering my question?"
Robert Briggs	4:27 PM	Regarding slide #35, I'm a little concerned regarding the simplistic choices we have been encourgaed to provide feedback on. If you're serious about getting feedback, it needs to be unbundled and have far more technical detail. I prefer the green line (Secenario 1), but why do we not see renewable builds until year 9? I'm confused.
Kevin Jones	4:27 PM	I look forward to that discussion My question - do you have any insights at this time?
James Adcock	4:28 PM	So Once Again -- You are not Answering My Question???
Kevin Jones	4:29 PM	Let me rephrase with more content: Thanks for your reply on DR Elizabeth. My question - did PSE receive any insights on DR from the UTC DR Workshop?
David Perk	4:29 PM	Take a deep breath, James!
James Adcock	4:29 PM	They always dodge my questions.
Kevin Jones	4:30 PM	I suggest PSE stay on for another 10 minutes to answer unanswered questions, allowing others to leave if they choose to.
Robert Briggs	4:30 PM	I second.
Kevin Jones	4:31 PM	Letting the clock take priority over public inputs is disrespectful.

PSE IRP Feedback Report
Webinar 2: Electric Price Forecast
June 10, 2020

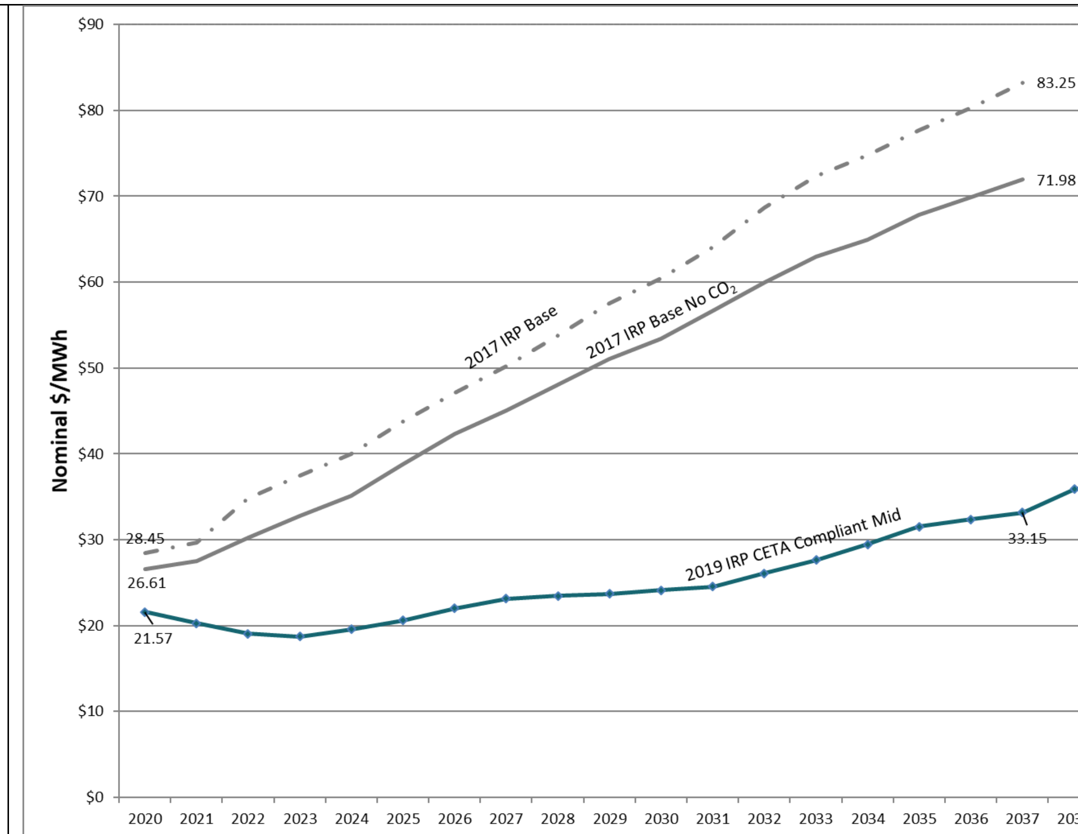
6/24/2020

The following stakeholder input was gathered through the online Feedback Form, from June 3 through June 17, 2020. PSE's response to the feedback can be found in the far right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on July 1, 2020.

2021 IRP Electric Price Forecast Workshop Feedback Report			
Feedback Form Date	**Stakeholder**	**Comment**	**PSE Response**
6/4/2020	James Adcock (1)	June 10 IRP meeting Expressed Concern I am expressing a concern that the "explanation" of how PSE performs "modeling" is being presented at such a low "Kindergarten Level" as to prevent any meaningful understanding of what modeling, and how, that PSE is performing -- and this is a presentation to a "Technical" group -- and yet you are giving the explanation at only a "Kindergarten Level". By giving the presentation at a "Kindergarten Level" you are preventing meaningful participation in the PSE IRP. PSE used to give much more meaningful explanations of their modeling methods in years past -- while still being very imprecise.	PSE acknowledges your concern.
6/4/2020	James Adcock (2)	PSE should provide a detailed technical explanation of how exactly they are performing modeling, including an explanation of all historical data used in their modeling, and the range of historical dates, from earliest date to latest date, of each of those historical data records.	Thank you for your suggestions. The 2021 IRP book will include more detail than the meeting presentations.
6/4/2020	James Adcock (3)	June 10 IRP meeting Question Can you please enumerate in detail all of the various types of historical data used anywhere in any of your modeling efforts, including the earliest calendar year and latest calendar year from which each of those historical data types was used. For example, in IRP's years past PSE has explained that it uses: Temperature data from a large range of years, "Water" data (hydroelectric dam generation related data), "Wind" data -- data used to develop predictions of Wind Power performance in Washington State or other states, Load data -- actual historical patterns of electrical use by PSE customers, Gas prices, Econometric data -- historical measures of how weak or strong the regional economy has been.	PSE will share historical data ranges for temperatures, hydro data and other data when it covers the IRP topic that references the data. The assumptions for the electric price forecast were shared in the webinar and a recording of the webinar is posted on the IRP website.
6/4/2020	James Adcock (4)	June 10 IRP meeting Question Page 20 (and page 34) On this page you state "With stakeholder input..." as in: "With stakeholder input, the 2019 IRP electric price forecast assumed a renewable need of 22.9 million MWh in 2030, approximately 8,700 MW nameplate capacity of new renewable resources added in Washington state." What I remember of the "stakeholder input" in the [PSE canceled] 2019 IRP Process is that the "stakeholders" roundly disagreed with virtually everything PSE discussed or was proposing -- and in turn PSE simply canceled the 2019 IRP Process. In this context can you please explain what you mean by "With stakeholder input" -- given that I don't think PSE accepted, but rather rejected, any and all "stakeholder input" ??? Given that PSE canceled the 2019 IRP Process before it completed, I ask that PSE here and now retract the claim that these issues were developed with "stakeholder input."	PSE updated the presentation and referenced the 2019 IRP Progress Report or the 2019 IRP process instead of 2019 IRP, where appropriate. During the 2019 IRP process, stakeholders gave feedback on the level of new renewable resources assumed for Washington to meet the CETA requirement. PSE then took that feedback and adjusted the amount of new renewable resources assumed based on the feedback.
6/4/2020	James Adcock (5)	Retract the claim here and elsewhere that the "2019 IRP Process" was actually developed with "stakeholder input" -- given that PSE unilaterally decided without advanced warning and with no stakeholder input to cancel the "2019 IRP Process" before it was complete and vetted by stakeholders. Further, do not refer to the "2019 IRP" because the "2019 IRP" does not exist -- because the "2019 IRP" was unilaterally canceled by PSE before the "2019 IRP" was completed.	PSE updated the presentation and referenced the 2019 IRP Progress Report or the 2019 IRP process instead of 2019 IRP, where appropriate. We will make best efforts to ensure that appropriate references are used going forward. On October 28, 2019, the Washington Utilities and Transportation Commission Staff filed a Petition for Exemption from WAC 480-100-238 pursuant to WAC 480-07-100 until December 31, 2020. On November 7, 2019 the WUTC held an Open Meeting concerning

			this matter and subsequently issued Order 2, exempting PSE (and other investor owned utilities in Washington) from WAC 480-100-238. Pursuant to Order 2, PSE filed an IRP Progress Report on November 15, 2019. On December 10, PSE filed a Revised Progress Report, available at pse/irp.com_2019 Progress Report
6/4/2020	James Adcock (6)	June 10 IRP meeting Question Page 24 On this page you state for the "2021 IRP electric price update" that the "Regional Demand from the 7th Power Plan" didn't change. Why didn't it change? Why would you not assume a downturn in demand due to the downturn in the economy due to COVID-19? Shouldn't your regional demand assumptions be updated to recognize the reality of the huge change in the regional economy, and thereby demand, caused by COVID-19? Economists are projecting that it will take a decade for the US Economy to recover from COVID-19.	PSE uses the regional demand forecast from the Northwest Power and Conservation Council. At the time of the presentation, PSE was not able to obtain to the regional demand from the Council. PSE has made an additional request for the 7th power plan mid-term update. There will be an update in the consultation update on whether we were able to get the updated regional demand forecast and if it can be used for the 2021 IRP.
6/4/2020	James Adcock (7)	PSE should reduce the expected regional demand (relative to the 7th power plan) to fully and fairly reflect based on projections from regional and national economists of the downturn in the economy based on COVID-19, and the projected decade-long recovery it will take the economy to recover from COVID-19.	As noted above, PSE has contacted the Council for the 7th power plan mid-term update.
6/4/2020	James Adcock (8)	June 10 IRP meeting Question Page 28 You are pulling this chart "like a rabbit out of a hat" -- with no technical explanation whatsoever of how you have developed this plot, and what assumptions go into this plot. Can you please list all of the assumptions, and all of the data used, including historical range of dates from which that data was collected, in generating this plot?	The plot on slide 28 provides an overview of the hourly power prices over the entire time horizon (2022 through 2041) for the 2021 IRP. Each hour of the year is represented as a single green point on the plot. These data are the output of the Aurora Power Price model, which was run using the assumptions discussed throughout the presentation. Also provided on the plot are box and whisker charts which provide some high-level statistics about the power prices for each year (mean, median, 10th, 25th, 75th and 90th percentiles). The intended message of the plot is to show an increase in variability of power prices in the late years of the time horizon as more and more renewable resources are added to the WECC.
6/4/2020	James Adcock (9)	June 10 IRP meeting Question Page 37 Given that the 2019 IRP was canceled before it was completed, can you please delete the "2019 IRP Base" claim -- There is no "2019 IRP" because it was never completed -- because PSE chose unilaterally without consulting with stakeholders to terminate the "2019 IRP" effort before it was completed and before stakeholders had a chance to vet it, or comment on it. Since there is not "2019 IRP" there can be no "2019 IRP Base"	Thank you for your input. Going forward, PSE will make best efforts not to reference the “2019 IRP” but rather the “2019 IRP process” or the “2019 IRP Progress Report” including labels on slides.
6/4/2020	James Adcock (10)	Delete the "2019 IRP Base" claim -- There is no "2019 IRP" because it was never completed -- because PSE chose unilaterally without consulting with stakeholders to terminate the "2019 IRP" effort before it was completed and before stakeholders had a chance to vet it, or comment on it. Since there is not "2019 IRP" there can be no "2019 IRP Base."	As stated above, PSE will make best efforts not to reference the “2019 IRP” but rather the “2019 IRP process” or the “2019 IRP Progress Report”.
6/4/2020	James Adcock (11)	June 10 IRP meeting Question Page 42 Given that CETA is now "the law of the land" why is it appropriate to develop a scenario where you assume that you do not have to meet the CETA requirements? Shouldn't the range of scenarios you consider be drawn from the "legal" list of possibilities, and not contemplate running PSE in an "illegal" manner?	PSE is reviewing all the suggestions and contacting some stakeholders for further discussion. PSE will have the final list of scenarios for the July 1 consultation update.
6/4/2020	James Adcock (12)	Draw all your "scenarios" from "legal" sets of possibilities which do not contemplate running PSE in an "illegal" manner.	Thank you for your feedback. PSE is developing the 2021 IRP in compliance with all legal and regulatory requirements.
6/4/2020	James Adcock (13)	June 10 IRP meeting Question Page 19 On Page 19 you reference the "2019 IRP" but there is no "2019 IRP" because PSE chose to abruptly without warning terminate the "2019 IRP" before it was completed.	Please see our response to your comments 5 & 10.

6/4/2020	James Adcock (14)	Do not reference the "2019 IRP" because there is no "2019 IRP" -- because PSE chose unilaterally with consulting stakeholders to terminate the 2019 IRP Process before it was completed.	Please see our response to your comments 5,10 & 13.
6/10/2020	Vlad Gutman-Britten, Climate Solutions	Slide 17: Why are no thermal plants built in WA? Is this CETA or some other constraint? It again reads like SCC is only applied to plants in Washington and not outside of it, which isn't in keeping with the requirements of CETA or the previous UTC acknowledgement letter. Slide 19: There are other extant policies/commitments that should be included—Xcel has committed to 100% clean by 2050, Idaho Power and Avista have both made the same commitment. A number of CO laws also matter here: Colorado utilities must consider SCC in planning and the PUC must make progress toward 90% carbon reduction by 2050. These will impact resource choices and price forecasts. Slide 20: For the utilities below 80%, these are likely to somewhat overcomply with the 2030 requirement in order to address variability in hydro. It could be worth modeling actual compliance strategies as this will yield a different mix of renewables and thus impact price forecasts. Slide 21: Assumption shouldn't be no new renewable energy investments until 2028. Considering only state-wide RE need doesn't reflect how utilities, especially investor-owned utilities, will comply. Slide 22: Would like to see the 2017 with high CO2 comparison since the 2019 does have CO2 included. Slide 29: why did price increase on this slide when on slide 27 it appears to have declined slightly? Slide 34: A little confused on the difference between the two scenarios with CA/WA; shouldn't frame CA 2045 law as a "goal"; CA 2030 requirement is RPS only, not carbon-free. Slide 42: Scenario #3 should have a higher CO2 price, going beyond what is required by law for the "high scenario." Scenario #4 appears to be a baseline comparison, and should include CETA but not the clean energy standards.	Slide 17: Given that PSE is modeling the entire region as a whole, the model assumes that there is plenty of resources in the region given normal hydro conditions and mid load. This is different than the PSE portfolio model, where PSE is accounting for transmission constraints into the PSE service territory. So even though there might be enough resources in the region, it may not be delivered to load due to transmission constraints. To reflect the social cost of carbon planning adder in PSE's portfolio model, market purchases will include a wheeling cost equivalent to the SCC adder during the capacity expansion run. Slide 19: PSE has elected not to include corporate or non-binding policies into the Power Price model due to lack of accountability of these policies and difficulty in modeling numerous policies at the balancing authority resolution. Slide 20: Thank you for the suggestion, however, PSE is unable to incorporate actual clean energy adoption strategies into the modeling process due to lack of insight into the resource acquisition strategies of each Washington utility. Therefore, PSE has elected to model either the 80% clean energy implementation required by CETA or a generic more aggressive (~90%) clean energy implementation for the 2021 IRP. Slide 21: Thank you for the suggestion, PSE is updating the assumption and will have the updated targets for the July 1 consultation update. Slide 22: Below is the updated chart which includes the 2017 IRP Base power price:



Slide 29: Slide 27 shows the annual, nominal power price for the 2019 IRP process and draft 2021 IRP power price. Slide 29 shows the levelized power price over the timeframe for each IRP process, which incorporates the time value of money (net present value). Each slide is an NPV over different time periods which is why they are slightly different.

Slide 34: CA SB 100, Chapter 312

SEC. 5.

Section 454.53 is added to the Public Utilities Code, to read:

454.53.

(a) It is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 100 percent of all retail sales of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045. The achievement of this policy for California shall not increase carbon emissions elsewhere in the western grid and shall not allow resource shuffling. The commission and Energy Commission, in consultation with the State Air Resources Board, shall take steps to ensure that a transition to a zero-carbon electric system for the State of California does not cause or contribute to greenhouse gas emissions increases elsewhere in the western grid, and is undertaken in a manner consistent with clause 3 of Section 8 of Article I of the United States Constitution. The commission, the Energy Commission, the State Air Resources Board, and all other state agencies shall incorporate this policy into all relevant planning.

			California law states that zero-carbon resources will supply 100% of sales by 2045, so it does not have to be met by all renewable resources, other carbon-free resources can be used. Slide 42: Thank you for your feedback on the scenarios. PSE is reviewing through all the suggestions and getting in contact with some stakeholders for further discussion. PSE will have the final list of scenarios for the consultation update.
6/10/2020	James Adcock (15)	In these times, and with the extremely limited amount of time PSE is setting aside from their Presentations to allow actual Stakeholder Participation, telling stakeholders, who are adult professionals, how they ought to live their lives in order to reduce stress and health effects, seems particularly inappropriate. In the same spirit, let me offer PSE a few "safety suggestions" on things PSE could do to "reduce stress" (below) 1) PSE should make sure that trench retention devices are always actually in place before an employee or contractor climbs into a trench so that person will not get killed. 2) 3) PSE should make sure that employees or subcontractors in the field are actually wearing masks, and/or maintaining 6 feet of distance from each other -- because they are not doing so. It is stressful for us to see that PSE is in practice spreading COVID-19. 4) PSE can actually substantially reduce their CO2e emissions now, in order to reduce our stress that we will not actually have a planet for our children and grandchildren to live safely and healthily upon.	It is a PSE corporate policy to include a Safety Moment in meetings with more than 5 people. PSE regrets that you found our Safety Moment inappropriate, it was provided with the best intentions.
6/10/2020	James Adcock (16)	One thing that greatly saddens me with the current choice of format -- where stakeholders have to type their input into a chat box -- is that it makes it virtually impossible to "hear" the input from other stakeholders -- in that I am trying to listen to the PSE presenter, read the PSE slide, while at the same time read stakeholder feedback in the chat box -- and while trying to type my own feedback or questions into the chat box. And doing all of these half dozen things at the same time is literally impossible. Which means in practice that I do not get to "hear" the input from the other stakeholders as the PSE presentation is being made. Again, the WAC IRP requirements are for Stakeholder Participation NOT "PSE Presents while Stakeholders Listen." Change the meeting format back to something more similar to previous years' IRPs where stakeholders are directly allowed to ask questions and clarification using their voices, so that other stakeholders can literally hear what they are saying -- not just hear what PSE is saying! Again, the "raised hand" followed by microphone-speech format used in PSE in previous years, and has been used recently online by both Commerce and UTC, works perfectly fine.	PSE agrees that having these meeting remote is challenging and acknowledge your frustrations. We are experimenting with different platforms to identify the best tool for these meetings. The May 28 meeting was conducted on GoToWebinar. The June 10 meeting was conducted on GoToMeeting. On June 17, a survey was sent to stakeholders to gather feedback on the meeting experience to date. The June 20 meeting will be conducted on Zoom. Our preference is to select the best tool for all the meetings and be consistent through the remainder of the process.
6/11/2020	James Adcock (17)	Draft WAC 480-100-650(2) requires that utilities adaptively manage their planning and investment activities: "Each utility must continuously review and update as appropriate its planning and investment activities to adapt to changing market conditions and developing technologies" At the June 10 2020 IRP Meeting PSE stated that they do not do so. For example, PSE uses unmodified the 7th Power Plan regional load estimates, even though those load estimates were developed starting in 2010, published in 2016, and do not include the effects of the COVID-19 Economic Crash of 2020. It is well-known from past economic crashes -- and basic econometric studies -- that economic crashes reduce electricity demand, and that electricity demand does not recover until the economy recovers. National economists estimate that it will take a decade for the economy to fully recover from the COVID-19 crash, meaning that predicted electrical load growth path will not fully recover for a decade. PSE must actually update their future load forecasts, including modifying their use of the 7th Power Plan estimates, to fully and fairly reflect the on-going reductions in load (relative to the no-COVID-19 crash condition) that can reasonably be expected from the COVID-19 economic crash. Further, PSE must update their planning to include developed and developing technologies in the Wind Power field over the last 20 years. My understanding is that PSE is still doing Wind modeling based on the assumption of a Vestas V90 Wind Turbine design. This design is now 20 years old. The Wind Industry has progressed in the last 20 years, providing higher hub heights for greater wind availability, longer blade lengths to extract more power, customized blade shapes to optimize availability to lower wind speeds as found in Washington State, and optimized higher generator power in high wind speeds, such as found in Montana.	As noted above, PSE has contacted the Council for the 7th power plan mid-term update demand forecast. As noted in the feedback report from the generic resource costs webinar, PSE is using the power curve for a GE3.03-140 as a model turbine

<table>
<tr>
<td>6/17/2020</td>
<td>Willard Westre, Union of Concerned Scientists</td>
<td>Question 1) Since the renewable percentage will be determined for all power delivered by PSE, how does PSE intend to control the renewable content of the portion coming from the Mid-C market?

Question 2) What is the recent renewable percentage data of previous PSE Mid-C purchased power?

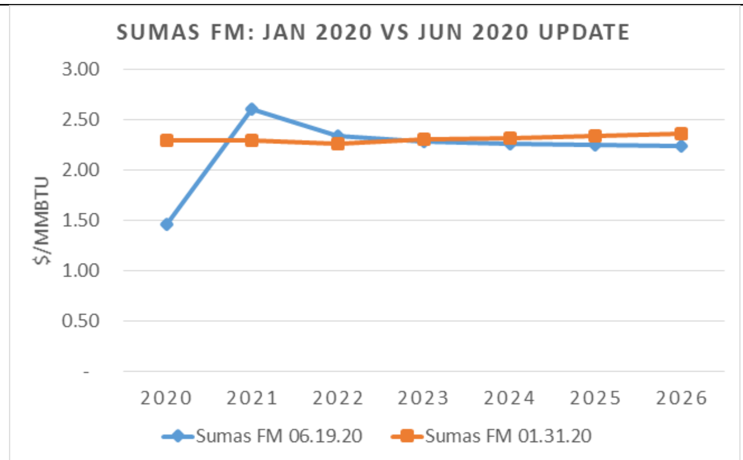
Question 3) How is that determined?</td>
<td>
1. The assumptions on how PSE will treat unspecified system purchases to meet PSE load will be addressed in the July 21 webinar on social cost of carbon.
2. PSE's recent renewable percentage data of unspecified market purchases based on the 2018 Washington State Electric Utility Fuel Mix Disclosure Reports is 61% renewable. Link to the 2018 Washington State Electric Utility Fuel Mix Disclosure Reports: https://www.commerce.wa.gov/wp-content/uploads/2020/04/Energy-Fuel-Mix-Disclosure-2018.pdf
3. PSE used the Northwest Power Pool Fuel Mix percentage provided by the Department of Commerce in mid-September of 2019 to determine the allocation for unspecified market purchases. The fuel mix percentage by category is multiplied by the total unspecified purchases of 4,352,868 MWhs reported for 2018. The percent allocated MWhs for all renewables were added together and calculated as a percent of total to determine the 61% value.

PSE's unspecified purchases for 2018* 4,352,868

<table>
<tr><th>Report Year</th><th>Fuel Category</th><th>Northwest Power Pool (NWPP) Fuel Category Percentage**</th><th>Renewable MWhs</th></tr>
<tr><td>2018</td><td>Biogas</td><td>0.23%</td><td>10,012</td></tr>
<tr><td>2018</td><td>Biomass</td><td>0.74%</td><td>32,211</td></tr>
<tr><td>2018</td><td>Coal</td><td>23.18%</td><td></td></tr>
<tr><td>2018</td><td>Geothermal</td><td>1.01%</td><td>43,964</td></tr>
<tr><td>2018</td><td>Hydro</td><td>46.30%</td><td>2,015,378</td></tr>
<tr><td>2018</td><td>Natural Gas</td><td>15.43%</td><td></td></tr>
<tr><td>2018</td><td>Nuclear</td><td>3.25%</td><td>141,468</td></tr>
<tr><td>2018</td><td>Other Biogenic</td><td>0.05%</td><td>2,176</td></tr>
<tr><td>2018</td><td>Other Non-Biogenic</td><td>0.40%</td><td>17,411</td></tr>
<tr><td>2018</td><td>Petroleum</td><td>0.18%</td><td></td></tr>
<tr><td>2018</td><td>Solar</td><td>1.14%</td><td>49,623</td></tr>
<tr><td>2018</td><td>Waste</td><td>0.03%</td><td>1,306</td></tr>
<tr><td>2018</td><td>Wind</td><td>8.06%</td><td>350,841</td></tr>
<tr><td></td><td>Total</td><td>100.0%</td><td>2,664,391</td></tr>
<tr><td></td><td></td><td>% of Total</td><td>61%</td></tr>
</table>
Notes:
*PSE's unspecified market purchases reported in the 2018 WA Fuel Mix Report is 4,352,868 MWhs
Link to the 2018 Washington State Electric Utility Fuel Mix Disclosure Reports: https://www.commerce.wa.gov/wp-content/uploads/2020/04/Energy-Fuel-Mix-Disclosure-2018.pdf
The 2019 Fuel Mix Report won't be available until Q4 of 2020.
**Northwest Power Pool Fuel Mix as provided by the Department of Commerce in mid-September 2019
</td>
</tr>
<tr>
<td>6/17/2020</td>
<td>Willard Westre, Union of</td>
<td>Slide 21 showing renewable energy needed in WA is interesting but does not define the amount of renewable energy needed by PSE. Although the Process Timeline shows "Establish Resource Need" by September, apparently, neither of the remaining topics on the</td>
<td>Updated meeting schedule is currently under development and will be made available by the June 30 webinar.</td>
</tr>
</table>

	Concerned Scientists	schedule does that. There is no session for Demand Forecast. When will the discussion on the real new renewable resources need be addressed?	
6/17/2020	Bill Pascoe, Absaroka Energy and Orion Renewables	I am requesting an electric price forecast scenario with a WECC-wide carbon tax equal to the social cost of carbon.	Thank you for your feedback on the scenarios. PSE is reviewing through all the suggestions and getting in contact with some stakeholders for further discussion. PSE will have the final list of scenarios for the consultation update.
6/17/2020	Katie Ware, Renewable Northwest	Slide 34 — RNW suggests PSE should consider how Scenario 1 and Scenario 2 would affect CETA's incremental cost of compliance calculation, and based on the results, consider which scenario would have a better chance of achieving the GHG neutral standard across WA utilities. Slide 43 — Stakeholder feedback scenarios: MID/MID and HIGH/HIGH scenarios studied with the SCC applied as an adder WECC-wide during dispatch.	Slide 34: Thank you for your feedback, PSE will be using Scenario 1 for the clean energy implementation. Slide 43: Thank you for your feedback on the scenarios. PSE is reviewing through all the suggestions and getting in contact with some stakeholders for further discussion. PSE will have the final list of scenarios for the consultation update.
6/17/2020	Kathi Scanlan, WUTC	1) This feedback, dated June 17, 2020, states the informal comments, questions, and recommendations of Washington Utilities and Transportation Commission Staff. Timely feedback is offered as technical assistance and is not intended as legal advice. Staff reserves the right to amend these opinions should circumstances change or additional information be brought to our attention. Staff opinions are not binding on the commission. 2) Slide 17 – Social cost of greenhouse gas methodology as a planning adder in the electric price forecast: a. PSE explains this cost is added for any thermal builds in Washington (tons c02*SCC($/ton) = emission cost ($), where the emission cost is then applied back to the fixed cost of thermal plants in Washington. Please further clarify, is this energy delivered to Washington? Are these thermal units that are built in, and physically located in, Washington? b. Please explain why this methodology is appropriate for the electric price forecast in the context of the Clean Energy Transformation Act (CETA) requirements. 3) Slides 37-38, 42 – Scenario Development and CETA. The two scenarios where the Washington renewable requirement is modeled at 80 vs. 90% creates a difference in Mid-C price during the mid-term but eventually converges, since both scenarios go to 100%. PSE seeks feedback on the higher and lower scenario: a. Staff generally agrees a 90% estimate could be a more reasonable (and conservative) assumption given hydro-heavy utilities in the state. b. No CETA Scenario - Staff requests more information on the assumptions that create the future conditions regarding "No CETA". Does PSE anticipate using this scenario as the baseline for calculating the incremental cost of compliance, per RCW 19.405.060(3)? If yes, we recommend refining the name of the scenario. Although No CETA is easy shorthand, it is not accurate for describing the incremental cost baseline, as the baseline should include the other elements of CETA other than RCW 19.405.040 and 050. Further clarification on this scenario would be helpful. 4) Slide 24 – What did not change since the 2019 Progress Report? And what changed? a. PSE states it intends to use, "regional demand from the 7th Power Plan". Why? b. Is PSE planning to update its regional demand inputs? The Seventh Power Plan Midterm Assessment has updated regional data, which is available, and can provide more recent inputs: https://www.nwcouncil.org/sites/default/files/7th%20Plan%20Midterm%20Assessment%20Final%20Cncl%20Doc%20%232019-3.pdf 5) Slide 25 – Gas Price Forecast: a. What is the date of the Fall 2019 Wood Mackenzie report that PSE is relying on for the 2021 IRP, and is this PSE's most up-to-date Wood Mackenzie gas price forecast report? b. Given the significant unforeseen changes to the economy since March 2020, is it possible to go back to Wood MacKenzie and request a more recent update? 6) Slides 37 & 42 - California and BC Assumptions:	1. Thank you and noted. 2. Social cost of carbon as a planning adder a. The social cost of carbon is an adder to thermal plants physically located in Washington. Since Washington state is a part of the Mid-C market along with Oregon, Idaho and western Montana, PSE cannot separate out Washington state from the rest of the Mid-C and therefore unable to determine where the energy is being delivered to. The assumptions on how PSE will treat unspecified system purchases to meet PSE load will be addressed in the July 21 webinar on social cost of carbon. b. Instructions on how to incorporate the SCC are provided by the Clean Energy Transformation Act (CETA). The references to the SCC in CETA are provided below: *"(3) (a) An electric utility shall consider the social cost of greenhouse gas emissions, as determined by the commission for investor-owned utilities pursuant to section of this act and the department for consumer-owned utilities, when developing integrated resource plans and clean energy action plans. An electric utility must incorporate the social cost of greenhouse gas emissions as a* **cost adder** *when:* *(i) Evaluating and selecting conservation policies, programs, and targets;* *(ii) Developing integrated resource plans and clean energy action plans; and * *(iii) Evaluating and selecting intermediate term and long-term resource options. p. 33 E2SSB 5116.S*

		a. Staff requests more clarification on how PSE is modeling California renewables; it is not clear regarding the ramp between 60% and 100%. Will it be at ~80 percent in 2030? b. What C02 price is applied for CA AB32 and BC? 7) Other questions regarding PSE's social cost of greenhouse gas emissions modeling: a. PSE explains the methodology will be discussed at a later July 21 webinar. Does PSE plan to model SCC applied to thermal power imports into WA? b. It is staff's understanding in Aurora a "wheeling adder" can be added for imports into California, which is then used to capture the cost of carbon imports. Is this approach also appropriate for Washington to model the social cost adder of greenhouse gas emissions for imports?	*(b) For the purposes of this subsection (3):* *(i) Gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anaerobic digesters must be considered a non-emitting resource; and* *(ii) Qualified biomass energy must be considered a non-emitting resource."* ***Section 14, Page 33*** The legislation explicitly instructs utilities to use the SCC as a cost adder when evaluating conservation efforts, developing IRPs and CEAPs, and evaluating resources options. PSE understands this "cost adder" to mean that the SCC is included in planning decisions, but not in the actual cost and dispatch of any resource that it is applied to. 3.a. Thank you for your feedback, PSE will be using Scenario 1 for the clean energy implementation. b. Thank you for your feedback on the scenarios. PSE is reviewing through all the suggestions and getting in contact with some stakeholders for further discussion. PSE will have the final list of scenarios for the consultation update. 4. PSE has contacted the Northwest Power and Conservation Council to request for the 7th power plan mid-term update. There will be an update in the consultation update on whether we were able to get the demand forecast and if it is usable for the 2021 IRP. 5. The Wood Mackenzie gas price forecast is from fall 2019. This is the most recent forecast for Wood Mackenzie, the update forecast will not be ready for several weeks. However, PSE can update the foreword marks through 2026. The updated foreword marks (blue line) is the 3-month average ending June 30, 2020. As seen in the chart, the 2020 costs are much lower than the January 31 estimate and then the 2021 costs are higher during the current economic recovery. However the prices return back to January estimate by 2022 and continue to match closely through 2026. Since the time horizon for the 2021 IRP starts in 2022, this update will not have much of an impact.



6.

a. The California SB100 requires 60% renewable resources by 2030, so PSE is modeling 60% by 2030 and then ramping into 100% by 2045.

b. Below is the assumed CO2 price in Aurora for the state of California:

Year	Aurora Default carbon emission price for California's carbon cap-and-trade program (2012$)
2022	15.13
2023	15.89
2024	16.69
2025	17.52
2026	18.40
2027	19.32
2028	20.28
2029	21.30
2030	22.36
2031	22.36
2032	22.36
2033	22.36
2034	22.36
2035	22.36
2036	22.36
2037	22.36
2038	22.36
2039	22.36
2040	23.16
2041	24.06
2042	24.96
2043	25.86

			<table><tr><td>2044</td><td>26.76</td></tr><tr><td>2045</td><td>27.66</td></tr></table> Currently, there is no assumed CO2 price for BC. PSE will make this correction to the Aurora model. 7. a. PSE will discuss how the social cost of carbon is applied to PSE's portfolio model in the July 21 webinar and will be happy to answer additional questions then. b. This relates back to 2a. If Washington was a separate zone, PSE could apply a wheeling cost to market purchases heading into Washington. However, Washington has been combined with Oregon, Idaho, and Western Montana to create the Mid-C zone, making it difficult to separate Washington.
6/17/2020	Joni Bosh, NWEC	Questions on Feedback session #2 Resource Costs Slide 11 – • Under IRP: Does the electric price forecast for economic dispatch of power plants used in modeling "to support resource acquisitions" include the Social Cost of Greenhouse gases? What is the value used for SCGHG? • Under Avoided Cost: Please illustrate/explain how the price forecast is used to develop avoided costs for EES and PURPA. • Resource acquisitions: Clarify what steps PSE takes and which model(s) it uses in the resource acquisition analysis. Slide 17 – • Emissions costs are operating costs, not fixed costs. Please explain why the SCGHG emission costs in step three of the Aurora modeling is added back to the fixed costs of thermal plants? Slide 20 – • Explain how elements relating to statewide renewable need on slide 20 and the outcomes on slide 21 are incorporated in the price forecast. Slide 22 – • Please express the results in this chart in real dollar terms as well. NWEC urges PSE to include real dollar results along with the nominal dollar results at least for summary tables and charts throughout the IRP. This will help improve comparability across different analyses and time horizons. Slide 24 – • By using 80 years of observational weather data as is incorporated in the Regional Demand from the 7th Power Plan (the data which is now at least five years old), future climate impacts on load are not adequately represented. PSE should review the Council's climate adjusted demand forecast when it becomes available to compare the impact on energy price forecasts. Slides 25 and 26 – • PSE should add a sensitivity using a high gas price that is 25% more than the baseline price, to reflect the risk from the reality of reduced gas production in North America. Slide 29 • Please also show this chart in discounted present value levelized dollars. Slide 34 –	Slide 11: a. Yes, the electric prices include SCGHG as a planning adder. PSE is using the SCGHG value identified in SB5116 and updated to include inflation as released by the Washington UTC. b. The price forecast is the avoided cost of energy used in the avoided costs for EES and PURPA. A complete write-up of the methodology can be found in dockets UE-190665 and UE-191062 c. The resources acquisition process uses all the same models as the IRP. The IRP sets the power prices using the AURORA power price model and then sets the peak capacity need using the Resource Adequacy model and also does the flexibility analysis using the Plexos model. Both the RA model and Plexos model are updated with the resources bid through the acquisitions and then tested in the portfolio model. Slide 17: See reply to Kathi Scanlan, WUTC, question number 2. The law states that the SCGHG is a "cost adder" not a dispatch cost and therefore it follows the methodology described. Slide 20: Renewable need is forced into Capacity Expansion as a must-build resource, so the model builds enough renewable resource to meet renewable constraints, see slide 33. Slide 22: As part of the Webinar #2: Power Price Forecast Consultation Update (to be released on 07/01/2020), PSE will provide a spreadsheet (Excel workbook) with the final 2021 IRP power price scenarios. PSE will include a conversion tool from nominal to real dollars as part of this spreadsheet. Slide 24: The Council's updated demand forecast is not ready for release yet and PSE has reached out to the Council regarding the mid-term update. Slide 25 and 26: Thank you for your feedback on the scenarios. PSE is reviewing through all the suggestions and getting in contact with some stakeholders for further discussion. PSE will have the final list of scenarios for the consultation update. Slide 29: As part of the Webinar #2: Power Price Forecast Consultation Update (to be released on 07/01/2020), PSE will provide a spreadsheet (Excel workbook) with the final 2021 IRP power price scenarios. PSE will include a conversion tool from nominal to real dollars as part of this spreadsheet.

		• Please explain these two scenarios and the assumptions behind implementation scenarios 1 and 2. We are not able to advise on the question posed on slide 38 without a better understanding of the two scenarios. Slide 38 – • We would appreciate PSE explaining the pros and cons of the options posed on this slide. The context of this question is unclear. Slide 42 and 43 – • What is the purpose of including a No CETA scenario? • We would like to see a low demand/high gas price scenario.	Slide 34: PSE has contacted Joni for further discussion. Since Joni is unavailable until early July, PSE will meet with Fred Huette from NWEC in her place. Slide 38: PSE will meet with Fred Huette to clarify the slide and help with any confusion related to the stakeholder feedback. Slide 42 and 43: Thank you for your feedback on the scenarios. PSE is reviewing through all the suggestions and getting in contact with some stakeholders for further discussion. PSE will have the final list of scenarios for the consultation update.
6/17/2020	Vlad Gutman-Britten, Climate Solutions	- Social Cost of Greenhouse Gas Application (Slide 17) - Why does this apply to the electric price forecast, rather than just in the portfolio model? If the SCGHG is applied during portfolio modeling at the end, it would appear to double count the SCGHG by also including it upfront in the electric price forecast. Because SCGHG is an adder, it will not actually impact market prices. We believe that IRP modeling should reflect reality to the extent possible, and so SCGHG should be accounted for post-economic dispatch in order to evaluate competing resource portfolios as they would function in the real world. - However, if PSE does continue to apply the SCGHG in developing the electric price forecast, it is still unclear why the SCGHG is only applied to Washington resources. While we understand that this is a cost adder, the cost adder in CETA does not only apply to facilities physically located in Washington, but rather to any energy delivered to Washington customers, regardless of the point of generation. Given that PSE can model the specific cost adders of California and British Columbia, why is it not possible to apply the SCGHG adder to all electricity being delivered to Washington customers? - PSE noted in the slide that there are no new thermal builds in Washington. It was unclear during the presentation whether this was a modeling constraint based on the assumption that CETA would prevent new thermal builds in Washington, or due to another underlying assumption. If it is a result of the former, this appears out of step with previous PSE model runs and projections. - Renewable Resource need in WA (Slide 21) - While CETA does not have any firm requirements until 2030, the law does require that utilities demonstrate continuous progress towards achieving the GHG neutral and 100% requirements of CETA. This slide pertains to all resource needs in Washington for compliance with the act--if utilities make progress towards the law between 2022-2030, we anticipate the glide path beginning in earlier years and potentially having an impact on the electric price forecast. - Stakeholder feedback (Slide 38): - Assumptions on WA/CA compliance: We appreciate the two end cases, reflecting various compliance scenarios for Washington and California. While both provide useful information, we can anticipate compliance will fall in between the two end cases for Washington. Washington utilities already serving load with more than 80% nonemitting and renewable resources will still be required to demonstrate progress towards achieving the GHG neutral standard, but may fall short of achieving 100% clean energy by 2030. Some utilities in Washington currently serving load with less than 80% clean energy may choose to somewhat overcomply to mitigate for hydro variability. In California, while utilities have some flexibility in how to meet the requirements of the law, we do not expect new large investments in nonemitting resources (nuclear), and the state's one remaining nuclear plant is scheduled to retire in the mid-2020s. It would be a reasonable assumption that California will continue receiving nuclear energy from other nuclear facilities, principally Palo Verde Nuclear Generating Station which represents about 3% of current load, but serve all new resource needs with 100% renewable energy, including renewable natural gas, synthetic gas, and hydropower. - Consistency: We recommend consistent application of the clean energy regulation in order to compare the results. However, we do recommend running sensitivities on the end-cases in order to see how results may change. - Drat scenarios (Slide 42)	Slide 17: a. Thank you for your feedback. PSE agrees that the SCGHG should be accounted for post-economic dispatch and the method that PSE created does this. b. The social cost of carbon is an adder to thermal plants physically located in Washington. Since Washington state is a part of the Mid-C market along with Oregon, Idaho and western Montana, PSE cannot separate out Washington state from the rest of the Mid-C at this point and therefore unable to determine where the energy is being delivered to. The assumptions on how PSE will treat unspecified system purchases to meet PSE load will be addressed in the July 21 webinar on social cost of carbon. c. This relates back to part b of this question. Given that PSE is modeling the entire region as a whole, the model believes that there is plenty of resources in the region given normal hydro conditions and mid load. This is different than the PSE portfolio model, where PSE is accounting for transmission constraints into the PSE service territory. So even though there might be enough resources in the region, it may not be delivered to load due to transmission constraints. To reflect the social cost of carbon planning adder in PSE's portfolio model, market purchases will include a wheeling costs equivalent to the SCC adder during the capacity expansion run. Slide 21: Thank you for the suggestion, PSE is updating the assumption and will have the updated targets for the July 1 consultation update. Slide 38: Thank you for your feedback, PSE will be using Scenario 1 (90%) for the clean energy implementation. Slide 42 and 43: Thank you for your feedback on the scenarios. PSE is reviewing through all the suggestions and getting in contact with some stakeholders for further discussion. PSE will have the final list of scenarios for the consultation update. At this point, PSE is only modeling clean energy and RPS laws and the current law is Oregon is to reach 50% by 2030.

		- The "High" scenario includes high demand and a high gas price, but does not include a higher SCGHG. While CETA requires SCGHG as a minimum cost adder, that cost may still be an underestimate and PSE should reflect the risk of a higher emissions cost in the high scenario. - The "No CETA" scenario would provide useful information for the alternative lowest reasonable cost scenario for comparison with the compliance scenario. However, the incremental cost cap is based only on compliance with the GHG neutral and 100% Clean Energy Standards. The "No CETA" scenario should be renamed "Non compliance scenario" and should incorporate other components of CETA beyond the clean energy standards into the lowest reasonable cost. - Stakeholder feedback (Slide 43) - Additional electric price scenarios: - Low demand to reflect a recession, high gas prices to incorporate greater risks of reliance on fossil fuels, and compliance with all laws - Addition of a 100% clean electricity requirement consistent with CETA in Oregon. - Passage of a carbon price for all Washington consumed electricity starting at $15/ton beginning in 2022.	

PSE IRP Consultation Update
Webinar 2: Electric Price Forecast
June 10, 2020

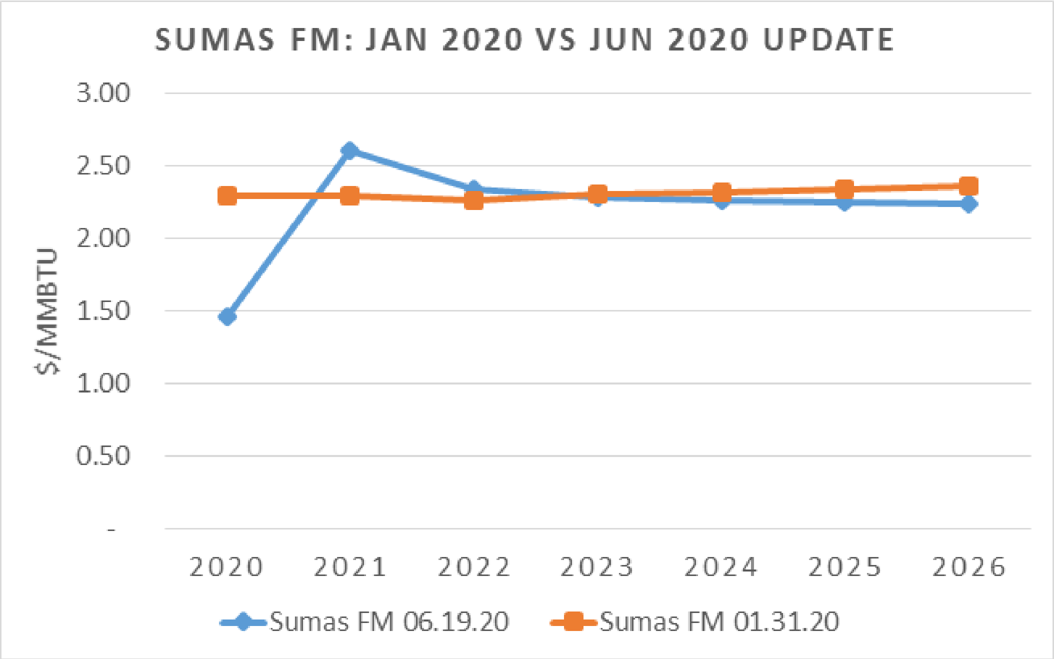
7/1/2020

The following consultation update is the result of stakeholder suggestions gathered through an online Feedback Form, collected between June 4 through June 17, 2020 and summarized in the June 24 Feedback Report. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

PSE also thanks Fred Huette of Northwest Energy Coalition (NWEC), Vlad Gutman-Britten of Climate Solutions, Bill Pascoe of Pascoe Energy representing Absoroka Energy & Orion Renewables and Katie Ware of Renewables Northwest for meeting with PSE staff to help further clarify their questions and suggestions in follow-up meetings.

Gas price forecast

PSE received feedback from Kathi Scanlan, Washington Utilities and Transportation Commission (WUTC) Staff, requesting the use of an updated gas price forecast to reflect the socioeconomic changes of the COVID-19 pandemic. The PSE gas price forecast is an amalgam of two price forecasts incorporating forward marks for the short-term forecast (5 years in the future) and a Wood Mackenzie forecast for the long-term forecast (greater than 5 years into the future). PSE has updated the forward marks portion of the forecast as reflected on the chart below. The chart compares the January 2020 and June 2020 gas forward marks forecast for the Sumas hub. The chart shows a significant drop in prices in year 2020 and a slight increase in prices for year 2021, and a very similar projection in years 2022 through 2026. Given the 2021 IRP timeframe extends from 2022 to 2045, PSE does not anticipate the change in forward marks prices to have a meaningful impact on the power price forecast.



PSE has contacted Wood Mackenzie for an updated long-term gas price forecast and was informed the forecast would be released in the coming weeks. PSE will examine the magnitude of change of the updated long-term gas price forecast and, if deemed significant, incorporate the new forecast into the power price model. Further details will be provided upon receipt and analysis of the new long-term gas price forecast.

Regional demand forecast

PSE received feedback from James Adcock, Kathi Scanlan, WUTC Staff, and Joni Bosh and Fred Heutte, NWEC, concerning PSE's use of the Northwest Power and Conservation Council's (the Council) 7th Power Plan regional demand forecast. Since the 7th Power Plan was published in 2016, concerns were raised about the applicability of the regional demand forecast for PSE's 2021 IRP power price forecast. PSE has contacted the Council to request an updated demand forecast. The Council responded that the regional demand forecast intended for use in the 2021 Power Plan is not available for release at this time. However, the Council was able to provide the regional demand forecast used in the 2019 Update of the 7th Power Plan.

PSE is currently reviewing the "2019 Update" regional demand forecast and intends to incorporate the updated information into the 2021 IRP power price forecast. Further details will be provided upon analysis of the updated regional demand forecast.

Renewable need

On slide 38 of the Draft Electric Price Forecast presentation, PSE solicited feedback on how to model Washington State's renewable need. Two scenarios were presented: 22.9 million MWh by 2030 which equates to 90% adoption of renewable resources (Scenario 1) and 12.2 million MWh by 2030 which equates to 80% adoption of renewable resources (Scenario 2).

PSE received feedback from Vlad Gutman-Britten, Climate Solutions, Katie Ware, Renewable Northwest, Kathi Scanlan, WUTC Staff, and Joni Bosh and Fred Heutte, NWEC, on this topic. The majority of stakeholders suggested that PSE move forward with modeling Scenario 1 (higher renewable resource implementation in 2030) for the 2021 power price forecast.

PSE received feedback from Vlad Gutman-Britten, Climate Solutions, and James Adcock regarding the starting point for the ramp used for Washington state CETA requirements, as shown on slide 21. The renewable need will be updated with the demand forecast and an adjusted starting point for the renewable need ramp to start at the existing amount of non-emitting/renewable resources in 2022 and then ramp to the 2030 need. The ramp rate and demand forecast will be updated and further details will be provided upon completion of this analysis alongside other updates to gas price forecast and regional demand forecast discussed above.

Electric price forecast scenario selection

On slide 43 of the Draft Electric Price Forecast presentation, PSE solicited feedback on power price scenarios to include as part of the 2021 IRP. PSE received feedback from Vlad Gutman-Britten, Climate Solutions, Katie Ware, Renewable Northwest, Bill Pascoe representing Absaroka Energy & Orion Renewables, Kathi Scanlan, WUTC Staff, and Joni Bosh and Fred Heutte of NWEC on this topic. The table on the next page summarizes the stakeholder suggestions for power price forecast scenarios.

In the table, cells highlighted orange represent a change from Scenario 1 and dark grey cells represent scenarios proposed by stakeholders but will not be included in the 2021 IRP. The 'Comments' column provides an explanation of how the scenario may be applied in the 2021 IRP. The 2021 IRP Scenarios will include Scenarios 1, 2, 3, 6, 9, 10, 11, and 12.

2021 IRP Power Price Forecast Scenarios

	Scenario Name & Requestor	Demand	Gas Price	CO_2 Price/Regulation	RPS/Clean Energy Regulation	Comments
1	Mid	Mid	Mid	CO_2 Regulation: Social cost of carbon included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC	2021 IRP Scenario
2	Low	Low	Low	CO_2 Regulation: Social cost of carbon included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC	2021 IRP Scenario
3	High	High	High	CO_2 Regulation: Social cost of carbon included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC	2021 IRP Scenario
4	High + High CO_2 Price (Vlad Gutman-Britten, Climate Solutions)	High	High	CO_2 Regulation: High Social cost of carbon included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC	PSE recognizes the value in modeling a 'very high cost of carbon'. However, this model run is better suited as a *sensitivity* on the existing High Scenario (Scenario 3) than as a standalone scenario.
5	WECC Wide CO_2 Price (Bill Pascoe, Absaroka Energy & Orion Renewables)	Mid	Mid	WECC wide CO_2 price (federal tax)	Washington CETA, plus all regional RPS regulations in the WECC	Given the similarity to Scenario 6, PSE has elected to combine the essence of this suggestion into the modeling of Scenario 6, which also incorporates a CO_2 tax across the WECC.
6	Mid + CO_2 Tax (Katie Ware, Renewable Northwest and Vlad Gutman-Britten, Climate Solutions)	Mid	Mid	WECC wide CO_2 price (federal tax)	Washington CETA, plus all regional RPS regulations in the WECC	2021 IRP scenario where the cost of carbon is modeled as a tax instead of a cost adder. The cost will extend across the entire WECC as if by federal mandate. The cost is yet to be determined.
7	High + CO_2 Tax (Katie Ware, Renewable Northwest)	High	High	WECC wide CO_2 price (federal tax)	Washington CETA, plus all regional RPS regulations in the WECC	PSE recognizes the benefit of a High plus WECC wide CO_2 price as a tax. PSE will make every attempt to include this scenario in the 2021 IRP. However, given the similarity to Scenario 6, PSE will only be able to include this scenario if resources and schedule allow.
8	Mid + Very Gas Price (Joni Bosh, NWEC)	Mid	Very High (25% greater than Mid)	CO_2 Regulation: Social cost of carbon included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC	PSE recognizes the value in identifying the impact of higher than expected gas prices on the power price forecast. However, given the similarity to Scenario 9, this scenario will not be modeled.

	Scenario Name & Requestor	Demand	Gas Price	CO_2 Price/Regulation	RPS/Clean Energy Regulation	Comments
9	Low Demand + Very High Gas Price (Joni Bosh, NWEC and Vlad Gutman-Britten, Climate Solutions)	Low	Very High (25% greater than Mid)	CO_2 Regulation: Social cost of carbon included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC	2021 IRP scenario to understand the impact of higher gas prices combined with low demand on the power price forecast. This scenario has been selected instead of Scenario 8.
10	Mid + $15 CO2 tax (Vlad Gutman-Britten, Climate Solutions)	Mid	Mid	CO_2 Regulation: Social cost of carbon included in Washington state, plus upstream natural gas GHG emissions WECC wide CO_2 tax of $15/ton + inflation	Washington CETA, plus all regional RPS regulations in the WECC	2021 IRP scenario to evaluate CO_2 tax pricing structure in addition to existing regulation on the power price forecast.
11	Mid + Increased Renewable Energy (Vlad Gutman-Britten, Climate Solutions)	Mid	Mid	CO_2 Regulation: Social cost of carbon included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC 100% OR RPS (similar to CETA), Xcel Energy, Idaho Power, Avista clean energy commitments	2021 IRP scenario included to understand future clean energy regulation and utility commitments on the power price forecast.
12	Low Growth	Low	Mid	CO_2 Regulation: Social cost of carbon included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC	2021 IRP scenario included to understand the potential long-term impact of COVID-19 on the regional economy and slower regional growth impact on the power price forecast.

Summary of all updates

PSE appreciates the feedback provided by stakeholders. In summary, the following changes will be implemented into the power price model:

- Updated gas price forecast to include recent socioeconomic impacts of COVID-19 pandemic
- Inclusion of the 2019 Update to the 7th Power Plan regional demand forecast
- Modeling of higher Washington State clean energy implementation in 2030 (i.e. Scenario 1)
- The renewable need will be recalculated with the 2019 Update of the 7th Power Plan regional demand forecast and a Washington CETA requirement ramp starting point at the existing amount of non-emitting/renewable resources in 2022

When the 2021 IRP power price scenarios are completed, PSE will provide a spreadsheet with a conversion from nominal to real dollars.

PSE is committed to keeping our stakeholders informed of our progress toward incorportating feedback into the IRP process. PSE will review the list of scenarios with stakeholders at the August 11, 2020 webinar and open for the floor for discussion around the details of these scenarios. Then the completed power price forecast scenarios will be presented at the October 20, 2020 webinar.

Webinar 3, June 30, 2020

Transmission Constraints

PUGET SOUND ENERGY

Webinar #3: Transmission Constraints
June 30, 2020 from 1:30 p.m. to 4:00 p.m. PST

Virtual webinar link:
https://us02web.zoom.us/j/88985995321?pwd=c0lEV1JlcTY1S2tzSUh3SlVFRHhnZz09

Webinar ID: 889 8599 5321
Password: 582653

Call-in telephone number (audio only): +1 253 215 8782

Topic	Lead
Welcome • Agenda review • Safety moment • How to participate	EnviroIssues
The 2021 IRP • Speaker introductions • IRP process • Project timeline • Upcoming meeting schedule	Irena Netik, Director, Energy Supply Planning & Analytics
Electric IRP models • Modeling process • Transmission constraint background	Elizabeth Hossner, Manager, Resource Planning & Analysis
Transmission capacity constraints • Modeling methodology • Capacity magnitudes • Capacity uncertainty	Tom Flynn, Manager, Energy Delivery
Transmission cost assumptions • Transmission rates and losses in the 2021 IRP	Tom Flynn, Manager, Energy Delivery
5-minute break	
Transmission cost assumptions (continued) • Transmission rates and losses in the 2021 IRP	Tom Flynn, Manager, Energy Delivery
Question & answer • More participant questions • Using the Feedback Form	Facilitated by EnviroIssues
Wrap up • Next steps • Thank you’s	Irena Netik, Director, Energy Supply Planning & Analytics

2021 IRP Webinar #3: Transmission Constraints

Planning Assumptions for the Electric Portfolio Model

June 30, 2020

Agenda

- Safety moment
- Speaker introductions
- IRP modeling process
- Transmission constraint background
- Transmission capacity constraints
- Transmission cost assumptions
- Final Q&A

Safety Moment: Hiking safety

Ten essential items that every hiker should carry

1. **Navigation** – Always carry a detailed map of the area that you are hiking in and a compass (even if use a GPS or smartphone)
2. **Hydration** – It is essential to drink a lot of water while hiking
3. **Nutrition** - Always bring extra food when hiking in case an unexpected situation delays your return
4. **Rain gear and insulation** - Always tuck rain gear into your backpack and bring along layers of clothes. Avoid cotton clothing in favor of wool or poly blends that wick moisture away from your skin
5. **Fire starter** - Always bring along waterproof matches in a water-tight container and have a dry or waterproof striker
6. **First Aid Kit** - Make sure you have the supplies to deal with major injuries, and make sure you have the knowledge
7. **Tools** - Knives or a multi-tool is indispensable
8. **Illumination** - A light source is vital if you get caught in the woods after dark.
9. **Sun protection** - Sunglasses are a must
10. **Shelter** - An emergency tarp or space blanket can help protect you through a sudden storm or shelter you through an unexpected night outdoors

Other items to consider – insect repellant, watch, whistle, gloves, extra socks, and hand sanitizer

Public participation in the 2021 IRP

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How to participate with Zoom

Virtual webinar
link: https://us02web.zoom.us/j/88985995321?pwd=c0lEV1JlcTY1S2tzSUh3SlVFRHhnZz09

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Webinar ID: 889 8599 5321

Call-in telephone number: 1-253-215-8782

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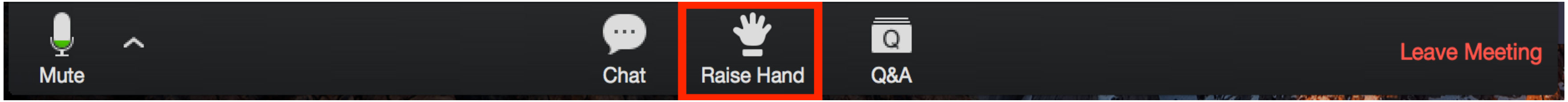
Participation norms

- Mute your mic while others are speaking
- We will ask for comments and questions along the way
- Participate using the chat box or ask questions verbally
- Use the "Raise hand" feature to signal you'd like to ask your question verbally
- Wait to be called on
- Please stay on topic; there may be time for additional questions and comments at the end
- Please be polite and respect all participants on the webinar



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Today's speakers

Irena Netik

Director Energy Supply Planning & Analysis, PSE

Elizabeth Hossner

Manager Resource Planning & Analysis, PSE

Tom Flynn

Manager Energy Delivery, PSE

Alexandra Streamer & Alison Peters

Co-facilitators, EnviroIssues

2021 IRP modeling process

The 2021 IRP will follow a 6-step process for analysis:

1. Establish peak capacity, energy and renewable energy need
2. Determine planning assumptions and identify supply-side and demand-side resource alternatives
3. Analyze scenarios and sensitivities using deterministic and stochastic risk analysis
4. Analyze results
5. Develop resource plan
6. Develop 10-year Clean Energy Action Plan

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2021 IRP process timeline

Meeting dates are available on [pse.com/irp](pse.com/irp) and will be updated throughout the process. This is a tentative timeline subject to revision.

Details of upcoming meetings can be found at pse.com/irp

Date	Topic
July 14, 1:30 - 4:30 pm	Demand Side Resources including Demand Response
July 21, 1:30 – 4:30 pm	Social Cost of Carbon
August 11, 9:30 am – 12:30 pm	Portfolio sensitivities development (electric & gas) CETA assumptions Distributed energy resources
September 1, 1:00 – 5:00 pm	Demand forecast (electric & gas) Resource adequacy Resource need: peak capacity, energy & renewable energy need
October 20, 1:30 – 4:30 pm	Portfolio sensitivities draft results Flexibility analysis
November 4, 1:30 – 4:30 pm	Clean Energy Action Plan 10-year Distribution & Transmission Plan
December 9, 1:30 – 4:30 pm	Portfolio draft results Stochastic analysis Wholesale market risk

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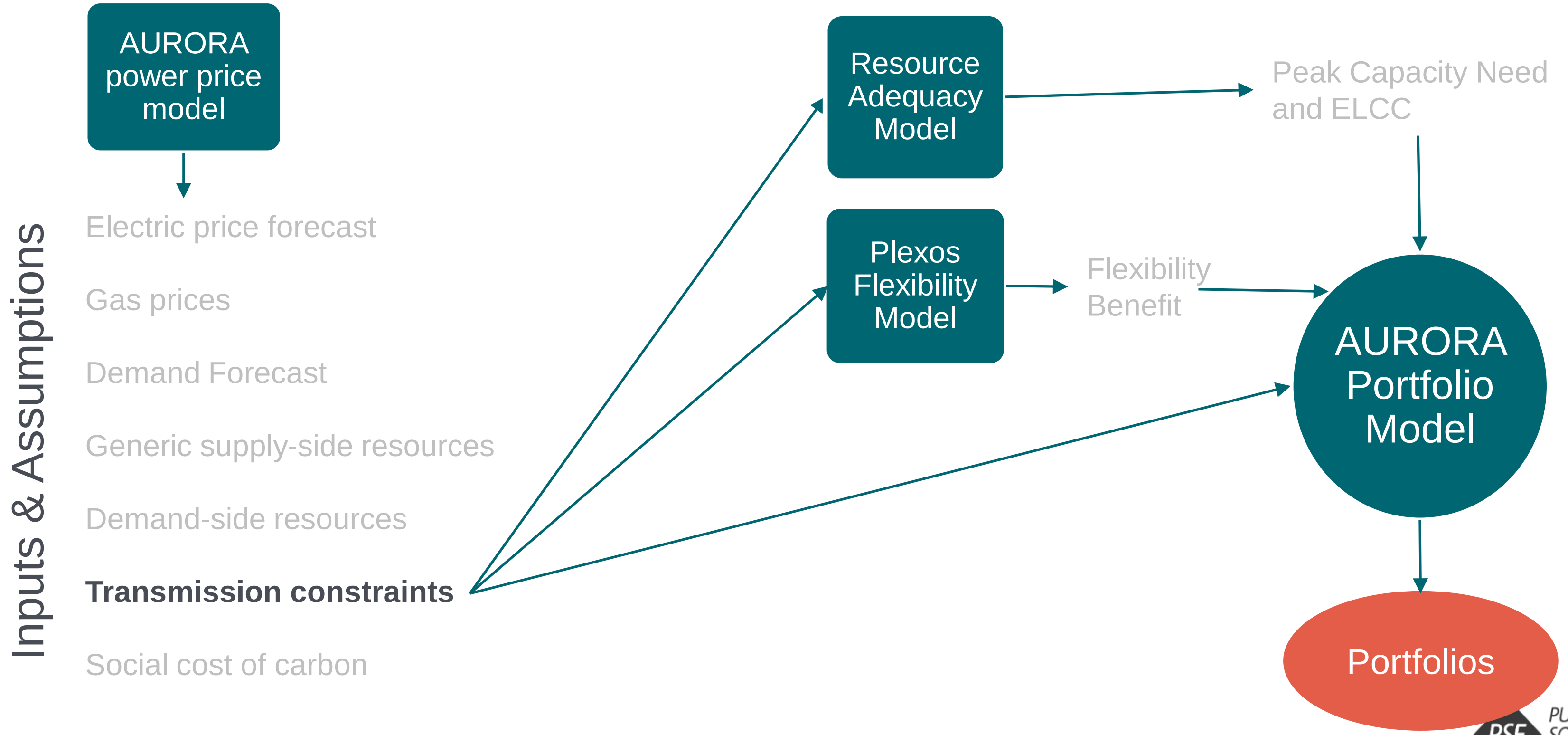
IRP modeling process

Electric IRP Models



Transmission constraint background

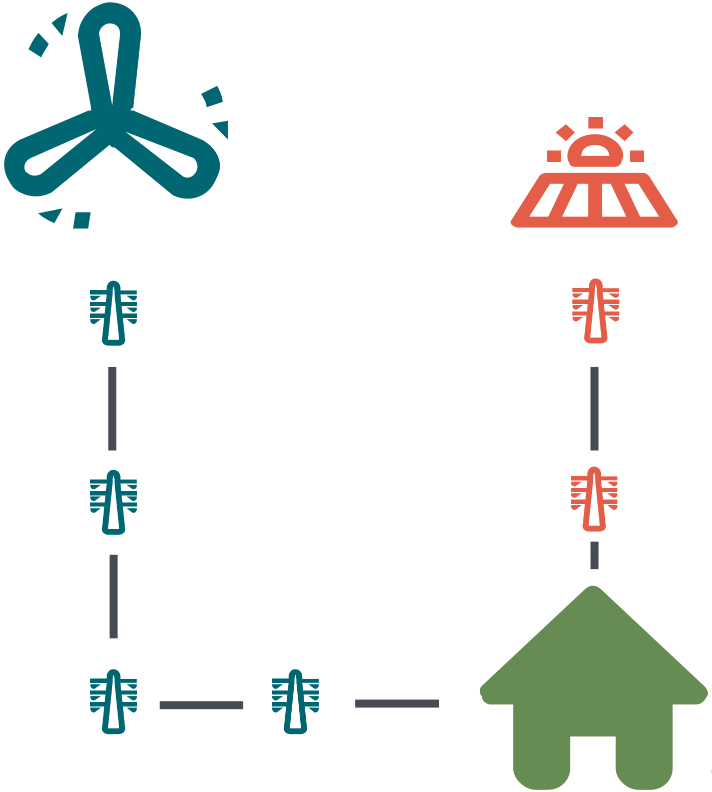
Significant renewable resource capacity will be needed to support CETA

- Renewable resource need increased by over 2,000 MW by 2030 in order to meet the 80% renewable requirement from CETA instead of the 15% RPS.

- Transmission constraints must be in place to ensure these additions are feasible.

- Modeling transmission constraints for new resources is new for the 2021 IRP.

Transmission constraints shape how power delivery is modeled

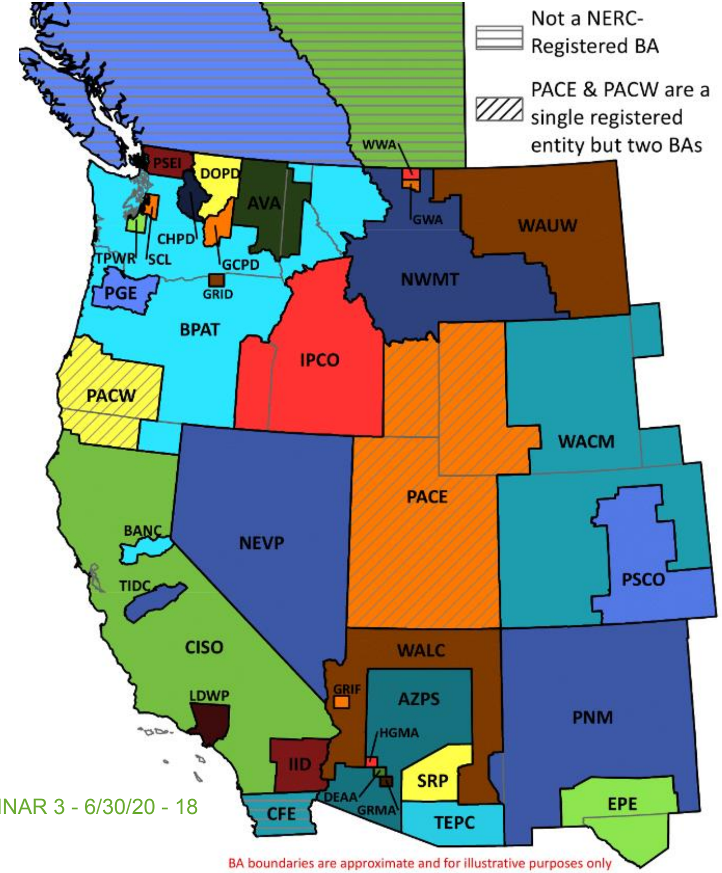


- AURORA is a fundamentals-based model that employs a multi-area, transmission-constrained dispatch logic to simulate real market conditions
- Loads must be served by **both** generation and transmission
- Therefore, new resource builds will be influenced by **both** generation and transmission characteristics
- Cost and capacity are key transmission constraints

PUGET SOUND ENERGY

Matching renewable generation with transmission capacity will be a challenge for PSE

- PSE has a relatively small territory, localized in NW Washington
- Renewable resources are scattered across the WECC
- PSE must work with surrounding balancing authorities to secure transmission across the WECC



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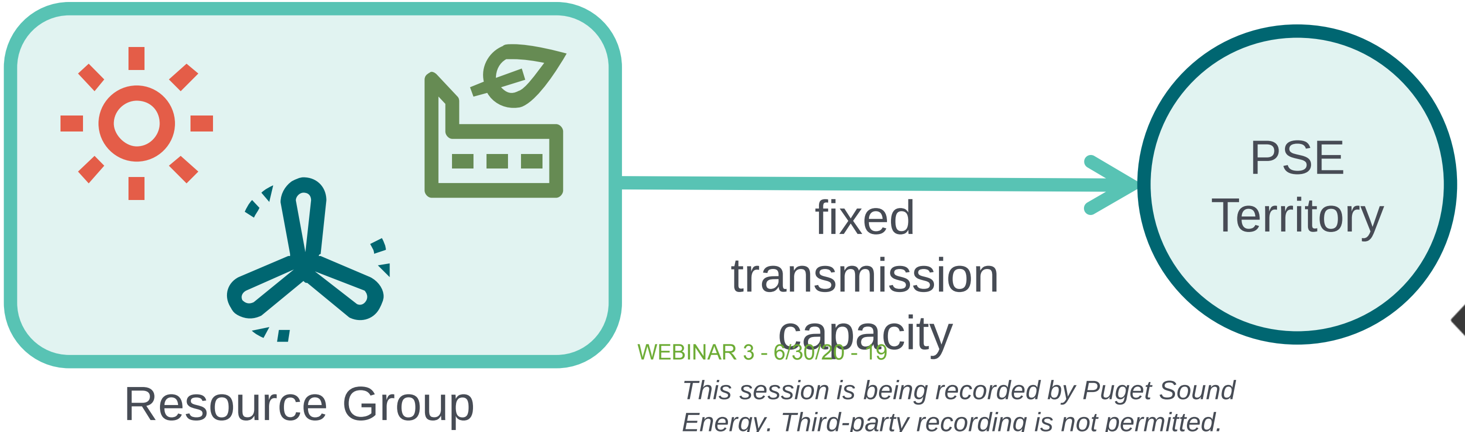
Modeling transmission constraints

- The AURORA Portfolio model is a two area system zonal model encompassing PSE territory and the Mid-C hub.
  - The zonal model is a generation optimization and capacity expansion model, not a transmission capacity model.
- Resource Groups in AURORA will allow different resources to be aggregated into unique ‘transmission regions’ sharing a fixed transmission capacity.
- The transmission capacity will be modeled as a build limit for the resource group.
- Allows MIP optimization to select the best resource to fit portfolio need within each Resource Group.



Transmission capacity constraints

Participation Objectives

- Stakeholders to share input on transmission capacity constraint modeling methodology
- Stakeholders to share input on transmission capacity constraint magnitudes
- Stakeholders to share input on how to model transmission capacity uncertainty

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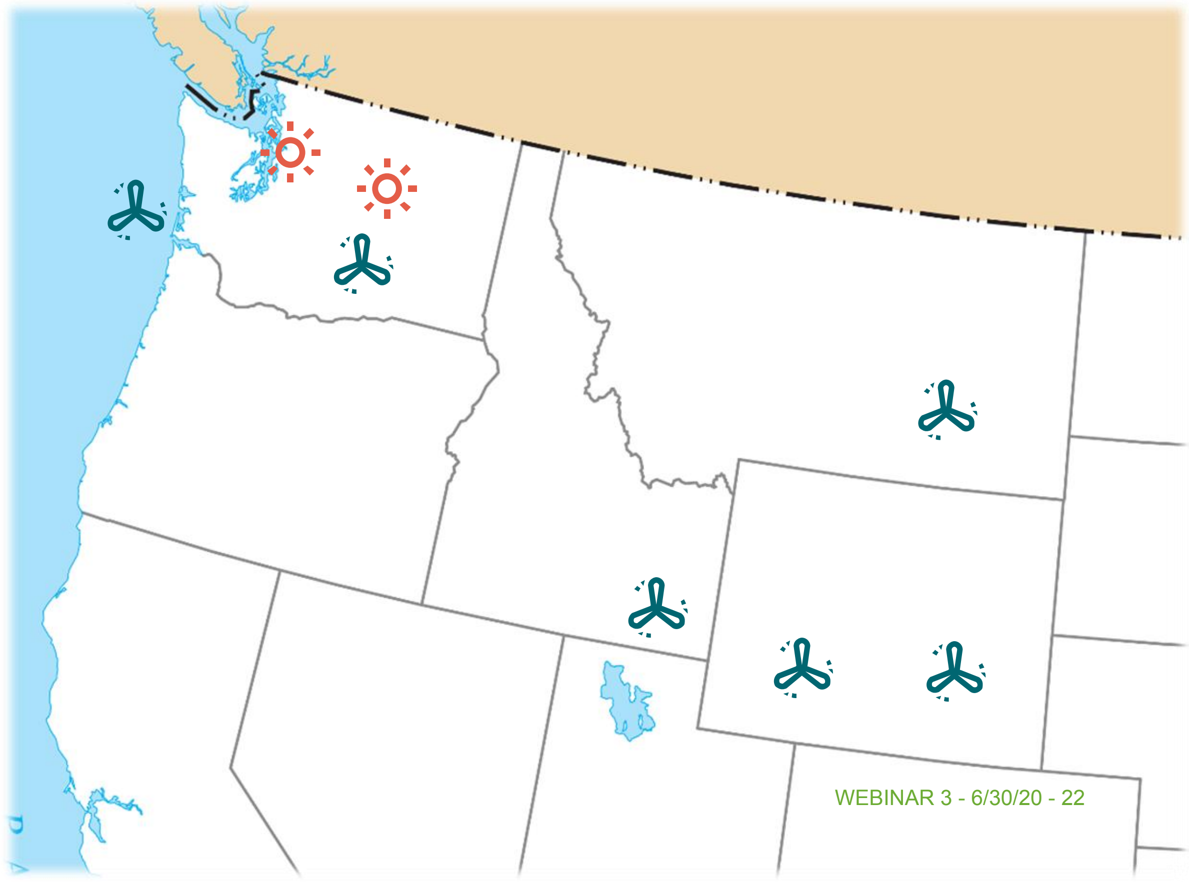
PSE's generic renewable resources are geographically diverse



- W Washington Solar
- E Washington Solar

- Offshore Wind
- Washington Wind
- Montana Wind
- Idaho Wind
- E Wyoming Wind
- W Wyoming Wind

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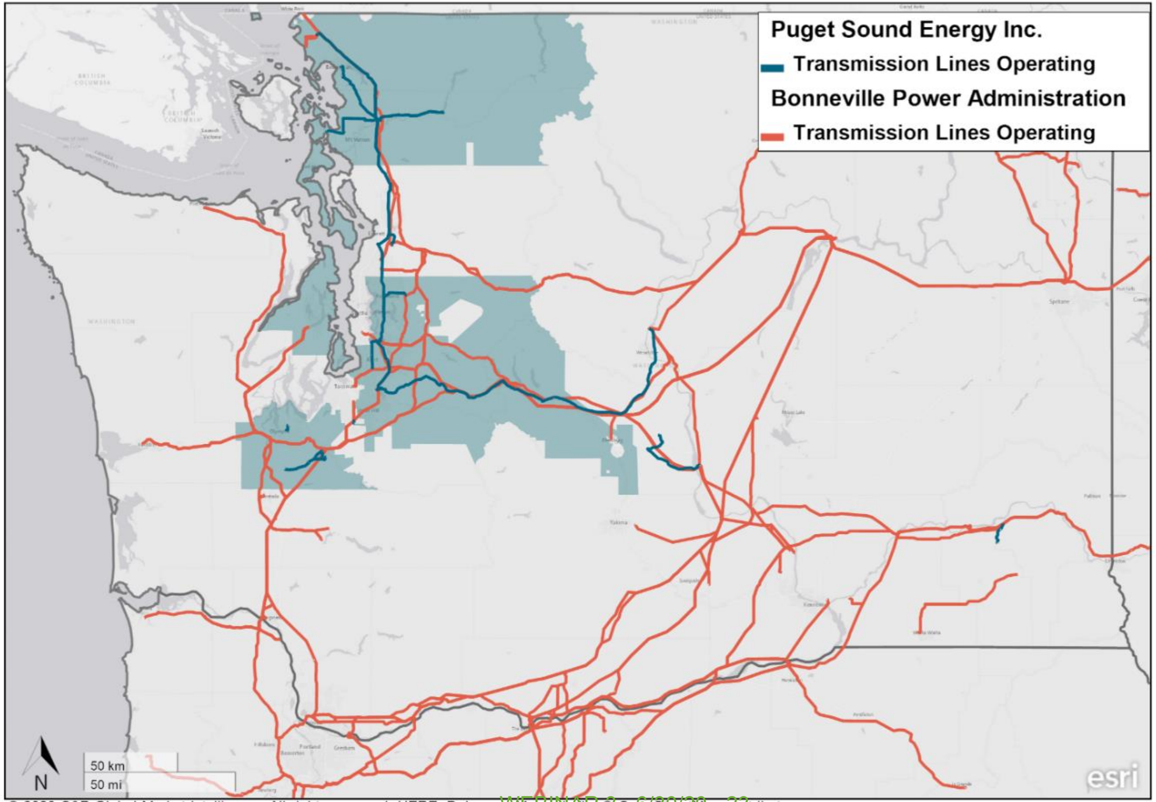
PSE PUGET SOUND ENERGY

PSE must work with existing, largely BPA, transmission to bring new resources to PSE territory



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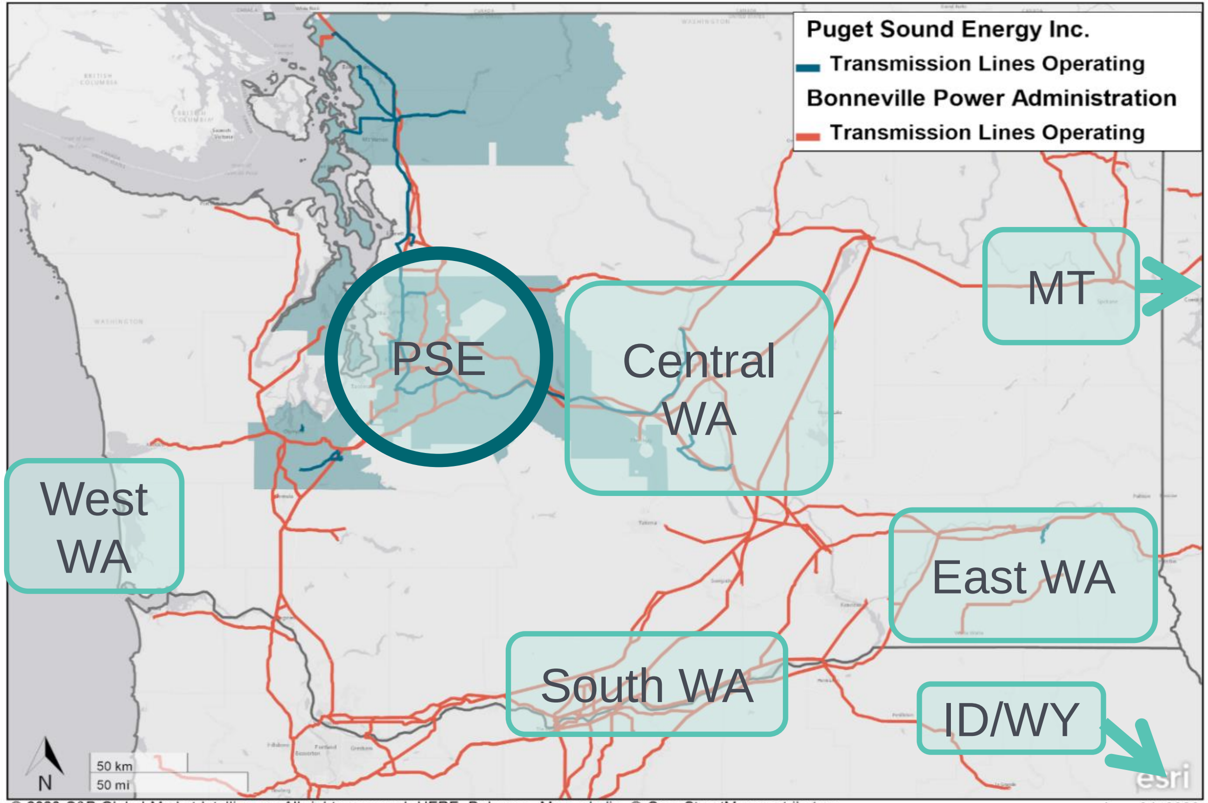
The PSE Energy Delivery team has identified 7 Resource Group regions which align with existing transmission resources



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PUGET SOUND ENERGY

Each Resource Group region will contain a distinct mix of generic resources

Resource Group Region	Generic Resource													
	WA Wind	MT Wind	Offshore Wind	ID Wind	East WY Wind	West WY Wind	CCCT	Frame	Recip	Biomass	Solar Residential	Solar Utility	Pumped Storage	Battery
PSE territory*							x	x	x	x	x			x
Eastern Washington	x									x		x	x	x
Central Washington	x									x		x	x	x
Western Washington	x		x							x		x	x	x
Southern Washington/Gorge	x									x		x	x	x
Montana		x												
Idaho / Wyoming				x	x	x								

*Not including the PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed

The transmission capacity from each region to PSE is uncertain

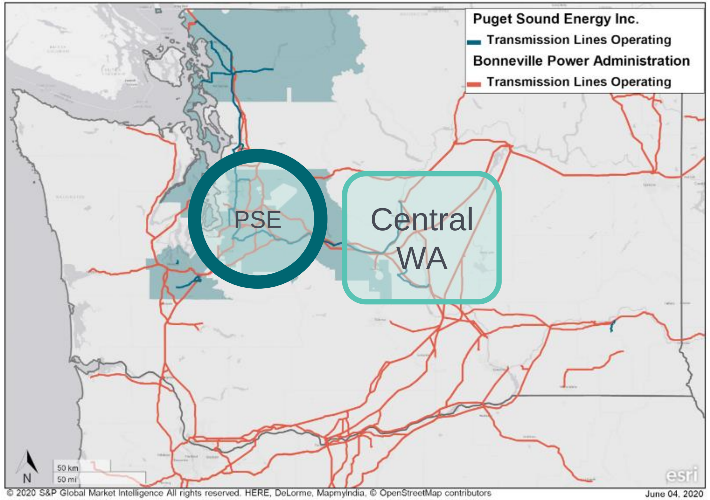
The PSE Energy Delivery team has assessed the status of transmission availability in the PNW and quantified potential new transmission capacity into four tiers:

Features	Tier 0	Tier 1	Tier 2	Tier 3
First year Available	2022	2022	2030	2030+
Amount (MW)	Unconstrained	1,050	3,070	5,205
Confidence		High	Moderate	Lowest
Composition		Repurposes Existing Tx	+ New Tx	New Tx with Longer Lead Times

Transmission capacity – Central Washington

- All tiers take advantage of 1,500 MW of Mid-C transmission reserved for Market Purchases
  - Give transmission a **dual purpose** to serve both market purchases and renewable resource generation
  - Quantity of repurposed transmission* increases with each tier

- Tier 2 and Tier 3 include 125 MW of new transmission on the Grant County PUD system for delivery of Kittitas area solar



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Added transmission (MW)		
Tier 1	**Tier 2**	**Tier 3**
250	**625**	**875**

**PSE has no available transmission rights to pair with proposed 2020 RFP resources. PSE's capacity need forecast for the 2020 RFP accounts for all of PSE's current transmission rights as existing capacity paired with either a specific generation resource or market purchases. The 2020 RFP seeks incremental capacity (i.e., capacity in addition to these existing resources) to meet PSE's projected capacity need.*

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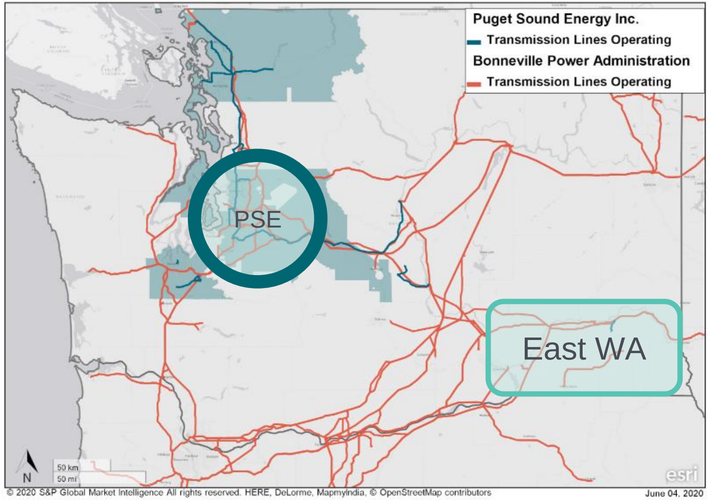
Transmission capacity – Eastern Washington

- PSE may attain between 150 and 640 MW of transmission to the Lower Snake River phased self-builds through BPA Cluster study requests
  - New capacity ramped by tier: 150, 300, 640 MW
- Redirect BPA transmission freed up by sale of Colstrip Unit 4 may add 185 MW to Tier 3
- Between 150 and 315 MW of third-party transmission rights maybe acquired via:
  - Project developers including transmission in RFP submittals,
  - Third-party retirements
  - New capacity ramped by tier: 150, 375, 690 MW



Added transmission (MW)		
Tier 1	Tier 2	Tier 3
300	675	1,515

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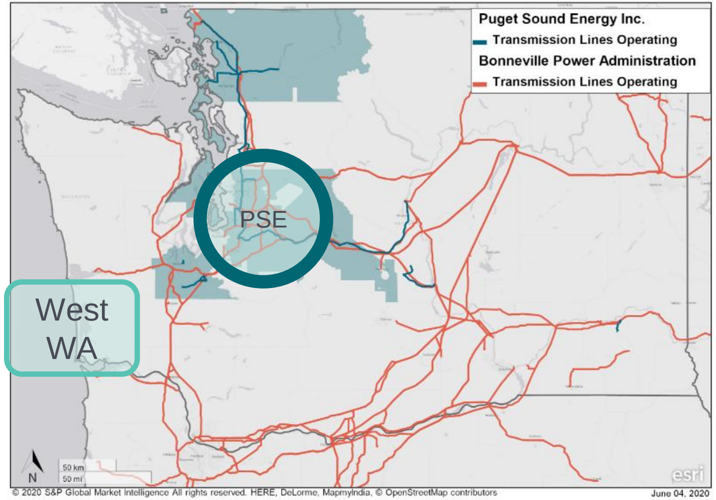
Transmission capacity – Western Washington

- 100 MW of BPA transmission for PSE's TransAlta PPA expires in 2025 and may be repurposed in Tier 2
- 335 MW of transmission for the Mint Farm CCCT could be **dual purposed** to prioritize renewable generation at Tier 3
- 200 MW of Tier 3, third-party transmission rights maybe acquired via:
  - Project developers including transmission in RFP submittals,
  - Third-party retirements



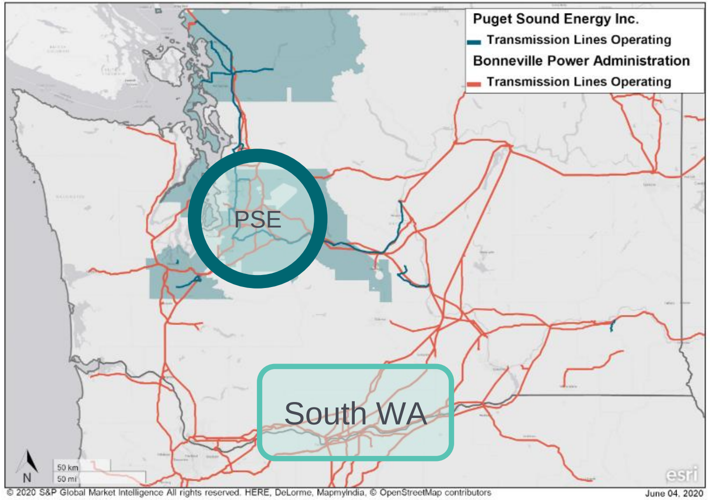
Added transmission (MW)		
Tier 1	Tier 2	Tier 3
-	100	635

PUGET SOUND ENERGY

Transmission capacity – Southern Washington / Gorge

- 330 MW of transmission for the Goldendale CCCT could be **dual purposed** to prioritize renewable generation in Tier 2

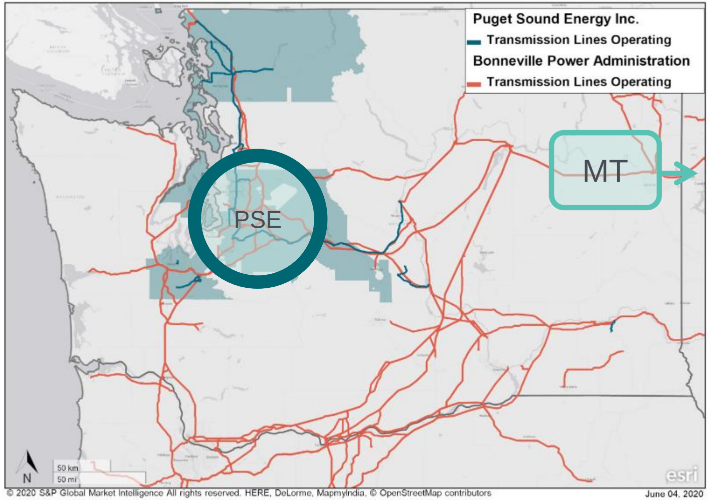
- Between 150 and 310 MW of third-party transmission rights maybe acquired via:
  - Project developers including transmission in RFP submittals,
  - Third-party retirements
  - New capacity ramped by tier: 150, 375, 685 MW



Added transmission (MW)		
Tier 1	**Tier 2**	**Tier 3**
150	**705**	**1,015**

Transmission capacity – Montana

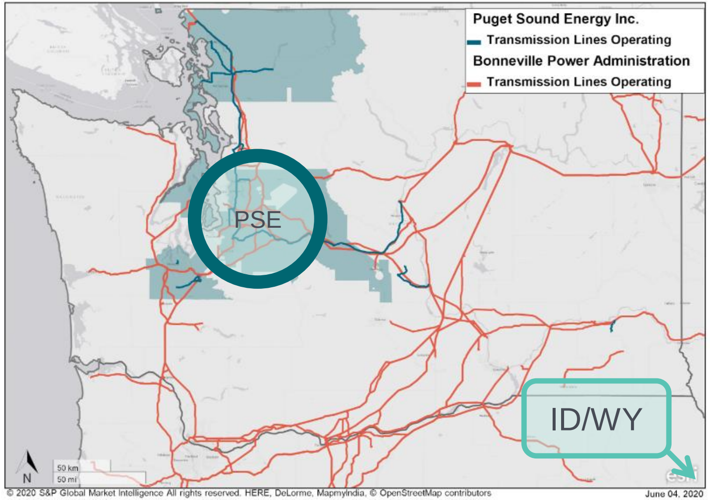
- Repurposing of transmission freed up by sale of Colstrip Unit 4 and removal of Unit 3 from PSE portfolio adds 350 and 565 MW to Tier 1 and Tier 2, respectively



Added transmission (MW)		
Tier 1	Tier 2	Tier 3
350	565	565

Transmission capacity – Idaho and Wyoming

- PSE may invest in new transmission projects including the proposed Boardman-to-Hemingway (B2H) and Gateway West projects
  - Adding between 400 and 600 MW to Tier 2 and Tier 3, respectively



Added transmission (MW)		
Tier 1	Tier 2	Tier 3
-	400	600

Transmission capacity – Summary

- PSE has identified viable transmission acquisition pathways for each of the Resource Group Regions at four tiers

	Added Transmission (MW)			
Resource Group Region	**Tier 0**	**Tier 1**	**Tier 2**	**Tier 3**
PSE territory*	unconstrained+	unconstrained+	unconstrained+	unconstrained+
Eastern Washington	unconstrained	300	675	1,515
Central Washington	unconstrained	250	625	875
Western Washington	unconstrained	0	100	635
Southern Washington/Gorge	unconstrained	150	705	1,015
Montana	565	350	565	565
Idaho / Wyoming	600	0	400	600
TOTAL	generally unconstrained	1,050	3,070	5,205

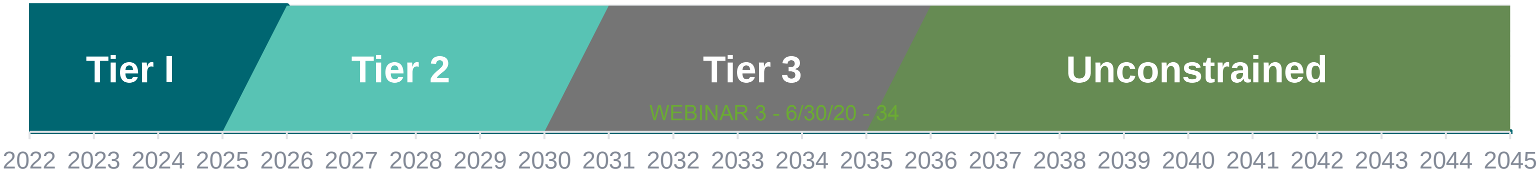
*Not including the PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed

+Not constrained in resource model, assumes adequate PSE transmission capacity to serve future load

Transmission capacity modeling approaches

- Option 1 – Model tiers as distinct sensitivities:
  - Transmission capacity will be constrained by tier (sensitivity) 2022 to 2030
  - Transmission capacity will be unconstrained from 2031 to 2045 to assess new transmission need

- Option 2 – Model transmission capacity as time-dependent periods:
  - Tier 1 amount attainable by 2025 // Tier 2 amount attainable by 2030 // Tier 3 amount attainable by 2035
  - Transmission capacity will be unconstrained from 2036 to 2045 to assess new transmission need



Transmission Capacity By % of Nameplate

- PSE's historical policy is to secure long-term firm (LTF) transmission up to the nameplate capacity of a resource, including renewable resources
- PSE is considering a change to policy to secure less than 100% LTF for renewable resources
  - Short-term transmission (redirects or purchases) scheduled as needed on firm and/or non-firm available transmission capacity
  - Approach different for wind, solar, and other renewables
  - Need to consider risk of delivery if short-term transmission is unavailable
  - Potentially model by resource region
- Model as a sensitivity (i.e. 80% nameplate in LTF)

PSE PUGET SOUND ENERGY

Distributed resources are needed to balance constrained transmission

- Transmission Tiers 1 and 2 may not provide adequate transmission to meet the CETA renewable need.
- Western Washington solar in the PSE service territory* is a 'transmission-free' resource which will allow for CETA compliance in these sensitivities.
- Lower capacity factors in Western Washington solar will influence the total MW of renewable resources needed for CETA compliance.

*Not including the PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed

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Transmission capacity constraint summary and feedback

- Review
  - Renewable resources will be collected in Resource Group regions within AURORA Portfolio Model
  - Opt 1
    - Transmission capacity for each Resource Group region will be constrained by tier for the period 2022 – 2030
    - Transmission capacity will be unconstrained from 2030 – 2045
  - Opt 2
    - Tier 1: 2025 Tier 2: 2030 Tier 3: 2035

- Feedback
  - Share your thoughts on the general modeling approach and magnitudes of transmission availability
  - Input on Option 1 versus Option 2 modeling approaches

5-minute break

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Transmission cost assumptions

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Participation Objectives

- PSE is informing stakeholders of transmission rates and losses to be used in the 2021 IRP

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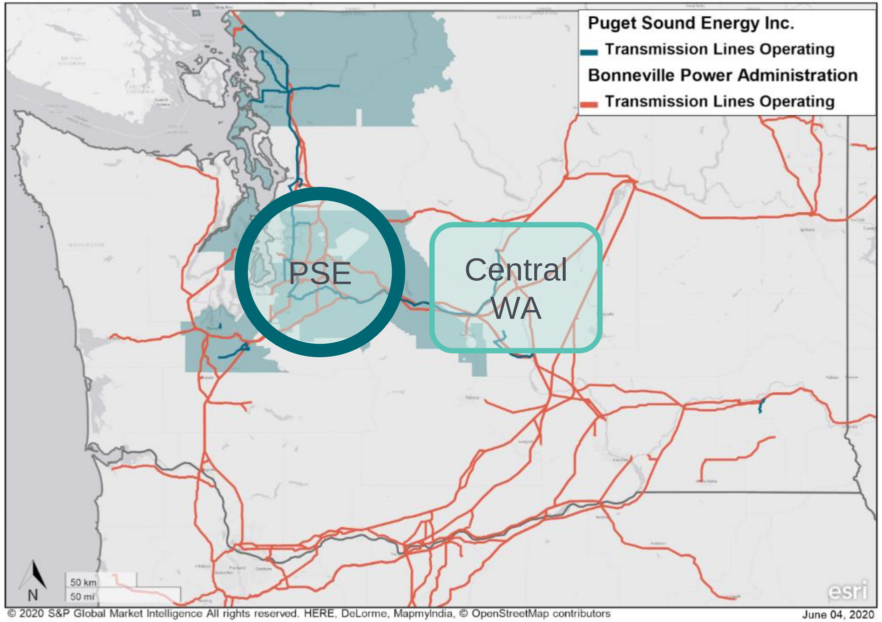
Various methods exist for setting transmission costs

- BPA Tariffs – cost included as an ongoing variable operation and maintenance cost
  - Formula Power Transmission (FPT)
  - Point-to-Point (PTP)
  - Network Integration (NT)
  - Regional Intertie Rates

- Build new transmission – cost included as a one-time capital cost adder

Transmission Cost – Central Washington

Transmission Path	Cost ($/kW-Year)
Kittitas - MidC (Wanapum) (PSEI PTP)*	24.91
Wanapum Energy Transfer	Unknown
MidC (Wanapum) - PSEI (BPA) +	22.20
Balancing Services – Solar (BPA) +	8.28
TOTAL	55.39



*https://www.oasis.oati.com/psei/index.html
+https://www.bpa.gov/Finance/RateInformation/Pages/Current-Transmission-Rates.aspx

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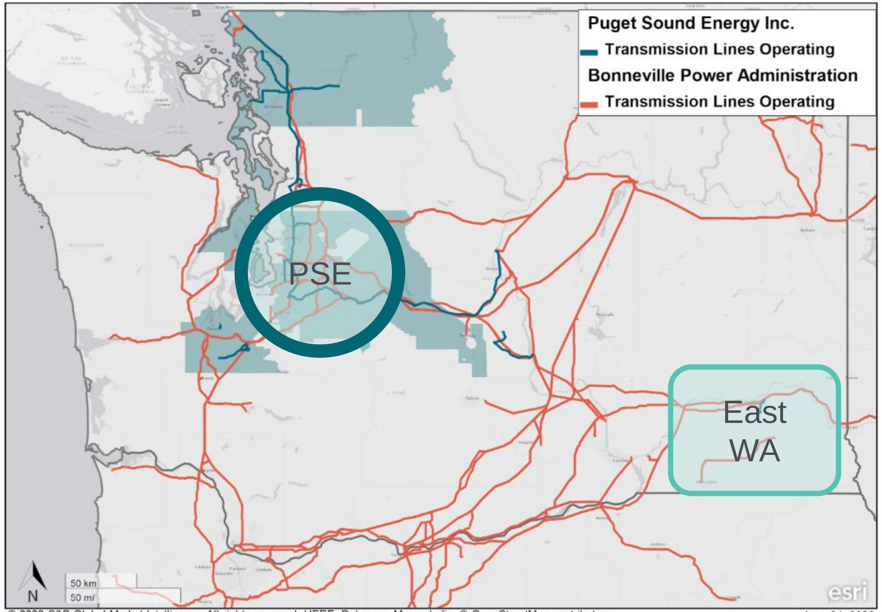
Transmission Cost – Eastern Washington

Transmission Path	Cost ($/kW-Year)
Central Ferry - PSEI (BPA)	22.20
Generation Imbalance (Band 1 & 2) *	Variable
Balancing Services – Wind (BPA)*	11.16
Intentional Deviation Penalty*	Variable
TOTAL	33.36



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*https://www.bpa.gov/Finance/RateInformation/Pages/Current-Transmission-Rates.aspx

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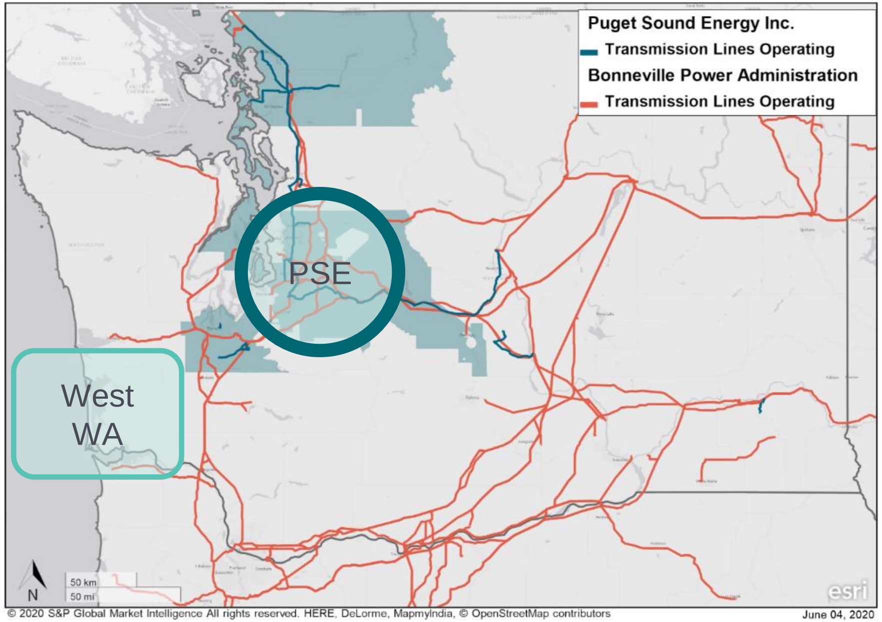
Transmission Cost – Western Washington

Transmission Path	Cost ($/kW-Year)
BPA Transmission	22.20
Balancing Services – Wind (BPA)	11.16
Marine Transmission	Under Review
TOTAL	33.36



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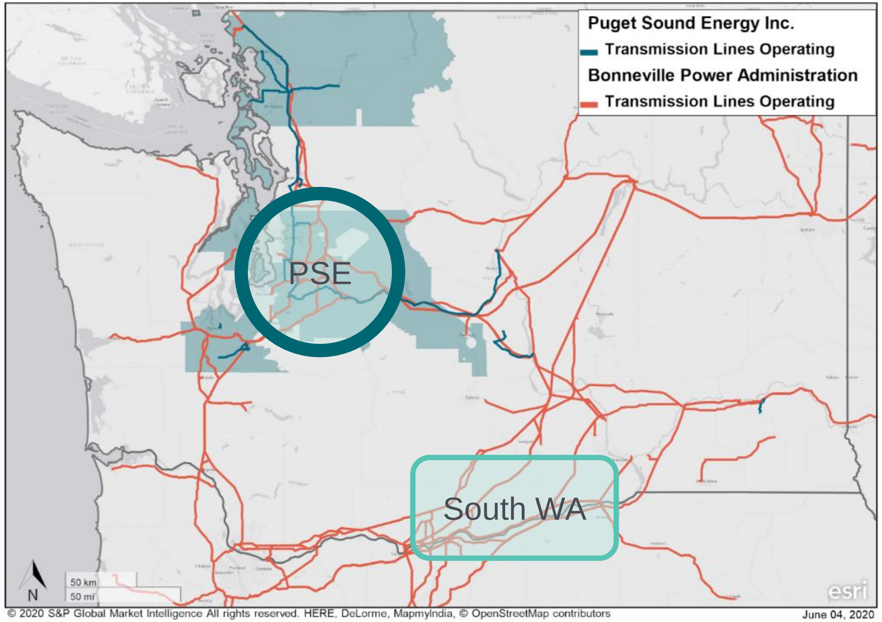
Transmission Cost – Southern Washington / Gorge

Transmission Path	Cost ($/kW-Year)
Goldendale - PSEI (BPA)	22.20
Generation Imbalance (Band 1 & 2)	Variable
Balancing Services - Solar (BPA)	8.28
Intentional Deviation Penalty	Variable
TOTAL	30.48



Spin/Supplemental Reserve Requirement of $0.02/kWh also included

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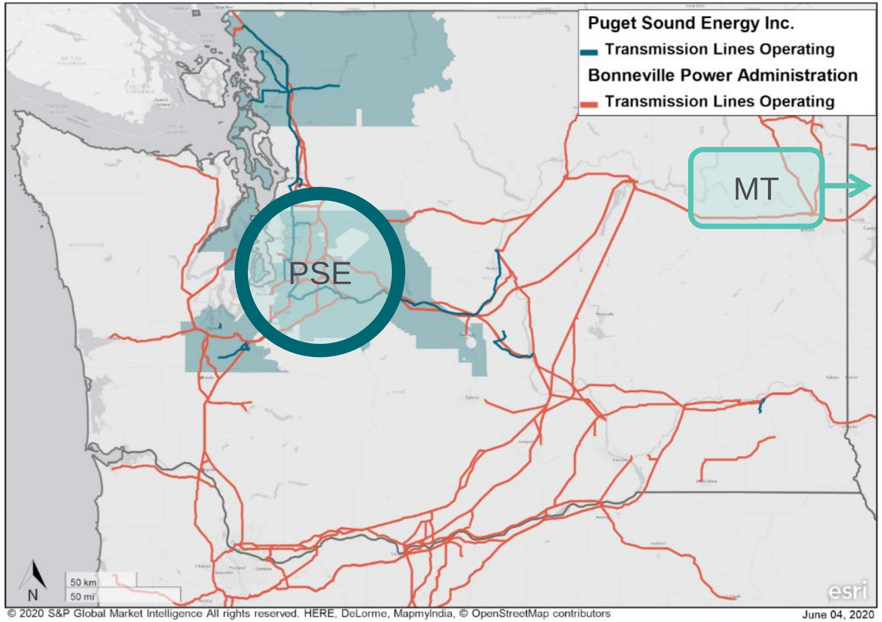
Transmission Cost – Montana

Transmission Path	Cost ($/kW-Year)
Colstrip/Broadview - Townsend (PSEI)*	10.22
Townsend - Garrison (BPA) +	6.07
Garrison - PSE (BPA) +	22.20
Estimated Wind Integration Costs (PSEI)	11.16
TOTAL	49.65



* https://www.oasis.oati.com/psei/index.html
+ https://www.bpa.gov/Finance/RateInformation/Pages/Current-Transmission-Rates.aspx

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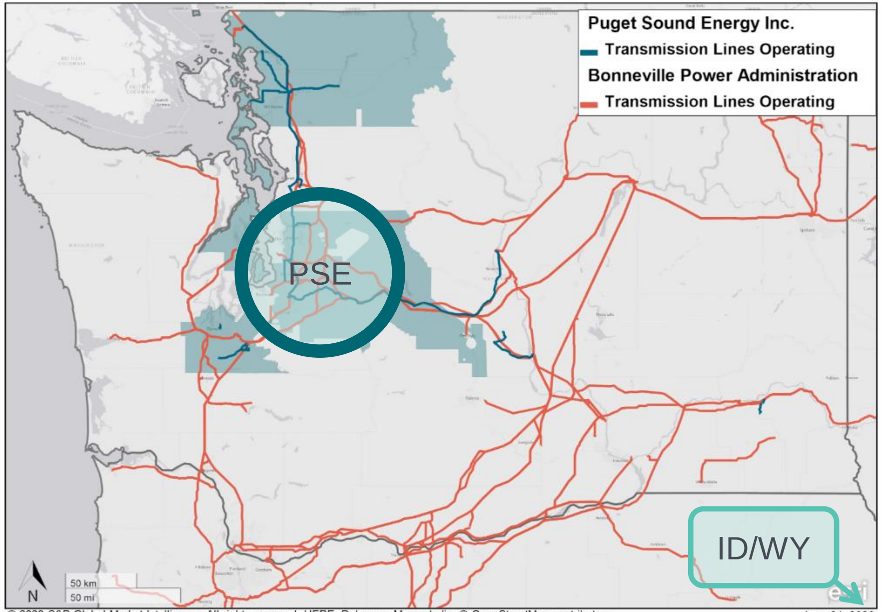
Transmission Cost – Idaho / Wyoming

Transmission Path	Cost ($/MW)
Shirley Basin (Aeolus) to Bridger/Anticline	216,000
Bridger/Anticline to Populus	578,000
Populus to Hemingway	778,000
Boardman to Hemingway (B2H)	585,000



June 04, 2020

Modeled as capital cost for transmission build

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Transmission Cost – Idaho / Wyoming

- ID Wind
  - Near Populus
  - $1.36M / MW
- West WY Wind
  - Near Anticline
  - $1.94M / MW
- East WY Wind
  - Near Aeolus
  - $2.16M / MW

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Transmission losses

- Losses due to the resistance in transmission lines are modeled using a loss factor for each transmission route

- BPA publishes an assumed loss of 1.9% on across their network
  - PSE will apply this loss to all Washington transmission wheels (N, S, E, W)

- Line losses for transmission between Colstrip and PSE have been estimated at 4.6%*
  - PSE will apply this loss to Montana transmission

- Line losses for transmission between Wyoming and PSE are under review
  - PSE will apply this loss to ID and WY transmission

*Does not include 5% losses for third party resources on MT Intertie

PSE PUGET SOUND ENERGY

Transmission cost constraint summary

Resource Group Region	Cost Type	Units	Total Cost
PSE territory	--	--	0
Eastern Washington	Tariff	$ / kW-yr	33.36
Central Washington	Tariff	$ / kW-yr	55.39
Western Washington	Tariff	$ / kW-yr	33.36
Southern Washington/Gorge	Tariff	$ / kW-yr	30.48
Montana	Tariff	$ / kW-yr	49.65
ID / W. WY / E. WY	Capital	$M / MW	1.36 / 1.94 / 2.16

Consultation update – generic resource overnight capital cost

- Pumped Storage Hydro overnight capital costs revised to include more data sources and averaged across vintage year 2021 instead of 2020.

- Added a wind + battery resource; 100 MW WA wind with a 25 MW 2-hr Lithium Ion battery.

- PSE has adopted the NREL ATB cost curves.

- Lithium Ion 2-hr battery and flow 4-hr and 6-hr battery added.

(2021 Vintage, 2016 U.S. Dollars)	Overnight Capital Cost ($/kW)		
	2019 IRP	2021 IRP draft	2021 IRP proposed
CCCT	991	927	943
Frame Peaker	618	660	664
Recip Peaker	931	1,248	1,256
Solar Utility	1,422	1,226	1,264
Solar Residential	--	2,848	2,957
Onshore Wind	1,438	1,484	1,421
Offshore Wind	5,730	4,971	4,377
Pumped Storage	2,176	2,515	2,145
Battery (4hr, Li-Ion)	2,427	1,900	1,542
Battery (2hr, Li-Ion)	1,455	--	849
Battery (4hr, Flow)	1,625	--	2,051
Battery (6hr, Flow)	2,244	--	2,860
Solar + Battery	2,698	--	1,901
Wind + Battery	--	--	2,043
Biomass	7,744	5,119	5,246

Consultation update – generic resource all-in capital costs

- AFUDC assumed at 10% for all resources
- Interconnection costs include substation costs, 5 miles of transmission to system, and 5 miles of pipeline for natural gas

(2021 Vintage, 2016 U.S. Dollars)	Overnight Capital	AFUDC	Interconnection Costs	Total All-In Capital cost
CCCT	943	94	91	1,128
Frame Peaker	664	66	134	865
Recip Peaker	1,256	126	143	1,525
Solar Utility	1,264	126	100	1,489
Solar Residential	2,957	296	--	3,252
Onshore Wind – WA	1,421	142	47	1,610
Onshore Wind – MT	1,421	142	44	1,608
Onshore Wind – ID/WY	1,421	142	--	1,563
Offshore Wind	4,377	438	65	4,878
Pumped Storage	2,145	214	47	2,406
Battery (4hr, Li-Ion)	1,542	154	367	2,063
Battery (2hr, Li-Ion)	849	85	367	1,301
Battery (4hr, Flow)	2,051	205	367	2,624
Battery (6hr, Flow)	2,860	286	367	3,513
Solar + Battery	1,901	190	420	2,511
Wind + Battery	2,043	204	373	2,620
Biomass	5,246	525	607	6,378

($/kW)	Transmission Cost	Total Cost
ID Wind	1,363	2,926
WY W. Wind	1,641	3,504
WY E. Wind	2,157	3,720

Consultation update – operating and maintenance costs

(2021 Vintage, 2016 U.S. Dollars)	Fix O&M ($/kW-yr)			Variable O&M ($/MWh)		
	2019 IRP	2021 IRP draft	2021 IRP proposed	2019 IRP	2021 IRP draft	2021 IRP proposed
CCCT	13.68	12.12	11.66	2.44	3.18	3.01
Frame Peaker	3.80	6.95	6.95	6.34	7.12	7.12
Recip Peaker	3.61	5.80	5.80	5.12	6.38	6.38
Solar Utility	21.16	15.77	20.14	0.00	0.00	0.00
Solar Residential	--	--	--	--	--	--
Onshore Wind	35.75	36.79	36.79	0.00	0.00	0.00
Offshore Wind	115.96	99.73	99.73	0.00	0.00	0.00
Pumped Storage	14.06	14.84	14.50	0.00	0.00	0.00
Battery (4hr, Li-Ion)	31.08	39.42	28.93	0.00	0.00	0.00
Battery (2hr, Li-Ion)	19.85	--	21.28	0.00	--	0.00
Battery (4hr, Flow)	29.76	--	19.71	0.00	--	0.00
Battery (6hr, Flow)	38.91	--	34.40	0.00	--	0.00
Solar + Battery	41.63	--	41.42		--	0.00
Wind + Battery	--	--	58.06	--	--	0.00
Biomass	333.58	187.53	187.53	6.38	5.62	5.62

Consultation update – FOM + Transmission

(2021 Vintage, 2016 U.S. Dollars)	Fix O&M ($/kW-yr)
	2021 IRP proposed
CCCT	11.66
Frame Peaker	6.95
Recip Peaker	5.80
Solar Utility	20.14
Solar Residential	--
Onshore Wind	36.79
Offshore Wind	99.73
Pumped Storage	14.50
Battery (4hr, Li-Ion)	28.93
Battery (2hr, Li-Ion)	21.28
Battery (4hr, Flow)	19.71
Battery (6hr, Flow)	34.40
Solar + Battery	41.42
Wind + Battery	58.06
Biomass	187.53

Resource FOM
Transmission Wheels
+ Integration Costs

Total FOM cost

Choose region

Central WA	Eastern WA	Western WA	Southern WA
47.11	22.20	22.20	22.20

Choose Integration

Solar	Wind
8.28	11.16

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20.14 + 22.20 + 8.28 = 50.63 $/kW-yr

Question and Answer

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Next steps

- Submit Feedback Form to PSE by **July 7, 2020**
- A recording from today's webinar will be posted to the website **tomorrow**
- PSE will compile all the feedback in the Feedback Report and post all the questions by **July 14**
- By **July 21**, PSE will make a decision on what transmission constraints to use. The documentation for the decision made will be released in a Consultation Update that will be posted to the website

Details of upcoming meetings can be found at pse.com/irp

Date	Topic
July 14, 1:30 - 4:30 pm	Demand Side Resources including Demand Response
July 21, 1:30 – 4:30 pm	Social Cost of Carbon
August 11, 9:30 am – 12:30 pm	Portfolio sensitivities development (electric & gas) CETA assumptions Distributed energy resources
September 1, 1:00 – 5:00 pm	Demand forecast (electric & gas) Resource adequacy Resource need: peak capacity, energy & renewable energy need
October 20, 1:30 – 4:30 pm	Portfolio sensitivities draft results Flexibility analysis
November 4, 1:30 – 4:30 pm	Clean Energy Action Plan 10-year Distribution & Transmission Plan
December 9, 1:30 – 4:30 pm	Portfolio draft results Stochastic analysis Wholesale market risk

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PSE PUGET SOUND ENERGY

Thank you for your attention and input.

Please complete
your Feedback Form by July 7, 2020

We look forward to your attendance at PSE's next public participation webinar:

Demand Side Resources

July 14, 2020

PUGET SOUND ENERGY

Webinar #3: Transmission Constraints Q&A

DRAFT 7/1/2020

Overview

On June 30, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss transmission constraints. Stakeholders shared their input on transmission capacity constraint modeling methodology, transmission capacity constraint magnitudes, and how to model transmission capacity uncertainty. Additionally, participants were able to ask questions and make comments using a chat box provided by the Zoom platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 61 people attended the meeting, plus another 13 attendees who only called into the meeting and did not identify themselves (74 people total).

Attendees included: James Adcock, Anika Argunta, Larry Becker, Charlie Black, Rob Briggs, Rachel Brombaugh, Colin Crowley, Cody Duncan, Kara Durbin, Lori E, Ben Farrow, John Fazio, Jeff Fox, Kyle Frankiewich, Zach Genta, Brian Grunkemeyer, Ron Hankewich, Fred Heutte, Brandon Houskeeper, Doug Howell, Kevin Jones, Pete Jones, Eric Kang, Brendan Kelly, Mark Klein, Cathy Koch, Corey Kupersmith,, Sarah Laycock, Steve Lewis, Virginia Lohr, Jim Loring, Lisa MacKay, Kassie Markos, Don Marsh, Jennifer Mersing, David Meyer, Justin Moffett, Brian Muoneke, Anne Newcomb, R.C .Olson, Anthony O'Rourke, Bill Pascoe, David Perk, Phillip Popoff, Andrew Rector, Lowell Rogers, Jason Sanders, Matthew Shapiro, Cindy Song, David Tomlinson, Brian Tyson, Katie Ware, Wendy Weiker, Elyette Weinstein, Willard Westre, Bob Williams, Scott Williams, Ned Witting, and Zac Yanez.

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 1:30 PM PDT and ended at 4:06 PM PDT.

Time sent	Name	Comment
13:31:59	Alison Peters	For those just joining, we are waiting just a couple more minutes for folks to arrive. Thank you!
13:34:28	Fred Huette	Will we be able to ask questions and make comments by voice or only in the chat?
13:36:11	Alison Peters	Hi Fred, I can answer that now and let's make sure everyone sees the response. Attendees can ask questions in chat or verbally. Thank you!
13:37:12	James Adcock	Jim Adcock is here.
13:37:29	Doug Howell	Doug Howell is here.
13:37:35	Don Marsh	Don Marsh
13:38:29	James Adcock	Where's the mute button?
13:38:33	Kyle Frankiewich	Hello everyone, Kyle Frankiewich with WUTC staff here.
13:38:43	Kevin Jones	Jim, Doug and Don - please check your email for a recent communication from me
13:39:06	Charlie	Charlie Black is present
13:39:18	Virginia Lohr	Was there a way for us to know PSE's level of public engagement intended for this meeting beforethe meeting?
13:39:18	Fred Heutte	We're not seeing the mute button in Zoom on our end, so presume the audio has been disabled for participants.
13:39:39	Don Marsh	I assume "unmute" will become available later in the presentation?
13:40:39	Don Marsh	I know how to use "unmute" on Zoom, but there is no option on this webinar. Check your settings presenters?
13:41:04	Don Marsh	Unmute is available now. Thanks.
13:41:06	David Perk	Aha, received the unmute option, thank you
13:41:11	R.C. Olson	Court Olson is present.
13:41:59	Fred Heutte	ok working now thanks
13:41:59	Kevin Jones	Virginia - please check your email for a recent communication from me.
13:42:35	James Adcock	Thank you -- a mute/unmute options just appeared in my Zoom.
13:46:24	R.C. Olson	Kevin, please copy me too.
13:52:23	Kevin Jones	Court - done.
13:52:37	James Adcock	Do all participants know what a "Wheel" is?
13:55:25	David Perk	Thanks, Jim, appreciate that clarification.

Time sent	Name	Comment
13:56:28	James Adcock	Can you explain why you have a "two area system zonal model" but then multiple area "Resource Groups?"
13:57:37	Kyle Frankiewich	Do PSE's generation portfolio optimization tools include some representation of the cost of additional transmission if, for example, some new or augmented T is needed for a given proxy resource?
14:02:09	Kevin Jones	Thanks for explaining the generation / transmission analysis approach. How is storage then added into this analysis approach?
14:05:00	Andrew Rector	I still don't think I get what "PSE's system" is. Is it just PSE's BA or...?
14:06:45	R.C. Olson	Do your lowest costs in the optimization include the social cost of carbon?
14:07:14	Don Marsh	Is Aurora the best modeling software for handling generation, transmission, and storage optimization? Are other utilities using something different?
14:11:00	Kyle Frankiewich	Is WA or OR solar also included?
14:11:28	Zach Genta	Is PSE considering solar from any other regions with higher solar resource values (i.e. Oregon, Idaho, etc.)?
14:11:45	Kyle Frankiewich	I trust that slide 20 was a broad representation of the distance of some of the higher-capacity-factor renewable resources, rather than the exhaustive list of what is being considered.
14:12:15	R.C. Olson	Last year there was talk of considering solar in Idaho, so why does this not appear on your renewable resource options map? (The advantage is they come on line earlielr, because they are farther east.)
14:13:30	Charlie	The map shown on slide 20 only displays solar in wester and eastern Washington. Will this preclude consideration of co-located renewables (e.g., wind and solar) outside Washington?
14:14:24	Fred Heutte	Also asked these in the comment form. At the appropriate time here are two initial questions: (1) what transmission planning models does PSE use (powerflow and production cost) and how will the analysis with those models interact with the AURORA IRP analysis (2) is PSE using the most recent ATC values published by BPA for its transmission paths, especially those with substantial effect on PSE's system, such as West of Cascades North, North of Hanford, Raver-Paul, BC Intertie and the paths from Montana westward
14:14:44	James Adcock	What capacity, if any, does PSE have on the IP line?
14:16:55	Kevin Jones	What plans does PSE have to repurpose the transmission lines from Colstrip MT?
14:17:01	Don Marsh	Are the Tier amounts the maximum available at all times of day, or is there additional capacity at low demand hours?
14:23:05	R.C. Olson	The map on slide 21 shows a transmission connection going toward southern Idaho and Wyoming. Could this line not carry solar power from Southern Idaho
14:25:23	Doug Howell	Many new proposals include combinations of wind and/or solar and/or battery. Does the transmission study account for possible combinations of renewables and/or batteries in one Resource Group Area?

Time sent	Name	Comment
14:26:17	Fred Heutte	my third question: what approach does PSE employ to consider non-wires alternatives to transmission expansion (i.e., new lines) to expand the capability of the existing grid -- thinking broadly this could include in-system elements (phase shifters, static var compensators, storage as a transmission asset, etc.) and also flexible demand/demand response and storage
14:29:42	Ron Hankewich	can you explain how BPA transmission capacity from Lower Snake River area can be delivered across the Cascades? Is there adequate capacity?
14:31:35	Charlie	What is PSE assuming about ability to repurpose transmission from Centralia due to the coal plant retirement?
14:31:40	Brian Grunkemeyer	How does dual purposing your transmission lines affect resource adequacy? My understanding is many of the peakers you would be redirecting from (Goldendale & Mint Farm) are only used for a few peak hours. Sharing with renewable generation could limit your max capacity, correct?
14:36:26	Kyle Frankiewich	Brian, that's a good question, but I was thinking the opposite impact would be the case. If PSE is holding transmission rights for peakers all the time, but only use them infrequently, building renewable resources to piggyback off of those rights could better-utilize them, and the gas peakers could firm up the renewables.
14:36:57	Corey Kupersmith	Has PSE submitted any recent LTF transmission requests into BPA's annual cluster study to gauge the availability of Cross Cascades ATC that is discussed in the Eastern and Southern WA tiers?
14:37:35	Anne Newcomb	Will PSE and partner sources be creating new wind and solar as well as using already excisting? I will stay on mute
14:38:28	Andrew Rector	Are there any upgrades/alterations to the transmission lines in order to achieve dual purposing?
14:39:35	Kyle Frankiewich	Ah, ya, that makes sense, Brian. I don't think it would 'hurt' resource adequacy, but it also wouldn't help. This dual-purpose approach wouldn't increase total capacity available, but would increase the percentage of renewables used to meet load.
14:45:23	Anne Newcomb	Will PSE and partner sources be creating new wind and solar as well as using already excisting? I will stay on mute Thanks,
14:49:49	Anne Newcomb	Will PSE be selling Coalstrip power to other power companies? Muted Anne :-)
14:57:46	Doug Howell	Zoom enables participants to communicate with other individual participants. Would you please enable that function?
14:58:59	Fred Heutte	I definitely have questions about PSE's interest in B2H and Gateway West
15:01:58	Corey Kupersmith	How did PSE consider BPA constraints from Boardman to PSE System for the 400 & 600MW of ID/WY capacity on B2H?
15:02:01	Ron Hankewich	How will you model BESS systems especially if coupled with renewable generation - incremental capacity requirement for discharge or generation time shift?

Time sent	Name	Comment
15:02:21	Alison Peters	Hi Doug, I'm seeing if I can enable this during the meeting. It may have been that it can only be turned off before the meeting starts.
15:04:44	David Perk	+ 1 Fred's comment on new opportunities
15:06:05	Alison Peters	Sharing with all; from Anne Newcomb--Will PSE be selling Coalstrip power to other power companies? (already asked verbally and answered)
15:06:48	Ron Hankewich	I was thinking for BESS more wrt transmission capacity.
15:12:23	James Adcock	Jim Adcock continues to raise his hand for a clarification question.
15:12:54	Don Marsh	Don Marsh has hand raised
15:18:04	David Perk	Agree with Don, an east side battery scenario would be great to see
15:20:57	David Perk	Not an expert, but it would seem that Opt 2 (slide 32) provides a good baseline that could be revised in subsequent IRPs.
15:21:44	Don Marsh	Reducing TX capacity sounds like a good deal for ratepayers if it is backed up by BESS on our side of the Cascades.
15:21:56	Fred Heutte	What thoughts does PSE have about BPA's ongoing changes to its transmission products, especially more flexible variations of Conditional Firm?
15:22:50	James Adcock	Comment: Modern Wind Farm options include choices of hub height for availability, blade design optimized for lower average wind speeds, and inverter options about how high "nameplate" the Wind Turbines can generate before limited by the inverter option chosen. So it's not just a "Transmission Model" issue.
15:22:59	Don Marsh	We would love to see PSE support more rooftop solar panels and batteries. Great for CETA compliance.
15:24:21	James Adcock	Feedback: I would be happy with just "Opt 1" -- which corresponds to the CETA breakpoints of 2030 and 2045.
15:39:49	Jeff Fox	No question, but thank you for mentioning your assumption for MT wind integration cost & that BPA is a potential option for integration. Oh & thanks for MT transmission loss update.
15:40:27	James Adcock	Clarification question re costs on Slide 46?
15:40:46	R.C. Olson	Again, I encourage PSE to consider solar PV in Southern Idaho (along with wind), since it has significant potential to help in the morning peak hours.
15:40:48	Ron Hankewich	Could you translate for us the cost of WY/ID wind to $-kW month so that we have an comparative estimate to the other options?
15:44:57	R.C. Olson	Also add the Idaho solar to the chart on slide 23.
15:47:30	Ron Hankewich	might be easier for me to ask directly? sure I would like to follow up
15:50:34	Fred Heutte	I have a comment on future resource costs.
15:53:37	Brian Grunkemeyer	Why are the battery interconnection costs so high? They're 3x the cost of adding in a peaker plant + its gas pipeline.
15:55:06	R.C. Olson	Are the social costs of carbon included in the CCCT and Peaker costs?

Time sent	Name	Comment
15:55:11	Matthew Shapiro	Is it realistic to include gas turbines in the IRP when the requirement for carbon-free by 2045, since that would mean limiting their use to about 20 years? Or would that shorter lifespan be factored into their economic analysis in the IRP?
15:56:34	Virginia Lohr	I have questiond about the process from May 28 and June 10
15:57:01	Kyle Frankiewich	Are integration costs billed as $/kw-yr or as $/MWh? If it's $/MWh, is there a reason to convert that to $/kw-yr in the optimization model?
15:57:19	R.C. Olson	The social cost of carbon needs to be figured in your cost modeling!!!!
15:58:31	James Adcock	Did you miss Brian's question?
15:58:43	Anne Newcomb	Considering we are moving to 80% renewable by 2030, is it a waste of $ to invest in pipelines and NG infrastructure from now on?
16:01:58	Irena Netik	https://pse-irp.participate.online/get-involved/planning-assumptions-resource-alternatives
16:04:13	Ron Hankewich	Thanks PSE team. you did a great job today. Very informative.
16:05:14	Don Marsh	Appreciate the opportunity to speak in real time. Better than before.
16:05:39	James Adcock	Not happy that our questions do not get answered!
16:06:19	James Adcock	Interconnect costs on 2 hour battery are 43% of capital cost -- Not Reasonable!

The following stakeholder input was gathered through the online Feedback Form, from June 23 through July 7, 2020. PSE's response to the feedback can be found in the far right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on July 21, 2020.

2021 IRP Electric Price Forecast Workshop Feedback Report			
Feedback Form Date	**Stakeholder**	**Comment**	**PSE Response**
6/24/2020	James Adcock (1)	Re Page 50 Please compare battery costs to: Cole, Wesley, and A. Will Frazier. 2019. Cost Projections for Utility-Scale Battery Storage. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-73222. https://www.nrel.gov/docs/fy19osti/73222.pdf. Please make sure that your battery costs are consistent with latest publications, including this recent NREL publication.	Thank you for suggesting an additional data source for inclusion in the 2021 IRP generic resource cost calculation. PSE has reviewed the publication and found that the contents of the report have already been incorporated into our analysis as part of the National Renewable Energy Laboratory's 2019 Annual Technology Baseline (ATB). The Cole and Frazier report was used as the basis for cost projections for the 2019 ATB as discussed on the Battery Storage discussion page of the ATB website (https://atb.nrel.gov/electricity/2019/index.html?t=st).
6/29/20	Kathi Scanlan, WUTC	Question before webinar on transmission constraints: It is important to know the assumptions for the MW capacity of imports on the "interties," B.C. to NW, MT to NW, SW (CA+ AZ effect) to NW. How is company modeling this?	PSE is modeling the following: BC to NW: PSE will not model any capacity on the BC to NW intertie for BC hydro resources. MT to NW: Capacity on the MT to NW intertie is modeled in the Montana resource region. SW (CA + AZ effect) to NW: Capacity on CA/SW to NW intertie is assumed to be unavailable due to constraints on the BPA transmission system.
6/30/20	Virginia Lohr, Vashon Climate Action Group	The Consultation Report from the May 28 IRP meeting has links to find relevant information, but they do not take you to the needed information, only to the overall IRP entire website, leaving the person seeking that information to spend time searching through your website to try to find the information. Here is an example from the Consultation Report: "The capital cost has been updated in the revised summary workbook Excel file for the generic resources assumptions available on PSE's IRP website under materials for Webinar 1 on pse.com/irp." If you follow the link, you will see nothing on that page that says "Webinar 1." I searched a number of pages linked to pse.com/irp, and I could find nothing called "Webinar 1" except in the Consultation Report itself. Please provide meaningful links with accurate titles to the referenced material.	Thank you for your suggestion concerning improving the process with meaningful links with accurate titles to the referenced material. PSE is adopting your suggestions and will continue to improve this aspect of the process to promote meaningful stakeholder participation.
6/30/20	Fred Huette, NW Energy Coalition (1)	Initial questions: (1) what transmission planning models does PSE use (powerflow and production cost) and how will the analysis with those models interact with the AURORA IRP analysis (2) is PSE using the most recent ATC values published by BPA for its transmission paths, especially those with substantial effect on PSE's system, such as West of Cascades North, North of Hanford, Raver-Paul, BC Intertie and the paths from Montana westward	For the purpose of long-term resource planning, PSE does not use transmission planning models to provide the values that are inputted into AURORA. PSE is using the most recent available transfer capacity (ATC) values published by BPA. PSE uses the latest ATC values from BPA for any study or analysis.
6/30/20	James Adcock (2)	While I was generally much happier with the format of today's meeting, I was disappointed that PSE chose to "cut and run" at the end of the meeting rather than allowing the last questions to get asked and answered. In particular, I do not find that your modeling choices of interconnect costs on batteries are AT ALL reasonable! For example you are modeling interconnect costs on 2 hour batteries -- slide 50 -- as being 43% of capital costs!!! This is NOT at all reasonable "modeling" -- in that a utility would never build a project in that manner. In turn, the reason that you are creating such high interconnect costs for batteries is that you are needlessly assuming that battery system sizes are very small compared to other projects such as NG Peakers -- thereby artificially raising the percentage of interconnect costs associated with batteries. In practice, for example, if a utility chose to	Thank you for your feedback. PSE has consistently applied the interconnection cost described in the 2019 HDR Report (linked below) for all generic resources. For all battery types, the assessment assumes a 115 kV, 5-mile tie line to the point of interconnection and a breaker and one half interconnection arrangement at the point of interconnection. These are fixed capital costs, regardless of resource nameplate capacity. The capital cost adder in dollars per kilowatt may appear inflated for

		implement 2 hour batteries, they would choose a much larger battery system size, in order to reduce the percentage of "overhead" associated with transmission connection costs. Can you please review and rework this modeling to more fairly represent interconnect costs on batteries, because frankly right now it looks like you are just trying to "cook the books" to unfairly make batteries appear to be uncompetitive compared to NG Peakers! And frankly batteries have greater siting flexibility that NG Peakers due to lower noise and air pollution profiles, so battery interconnect costs should be much smaller than NG Peakers costs! Recalculate battery storage system interconnect costs to be LOWER than NG Peaker costs on a per megawatt nameplate basis due to the much better siting flexibility that battery storage systems allow.	smaller nameplate resources such as battery resources (25 MW nameplate) and biomass facilities (15 MW nameplate). Given the expectation for significant quantities of battery energy storage systems in the 2021 IRP, PSE will include a 100 MW nameplate battery. The interconnection for a 100 MW nameplate battery would be $91.80/kW in real 2016 US dollars. 2019 HDR Report: https://www.pse.com/-/media/PDFs/001-Energy-Supply/001-Resource-Planning/10111615-0ZR-P0001_PSE_IRP.pdf
7/1/20	James Adcock (3)	In Regards to Transmission Constraints Presentation Page 50 I believe your "Interconnection Costs" for battery storage systems are about 16X too high. For the battery plants the assumption of a 5 mile stub line is unreasonable, since the plant have little siting constraints they can be sited near major transmission lines. Looking for generic costs of interconnect -- since the interconnect requirements for 100 MW of battery storage are essentially "identical" to the interconnect requirements for 100 MW of CT NG Turbine plants, I looked to the following document (from Brattle) page 22. https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx PJM Electrical Interconnection for CT NG Turbine plants $8 Million for a 355 MW plant. Or $22,535 per MW. Or $22 per KW Where for similar interconnection requirements for Battery Storage Systems you are quoting $367 per KW -- or about 16X higher interconnect costs! Can you please give me references for how you derived your assumed much-higher interconnection costs of $367 per KW ? Thank You, Jim Adcock	See response to James Adcock (2).
7/1/20	James Adcock (3)	Lower your assumed interconnection costs (Transmission Constraints Presentation Page 50) for utility-scale battery storage from $367 per KW to $22 per KW.	See response to James Adcock (2).
7/1/20	Don Marsh, CENSE (1)	Dear IRP Team, In yesterday's presentation on Transmission Constraints, you showed a cost table that anticipated interconnection costs of $367/kW for batteries of any type or duration. This is far higher than the interconnection costs for gas plants, and one of the participants asked why. The answer from PSE was because of the small size of batteries. If I recall correctly, PSE said that the costs were for a 10 MW battery, which is a capacity approximately 30 times smaller than a gas plant, so the economies of scale work out badly for batteries, especially if you assume five miles of transmission line to connect the battery to the grid. There are many flaws with this reasoning: 1. Why is the battery assumed to be so small? A 10 MW battery might have been "cutting edge" a few years ago, but that would be quite small by today's standards. For example, Southern California Edison recently signed seven contracts to acquire 770 MW of lithium-ion battery storage projects (https://pv-magazine-usa.com/2020/05/02/southern-california-edison-wants-huge-770-mw-battery-storage-procurement-online-fast/). Here are the sizes: a) 88 MW/352 MWh Garland Project b) 72 MW/288 MWh Tranquility Project c) 115 MW/460 MWh Blythe 2	See response to James Adcock (2).

		d) 115 MW/460 MWh Blythe 3 e) 230 MW/920 MWh McCoy Project (connected to 250 MW solar farm) f) 50 MW/200 MWh Sanborn Project g) 100 MW/400 MWh (stand-alone) The average size of these projects is 110 MW/440 MW. Why is PSE assuming a battery less than one-tenth this size? Also, the McCoy project is almost the capacity of a peaker plant, so there appears to be little justification for claiming that a battery would have different interconnection costs compared to a peaker. 2. Five miles of transmission cost for a battery overstates the typical scenario. The beauty of batteries is that they can be located close to the load (or the generation resource), without concern for the emissions that make it hard to site gas plants close to neighborhoods. PSE states that siting problems prevented the company from siting a peaker plant anywhere on the Eastside as an alternative to the transmission upgrade project, Energize Eastside. We agree. A gas plant would have significantly more transmission cost to keep it away from population centers and residents who might experience breathing difficulties as a result of the emissions. To properly account for this, we expect the interconnection costs to be higher for gas plants than batteries. Please make this correction. 3. Batteries are more easily scaled to higher or lower capacities than peaker plants. Although there are some modular designs for peakers, the increments are pretty coarse compared to batteries. This means that some of the capacity of a peaker plant might not be needed in a particular location, while batteries can be more easily customized to the exact need. PSE appears to be penalizing batteries for their ability to scale down to 10 MW, whereas it would be hard to find a peaker plant with that miniscule capacity. It would be prohibitively expensive if there were one that small. To be fair, we must compare apples to apples. Please be explicit in your cost table about the size of the resource and its location. For example, if you compare the cost of a 300 MW battery to a peaker, but you divide that battery into 30 pieces and charge 150 miles of transmission lines, that is not the same scenario as a single peaker plant with only 5 miles of transmission. It may well be that 30 distributed batteries provide more reliability, resiliency, and system benefit than a single peaker plant. The batteries should get credit for that. When I first saw these numbers, I feared that my interpretation of the numbers must be incorrect. However, there is ample evidence that other utilities around the country are finding batteries to be a economical choice compared to gas plants. As just one data point, there is this quote from today's issue of T&D World: "According to research completed in 2019 by the Rocky Mountain Institute, 90% of proposed gas-fired power plant construction through 2025 is more costly than equivalent clean energy portfolios consisting of distributed solar, storage and energy efficiency. Further, the economics to operate fossil fuel powered generation is expected to decline significantly, resulting in a higher risk of stranded assets." (https://www.tdworld.com/smart-utility/data-analytics/article/21133422/why-arent-utilities-combining-energy-efficiency-solar-and-storage) If my reasoning and intuition has led me astray, I hope you will explain your rationale for the high cost of battery interconnection. I would expect you would have made this clear during the presentation rather than showing us opaque numbers without adequate explanation. This whole process feels more like hide-and-seek than a collaborative exchange with both parties being treated with professional respect. If this isn't quickly rectified, stakeholders may have to seek remediation from appropriate agencies. That would be a tragic outcome of our sincere effort to participate in matters that directly affect us, our planet, and future generations. Sincerely, Don Marsh	
7/1/20	Don Marsh, CENSE (2)	To accurately assess resource costs, you must factor in the following benefits of batteries: 1. Easier siting than peakers. (Shorter transmission lines.) 2. Stacked benefits (voltage regulation, storage of cheap, clean renewable electricity, relatively easy scaling, T&D deferral, peak demand service, outage service, and others) 3. No emissions. 4. Very fast response (no long warm-up times with high levels of emissions)	See response to James Adcock (2).

		5. Distributed resource (more reliable and resilient than a large plant with a single point of failure) PSE's current analysis appears to ignore these advantages, and we are not confident they will be accurately assessed later in the IRP proceeding.	
7/2/20	Don Marsh, CENSE (3)	Dear IRP Team, We formally request that PSE include in its 2021 IRP and CETA modeling the option of using grid-scale batteries to meet Eastside energy needs as an alternative to the proposed "Energize Eastside" transmission line upgrade. Specifically, we would like to understand how costs and operations compare if a reasonable amount of storage were to be located near centers of heaviest peak demand in Eastside cities. To our knowledge, this option has not been studied (a 2018 Strategen study assumed batteries were placed many miles away from load centers, making batteries only 20% effective in reducing loads on critical transformers). As I mentioned in the Transmission Constraint webinar, batteries offer many economic, environmental, and reliability benefits compared to an 18-mile transmission line: 1. Batteries will save money for ratepayers. The transmission line upgrade is only needed a few hours per year (if that), while a battery can provide grid benefits around the clock, 365 days per year. For example, batteries can earn money by stabilizing voltages, time shifting cheap renewable energy for use during peak demand, and reducing the cost of atmospheric emissions. The Tesla battery in Australia is generating astonishing financial returns (https://reneweconomy.com.au/tesla-big-battery-at-hornsdale-gets-big-jump-in-revenues-more-to-come-65622/). Admittedly, Australia is an extreme case, but we think it's obvious that batteries will save more money each year for ratepayers than a transmission line will. 2. Batteries will help PSE meet CETA goals. By releasing clean renewable energy during peak hours, batteries will reduce the need to run gas peaker plants, which will account for a higher percentage of PSE's emissions as the energy mix shifts to renewables. Batteries also help the environment by preserving thousands of valuable urban trees that are threatened by the transmission line project. These trees not only sequester carbon, but their shade moderates the intensity of urban heat islands, reducing the need for more air conditioning during hot summer days. 3. Batteries enhance reliability. Batteries can be distributed throughout the Eastside. Many can be located in existing substations. Besides reducing the risk of a single point of failure, distributed batteries can provide power during local outages, and this is a significant advantage because many power outages occur due to failures of neighborhood distribution lines. Since PSE has had a poor reliability record in recent years (as reported to the WUTC), distributed batteries could help reverse disappointing reliability trends. A holistic view of our energy grid will show that batteries deliver multiple benefits and should be valued accordingly. PSE's current analysis does not properly value all of these benefits, and therefore batteries appear to be more expensive than gas peaker plants. Many utilities that are using more objective measures are choosing batteries over peaker plants, and it is time for PSE to do the same. If PSE ignores these realities, there is significant risk that the UTC will not allow full cost recovery of Energize Eastside, causing financial hardship for the company and its investors. Please protect their investment and our communities by doing an accurate assessment of the advantages I've described here. Sincerely, Don Marsh	Thank you for sharing your thoughts and suggestions.
7/2/20	Don Marsh, CENSE (4)	Please protect your investors and our communities by doing an accurate assessment of the advantages batteries provide compared to the proposed "Energize Eastside" transmission upgrade. The 2018 Strategen report on batteries, paid for by PSE, contains invalid assumptions and cannot be cited as a realistic analysis of the potential of this technology.	Thank you for your comment and suggestion.
7/4/20	Willard Westre, Union of	Slide 28 - Dual purposed transmission of Renewable resources and existing Gas plants is a creative approach. This helps address intermittency, peak load, and resource adequacy issues with renewables without addition of new transmission resources. Dual purposed transmission should be used wherever practical.	Thank you for your comment and suggestion.

	Concerned Scientists (1)		
7/4/20	Willard Westre, Union of Concerned Scientists (2)	Slide 29 – This slide is very misleading. The proposed sale of Colstrip Unit 4 actually reduces the Colstrip transmission line capacity (for PSE) from 750MW to 565MW equaling a 185MW reduction. This proposed sale is very troubling for a number of reasons. From the ratepayer perspective, in my opinion, the proposed sale raises the appearance of a blatant disregard of public trust. Ratepayers would in effect be paying for 185MW of transmission twice – once for the original Colstrip construction and now to restore that capacity. The value of this 185MW of capacity would be approximately $380 million using transmission cost data for new transmission lines from similar locations on the east side of the Rocky Mountains as noted on slide 46. This certainly does not appear to be prudent. From the CETA perspective, the proposed sale increases the cost of replacing the coal power with renewables. The analysis preceding the Dec 11 webinar established that Montana wind was the lowest cost renewable energy generation source available. The proposed sale reduces the amount of that lowest cost resource by at least 185MW thus increasing the CETA implementation cost. From a performance perspective, MT wind has the highest winter season capacity factor matching PSE's peak seasonal load and the highest ELCC rating (needed to meet resource adequacy requirements) of all renewables. With the serious transmission constraint this is critical. Other resource options with lower capacity factors require much higher nameplate MW's and hence require even more transmission capacity. From an environment perspective – one of the rationales given for this proposed sale is to satisfy environment organizational pressure to close the coal plants. Nearly all environmental groups oppose this sale. We only have one atmosphere and it doesn't matter where the emissions are released, they affect everyone everywhere. The proposed sale allows Unit #4 to continue for many years into the future in direct contradiction to the intention of the CETA requirement that they close in 2025. 1. Terminate the proposed sale of Colstrip #4. 2. Retain the full 750MW transmission capacity. 3. The Colstrip transmission line is one of the most valuable assets PSE owns. Maximize its use.	PSE will not model 185 MW as a sensitivity in the IRP analysis because there is a pending WUTC filing for the sale of Colstrip Unit 4.
7/4/20	Willard Westre, Union of Concerned Scientists (3)	Slide 33 – I agree with changing the long-term firm (LTF) transmission policy for renewables. Renewable generation resources rarely operate at their nameplate rating because of weather dependence as evidenced by lower capacity factors. If existing interpretation of LTF is used, transmission lines would rarely be efficiently loaded to capacity requiring significantly more transmission capacity. I recommend transmission policy be linked to the peak seasonal capacity factor of each resource.	Thank you for your support concerning PSE changing the policy to match renewable transmission with actuals instead of name plate capacity factors. PSE is still considering a sensitivity where firm transmission is obtained for lower than 100% of nameplate.
7/4/20	Willard Westre, Union of Concerned Scientists (4)	Slides 48-52 – I appreciate the cost data, but you repeatedly leave out the most important cost and sometimes largest cost – Fuel. You do not even mention it or explain where it fits in the analysis. Newer participants who try to add up the costs to come to some conclusion are misled. Is this intentional? Just give us 1 more slide on fuel cost along with the other costs so it isn't forgotten. Better yet - report all cost data in $/MW, $/KW, $/KWh, or $ MWh.	Natural gas (fuel) prices were discussed at the June 10, 2020 IRP meeting. Though natural gas prices are variable costs that depend on dispatch, natural gas prices are added as a separate cost from the rest of the variable costs. Variable costs are stated as $/MWh because they are dependent on how much electricity is produced at the plant, whereas fuel costs are stated as $/mmBtu since they are dependent on how much fuel is burned.
7/4/20	James Adcock (4)	At the June 30 Transmission Meeting PSE was quoting very high transmission connection costs for battery storage units -- much higher than other technologies. My estimates were that these connection costs were estimated to be 16X too high. I also suggested that battery storage units tend to be located very close to existing connection points -- not the 5-mile connection distance that PSE was estimating. I went back and used aerial photographs to estimate the connection distances for recent large battery storage projects as follows: Ventura Energy Storage: 0.1 Miles to adjacent solar generation facility AES Alamitos Energy Battery Storage: 0.1 Miles to adjacent substation	See response to James Adcock (2).

		Tesla Moss Landing: 0.08 Miles to adjacent substation Reduce the assumed connection distance for battery storage units to the closest reasonable transmission line or substation from current estimate of 5 miles to down to 0.1 miles.	
7/6/20	Bill Pascoe	General Comment PSE appears to be taking a progressive approach to modelling transmission opportunities and constraints for the IRP. This type of forward-thinking approach is necessary to optimize transmission rights in a new planning and market environment with increasing reliance on clean energy resources. Comments on June 30, 2020 Presentation Slide 23 – Pumped storage hydro (PSH) should be modelled in the Montana resource region. Gordon Butte PSH has a FERC license and could use PSE's existing Montana transmission rights, perhaps in combination with Montana wind to "dual purpose" these rights. Slides 25, 27 and 28 – PSE is to be commended for considering "dual purposing" of transmission rights in this IRP. Slide 29 – PSE should model cases with 750 MW of existing Montana transmission rights to reflect the possibility that the proposed sale of 185 MW of capacity to NorthWestern Energy does not go through. Slide 33 – PSE is to be commended for considering less than 100% long term firm transmission rights in this IRP. Slides 45, 46 and 48 – Idaho/Wyoming transmission costs should include wheels on BPA (and any other intermediate systems) in addition to the costs of the ID/WY new builds.	Thank you for your positive and supportive general comment concerning PSE's approach to modelling transmission opportunities and constraints for the IRP. Slides 23: Thank you for your suggestion, pumped storage hydro will be included in the Montana resource group for the 2021 IRP. Slides 25, 27 and 28: Thank you for your positive and supportive general comment concerning PSE's approach to modelling transmission opportunities and constraints for the IRP. Slide 29: PSE will not model 185 MW as a sensitivity in the IRP analysis because there is a pending WUTC filing for the sale of Colstrip Unit 4. Slide 33: Thank you for your support concerning PSE changing the policy to reduce the amount of long-term firm transmission to less than name plate capacity. Slides 45, 46, and 48: For the Idaho/Wyoming wind, the transmission line will only deliver the power to Boardman, so PSE will need to rely on a BPA wheel to deliver the power to PSE load. The BPA tariff rates will be included on top of the costs for Idaho/Wyoming wind.
7/7/20	Anika Arugunta	With the depletion of natural resources each day, there is great need to protect our environment so I feel that there is a great need to encourage organizations such as PSE . PSE is doing a great job in bringing to light these environmental issues and it's working to not only educate others about these issues but also to solve these issues as well, which is one of the reasons why I love to work with PSE. Even considering it would be a long 900 miles to travel on the transmission lines, is PSE looking into creating wind and or solar in or on Coalstrip? This would not only be close to transmission lines and a good utilization of land but also create jobs for any workers displaced by the coal stacks closing down.	Thank you for your comment and suggestion. Because of the location of the site and ownership arrangement of Colstrip, PSE is not looking at developing the Colstrip land for wind or solar. However, PSE is analyzing other wind opportunities in Montana.
7/7/20	Anne Newcomb	Thank you for your dedication to move PSE into the clean energy future! I'm so happy it's finally happening! Increase solar on the Westside of the cascades through incentivizing home and business owners as well as public places to create new solar reducing transmission load over the pass. Work towards more solar that can be produced, used and stored onsite in addition to being fed back into PSE lines, to help with the reduction of load on transmission lines	Thank you for your comment and suggestion.
7/7/20	Katie Ware, Renewables NW	*See attached PDF for comments (2020-07-07 RNW Feedback re PSE Transmission Constraints.pdf)*	PSE responses by number: 1. PSE will not model 185 MW as a sensitivity in the IRP analysis because there is a pending WUTC filing for the sale of Colstrip Unit 4. 2. Thank you for your comment. PSE will ensure all modeling resources accurately reflect the 4.6% line loss for transmission from the Colstrip substation. 3. Thank you for your comment and suggestion. Given that all renewable resources outside of PSE will require wheeling through BPA, the BPA tariff

			rate is a reasonable assumption given that PSE does not have an available integration cost. 4. Thank you for your comment and suggestion. 5. Thank you for your support concerning PSE changing the policy to reduce the amount of long-term firm transmission to less than name plate capacity. 6. Thank you for your suggestion, PSE is weighing feedback received by all stakeholders and will provide a final determination of our modeling approach in the July 21 Consultation Update. 7. Thank you for your suggestion, pumped storage hydro will be included in the Montana resource group for the 2021 IRP. 8. Thank you for your suggestion. PSE is considering the possible modeling approach to satisfy this request and will provide additional feedback in the July 21 Consultation Update.
7/7/20	Fred Heutte, NW Energy Coalition	July 7, 2020 To: Puget Sound Energy From: Fred Heutte, Senior Policy Associate on behalf of NW Energy Coalition Re: 2021 IRP Webinar #3: Transmission Constraints The NW Energy Coalition (NWEC) appreciates the opportunity to provide the following comments on the Puget Sound Energy (PSE) presentation in 2021 IRP Webinar #3: Transmission Constraints on June 30, 2020. 1. NWEC would like to have a review, perhaps in an informal discussion group with technically minded stakeholders, about the interaction between power planning (IRP) and transmission planning at PSE. On the transmission side, our questions include: what transmission models does PSE use (powerflow and production cost), what types of cases or scenarios are used to assess transmission constraints currently and in the future, and how does the transmission modeling assess new resources, resource retirement and transmission expansion over time. On the power planning side, does PSE apply the outputs of previous transmission studies throughout the IRP process, or is there additional transmission modeling to assess scenarios being considered as the IRP progresses? 2. What assumptions does PSE have about interregional transmission constraints, particularly for connections to BC Hydro and also the Pacific Intertie? 3. To what extent will PSE consider non-transmission alternatives to make more effective use of its existing transmission system and transmission rights? This includes both flexible demand (including demand response and storage of various kinds) and in-grid elements including traditional equipment such as static var compensators and phase shifters, and new approaches such as “storage as a transmission asset.” 4. With the ongoing progress of the proposed CAISO enhanced day ahead market (EDAM) proposal, NWEC recommends PSE incorporate a market flexibility scenario for the IRP specifically to address reducing constraints and better utilization of the transmission system. While the elements of EDAM are still in early review, the WIEB Western Flexibility Study and the forthcoming State-Level Market Study (with participation by the UTC and Washington State Energy Office) provide useful elements for modeling the potential capability of enhanced markets. 5. (slide 23) We join with other stakeholders in suggesting that pumped storage in Montana should definitely be included in the IRP Assessment. The Absaroka Gordon Butte project is a very important possibility for integrating Montana wind. 6. (slide 24) In terms of the timing for tiers representing transmission constraints, we suggest 2026 as an important checkpoint in view of the availability of Colstrip transmission facilities and rights, the potential availability of pumped storage, and possibilities for transmission expansion including the BPA Montana-to-Washington project, Boardman to Hemingway and Gateway West.	PSE responses by number: 1. PSE will follow up with NWEC and coordinate an informal meeting. 2. SW to NW: Capacity on CA/SW to NW intertie is assumed to be unavailable due to constraint on BPA system. BC to NW: PSE will not model any capacity on the BC to NW intertie for BC hydro resources. 3. PSE is considering a balanced approach to meeting CETA compliance. PSE will be discussing distributed energy resources (DERs) in the August 11 webinar. PSE will also be discussing transmission and distribution (T&D) planning during the November 4 webinar. 4. Thank you for the suggestion and the accompanying resources. However, given the CAISO enhanced day ahead market (EDAM) is still in the early stages of development PSE will not be including it as a viable market in the IRP process. 5. Thank you for your suggestion, pumped storage hydro will be included in the Montana resource group for the 2021 IRP. 6. Thank you for your comment and suggestion. 7. Thank you for the comment, dual purposed transmission will be included in the 2021 IRP modeling process. 8. The IRP team will be evaluating the portfolio benefits of these transmission project investments, which will assist PSE in making a future decision. 9. Thank you for your comment and suggestion. 10. Thank you for your comment and suggestion. PSE is happy to have a follow-up discussion on this topic. 11. Thank you for your comment and suggestion. 12. PSE is considering expanding cross-Cascades transmission capacity as an alternative and will have an update for the consultation update 13. Per the NREL website, the Mid Technology Cost Scenario is the characterized as "likely" while the Low Technology Cost Scenario is characterized as at the "limit of surprise". PSE has included only the most-likely cases (or an average of high and low cases, as applicable) from other data sources. For consistency, PSE will maintain this precedent for the NREL ATB. 14. See response to James Adcock (2).

		7. (slide 27) NWEC strongly supports PSE's interest in dual-purpose use of existing transmission and transmission rights for gas power plants by incorporating new renewable sources that will improve transmission utilization and provide more system value at low incremental transmission cost. 8. (slide 30) NWEC requests that PSE provide more context for the interest being expressed in the proposed Boardman to Hemingway and Gateway West projects. Since PSE would be a new entrant with existing project sponsors and co-developers, it is important to have a better understanding of what PSE's expectations are for the net benefits to be gained and the timing and form (equity ownership or long term transmission rights) of any such commitments. 9. (slide 31) NWEC requests that PSE discuss in more detail how it views the initiatives by BPA to develop new and more flexible transmission products, such as the anticipated revisions to Conditional Firm. 10. (slide 32) Concerning Option 1 and Option 2 for incorporating transmission constraints into the IRP modeling, NWEC thinks both options may add some value and is interested in a more detailed conversation with PSE on this point. 11. (slide 33) NWEC sees the concept of acquiring renewables while having less transmission capacity than their nameplate worth exploring, but we believe that a more in-depth discussion with renewable developers, Renewable Northwest and NIPPC will be important to understand the commercial considerations involved. 12. (slide 34) Is PSE considering expansion of its cross-Cascades transmission capacity? 13. (slide 49) Concerning the use of the NREL Annual Technology Baseline, we now understand that PSE is using the ATB for future resource cost projections, and we appreciate PSE's response to our previous recommendation that regard. However, we continue to view a midrange between the ATB Mid and Low cost projections the most likely, given our analysis particularly of solar PV costs and a separate experience curve analysis we have conducted. Since the ATB became available a few years ago, our view is that the Mid scenario has overestimated short term cost reductions and it is more appropriate to view the ATB Mid and Low projections as "middle-high" and "middle-low." The ATB does not have a "high" projection; the "constant" projection is simply a straight line extension of current cost estimates useful for their scenario modeling. Therefore, we believe a mid-range between the ATB medium and low projections is the most appropriate cost trajectory for use in IRP modeling. 14. (slide 50) As noted by other stakeholders, the battery interconnection costs indicated in the chart appear to be far too high. Thank you for considering NWEC's comments. /s/ Fred Heutte Senior Policy Associate NW Energy Coalition	
7/8/20	Steve Lewis, Sapere Consulting	1. It appears that some of the 450 MW on PSE's cross-Cascades transmission system is reserved for priority use by the Schedule 449 customers (see https://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/Posted_Path_Discussion28.pdf). How much of this transmission has been reserved for Schedule 449 customers historically and how much has been used? 2. If the transmission is not used by the Schedule 449 customers, do the remaining core customers of PSE utilize that transmission path as a cheaper alternative to using the BPA cross-Cascades transmission? 3. As long as PSE keeps the Schedule 449 customers whole with respect to cost and reliability, could PSE connect a new resource on the Kittitas transmission system and move the Schedule 449 customer's service onto PSE's long-term BPA transmission from the MIDC? If not, what specifically prevents this approach of reoptimizing PSE's generation and transmission assets for the benefit of their core customers?	1. Per a settlement with PSE's 449 customers, PSE provides firm transmission service to 449 customers on the cross-Cascades path up to the amount of their load. Most of the time, the 449 customers schedule less than their allotted capacity (due to seasonal loads) and the remaining unscheduled transmission is released to the market as non-firm transmission. 2. The non-firm transmission on this path is available in OASIS for purchase by any PSE transmission customer. PSE Merchant (PSE's energy trading group) will sometimes schedule delivery of Wild Horse energy on this path when there is non-firm transmission available. 3. There is not a regulatory or legal mechanism under the FERC Open Access Transmission regulations to transfer the 449 customer's rights under the settlement agreement with PSE (and WUTC Schedule 449 Retail Wheeling Service) to standard transmission tariff service with BPA.

7/9/20	Kyle Frankiewich, WUTC	This feedback, dated July 8, 2020, states the informal comments, questions, and recommendations of Washington Utilities and Transportation Commission Staff. Timely feedback is offered as technical assistance and is not intended as legal advice. Staff reserves the right to amend these opinions should circumstances change or additional information be brought to our attention. Staff opinions are not binding on the commission. Apologies for this comment being a bit late. I am getting up to speed with this new assignment after a few months out of office, but intend to submit future feedback forms within the requested 7-day window. As a newcomer to the 2021 process, I want to recognize PSE for the massive strides made in the company's transparency and public engagement. The website is useful, easy to navigate and contains all presentation information and materials. All meetings are recorded and freely available. This form is a great idea. The commitment to follow up on participants' questions and comments is a customer-focused investment, one that I would wager will pay dividends at the end of the IRP process. Questions from presentation: • slide 17: Does the AURORA zonal model include more than just two zones? The first bullet is a bit ambiguous; I trust that this means PSE considers new generation transmitted to PSE or Mid-C as effectively meeting load (also considering the limit on Mid-C transmission to PSE). Is this correct? Please provide the transmission modeling topology to clarify. To the extent this topology does not align with • slide 17: PSE's presentation included a mention of the limitations of generation-focused or transmission-focused modeling. PSE could use either a generation model or a transmission model, but not both, and chose the generation model. Does PSE run a Tx-given-Gen optimization? Is there a reason why that paradigm is less useful than the chosen Gen-given-Tx approach? • slides 21 and 22: Staff is trying to track PSE transmission that can deliver from the east side of the Cascades to Westside of the Cascades (to PSE BA or to a Westside transmission facility that can be delivered to the PSE BA). In table form, please provide the POD/POI of the existing transmission resources in each of the tiers discussing in the presentation. This could look something like Figure D-6 in the 2017 IRP (pg D-17), but augmented with endpoints. This could also perhaps pair with the maps on slides 21 and 22. Finally, it would be useful to describe the many varieties of transmission rights held by PSE – what attributes of these rights are and are not flexible. Please include this as part of the table. • slide 22: I'm not disagreeing with the use of these resource group areas, but I don't recall why the resource group areas are needed, and how the company settled on these groups rather than some other arrangement. Is there a reason why this modeling approach is more appropriate than other approaches? • slide 22: I heard during the presentation that the "South WA" resource group may include. some of Oregon. Are southern Oregon or CA resources considered? If so, how are any relevant transmission constraints modeled? • slide 23: Staff understands that some prospective pumped storage resources may be available in Montana. Does PSE intend on modeling those resources as well? • slides 25-30: Again, I don't disagree with this approach, but I want to understand how these tiers were generated. I understood that the potential projects and their assignment into tiers is based on PSE's subject matter expertise, rather than a quantitative analysis. Is this a fair description? If so, it may be worth doing some sensitivities to see how significant these assignments are to the resulting optimized portfolio. • slide 25: To clarify, the 1,500 MW of Mid-C T "reserved for Market Purchases" could be used for either purchases or new resource acquisitions, correct? Was that what was meant in the following bullet discussing "dual purpose" transmission? • slide 29: Does the possible sale of Colstrip to Northwestern include any transmission assets that could otherwise be used by PSE for other resources?	Thank you for your feedback concerning improvements to the 2021 IRP process. PSE's responses concerning the presentation by slide number: Slide 17: PSE portfolio model includes two zones, PSE and Mid-C. There is a transmission link between the PSE zone and the Mid-C equivalent to the available Mid-C transmission for market purchases and sales. Transmission constraints discussed in this meeting is the first step toward incorporating generation and transmission optimization. Currently transmission and generation do no interface in the portfolio model. Slides 21 and 22: PSE will be reaching out to you to clarify the request. Slide 22: PSE acknowledges that there are several possible approaches to model transmission constraints within the Aurora framework. These include 1) creation of additional zonal areas; 2) use of the nodal analysis framework; 3) use of the custom constraint matrix; 4) use of the operating constraints table; and 5) use of the resource group table. Creation of additional zonal areas or use of the nodal model would require extensive revision of PSE's current model topology. As this is the first IRP process which PSE is exploring the use of transmission constraints, extreme revision of the model topology did not seem appropriate at this time. PSE understands the remaining three methods could all be incorporated into the existing model topology. Given the resource group table is a 'standard component' of the Aurora model, PSE expects this method to be the most straightforward to use. However, PSE is also exploring the use of the custom constraint matrix and operating constraints table should there be a need for increased modeling flexibility. Slide 22: PSE is currently not considering resources in Southern Oregon or California due to lack of potential transmission. Slide 23: Thank you for your suggestion, pumped storage hydro will be included in the Montana resource group for the 2021 IRP. Slides 25-30: Tier 1, 2 and 3 will be modeled as sensitivities in the portfolio analysis. Slides 25: Yes, the Mid-C transmission could be used for either market purchases or delivery of new renewable resources. Slides 29: The sale of Colstrip Unit 4 to Northwestern includes up to 185 MW of transmission on the Colstrip Transmission System. Slides 33: BPA regularly posts its path ratings including cross Cascades, however it does not include sufficient information to see how those hours correspond to an hourly production profile.

		• slide 33: Has PSE analyzed the utilization of the east-to-west Cascade transmission capacity to determine, at least approximately, how many hours are constrained (i.e. for which short-term or short-term non-firm transmission capacity is available/not available) and how those hours correspond to the hourly production profile of the potential VERs resources? If that is • slide 34: I trust that other distributed resources, such as flexible demand / DR and behind-the-meter storage, will also be considered. Puget-area solar may have limited impact, but other distributed resources might also sidestep transmission constraints. • slide 35: Is there a price component to the assumption that T capacity will be unconstrained in the future? I understand that this modeling choice will help PSE determine where future T investments will bring the most value, but am confused about whether a $0 price along with unconstrained availability will cause the optimization to "wait" on resources to make use of that assumed availability. • slide 44: Are any of the MT transmission costs something that PSE would have to pay even if the asset is unused? Also, are any of PSE's rights along these lines subject to the potential sale of Colstrip? • slides 45 and 46: The ID/WY transmission options are modeled as a capital cost for Tx build. Are there also other Tx rights that would need to be acquired to get from, for example, PacifiCorp's transmission (which I understand would be co-built and co-owned with PSE under this Tx option), to PSE's BA? Are there any pancaked rates to wheel through BPA, or does this option presume that all needed BPA wheeling rights are already owned? • slide 50: The list of interconnection cost assumptions made me think about some extended interconnection delays in other parts of the WECC. Are there any known interconnection queue issues in the resource group regions that should be considered? If so, how are those interconnection constraints represented in PSE's modeling? 1. Testing the importance of tiers: Perform some sensitivity analysis to gauge whether the "tiering" of possible Tx projects has an outsized impact on the optimized portfolio. For example, if dual-purposing Goldendale's 330 MW of transmission is considered Tier 1 instead of Tier 2, how different is the resulting portfolio? Also, if the renewable resource sharing the transmission is not directly co-located, there may be other Tx costs or risks involved in redirecting transmission rights. 2. Transmission modeling options: I'm not fully tracking on the modeling approaches discussed on slide 32, but it seems that Option 2 'bakes in' limitations on Tier 2 and 3 resources such that they are not available at any cost earlier in time. If this is the case, it seems that Option 1 will enable PSE to identify what transmission constraints are best prioritized to access the most appropriate resources. I would appreciate a deeper explanation of how the results of the Option 1 sensitivities would guide PSE. 3. Tx capacity by % of nameplate: I'm very happy to see this being considered, and am excited to see the results. 4. Staff and other stakeholders submitted feedback prior to this presentation. Were those questions and comments recognized during or after the presentation? If not, please help us set expectations and clarify how the public engagement process works with pre-presentation feedback.	Slides 34: Yes, PSE is exploring DR and other distributed resources. These topics will be covered in greater detail in two upcoming webinars on July 14 and August 11. Slides 35: Wheeling and integration costs will be included similar to previous IRPs. Slides 44: We do not anticipate transmission to go unused because transmission can be redirected for short or long-term transmission usage elsewhere on BPA's system. Only the transmission on the Colstrip Transmission System is included in the Unit 4 sale. Slides 45-46: A transmission wheel will be needed on BPA's system from the Boardman site to PSE's system. Slide 50: PSE is only modeling the transmission constraints listed in the slides. PSE's responses concerning additional questions: 1. Thank you for the recommendation. To clarify, the Tier system is intended to provide sensitivity analysis on various possible transmission outcomes. PSE devised the Tier system as a means of exploring transmission uncertainty. During internal discussions, PSE established there were two possible methods of modeling that uncertainty, Option 1 - discreet sensitivity analyses or Option 2 - tying uncertainty to a specific timeframe, given that more transmission may be acquired as more time and effort is expended. PSE thought both these methods seemed a valid exploration of transmission uncertainty and therefore asked stakeholders to provide their perspective. 2. Thank you for your suggestion, PSE is weighing feedback received by all stakeholders and will provide a final determination of our modeling approach in the July 21 Consultation Update. 3. PSE appreciates that the WUTC supports the presentation of transmission capacity by percentage of nameplate and are looking forward to the results. 4. All feedback forms received before the presentation are included in this feedback report. PSE reviews feedback reports prior to the meeting and where possible, PSE revises the presentation of the material based on the feedback received prior to the meeting, where feasible. Pre-presentation feedback opportunities help inform PSE of stakeholder questions and feedback and provide more time for stakeholders to ask questions and have the questions addressed.

July 7, 2020

Puget Sound Energy
IRP Team

RE: Feedback of Renewable Northwest, Transmission Constraints
Puget Sound Energy's June 30, 2020, Feedback Webinar Relating to Transmission Constraints for PSE's 2021 Integrated Resource Plan.

I. INTRODUCTION

Renewable Northwest thanks Puget Sound Energy ("PSE") for this opportunity to provide feedback as a stakeholder in PSE's 2021 Integrated Resource Plan ("IRP"). This feedback is a response to PSE's June 30, 2020, Feedback Webinar regarding the Transmission Constraints of the 2021 IRP.

Renewable Northwest participated in the Feedback Webinar on June 30, 2020. Below, we provide feedback based on PSE's slide deck regarding transmission constraints for PSE's 2021 IRP.

II. FEEDBACK

1. Renewable Northwest recognizes the complexity of the ongoing negotiations for PSE's sale of Colstrip Units 3 and 4, a sale which includes 185 MW of Colstrip Transmission System capacity. Because this sale is uncertain and subject to regulatory approvals, we recommend that PSE run as a sensitivity in the development of its 2021 IRP a scenario where the Colstrip transaction does not close to test if that transmission capacity could be utilized over the 23 year planning horizon of PSE's IRP to deliver a more optimal resource mix for PSE customers.

2. Renewable Northwest has identified a discrepancy in PSE's determination of transmission losses applied to Montana transmission. Slide 47 of PSE's June 30, 2020 slide deck regarding transmission constraints sums the sources of line losses to 7.3%. However, breaking out that

value to its constituent parts (2.7% loss for PSE Colstrip Transmission[1] and 1.9% loss for BPA[2]), there remains an unaccounted-for percentage of line losses represented in the 7.3% total. PSE acknowledged this error in the webinar presentation of the materials. We thank PSE for its diligence in catching this error and encourage PSE to revise the aggregate line losses associated with Montana transmission constraints to 4.6% in all relevant modeling and documents for the 2021 IRP.

3. Renewable Northwest appreciates PSE's decision to apply uniform integration costs for all renewables, in this case using BPA integration costs, given the finding published in the 2018 Montana Renewables Development Action Plan that the current Dynamic Transfer Capacity (DTC) at the Garrison interchange can facilitate the dynamic transfer of at least 1,000 MW of Montana wind.[3] PSE also mentioned on the June 30, 2020 webinar that a different integration rate is being considered for renewables integrated in PSE's Balancing Area (BA) such as dynamically transferred Montana wind. We support examination of this consideration.

4. Renewable Northwest encourages PSE to release information concerning projected costs related to its potential investment in the Boardman to Hemingway (B2H) project. We acknowledge that additional transmission builds offer a number of potential benefits including improved system reliability, improved flexibility to integrate additional renewable resources onto PSE's system, and expanded market access to meet PSE's energy needs.

5. Renewable Northwest supports PSE's consideration of a policy change to secure less than 100% long term firm (LTF) transmission capacity for renewable resources, which could improve the efficiency of PSE's transmission system.

6. Renewable Northwest supports a transmission capacity modeling approach optimizing certainty of PSE's near-term transmission availability, with particular attention to the timeline leading up to 2030, the milestone for PSE to reach greenhouse gas neutrality per compliance with the Clean Energy Transformation Act (CETA). While slide 24 of PSE's June 30, 2020 slide deck characterizes Tiers 1-3 by "First Year Available," slides 25 through 30 do not appear to align Tiers 1-3 within each Resource Group with any particular timeline, thus making it difficult to assess whether the modeling approach should rely on tiers as sensitivities or as time-dependent

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[1] See https://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSEI_Current_OATT_Prices_2019_12_15.pdf.
[2] See https://www.bpa.gov/Finance/RateInformation/RatesInfoTransmission/FY20-21/2020%20Transmission%20Rates%20Summary.pdf.
[3] Montana Renewables Development Action Plan, Bonneville Power Administration, State of Montana (June 2018) at 9, *available at* https://www.bpa.gov/Projects/Initiatives/Montana-Renewable-Energy/Documents%20Montana/Montana-Renewables-Development-Action-Plan-June-2018.pdf.

periods. That said, Option 1 -- “Model tiers as distinct sensitivities” -- considers all potential transmission capacity additions in each Resource Group, independent from any presumptive timeline or measure of confidence. This option likely best represents the interplay of the various tiers within and across Resource Groups, with particular focus on the timeline to 2030, acknowledging high uncertainty beyond that point.

7. Renewable Northwest suggests that PSE expand its consideration of generic resources for the Montana Resource Group Region to include pumped storage. Montana has several candidate sites for pumped storage facilities, including a project that has already obtained most or all necessary regulatory and environmental approvals. Additionally, a pumped storage facility in Montana could potentially help to increase utilization of PSE’s existing transmission resources in Montana, in combination with wind and solar resources.

8. Renewable Northwest suggests that PSE model its participation in a Regional Transmission Organization beginning in the year 2030. Renewable Northwest acknowledges that the eventuality of an RTO with PSE participation and the timeline for its creation are very uncertain. However, with EIM market enhancements such as the development of an extended day-ahead market continuing at pace[4] and a State-led market options study underway[5], Renewable Northwest believes that now is an appropriate time for PSE to develop an RTO scenario in its IRP. Such a scenario could include assumptions about transmission hurdle rates and increased availability of transmission, perhaps drawing upon the Western Interstate Energy Board’s Western Flexibility Assessment for inspiration or guidance on what assumptions such a scenario might make.[6]

[4] See http://www.caiso.com/StakeholderProcesses/Extended-day-ahead-market.
[5] See https://annualmeeting.naseo.org/data/energymeetings/presentations/Moyer--Western-Regionalization-Study.pdf
[6] See https://westernenergyboard.org/wp-content/uploads/2019/12/12-10-19-ES-WIEB-Western-Flexibility-Assessment-Final-Report.pdf

III. CONCLUSION

Renewable Northwest thanks PSE for its consideration of this feedback. We look forward to continued engagement as a stakeholder in this 2021 IRP process.

Sincerely,

/s/ Katie Ware
Katie Ware
Washington Policy Manager
Renewable Northwest
katie@renewablenw.org

/s/ Jeff Fox
Jeff Fox
Senior Manager -- Transmission, Markets & Montana Policy
Renewable Northwest
jeff@renewablenw.org

PSE IRP Consultation Update
Webinar 3: Transmission Constraints
June 30, 2020

7/21/2020

The following consultation update is the result of stakeholder suggestions gathered through an online Feedback Form, collected between June 23 through July 7, 2020 and summarized in the July 14 Feedback Report. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

PSE also thanks Fred Huette and Joni Bosh of Northwest Energy Coalition (NWEC for meeting with PSE staff to help further clarify their questions and suggestions in follow-up meetings. A meeting with WUTC staff is scheduled for later in the month.

Battery interconnection cost

PSE received feedback from James Adcock, Don March (CENSE) and Fred Heutte (NWEC) concerning the proposed interconnection cost for batteries. PSE has consistently applied the interconnection cost described in the 2019 HDR Report (linked below) for all generic resources. For all battery types, the assessment assumes a 115 kV, 5-mile tie line to the point of interconnection and a breaker and one half interconnection arrangement at the point of interconnection. These are fixed capital costs, regardless of resource nameplate capacity. The capital cost adder in dollars per kilowatt may appear inflated for smaller nameplate resources such as battery resources (25 MW nameplate) and biomass facilities (15 MW nameplate).

Given the expectation for significant quantities of battery energy storage systems in the 2021 IRP, PSE will include a 100 MW nameplate battery. The interconnection for a 100 MW nameplate battery would be $91.80/kW in real 2016 US dollars.

HDR Report: https://www.pse.com/-/media/PDFs/001-Energy-Supply/001-Resource-Planning/10111615-0ZR-P0001_PSE_IRP.pdf

Dual purposed transmission

PSE received feedback from Willard Westre (Union of Concerned Scientists), Bill Pascoe, Katie Ware (Renewable Northwest) and Kyle Frankiewich (WUTC) supporting the inclusion of dual purposed transmission in the 2021 IRP. PSE will incorporate dual-purposed transmission where possible in the 2021 IRP models, in particular, transmission from the Mid-C hub, Goldendale Generating Station and Mint Farm Generating Station.

Colstrip Unit 4 transmission

PSE received feedback from Willard Westre, Bill Pascoe, Katie Ware (Renewable Northwest) and Kyle Frankiewich (WUTC) concerning the inclusion of 185 MW of transmission associated with Colstrip Unit 4. However, the pending sale of Colstrip Unit 4 includes the sale of 185 MW of transmission on the Colstrip Transmission System soit will not be modeled as part of the 2021 IRP process.

Firm transmission as a fraction of nameplate capacity

PSE received feedback from Willard Westre, Bill Pascoe, Katie Ware (Renewable Northwest), Fred Heutte (NWEC) and Kyle Frankiewich (WUTC) suggesting the inclusion of a sensitivity which models firm transmission as a fraction of full nameplate capacity for renewable resources. PSE will be modeling this as a sensitivity.

Pumped storage hydro in Montana

PSE received feedback from Bill Pascoe, Katie Ware (Renewable Northwest) and Fred Heutte (NWEC) supporting inclusion of pumped storage hydro as a resource in the Montana region. PSE reviewed available literature concerning the siting of pumped storage hydro and concluded that Montana does have significant potential for a pumped storage hydro resource. Therefore PSE will include pumped storage hydro as a resource in the Montana transmission region.

Modeling transmission uncertainty

On slide 35, PSE requested stakeholder feedback on methods to model transmission uncertainty. PSE proposed two possible methods: Option 1, modeling confidence level tiers as discrete sensitivities and Option 2, modeling confidence level tiers as time-dependent factors.

PSE received feedback from Katie Ware (Renewable Northwest), Fred Heutte (NWEC) and Kyle Frankiewich (WUTC) concering this topic. Stakeholders suggested that both methods provide value to the IRP modeling process. PSE has elected to model method Option 1, modeling confidence level tiers as discrete sensitivities.

Regional Transmission Organization (RTO) sensitivity

PSE received feedback from Katie Ware (Renewable Northwest) suggesting inclusion of a sensitivity to model the adoption of a Regional Transmission Organization (RTO) in the Pacific Northwest. PSE is still evaluating how modeling an RTO as a sensitivity could be successfully accomplished. A decision on whether this sensitivity will be included is dependent on PSE's models to accurately evaluate an RTO and will be made later in the IRP process.

Expanded cross-Cascade transmission

PSE received feedback from Fred Heutte (NWEC) inquiring about the possibility of modeling expanded cross-Cascade transmission alternatives. PSE is considering modeling expanding our cross-Cascade transmission as an option, but will not have sufficient cost information to model that alternative in the 2021 IRP.

Detailed PSE transmission assumptions

PSE received feedback from Kyle Frankiewich (WUTC) requesting a detailed breakdown to PSE's transmission wheels considered for the 2021 IRP. PSE will be following up with Kyle Frankiewich on July 27, 2020 to further understand his request.

California transmission region

PSE received feedback from Kathi Scanlan (WUTC), Kyle Frankiewich (WUTC) and Fred Heutte (NWEC) concerning transmission capacity and potential modeling of California-based resources. During the Energy Delivery team's review of plausible available transmission, it was found that transmission out of California is significantly constrained. Therefore, no California-based resources will be modeling for the 2021 IRP. However, PSE's existing activity in the Califorina ISO Energy Imbalance Market (EIM) will continue to be modeled.

Transmission from Boardman to Hemingway Project to PSE

PSE received feedback from Bill Pascoe, Katie Ware (Renewable Northwest) and Kyle Frankiewich (WUTC) concerning delivery of power from the Boardman to Hemingway (B2H) projectto PSE's system. This feedback concerns the possible acquisition of transmission on the B2H and Gateway West transmission projects to access Wyoming and Idaho-based resources. Stakeholders noted that an additional BPA transmission wheel is necessary to bring the power home to PSE territory from the northern terminus of the B2H project.

PSE will include Bonneville Power Authority (BPA) provided transmission from B2H to PSE using standard BPA rates. These rates are: $22.20/kW-year for firm transmission plus $11.16/kW-year for wind integration or $8.20/kW-year for solar integration. These costs are in addition to capital costs discussed during the webinar.

Summary of all updates

PSE appreciates the feedback provided by stakeholders. In summary, the following changes will be implemented into the portfolio model:

- Include a sensitivity to model firm transmission as a fraction of nameplate.
- Add pumped storage hydro to the Montana resource region.
- PSE has elected to model method Option 1, modeling confidence level tiers as discrete sensitivities.
- PSE is still evaluating how modeling an RTO as a sensitivity could be successfully accomplished. A decision on whether this sensitivity will be included is dependent on PSE's models to accurately evaluate an RTO and will be made later in the process.
- PSE does not have sufficient cost information to model the cross Cascade transmission in the 2021 IRP.
- PSE will include Bonneville Power Authority (BPA) provided transmission from Hemmingway to PSE using standard BPA rates.

PSE is committed to keeping our stakeholders informed of our progress toward incorportating feedback into the IRP process. PSE will review the list of proposed portfolio sensitivities with stakeholders at the August 11, 2020 webinar and will seek feedback around the details of these sensitivities and additional sensitivities.

Webinar 4, July 14, 2020

Demand-side Resources and Demand Response

PSE PUGET SOUND ENERGY

Webinar #4: Draft Demand Side Resources
July 14, 2020 from 1:30 p.m. to 5:00 p.m. PST

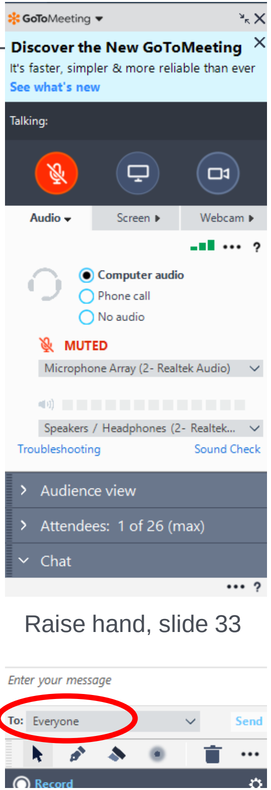
Virtual webinar link: https://global.gotomeeting.com/join/356063605
Access code: 356-063-605
Call-in telephone number (audio only): +1 646-749-3112

Topic	Lead
Welcome • Agenda review • Safety moment • How to participate • Speaker introductions	EnviroIssues
Conservation Potential Assessment (CPA) in the IRP • Overview • Methodology	Gurvinder Singh, Senior Resource Planning Analyst, PSE
Electric Potential • Energy Efficiency	Gurvinder Singh, Senior Resource Planning Analyst, PSE Lakin Garth, Senior Associate, Cadmus
10-minute break	
Electric Potential (continued) • Demand Response • Distributed Solar pV • Combined Heat and Power	Lakin Garth, Senior Associate, Cadmus
Natural Gas Potential • Natural gas energy efficiency potential results	Lakin Garth, Senior Associate, Cadmus
Distribution Efficiency and CPA input to IRP modeling • Distribution efficiency potential • CPA and demand response in the 2021 IRP	Gurvinder Singh, Senior Resource Planning Analyst, PSE
Feedback and final Q&A • More participant questions • Using the Feedback Form	Facilitated by EnviroIssues
Wrap up and next steps • Next steps • Upcoming meeting schedule • Thank you's	EnviroIssues

How to participate using Go2Meeting

Presentation Do's

- Mute your mic during the presentation
- You can participate in writing or verbally using the chat window
  - **In writing:** your question will be read
  - **Verbally:** type "Raise hand" and slide #, share with "Everyone"; please wait to be called on to ask your question
- Be considerate of others waiting to participate
- We will try to get to all questions



PUGET SOUND ENERGY

2021 IRP Webinar #4: Demand Side Resources

July 14, 2020

Agenda

- Safety moment
- Speaker Introductions and Preliminaries
- Overview of CPA in IRP
- CPA – methodology
- Electric Potential
    - Energy Efficiency
    - Demand Response
    - Distributed Solar pV
    - Combined Heat and Power
- Natural Gas Potential
- Distribution Efficiency Potential
- CPA input to IRP modeling
- Feedback and Final Q&A
- Next steps
- Appendix

Safety Moment

SOURCE: https://www.mayoclinic.org/healthy-lifestyle/adult-health/multimedia/back-pain/sls-20076866?s=2

Start in a safe position

Maintain the natural curve in your lower back

Use your legs

Squatting instead of kneeling

Let your legs do the work

Avoid twisting

PSE PUGET SOUND ENERGY

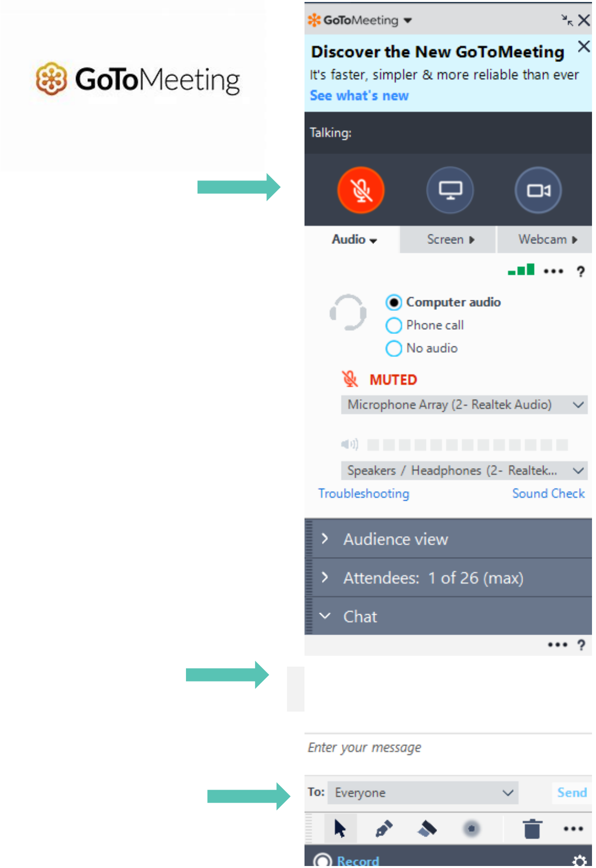
Today’s Speakers

Gurvinder Singh
Senior Resource Planning Analyst, PSE

Lakin Garth
Senior Associate, Cadmus

Alexandra Streamer & Alison Peters
Co-facilitators, EnviroIssues

Welcome to the webinar and thank you for participating!



Virtual webinar link: https://global.gotomeeting.com/join/356063605

Access Code: 356-063-605

Call-in telephone number: +1 (646) 749-3112

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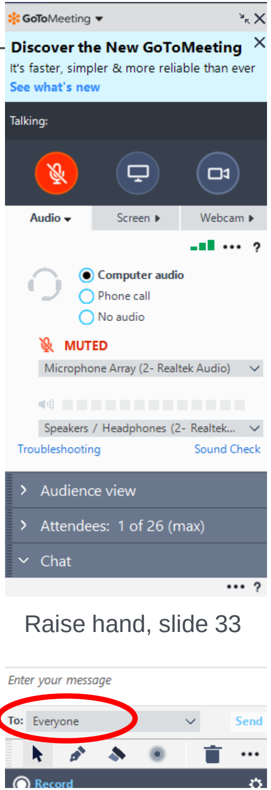

PUGET SOUND ENERGY

Participation Objectives

- Stakeholders share input on conservation potential assessment
- Stakeholders share input on sensitivities with demand side resources

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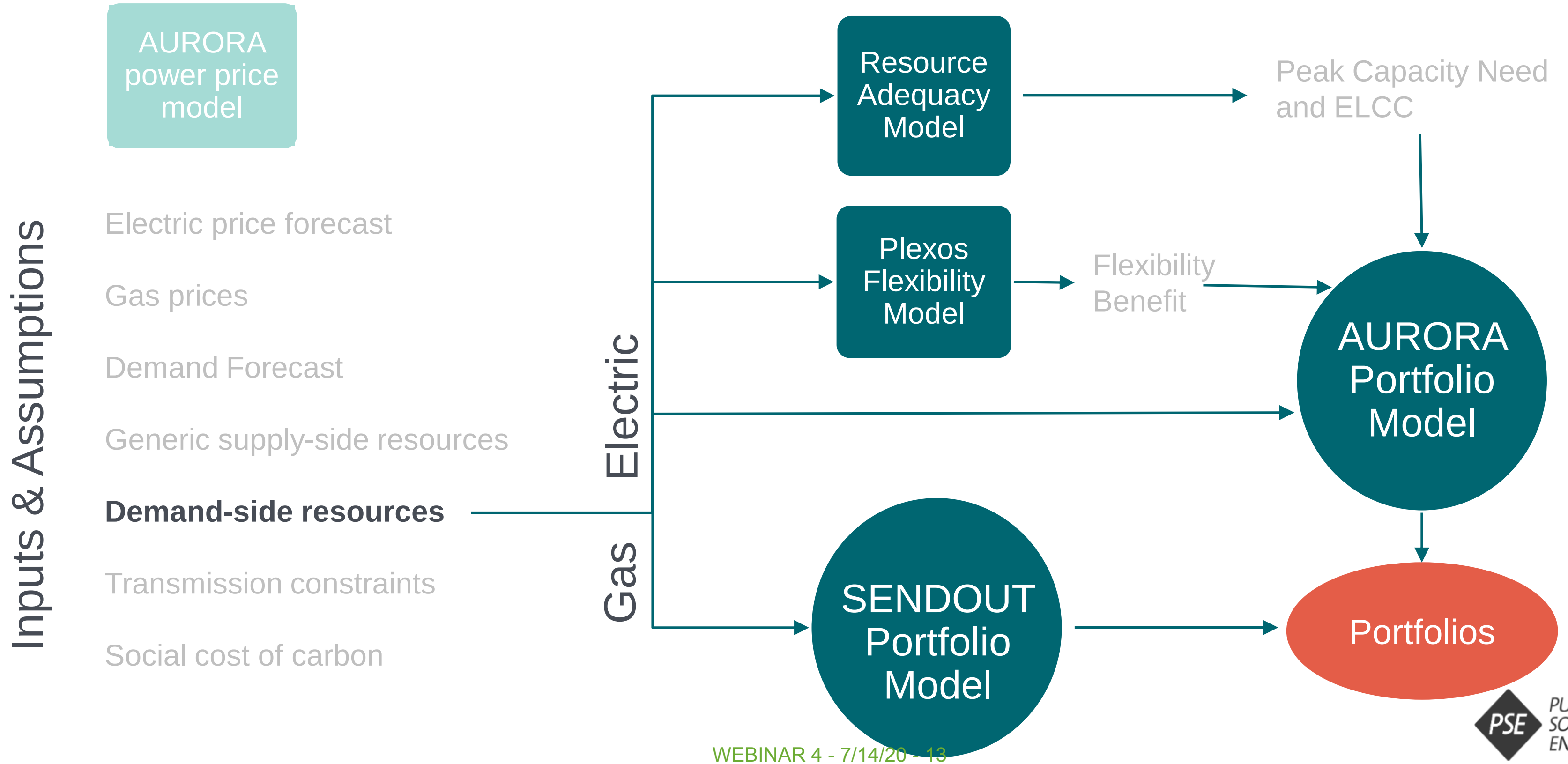
Overview of the Conservation Potential Assessment in the IRP

How is the Conservation Potential Assessment (CPA) used?

- The CPA is used in the IRP to determine the cost effective amount of demand side resources (energy efficiency, distribution efficiency, combined heat, demand response)
  - Cost effective conservation is used to inform the program target setting process:
    - For energy efficiency based on EIA/HB1257
    - For Demand Response per CETA
- CPA and cost-effective conservation will be used to inform the
  - Clean Energy Action Plan
  - Clean Energy Implementation Plan
- The CPA will also provide conservation forecast at the zip code level to be used by Delivery System Planning in their distributed energy resource planning process, also known as the non-wires alternative solutions
- Sensitivities can be used to test various assumptions and their impact on the output in the IRP

Electric and Gas IRP Models



PSE PUGET SOUND ENERGY

Consultations along the way

CRAG Stakeholders Jan 20, 2020

Consult meeting with Stakeholders April 20, 2020

Demand Response Webinar May 15, 2020

Consult meeting with stakeholders July 6, 2020

CPA results to stakeholders July 14, 2020

IRP Portfolio Analysis

Dept. of Commerce workshop on April 15
Consultation with PSE conservation staff April/May
UTC Workshop on Demand Response on June 8

Updates in 2021 CPA: T&D deferral benefit

- Updated T&D capital deferral benefit:

PSE deferral costs	$/kW-yr	$/kW-yr 2020$
Transmission	$ 5.22	$ 5.22
Distribution	$ 7.40	$ 7.40
T&D Deferral Costs	$ 12.61	**$ 12.61**
Power Council deferral costs 2021 Plan	**$/kW-yr 2016$**	**$/kW-yr 2020$**
Transmission	$ 3.08	$ 3.35
Distribution	$ 6.85	$ 7.45
T&D Deferral Costs	$ 9.93	**$ 10.79**
Power Council deferral costs 7th Plan	**$/kW-yr 2012$**	**$/kW-yr 2020$**
Transmission	$ 26.00	$ 29.55
Distribution	$ 31.00	$ 35.23
T&D Deferral Costs	$ 57.00	**$ 64.77**

- We will also be updating the gas distribution deferral benefit

Consistency with Council’s Methodology

Energy Independence Act Statute RCW 19.285.040

…using methodologies consistent with those used by the Pacific Northwest electric power and conservation planning council in the most recently published regional power plan…

…Nothing in the rule adopted under this subsection precludes a qualifying utility from using its utility specific conservation measures, values, and assumptions in identifying its achievable cost-effective conservation potential.

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DSR Potential Study Draft Results

Cadmus

Brief company overview

Our team has performed 40+ demand-side resource potential studies in the last ten years

Range of Clients	• Investor-owned utilities • Public power utilities • Public utility commissions • Federal and state agencies
Client Needs	• Integrated Resource Planning support • Program planning • Target setting and regulatory compliance
Demand-Side Management Resources	• Energy efficiency • Demand response • Customer-sited distributed energy resources • Electric utility infrastructure

Energy Efficiency

Methodology

CADMUS

Study Overview

Primary Objectives	Updated Data
▪ Produce updated forecasts of achievable technical potential ▪ Electric: 2022 - 2045 ▪ Gas: 2022 - 2041 ▪ Develop supply curve inputs ▪ Align savings and costs	▪ Load and customer forecasts ▪ Updated commercial square footage data ▪ PSE measure case and Regional Technical Forum unit-energy savings updates ▪ 2018 & 2019 PSE program accomplishments ▪ 2019 Legislation updates ▪ Council 2021 Plan updates

Scope of the Analysis

Five Sources	• Energy Efficiency • Demand Response • Distributed Solar Photovoltaics • Combined Heat and Power • Distribution Efficiency

Two Fuels	• Electric.
	  • Energy efficiency, Distributed Solar PV, Demand Response, Combined Heat and Power, and Distribution Efficiency
	• Natural Gas
	  • Energy Efficiency

Potential Types	• **Technical Potential**: All technically feasible potential • **Achievable Potential**: The subset of technical potential that homes and business will realistically adopt • **Economic Potential**: The cost-effective portion of achievable potential selected by PSE's Integrated Resource Plan
Comprehensive	• Over 300 unique electric and natural gas energy efficiency measures considered. Thousands of permutations • Five Combined Heat and Power technologies and up to six capacity bins for each technology • Sixteen demand response products

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Types of Energy Efficiency Potential

<table>
<tr><td rowspan="2">CPA Modeling</td><td>Not Technically Feasible</td><td colspan="3">Technical Potential</td></tr>
<tr><td>Not Technically Feasible</td><td>Market Barriers</td><td colspan="2">Achievable Technical Potential</td></tr>
<tr><td>IRP</td><td>Not Technically Feasible</td><td>Market Barriers</td><td>Not Cost Effective</td><td>Achievable Economic Potential</td></tr>
</table>

Methodology

Steps for estimating conservation potential

1. Compile Measure Data
2. Develop Units Forecast
3. Calculate Levelized Costs
4. Calculate Technical Potential
5. Calculate Achievable Technical Potential
6. Develop Supply Curves for IRP Modeling

Step 1. Compile Measure Data

Steps for estimating conservation potential

1

Determine unique measures: Includes measures from the following:
- PSE Measure Cases
- Regional Technical Forum unit energy savings
- Council Plans
- Cadmus supplemental measures

2

Compile measure data and determine PSE-specific inputs:

- Costs
- Applicability
- Per-unit savings
- Measure lives
- Saturations; number of units

Step 2. Develop Units Forecasts

Steps for estimating conservation potential

Sector Units × Saturation × Applicability Factor × Turnover Rate = Measure Units

Data Sources	
	▪ PSE customer and load forecast ▪ PSE Residential Characteristics Study ▪ PSE Non-residential customer database ▪ PSE supplemental customer data files (e.g. indoor ag) ▪ Regional stock assessment data (Northwest Energy Efficiency Alliance's Commercial Building Stock Assessment and Residential Building Stock Assessment) ▪ Council's Power Plans ▪ U.S. Census Bureau American Community Survey

Step 3. Calculate Levelized Costs

Steps for estimating conservation potential

- Compiled PSE financial assumptions
  - discount rates, line losses, etc.
- Levelized costs calculated using the costs and benefits below:

Costs Included	Benefits Netted Out
Capital and Labor	Deferred Transmission & Distribution Expansion
Annual Operations and Maintenance	Regional Act Credit
Program Administration	Avoided Periodic Replacement
Periodic Replacement	Other Fuel Benefits
Other Fuel Costs	Non-Energy Impacts
Non-Energy Impacts	

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Step 4. Estimate Technical Potential

Steps for estimating conservation potential

Sector Units × Saturation × Applicability Factor × Turnover Rate × Unit Energy Savings = Technical Potential

Unit energy savings derived from:	▪ PSE measure cases, ▪ Regional Technical Forum unit-energy savings workbooks, ▪ Council Plan, and ▪ Cadmus supplemental measures (e.g. commercial cooling)

- For a number of measures, Cadmus will change inputs into some RTF and 7th / 2021 Plan measures with PSE-specific values
- For example, the number of bathrooms per home or occupants per household for measures including showerheads, clothes washers, etc.

Step 5. Estimate Achievable Technical Potential

Steps for estimating conservation potential

Sector Units × Saturation × Applicability Factor × Turnover Rate × Unit Energy Savings × Maximum Achievability Factor × Ramp Rate Percent = Achievable Technical Potential

Maximum Achievability Factor

- Previous potential assessments: 85%
- 2021 update: vary by measure, Council 2021 Plan as a start

Ramp Rate Percent

- 10-year flat ramp for discretionary measures
- Adapted Council 2021 Plan ramp rates for lost opportunity measures

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Step 6. Develop Supply Curves for IRP Modeling

Steps for estimating conservation potential

For each fuel type, the supply curve graph shows the relationship of:

- cumulative achievable technical potential, and
- levelized cost

Cost are levelized over the study time frame, accounting for “end effects”

Potential is then “bundled” or “binned” by levelized cost ranges

For the 2021 CPA update, we will create additional bins, particularly at higher levelized cost ranges

- This is because, when accounting for the Social Cost of Carbon, we expect the value of energy efficiency to increase

Finally, we disaggregate annual potential into hourly estimates (for electric) and monthly (for gas) using end-use load shapes

2019 Legislative Updates

Considerations in 2021 CPA

HB1444	• 16 new appliance and equipment standards • Includes first-in-nation water heat standard • Enables low cost deployment of demand response communications • All energy efficiency baselines reviewed and updated where necessary (e.g. showerheads) to meet HB1444 standards
HB1257	• State energy performance standard for commercial buildings • Compliance with energy use index energy use intensity (EUI) targets or develop and implement energy efficiency measures • Performance-based incentive program in 2021 and mandatory requirement beginning in 2026 • Will spur efficiency improvement adoptions • Reflected in more aggressive ramp rates for lost opportunity measures • Retrofit measures all ramped in the first 10 years

Electric Energy Efficiency Results

Electric Energy Efficiency Potential

Achievable Technical Potential

Sector	2023	2031	2041	2045
Cumulative Achievable Technical Potential (aMW)				
Residential	24	169	314	339
Commercial	24	153	228	250
Industrial	2	9	10	10
Total	**51**	**331**	**552**	**600**
Percent of Baseline Sales				
Residential	1.8%	11.2%	18.0%	18.5%
Commercial	2.4%	13.6%	18.0%	18.8%
Industrial	1.4%	7.5%	8.3%	8.4%
Total	**2.1%**	**12.3%**	**18.1%**	**18.3%**

Comparison to 2019 CPA

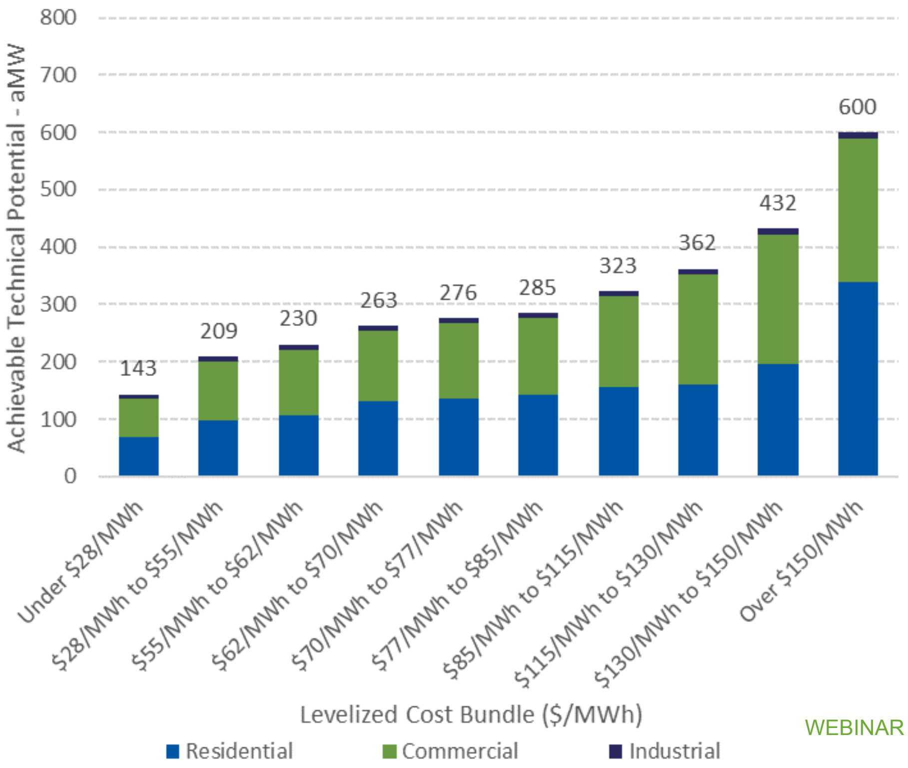
Electric Achievable Technical Potential

Electric	20-Year Achievable Technical Potential (Percent of Sales)			Total Achievable Technical Potential (aMW)
	Residential	Commercial	Industrial	
Energy Efficiency Potential				
2021 IRP	18%	18%	8%	552
2019 IRP	21%	16%	26%	692

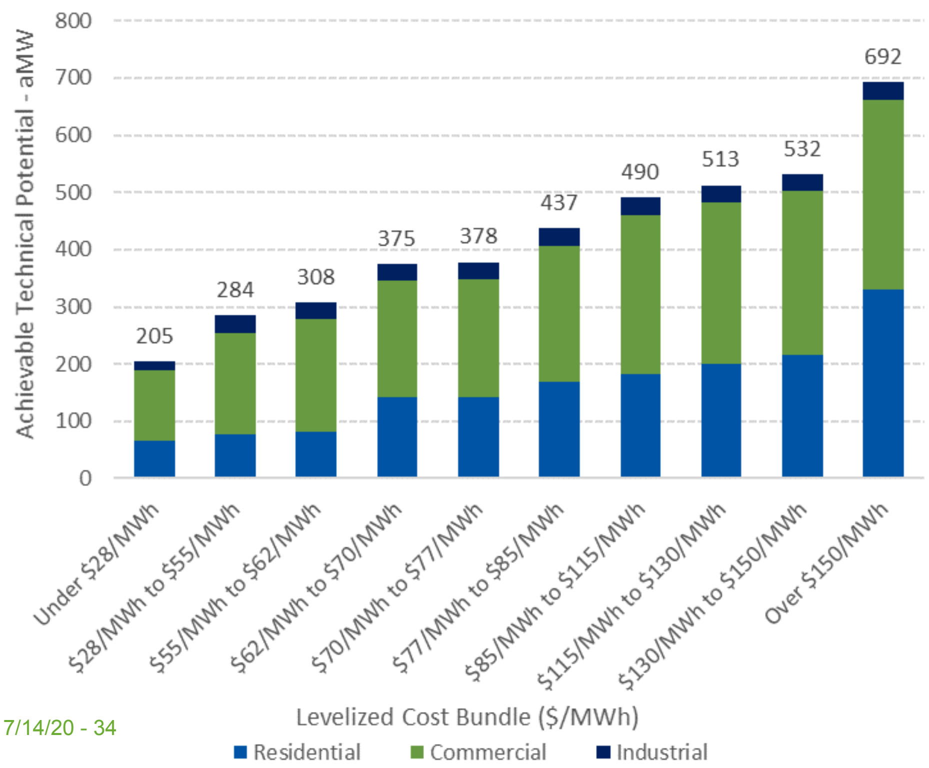
The 2021 IRP electric study period spans 24 years;
this table shows only the first 20 years for comparison purposes

Comparison to the 2019 CPA

2021 CPA Supply Curve



2019 CPA Supply Curve



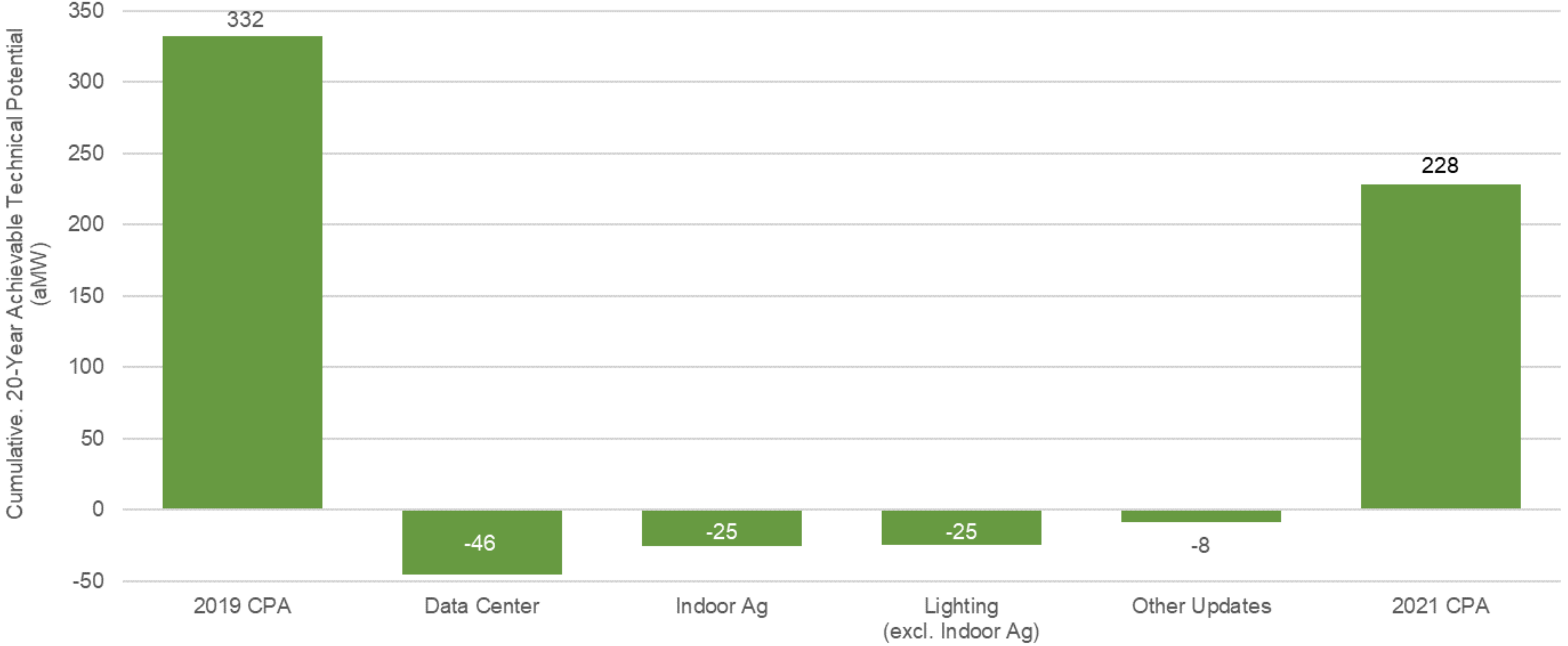
Comparison to the 2019 CPA

Electric Achievable Technical Potential

RESIDENTIAL	• Similar total potential • Estimated low income customer potential • Modeled new construction potential from whole home perspective • Slightly higher electric residential customer forecast
COMMERCIAL	• No enterprise data center potential • Lower interior lighting potential • Lower indoor agricultural potential • Lower electric commercial customer forecast
INDUSTRIAL	• Re-classification of some customer loads to commercial

Commercial Electric Potential

Updates to 2021 CPA



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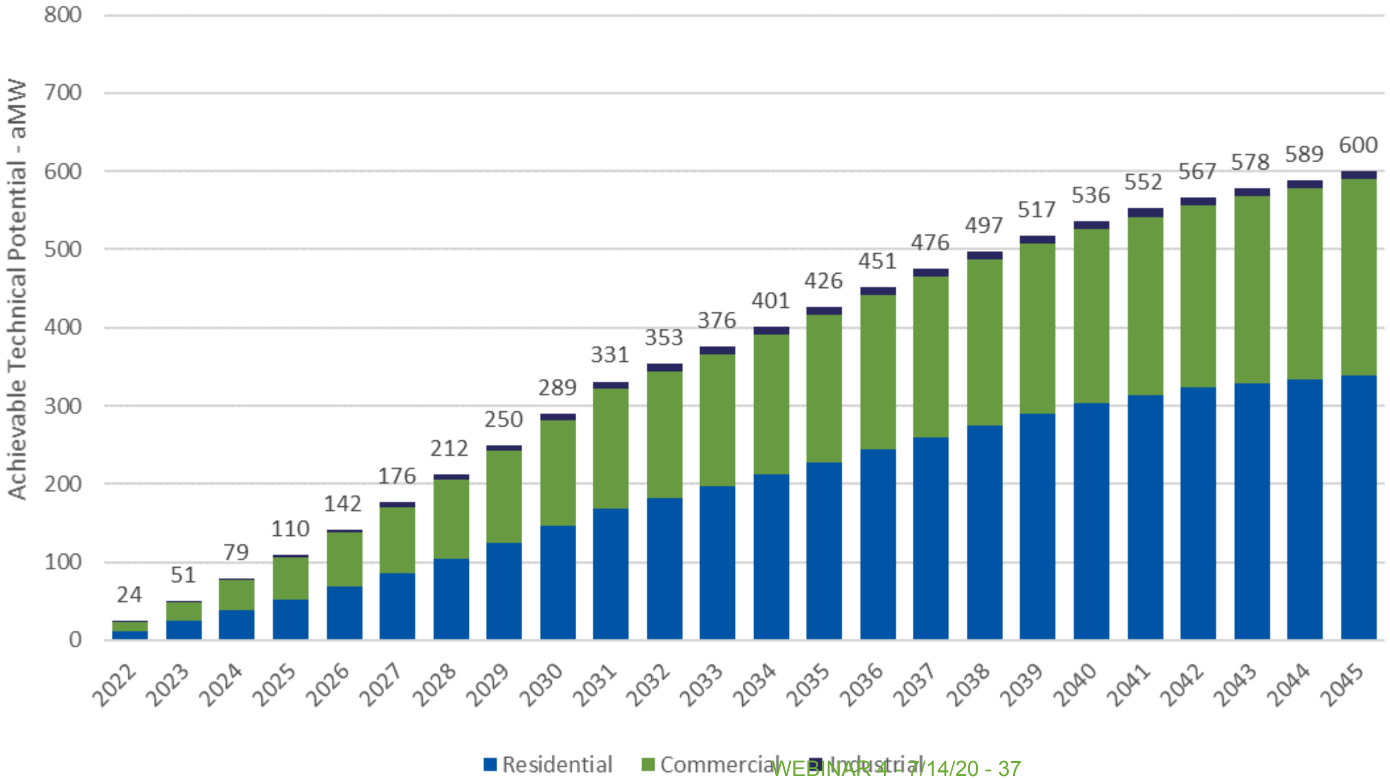
Electric Energy Efficiency Forecast

Cumulative Achievable Technical Potential Forecast



- Discretionary measures receive a flat 10-year ramp rate
- Lost opportunity measures (new construction and natural replacement) receive 2021 Plan ramp rates
- Cadmus adjusted some ramp rates to match program activity and expectations

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Top Residential Measures

Electric Energy Efficiency Potential

Measure Category	Weighted Average Levelized Cost ($/kWh)	Cumulative 10-Year Achievable Technical Potential	Cumulative 24-Year Achievable Technical Potential
Ductless Heat Pump	$0.270	16.3	58.0
Whole Home	-$0.044	5.2	57.7
Heat Pump Water Heater	$0.087	11.2	34.5
Window	$0.400	26.3	26.3
Clothes Dryer	$0.275	8.2	17.0
Home Energy Report	$0.003	16.6	16.6
Heat Pump	$0.152	4.9	17.7
Clothes Washer	-$0.064	5.9	14.2
Refrigerator	$0.147	5.1	12.7
Thermostat	$0.056	9.5	9.5
Solar Water Heater	$1.000	3.9	3.9
Ground Source Heat Pump	$0.100	0.7	8.1
Duct Sealing and Insulation	$0.077	5.4	5.4
Wall Insulation	$0.061	7.2	7.2
Duct Sealing	$0.063	4.9	4.9

- Levelized costs in this table are savings-weighted across individual measures and their applications (e.g. single family, low income, etc.).
- Some levelized costs may be negative due to non-energy impacts, periodic replacement benefits, the Council credit, and deferred transmission and distribution benefits.
- Retrofit measure savings are captured in the first 10 years and therefore have the same values in the 10- and 24-year columns.

Top Commercial Measures

Electric Energy Efficiency Potential

Measure Category	Weighted Average Levelized Cost ($/kWh)	Cumulative 10-Year Achievable Technical Potential	Cumulative 24-Year Achievable Technical Potential
LED Panel	$0.141	27.5	44.8
Variable Speed Efficient Motor	$0.066	11.6	40.4
Linear LED	$0.121	7.7	18.4
Variable Refrigerant Flow	$0.064	4.4	10.6
Wastewater	$0.059	9.6	9.6
High Bay LED Panel	$0.145	5.2	8.1
Circulator Pump (Bronze or Stainless Learning Run Hours)	-$0.147	7.1	7.1
Refrigeration Electrically-Commutated Motors	$0.050	6.7	6.7
Commercial Strategic Energy Management	$0.004	4.2	4.9
Pool Pump	$0.007	1.3	4.6
Parking Garage Lighting	-$0.014	4.5	4.5
LED Sign	$0.063	4.5	4.5
Residential-type Heat Pump Water Heater	$0.073	1.0	4.3
LED Other	-$0.135	4.2	4.2
Cooling DX 65 to 135 kBtuh Premium	$0.238	0.9	4.1

- Individual measure applications are grouped into categories in this table
- The top 15 measure categories account for about 71% of the total commercial electric achievable technical potential
- Retrofit measure savings are captured in the first 10 years and therefore have the same values in the 10- and 24-year columns.

Top Industrial Electric Measures

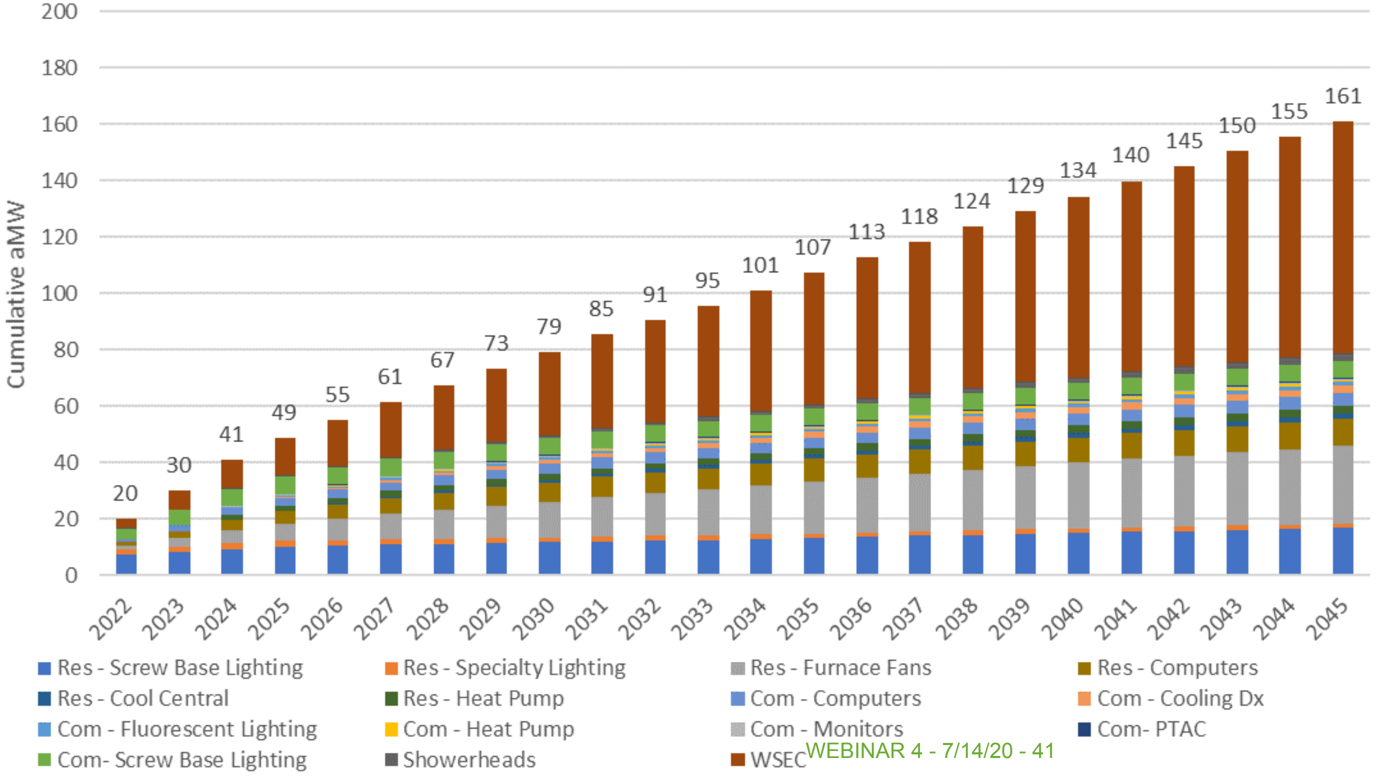
Electric Energy Efficiency Potential

Measure Category	Weighted Average Levelized Cost ($/kWh)	Cumulative 10-Year Achievable Technical Potential	Cumulative 24-Year Achievable Technical Potential
Plant Energy Management	$0.034	1.1	1.1
LED Streetlight - MH 400W – NR	-$0.022	0.7	0.9
Energy Project Management	$0.055	0.7	0.7
Fan System Optimization	$0.016	0.6	0.6
Integrated Plant Energy Management	-$0.004	0.6	0.6
Fan Equipment Upgrade	$0.049	0.6	0.6
Pump System Optimization	-$0.032	0.5	0.5
Pump Equipment Upgrade	$0.057	0.5	0.5
LED Streetlight - HPS 250W – NR	-$0.048	0.3	0.4
LED Streetlight - HPS 100W – NR	-$0.109	0.3	0.4
Wood: Replace Pneumatic Conveyor	-$0.079	0.3	0.3
Clean Room: Change Filter Strategy	-$0.002	0.3	0.3
Material Handling Variable Frequency Drive	$0.056	0.3	0.3
LED Streetlight - MH 200W - NR	-$0.077	0.2	0.2

- Individual measure applications are grouped into categories in this table
- The 15 measure categories account for about 75% of the total industrial electric achievable technical potential
- Retrofit measure savings are captured in the first 10 years and therefore have the same values in the 10- and 24-year columns.

Electric Codes and Standards Savings

Electric Energy Efficiency Potential



- Estimated the impact of the Washington State Energy Code (WSEC) and federal and state equipment standards
- WSEC accounts for 51% of codes and standards savings (82 aMW by 2045)

10-minute break

PUGET SOUND ENERGY

Demand Response Potential

Demand Response Products

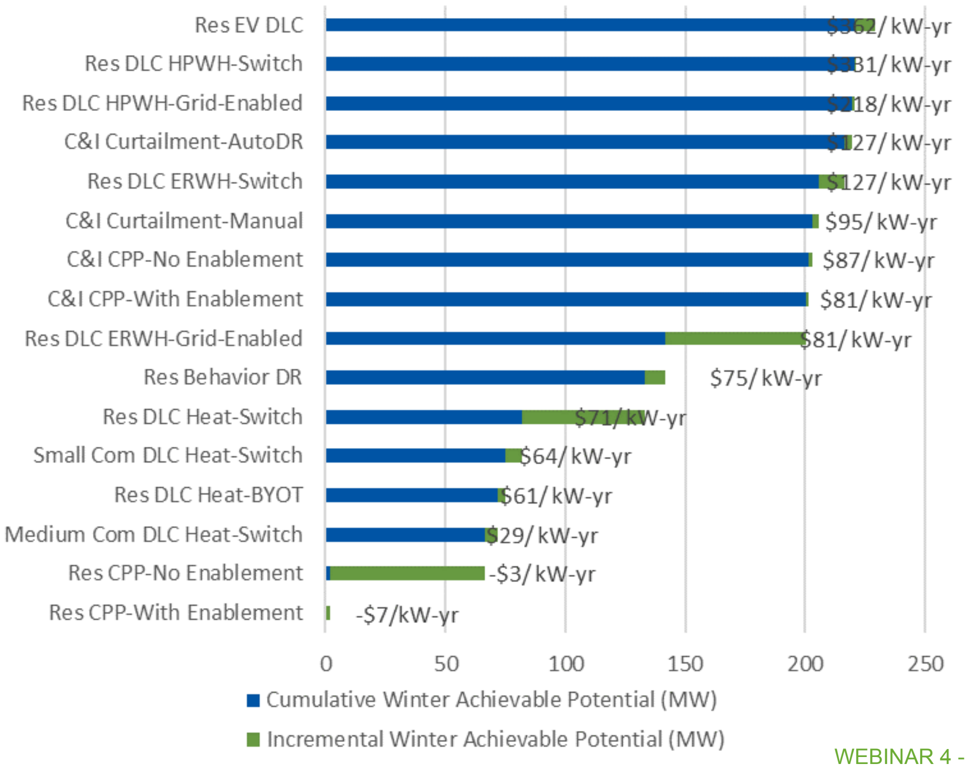
Direct Load Control (DLC)	• **Space Heat.** (smart thermostat or switch) • **Water Heat.** (switch or grid-enabled water heater) • **Electric Vehicle Supply Equipment.** Residential at-home charging
Critical Peak Pricing (CPP)	• Customers are sent a utility price signal prior to a peak event • With or without a smart thermostat
Commercial and Industrial Curtailment	• **Manual**: customers manually reduce energy usage during peak events • **Automated**: technology and controls are programmed to reduce usage during peak events
Behavioral Demand Response	• Similar to home energy reports offered by efficiency programs • Participants receive prior notification, usually day-ahead, via text or email notifying them of a peak event

Demand Response Product Matrix

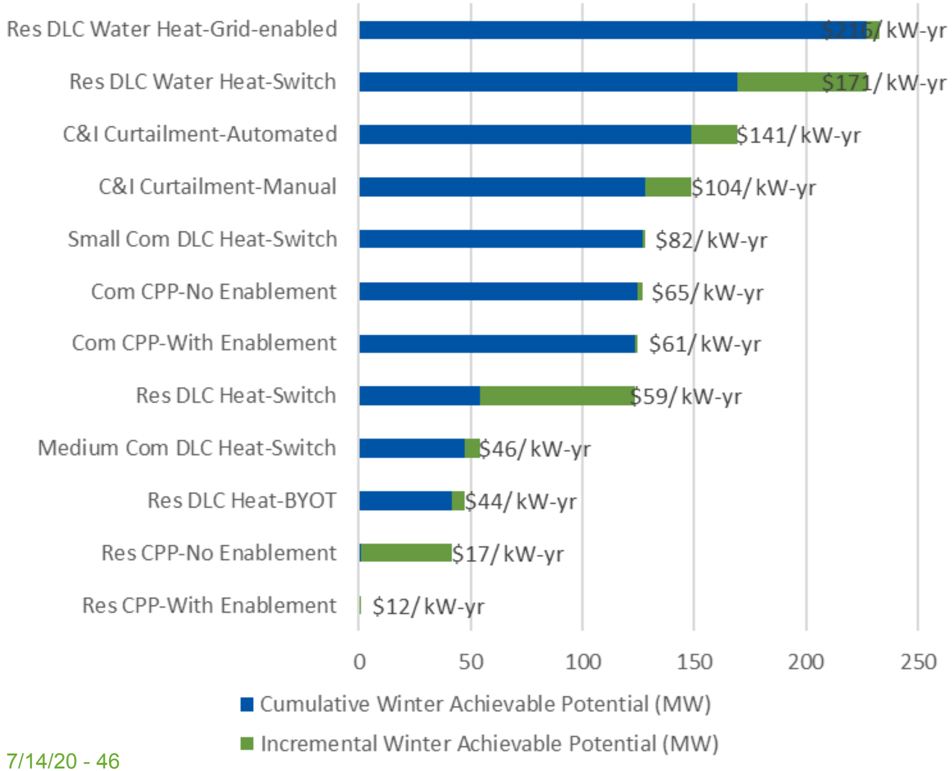
Demand Response Product	Demand Response Product Group	Number of Events and Hours Curtailed	Notification Type (e.g. day-ahead, hour-ahead, etc.)
Res CPP-No Enablement	Residential Critical Peak Pricing	Up to ten 4-hour events	Day-ahead (non-dispatchable)
Res CPP-With Enablement	Residential Critical Peak Pricing	Up to ten 4-hour events	Day-ahead
Res DLC Heat-Switch	Residential DLC Space Heat	Up to ten 4-hour events	0-min
Res DLC Heat-Thermostat (BYOT)	Residential DLC Space Heat	Up to ten 4-hour events	0-min
Res DLC ERWH-Switch	Residential DLC Water Heat	Up to ten 4-hour events	0-min
Res DLC ERWH-Grid-Enabled	Residential DLC Water Heat	Unlimited	0-min
Res DLC HPWH-Switch	Residential DLC Water Heat	Up to ten 4-hour events	0-min
Res DLC HPWH-Grid-Enabled	Residential DLC Water Heat	Unlimited	0-min
Small Com DLC Heat-Switch	Commercial DLC Space Heat	Up to ten 4-hour events	0-min
Medium Com DLC Heat-Switch	Commercial DLC Space Heat	Up to ten 4-hour events	0-min
C&I Curtailment-Manual	Commercial and Industrial Curtailment	Up to ten 4-hour events	Day-ahead (or as late as 2-hour-ahead)
C&I Curtailment-AutoDR	Commercial and Industrial Curtailment	Up to ten 4-hour events	0-min
C&I CPP-No Enablement	Commercial Critical Peak Pricing	Up to ten 4-hour events	Day-ahead (non-dispatchable)
C&I CPP-With Enablement	Commercial Critical Peak Pricing	Up to ten 4-hour events	Day-ahead
Res Electric Vehicle DLC	Residential Electric Vehicles	Up to ten 4-hour events	Day-ahead
Res Behavior DR	Residential Behavioral	Up to ten 4-hour events	Day-ahead (non-dispatchable)

Comparison to the 2019 CPA

2021 CPA Supply Curve



2019 CPA Supply Curve



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Comparison to the 2019 CPA

Demand Response Achievable Technical Potential

RESIDENTIAL	• Added behavioral demand response • Added residential Electric Vehicle Service Equipment DLC • Applied grid-enabled and switch water heat DLC to both electric resistance and heat pump water heaters • Lowered space heating DLC per unit kW impacts • Neither study considers smart appliance DLC due to uncertainties regarding customer acceptance
COMMERCIAL AND INDUSTRIAL	• No new products • Adjusted C&I curtailment program participation rate

Demand Response Considerations

Three highest-saving DR products

Residential Water Heat DLC (71 MW)	• Estimated potential across four electric water heater combinations • (1) electric resistance, (2) grid-enabled electric resistance, (3) heat pump, and (4) grid-enabled heat pump • Methodology similar to Council's for 2021 Plan • Standard units turn over to grid-enabled as measure lives expire
Residential Critical Peak Pricing (66 MW)	• With or without a smart thermostat • Participation limited to 15% of customers with electric service • Impacts vary by customer segment
Residential Space Heat DLC (54 MW)	• Participation limited to eligible customers with electric space heat • Peak load impacts vary by control option: BYOT or switch

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Demand Response Considerations

Interactions with Energy Efficiency

Assume energy efficiency takes place first

Adjusted Forecast	• Uses sales forecast net of technical achievable conservation as starting point for top-down products • Uses technical achievable end use saturations (e.g. smart thermostat penetration rates) for bottom-up products

Distributed Solar PV Potential

Distributed Solar PV Methodology

Achievable Potential

We estimate market penetration as function of customer payback.

Customer payback is a key input to a Bass diffusion model function.

For each scenario, we calculate annualized simple payback (ASP) for each year of the study

→

ASP for an average system in a given year is used to calculate the market penetration of solar for that year

→

Market penetration (MP) in a given year is taken as the fraction of technical potential that can be considered achievable potential

$$ASP = \frac{Net\ Costs\ (after\ incentives)}{Annual\ Energy\ Savings + Production\ Based\ Incentives}$$

$$MP = e^{(-sensitivity\ to\ payback\ * ASP)}$$

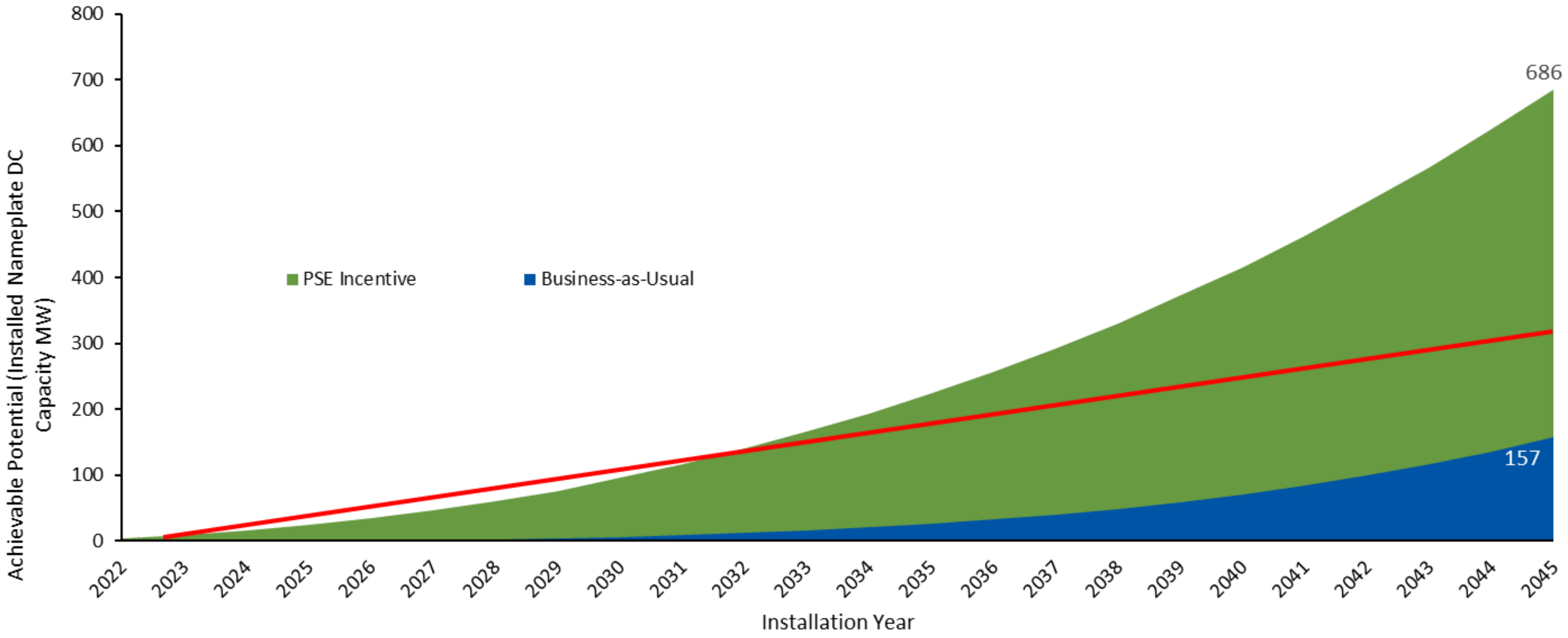
Achievable Potential Assumptions

Two Scenarios

Business as Usual	Utility Incentive

• Continuation of federal Investment Tax Credit in its current form:
  • 0% in 2022 for residential
  • 10% for commercial
• Washington State Renewable Energy System Incentive Program (RESIP) applications ended December 2019
• Net metering
• 5-year Modified Accelerated Cost Recovery System (MACRS) depreciation for commercial
	• Business as usual, plus
	• Utility incentive equal to \$0.048/kWh
	• Calculated from the 2019 Integrated Resource Plan as a levelized value of the 2022-2045 electric avoided costs
	• Factoring in a 5% assumption for admin costs

Distributed Solar PV Achievable Potential

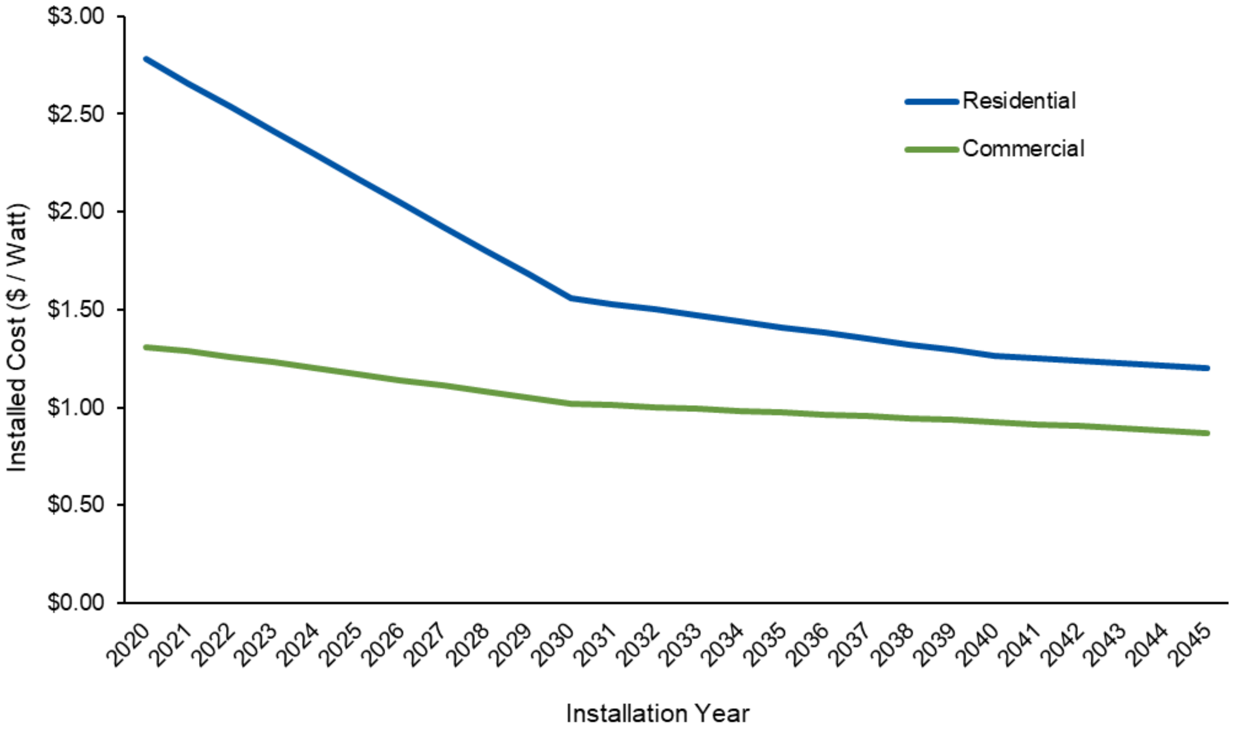


Red line represents PSE program team trend line projection ~ 300MW

The inherent disconnect is that there are no incentives currently available in business as usual

Distributed Solar PV Cost Forecast

Residential and Commercial Installed Cost



Reviewed actual and forecasted costs from Lazard, Wood Mackenzie, EnergySage and National Renewable Energy Laboratory

Residential costs varied between:

- Lazard ($2.88/watt)
- Wood Mackenzie ($2.84/w)
- EnergySage ($2.78/w).
- ➢ Used EnergySage costs and applied NREL cost forecasts.

Commercial costs varied between:

- Lazard ($2.35/w)
- Wood Mackenzie ($1.39/w)
- ➢ Used Wood Mac costs and cost forecasts from NREL.

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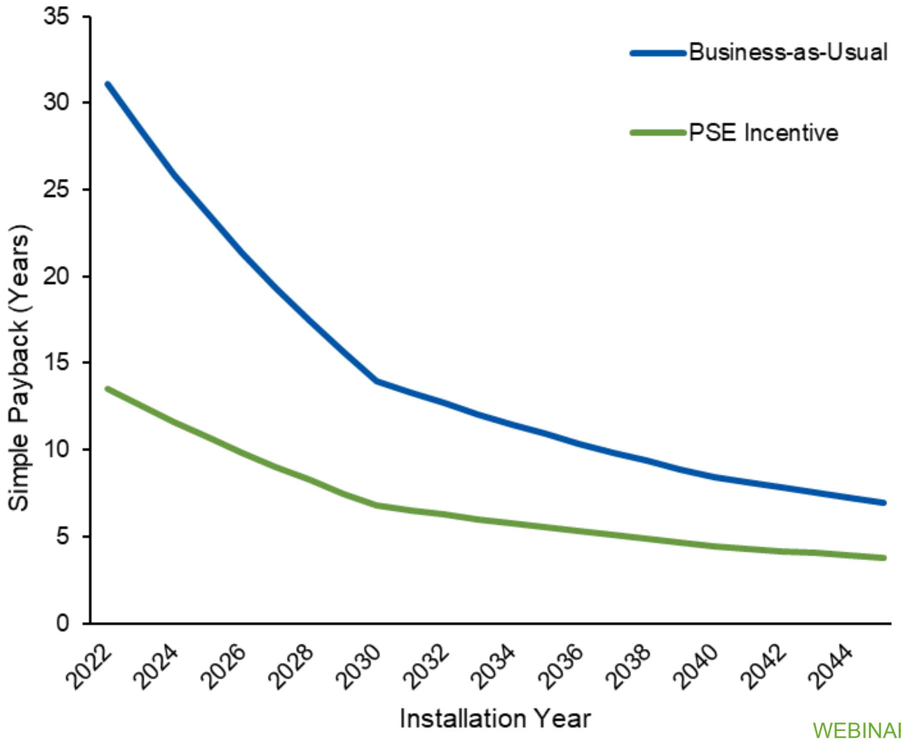
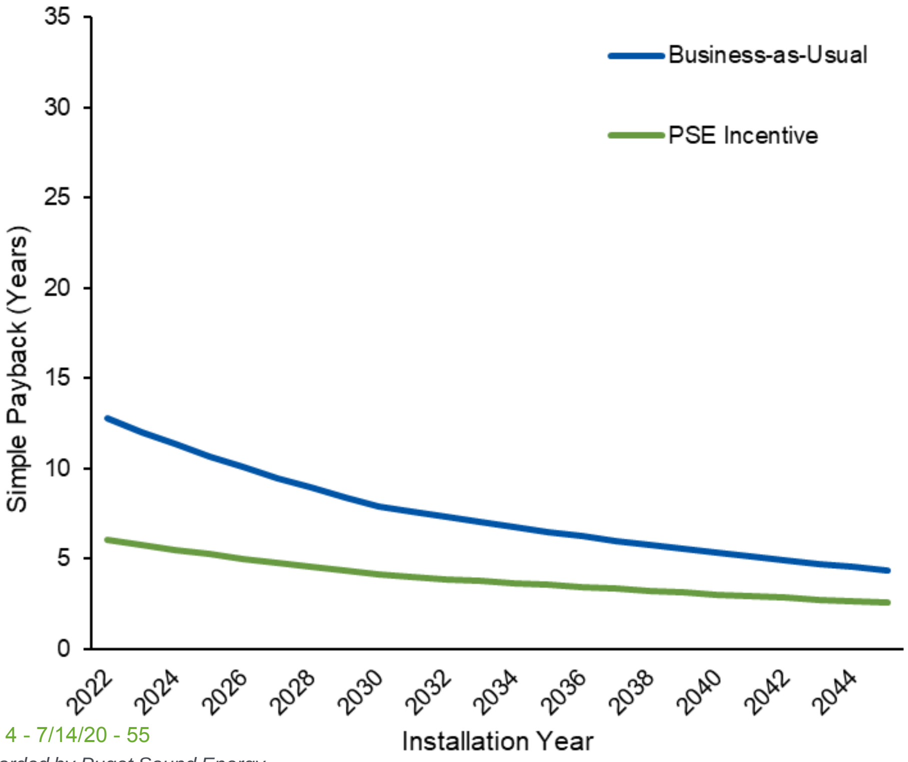
Distributed Solar PV Payback

Residential Payback Periods



Commercial Payback Periods



Combined Heat and Power Potential

Methodology

Combined Heat and Power

Technical Potential

- Non-renewable technologies:
  - Reciprocating engines
  - Microturbines
  - Gas turbines
- Renewable technologies:
  - Industrial biomass
  - Biogas
- Applicability
  - PSE electric customers with any gas service
  - C&I facilities with average monthly demand >= 30kW
  - Assume warehouses with high load are refrigerated – CHP ineligible

Achievable Potential

- ACEEE Study & CHP Install Database
- CHP Favorable States
  - CA: 0.66% per year
  - CT: 0.25% per year
  - MA: 0.27% per year
- Washington (non-favorable):
  - 0.13% per year
- Our Assumption
  - PSE Territory: 0.20% per year
- Higher than calculated value (0.13%) from ACEEE and CHP Install Database due to utility incentives

Achievable Potential Results

Combined Heat and Power

2045 Cumulative Achievable Potential (aMW) at Generator

Technology	2045
Nonrenewable - Natural Gas (Total)	
30–99 kW	1.04
100–199 kW	0.83
200–499 kW	1.10
500–999 kW	0.76
1–4.9 MW	1.41
5.0 MW+	0.96
Renewable - Biomass (Total)	
< 500 kW	0.00
500-999 kW	0.00
1–4.9 MW	0.01
5.0 MW+	0.35
Renewable - Biogas (Total)	
Landfill	0.21
Farm	0.85
Paper Mfg	0.03
Wastewater	0.26
Total CHP	**7.82**

2045 Cumulative System Installations

Technology	2045
Nonrenewable - Natural Gas (Total)	45
Reciprocating Engine	25
Gas Turbine	18
Microturbine	2
Renewables	2
Total CHP	47

Natural Gas Energy Efficiency Potential Results

Natural Gas Energy Efficiency Potential

Achievable Technical Potential

Sector	2023	2031	2041
Cumulative Achievable Potential (MMTherms)			
Residential	15.5	91.5	147.1
Commercial	3.0	18.2	25.0
Industrial	0.3	1.7	1.7
Total	**18.9**	**111.4**	**173.8**
Percent of Baseline Sales			
Residential	2.4%	13.3%	19.4%
Commercial	1.0%	5.4%	6.9%
Industrial	1.4%	7.0%	7.6%
Total	**2.0%**	**10.8%**	**15.5%**

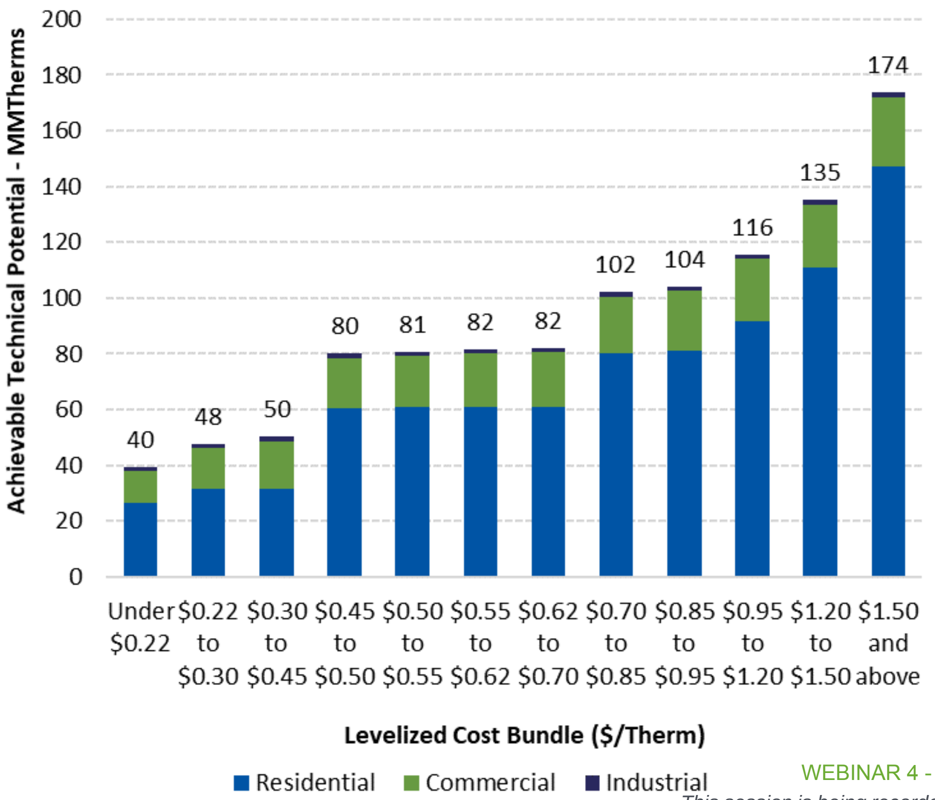
Comparison to 2019 CPA

Natural Gas Achievable Technical Potential

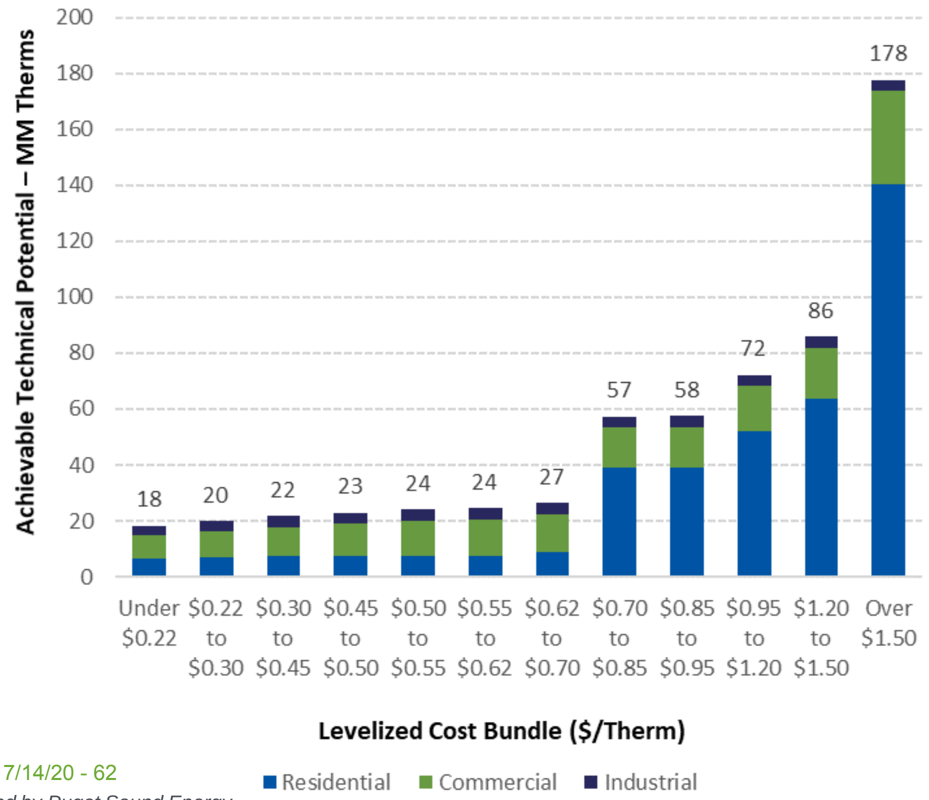
	20-Year Achievable Technical Potential (% of Sales)			Total Achievable Technical Potential (MMTherms)
	Residential	Commercial	Industrial	
Energy Efficiency Potential				
2021 IRP	19%	7%	8%	174
2019 IRP	20%	8%	17%	178

Comparison to the 2019 CPA

2021 CPA Supply Curve



2019 CPA Supply Curve



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Top Residential Gas Measures

Natural Gas Energy Efficiency Potential

Measure Name	Weighted Average Levelized Cost ($/Therm)	Cumulative 10-Year Achievable Technical Potential (MM Therms)	Cumulative 20-Year Achievable Technical Potential (MM Therms)
Furnace	$0.822	12.8	32.1
Whole Home	$0.354	3.3	25.7
Water Heater	$1.612	5.1	16.3
Thermostat	$0.823	11.2	11.2
Window	$19.353	10.5	10.5
Wall Insulation	$1.491	7.3	7.3
Duct Sealing and Insulation	$1.358	7.1	7.1
Duct Sealing	$1.219	5.4	5.4
Home Energy Report	$0.226	5.2	5.2
Thermostatic Restrictor Valve	-$2.087	3.1	3.1
Whole House Sealing	$4.615	3.0	3.0
Floor Insulation	$3.332	2.6	2.6
Showerhead	-$0.797	2.4	2.4
Aerators	-$2.791	2.3	2.3
Solar Water Heater	$22.668	2.3	2.3

- Individual measure applications are grouped into categories in this table
- The top 15 measure categories account for about 93% of the total residential achievable technical potential
- Retrofit measure savings are captured in the first 10 years and therefore have the same values in the 10- and 20-year columns.

Top Commercial Gas Measures

Natural Gas Energy Efficiency Potential

Measure Name	Weighted Average Levelized Cost ($Therm)	Cumulative 10-Year Achievable Technical Potential (MM Therm)	Cumulative 20-Year Achievable Technical Potential (MM Therm)
Gas Rooftop Unit Supply Fan Variable Frequency Drive and Controller	$0.457	3.0	3.0
Furnace (< 225 kBtuh High AFUE 92%)	$0.231	1.0	1.8
Furnace (< 225 kBtuh Premium AFUE 94%)	$0.356	0.8	1.9
Ozone Laundry	$0.260	1.5	1.5
Pool Heat Recovery	$0.107	1.0	1.0
Direct Digital Controls Energy Management	-$11.032	1.5	1.7
Commissioning Retro	$7.239	1.5	1.5
Boiler (300 to 2500 kBtuh AFUE 95%)	$1.048	0.4	1.1
Clothes Washer	-$16.976	0.5	0.9
Boiler (300 to 2500 kBtuh AFUE 85%)	$0.480	0.3	0.8
Demand Controlled Ventilation Kitchen	$0.881	0.6	0.6
Oven Double Rack	$0.202	0.2	0.6
Gas Water Heater 94% Efficient	$0.663	0.2	0.5
Boiler 300 to 2500 kBtuh AFUE 79%	$0.950	0.2	0.6
Convection Oven	$0.044	0.2	0.5

- Individual measure applications are grouped into categories in this table
- The top 15 measure categories account for about 72% of the total commercial gas achievable technical potential
- Retrofit measure savings are captured in the first 10 years and therefore have the same values in the 10- and 20-year columns.

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Top Industrial Measures

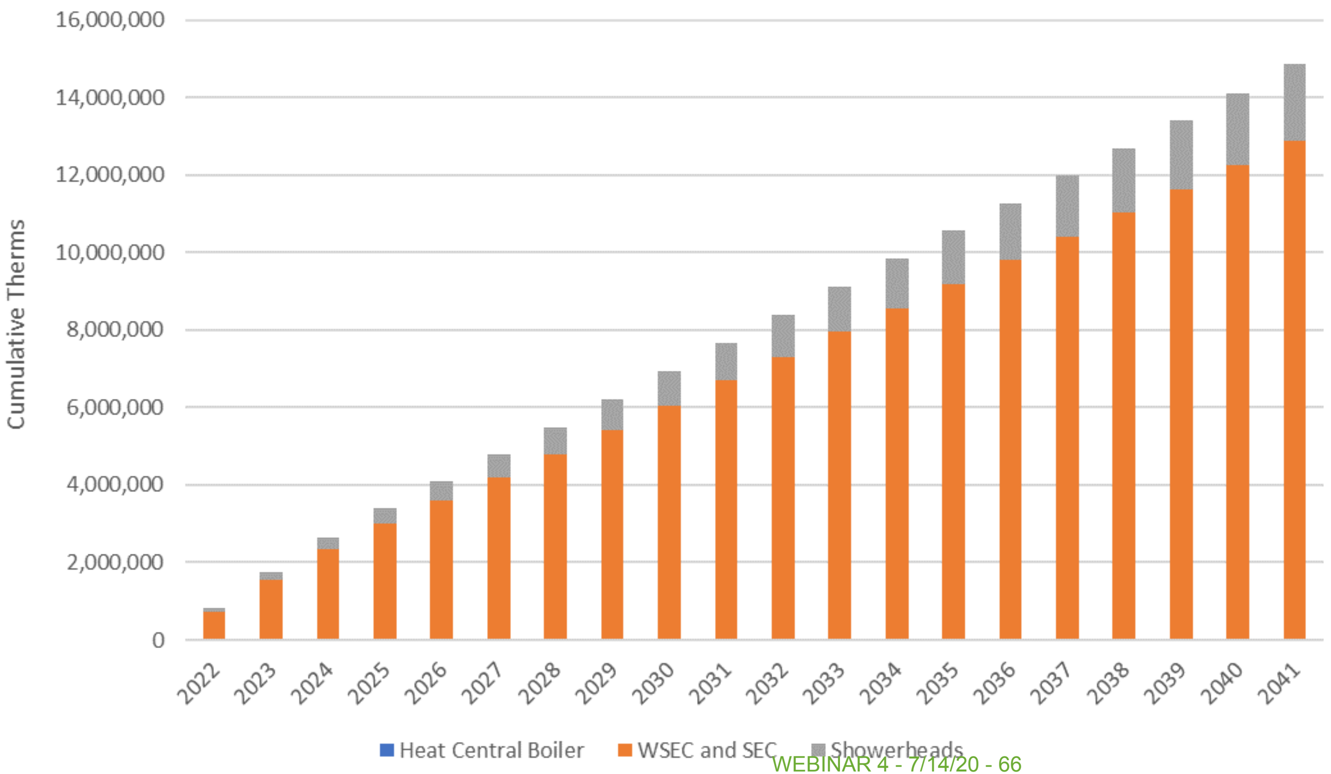
Industrial Natural Gas Energy Efficiency

Measure Name	Weighted Average Levelized Cost ($/Therm)	Cumulative 10-Year Achievable Technical Potential (Therm)	Cumulative 20-Year Achievable Technical Potential (Therm)
Equipment Upgrade - Replace Existing HVAC Unit With High Efficiency Model	$0.017	196,537	196,537
Process Improvements To Reduce Energy Requirements	$0.014	174,386	174,386
Improve Combustion Control Capability And Air Flow	-$0.027	138,408	138,408
HVAC Equipment Scheduling Improvements - HVAC Controls, Timers Or Thermostats	$0.070	114,484	114,484
Install Or Repair Insulation On Condensate Lines And Optimize Condensate	-$0.017	110,464	110,464
Optimize Ventilation System	$0.343	93,553	93,553
Waste Heat From Hot Flue Gases To Preheat	$0.015	86,669	86,669
Heat Recovery And Waste Heat For Process	$0.018	75,334	75,334
Equipment Upgrade - Boiler Replacement	$0.081	71,916	71,916
Optimize Heating System To Improve Burner Efficiency	-$0.054	71,900	71,900
Building Envelope Infiltration Improvements	-$0.015	64,671	64,671
Building Envelope Insulation and Window/Door Improvements	$0.289	62,980	62,980
Thermal Systems Reduce Infiltration; Isolate Hot Or Cold Equipment	$0.018	59,471	59,471
Replace Steam Traps	-$0.016	58,755	58,755
Repair And Eliminate Steam Leaks	-$0.007	53,159	53,159

- Individual measure applications are grouped into categories in this table
- The top 15 measure categories account for about 72% of the total industrial gas achievable technical potential
- Retrofit measure savings are captured in the first 10 years and therefore have the same values in the 10- and 20-year columns.

Natural Gas Codes and Standards Savings

Natural Gas Energy Efficiency Potential



- Estimated the impact of the Washington State Energy Code (WSEC), the Seattle Energy Code (SEC) and federal and state equipment standards
- WSEC accounts for 87% of codes and standards savings (13 MM therms by 2041)
- The overall impact of the boiler standard is relatively small

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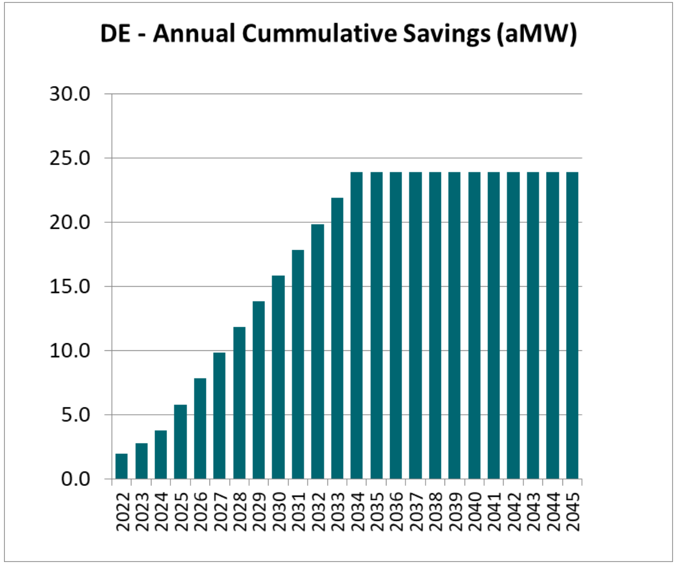
Distribution Efficiency

Distribution Efficiency Potential

- Alignment with Automated Metering Infrastructure (AMI) and Advanced Distribution Management Systems (ADMS) business cases
- Schedule feasibility and infrastructure requirements when implementing Volt-VAR Optimization (VVO)

By the numbers:

- 153 Substations total
- 17 complete by end of 2020
- Remaining 136 – 2019 IRP study period
- 2022 onwards incorporate controls to maintain stability in system
    - Shift from Line Drop Compensation (LDC) to Volt-VAR Optimization (VVO)



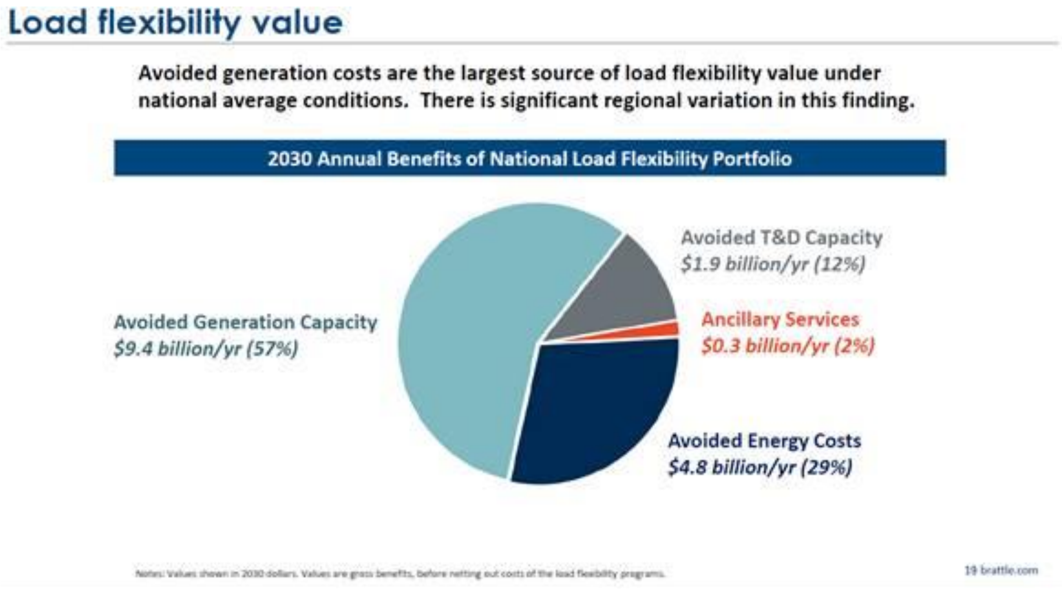
CPA input to the IRP analysis

- End use load shapes applied to measure level and measures and sectors are aggregated into levelized price points on the conservation supply curve:
  - Energy efficiency (programmatic and codes & standards), combined heat and power, and distribution efficiency are hourly inputs
  - Conservation bundles are 20 year vector (24 year electric), available in year one of study
- Distributed solar pV – hourly input, market bundle, no cost in IRP
- Similarly, gas conservation supply curve is input on a monthly basis by sector.
- The benefit of SCGHG to DSR is applied in the portfolio models

Additional Data:

- The CPA will also create disaggregated gas and electric bundles by zip code to inform Delivery System Planning

Demand Response in the 2021 IRP



Demand response is a capacity resource:

- Each program group's ELCC is determined in resource adequacy model: nameplate capacity is converted to peak contribution values → decrement to capacity in the portfolio model
- Demand response programs are also input thru the flexibility model to obtain their flexibility benefits value → added to the value of DR in the portfolio model
- Portfolio model can optimize by program capacity and timing of the program start year

PUGET SOUND ENERGY

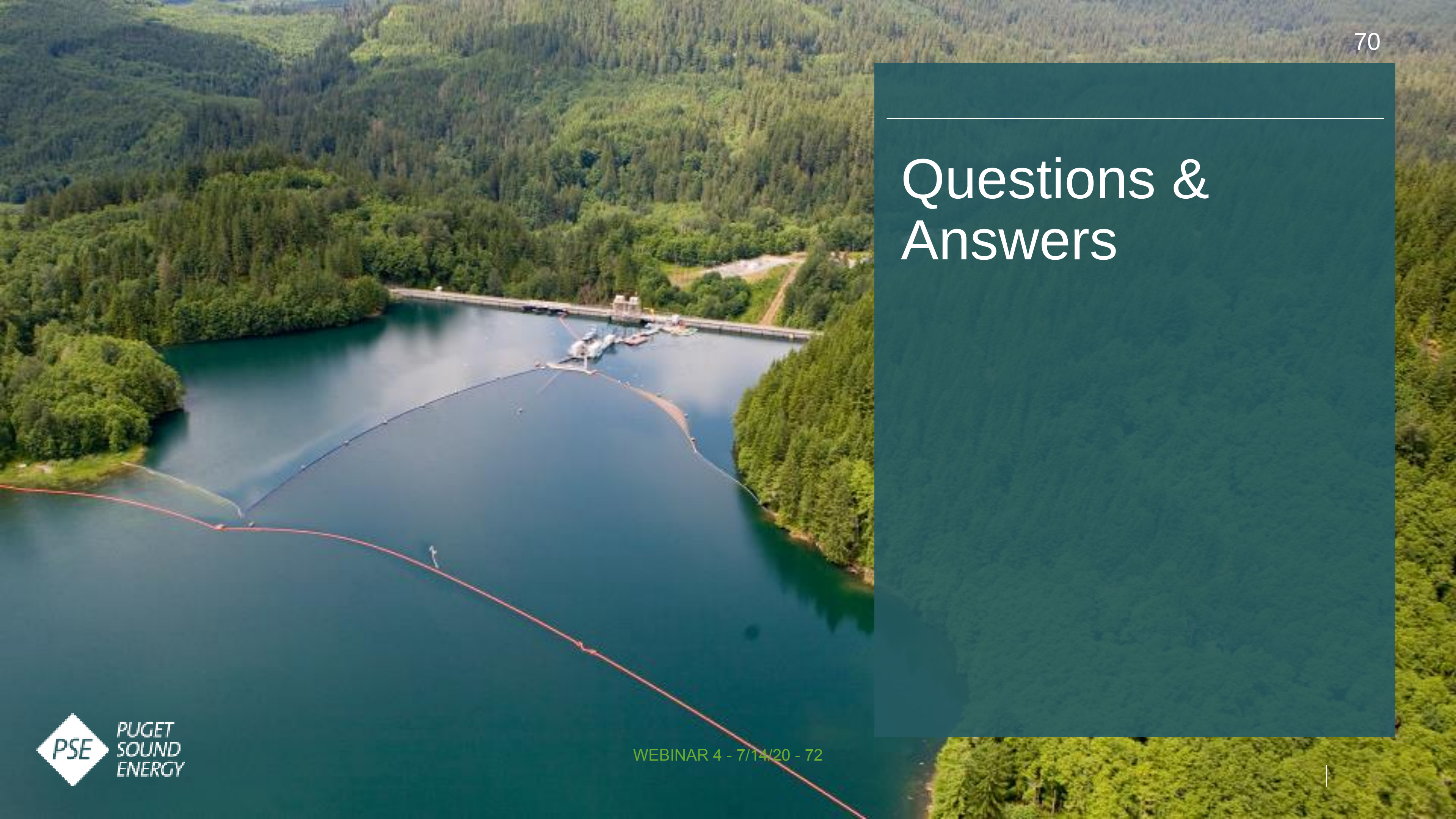
Stakeholder Feedback on DSR Sensitivities

- The purpose of the sensitivity is to test different resources in PSE’s portfolio.
- We have done sensitivities in the past IRPs:
  - Alternate discount rate
  - Extended DSR

We are asking for **stakeholder input on** what **DSR sensitivities** to consider for the 2021 IRP. We already have a couple to start.

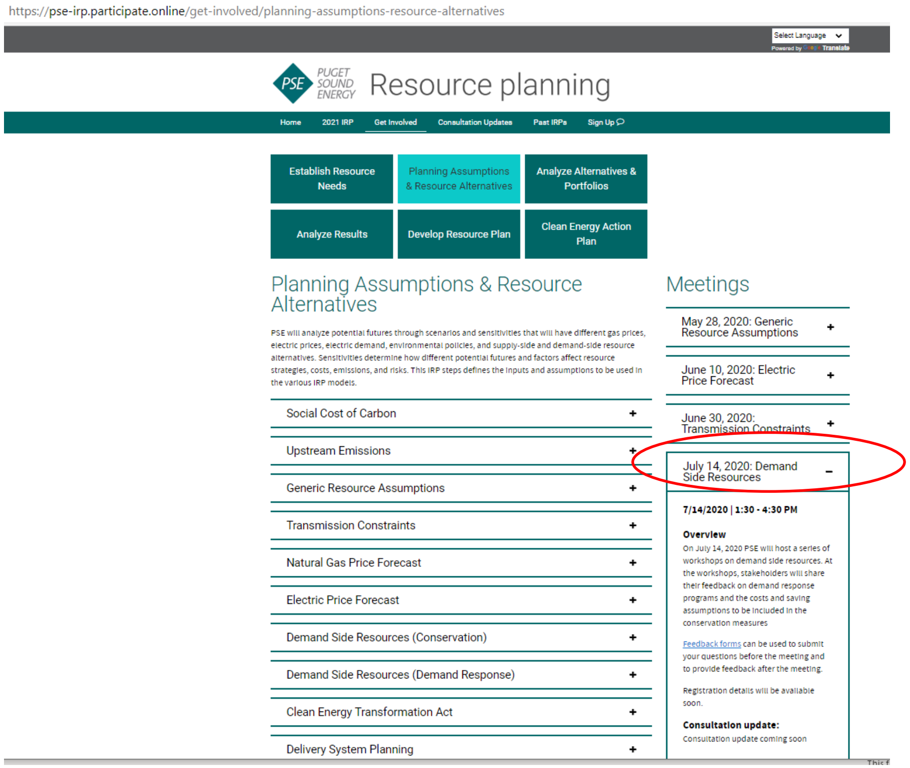
Proposed sensitivities:

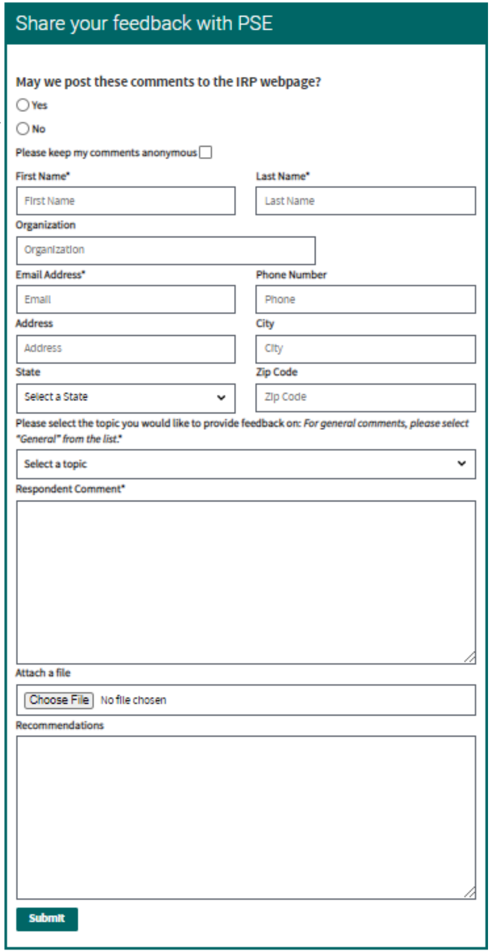
1. Distributed Solar pV – with PSE incentive
2. Distributed Solar pV – with PSE ownership.
3. **More??**



Questions & Answers

Feedback Form





Feedback Form

- An important way to share your input
- Available on the website 24/7
- Comments, questions and data can be submitted throughout the year, but timely feedback supports the technical process
- Please submit your Feedback Form within a week of the meeting topic

Feedback Form → **Feedback Report** → **Consultation Update**

Next steps

- Submit Feedback Form to PSE by **July 21, 2020**
- A recording and the chat from today's webinar will be posted to the website **tomorrow**
- PSE will compile all the feedback in the Feedback Report and post all the questions by **July 28, 2020**
- The Consultation Update will be shared on **August 4**

Details of upcoming meetings can be found at pse.com/irp

Date	Topic
July 21, 1:30 – 4:30 pm	Social Cost of Carbon
August 11, 8:30 am – 12:30 pm	Portfolio sensitivities development (electric & gas) CETA assumptions Distributed energy resources
September 1, 1:00 – 5:00 pm	Demand forecast (electric & gas) Resource adequacy Resource need: peak capacity, energy & renewable energy need
October 20, 1:30 – 4:30 pm	Portfolio sensitivities draft results Flexibility analysis
November 4, 1:00 – 4:30 pm	Clean Energy Action Plan 10-year Distribution & Transmission Plan
December 9, 1:00 – 4:30 pm	Portfolio draft results Stochastic analysis Wholesale market risk

Thank you for your attention and input.

Please complete your Feedback Form by July 21, 2020

We look forward to your attendance at PSE’s next public participation webinar:

Social Cost of Carbon

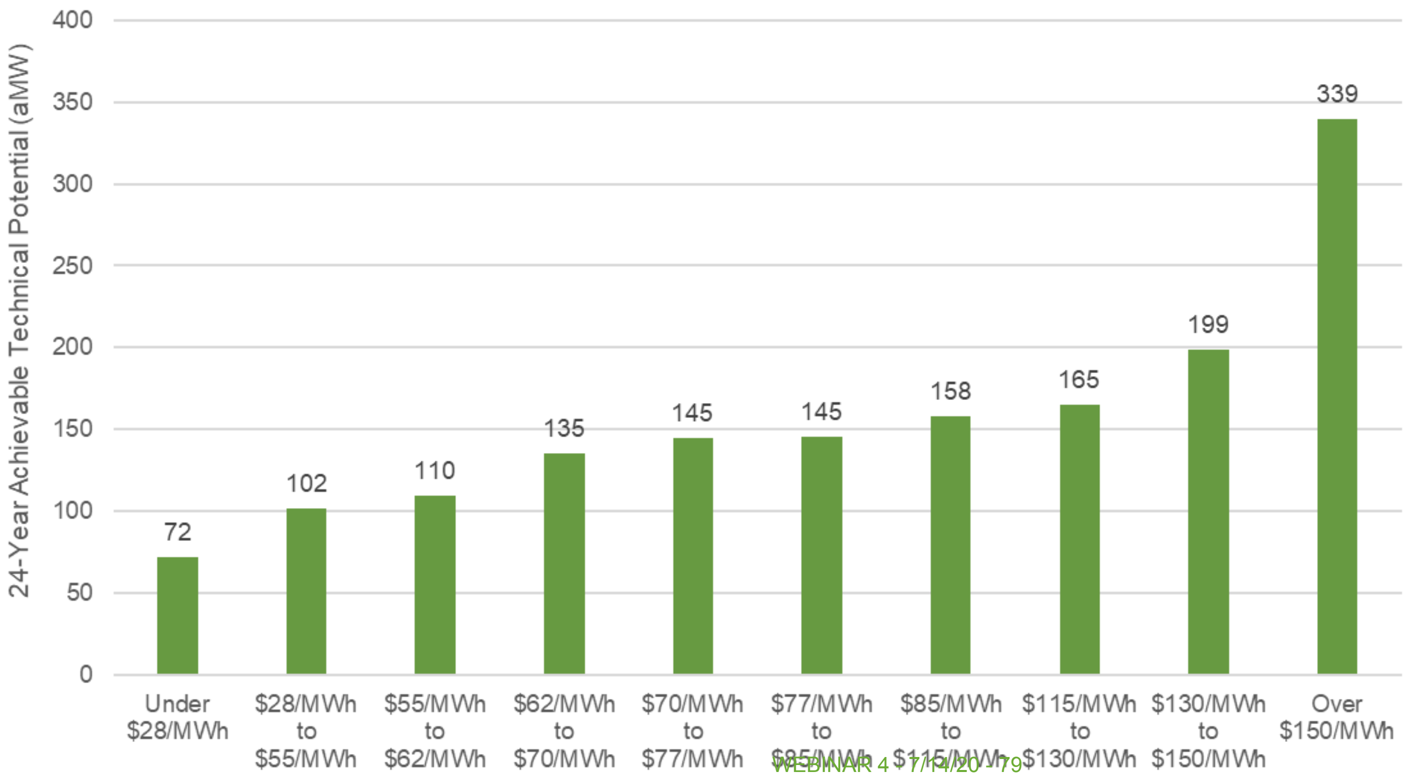
July 21, 2020

Appendix

PUGET SOUND ENERGY

Residential Electric Potential Summary

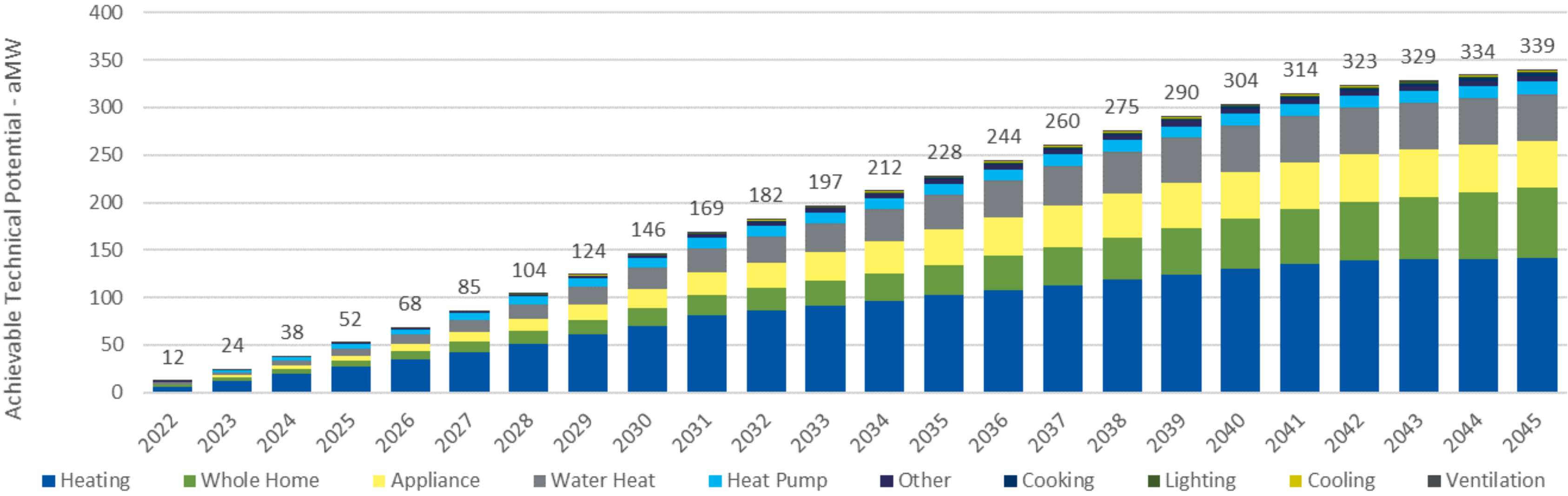
Residential Supply Curve

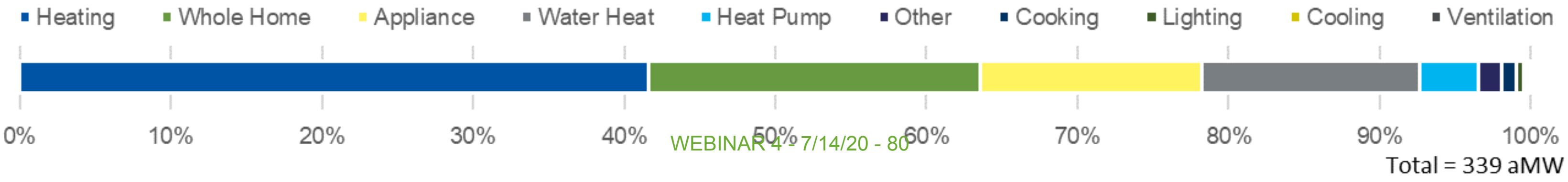


- Cumulative, 24-Year Achievable Technical Potential is 339 aMW
- Residential accounts for 57% of the total, 24-year achievable technical potential
- About 21% of residential electric potential costs less than $28/MWh, levelized
- About 59% (199 aMW) costs less than $1500/MWh, levelized

Residential Electric Potential Summary

Savings by End Use





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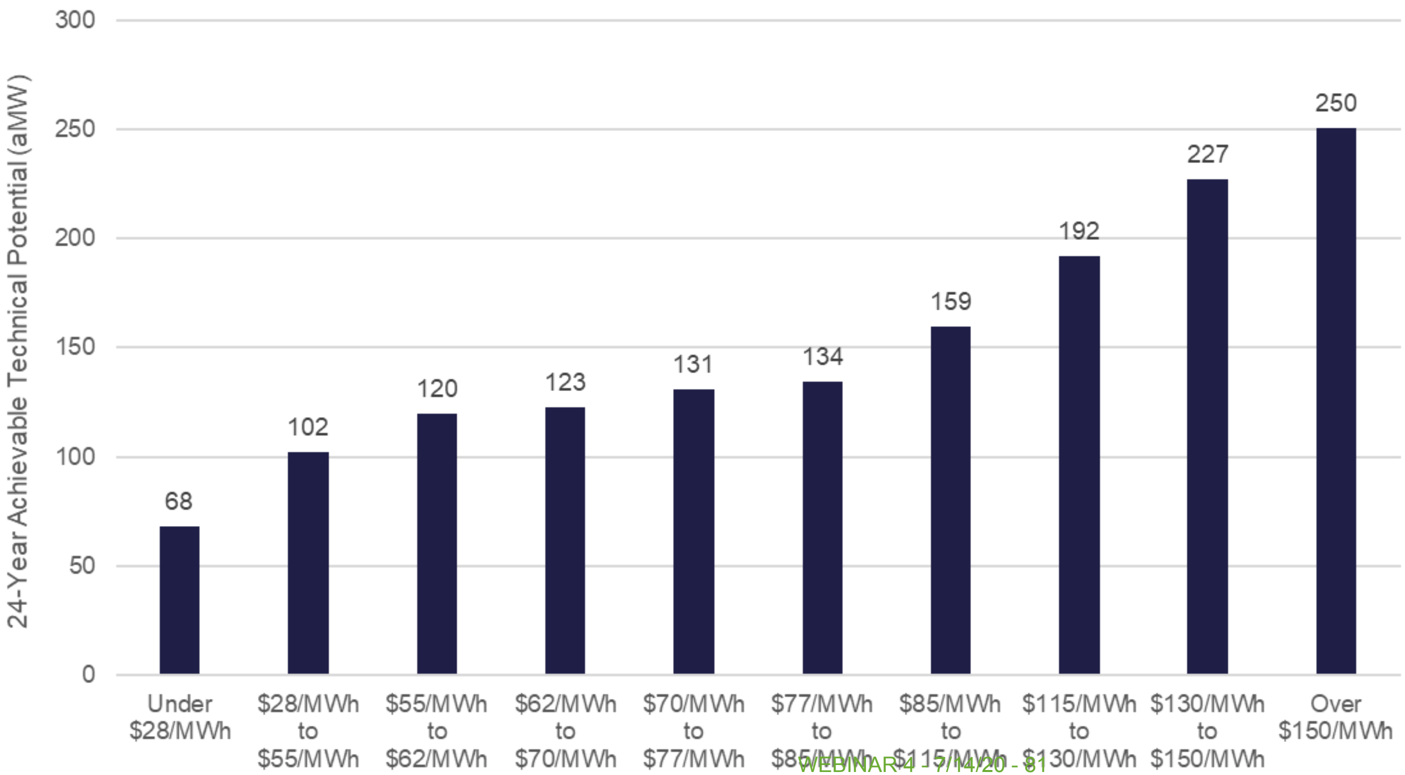
Commercial Electric Potential Summary

Commercial Electric Supply Curve



- Cumulative, 24-Year Achievable Technical Potential is 250 aMW
- Commercial accounts for 42% of the total, 24-year achievable technical potential
- About 27% of commercial electric potential costs less than $28/MWh, levelized
- About 91% (199 aMW) costs less than $150/MWh, levelized

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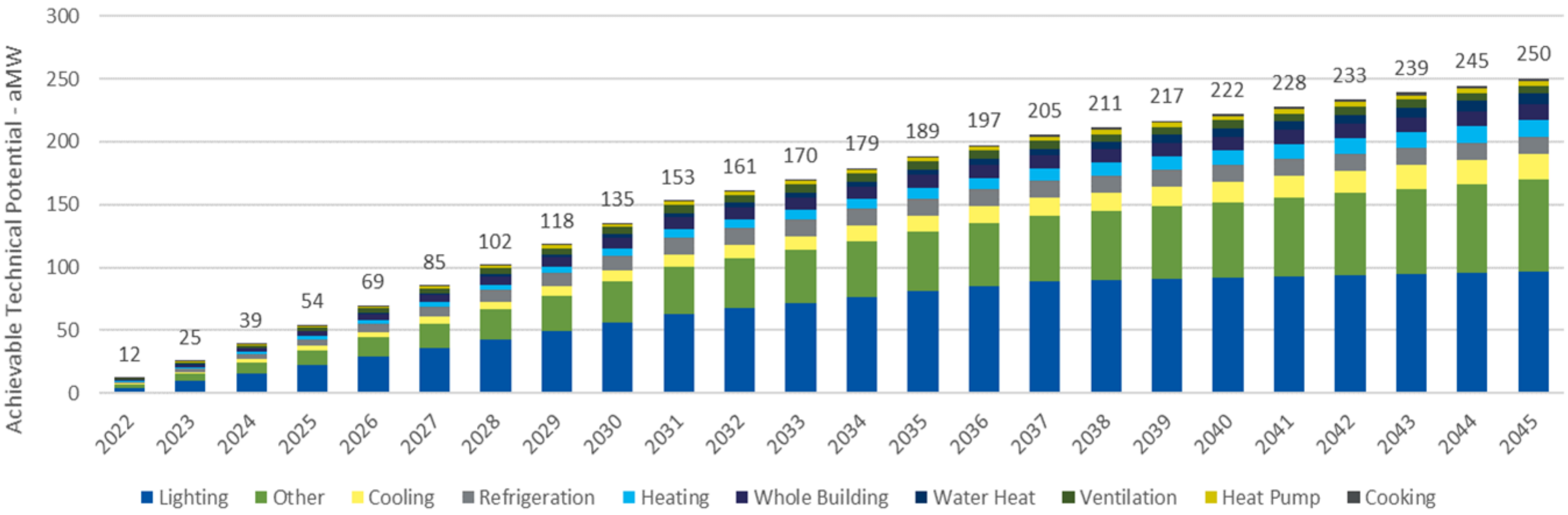
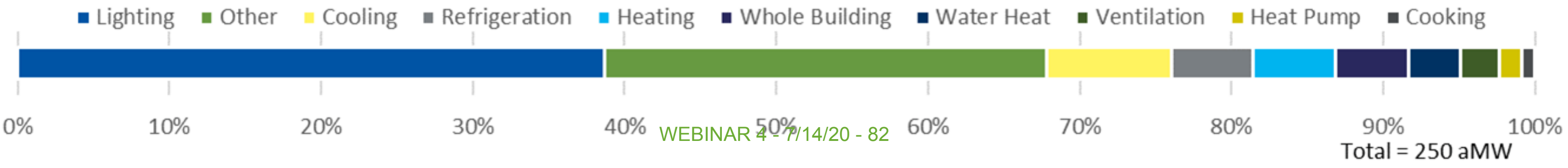
Commercial Electric Potential Summary

Savings by End Use





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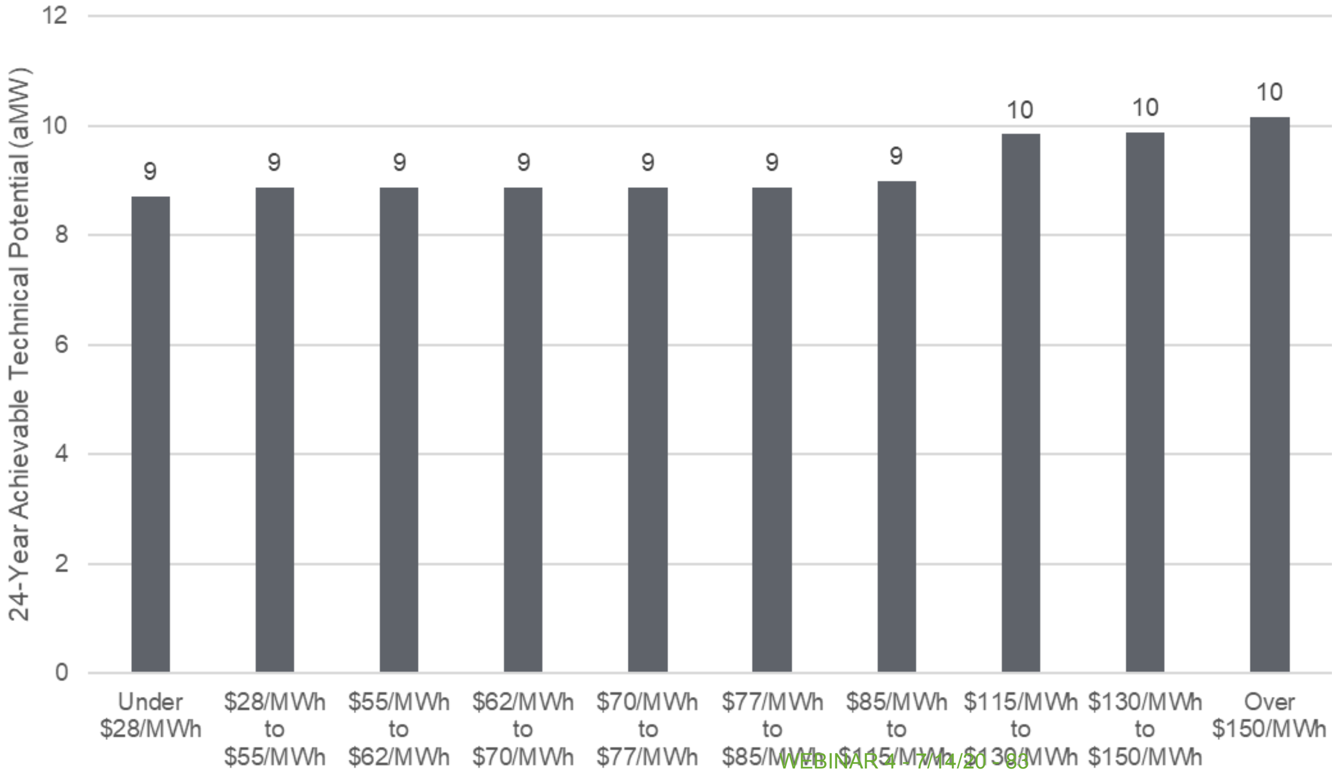
Industrial Electric Potential Summary

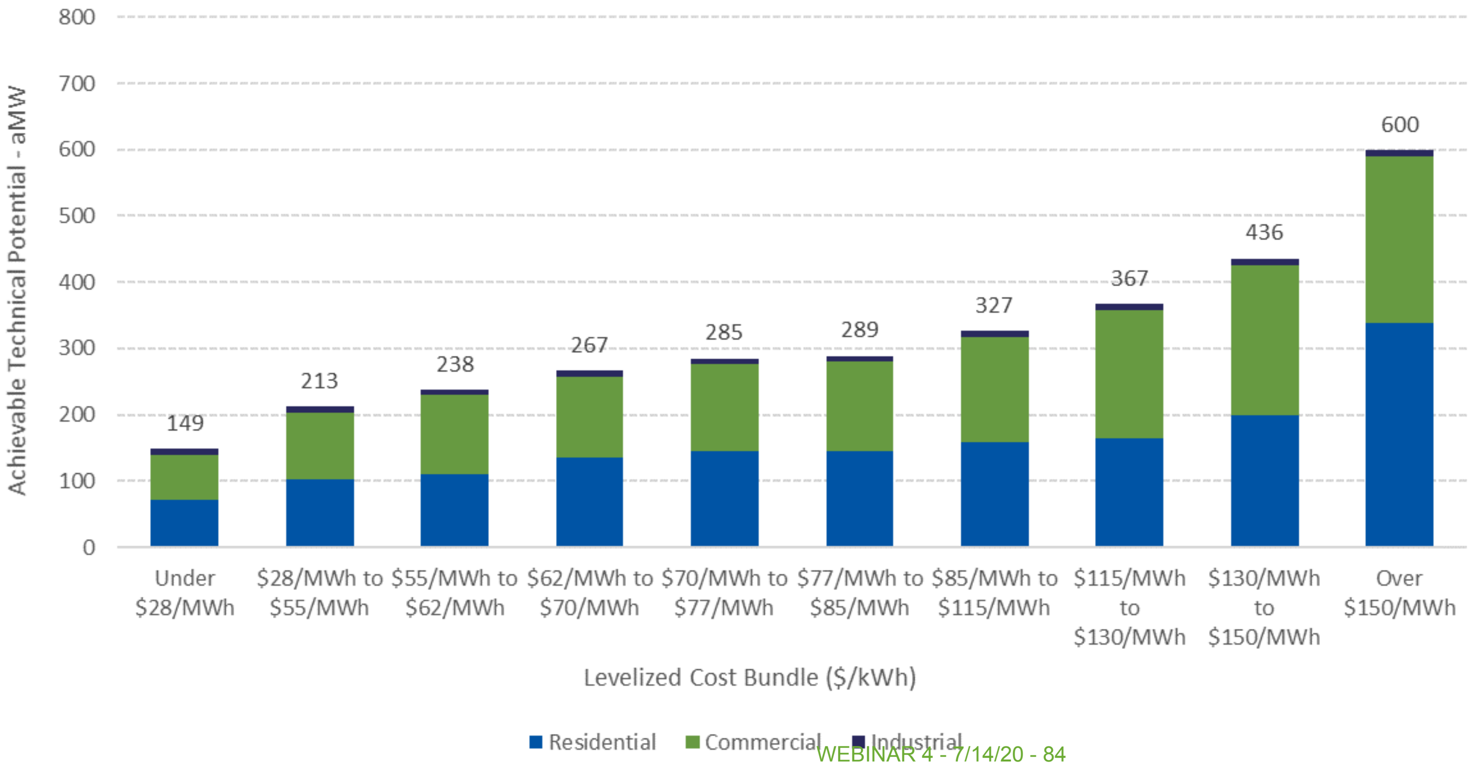
Industrial Supply Curve



- Cumulative, 24-Year Achievable Technical Potential is 10 aMW
- Industrial accounts for 2% of the total, 24-year achievable technical potential
- About 86% of commercial electric potential costs less than $28/MWh, levelized
- About 97% (199 aMW) costs less than $150/MWh, levelized

Electric Supply Curve

Cumulative 24-Year Achievable Technical Potential by Levelized Cost Bundle



- 25% of the 24-year cumulative achievable technical potential costs less than $28/MWh, levelized
- 73% of the 24-year cumulative achievable technical potential costs less than $150/MWh, levelized

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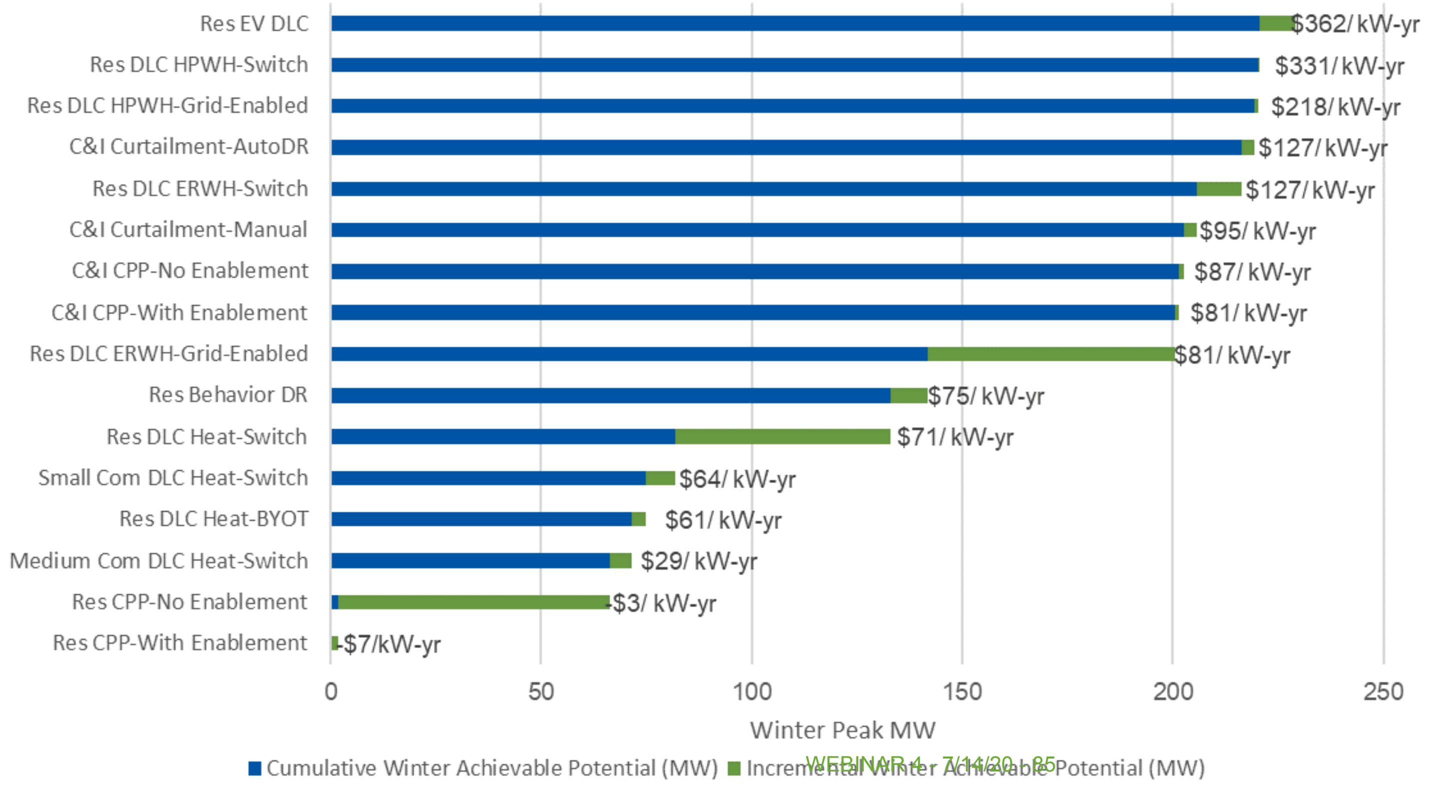
Demand Response Supply Curve

24-Year Demand Response Potential and Levelized Costs



- The total, cumulative 24-year demand response achievable technical potential equals approximately 4.6% of the 2045 forecast electric system peak
- About 90% of the 24-year cumulative achievable technical potential costs less than $100/kW-year, levelized

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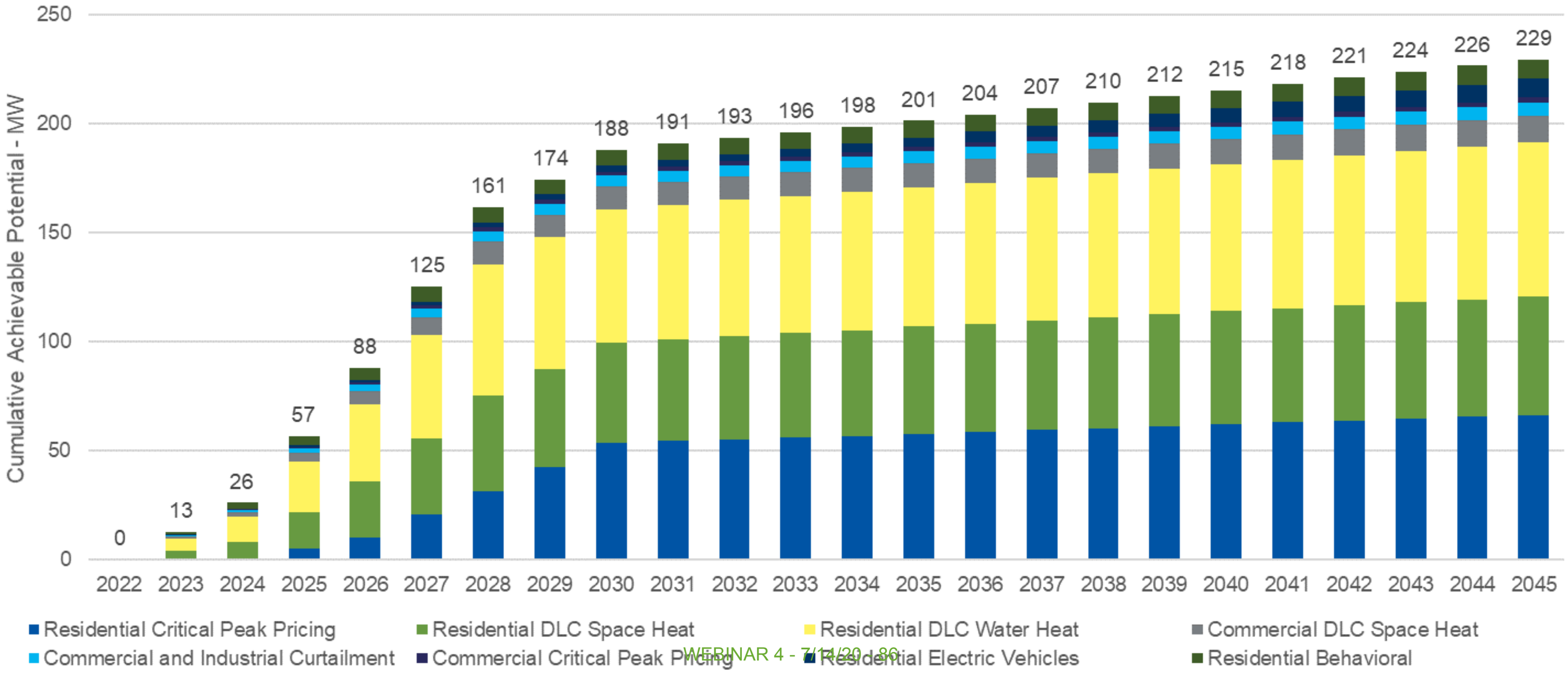
Overview of Results

Total 24-Year Demand Response Potential, by Year and Product Group



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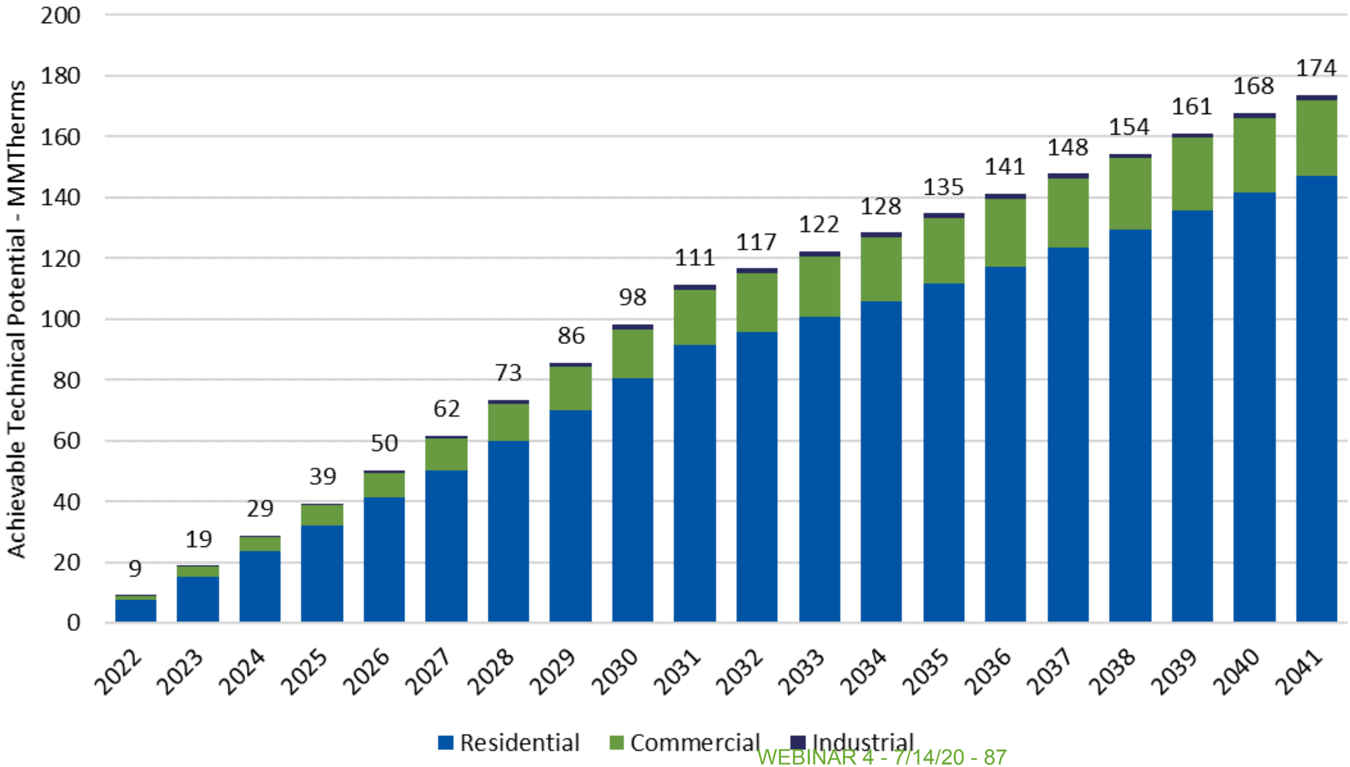
Natural Gas Conservation Forecast

Cumulative Achievable Technical Potential Forecast



- Discretionary measures receive a flat 10-year ramp rate
- Lost opportunity measures (new construction and natural replacement) receive 2021 Plan ramp rates
- Cadmus adjusted some ramp rates to match program activity and expectations

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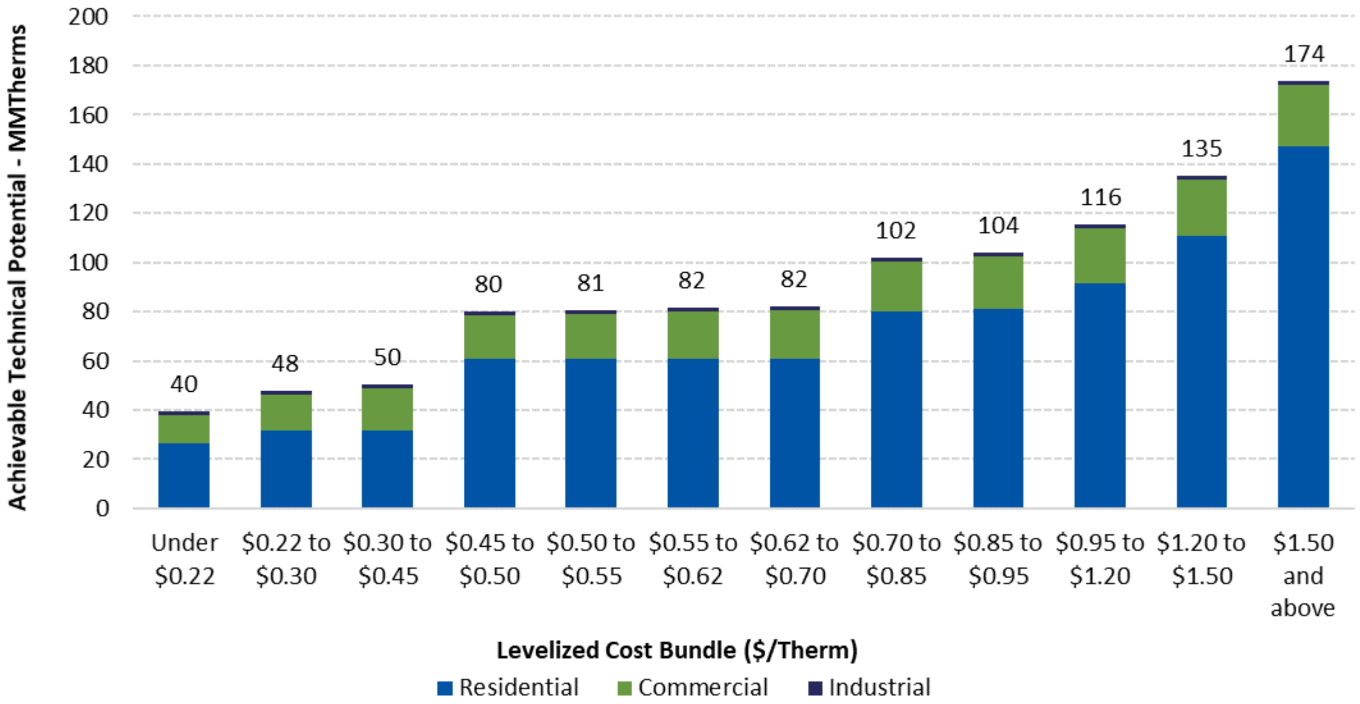
Natural Gas Supply Curve

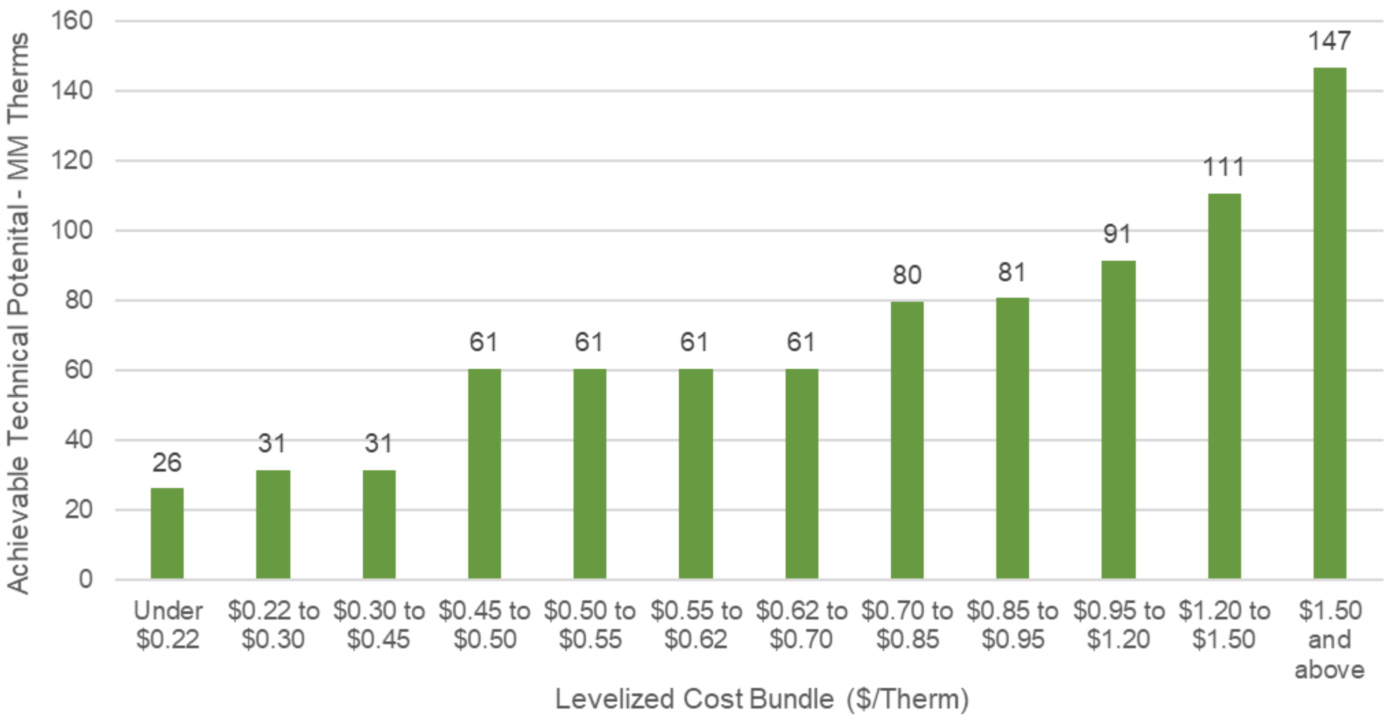
Cumulative 20-Year Achievable Technical Potential by Levelized Cost Bundle



- About 23% of the 20-year cumulative achievable technical potential costs less than $0.22/therm, levelized
- About 47% of the 20-year cumulative achievable technical potential costs less than $0.70/therm, levelized

Residential Gas Potential Summary

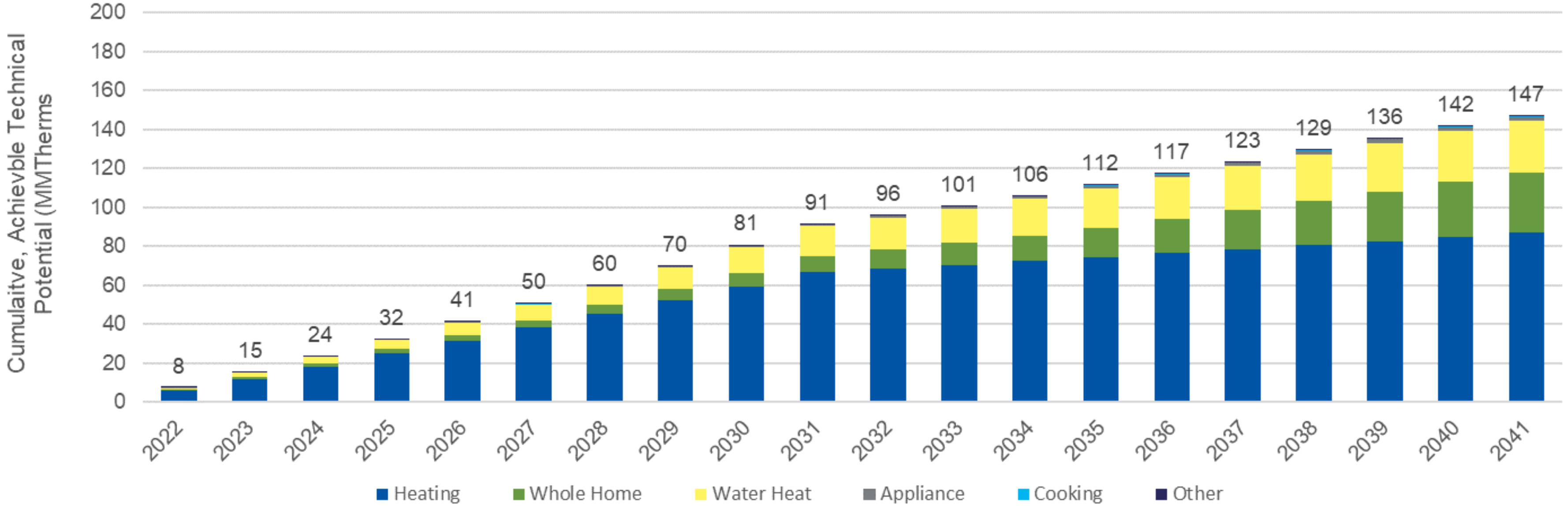
Residential Gas Supply Curve

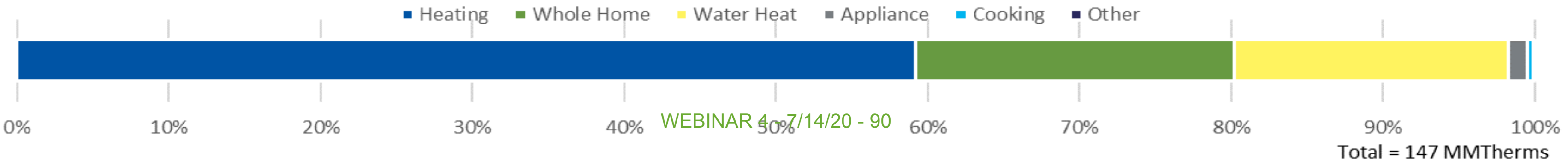


- Cumulative, 20-Year achievable technical potential is 147 million therms
- Residential accounts for 85% of the total, 20-year achievable technical potential
- About 18% of residential gas potential costs less than $0.22/therm, levelized
- About 41% (61 MM therms) costs less than $0.70/therm, levelized

Residential Gas Potential Summary

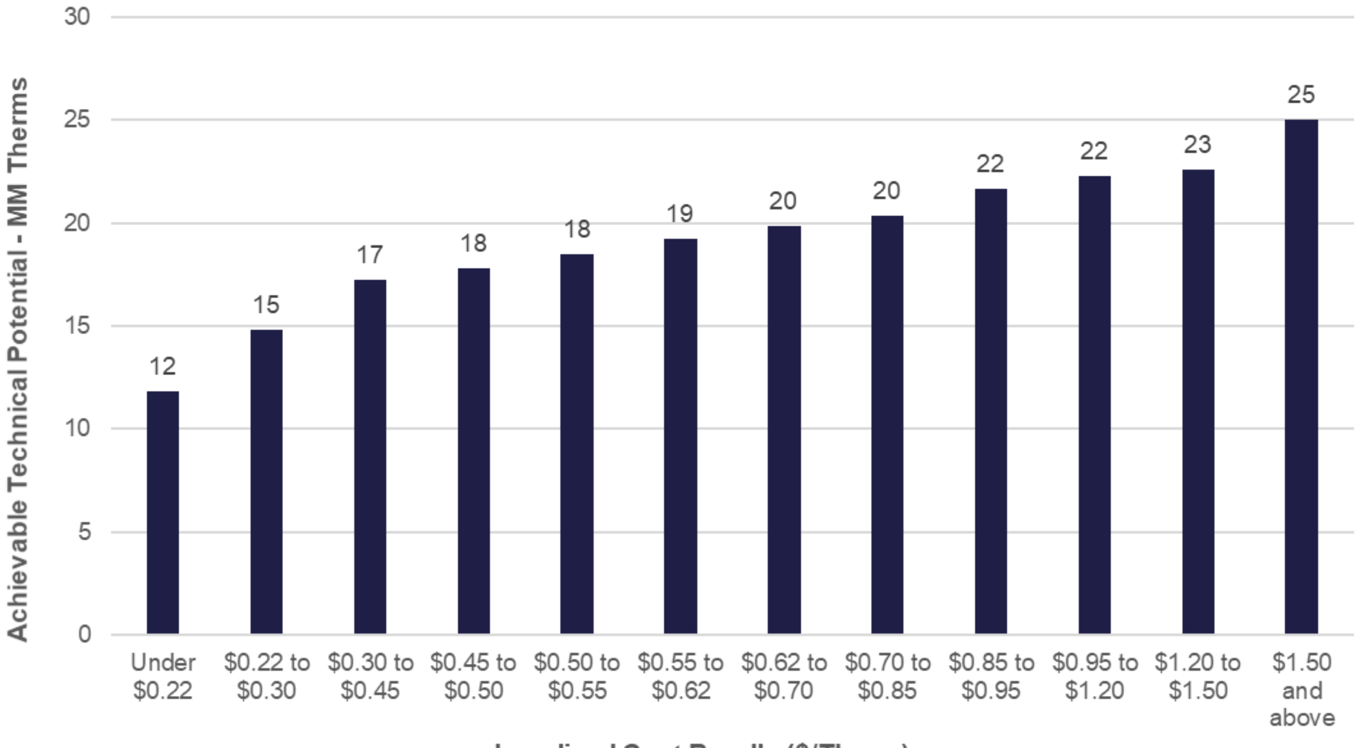
Natural Gas Energy Efficiency Potential – by End Use





Commercial Gas Potential Summary

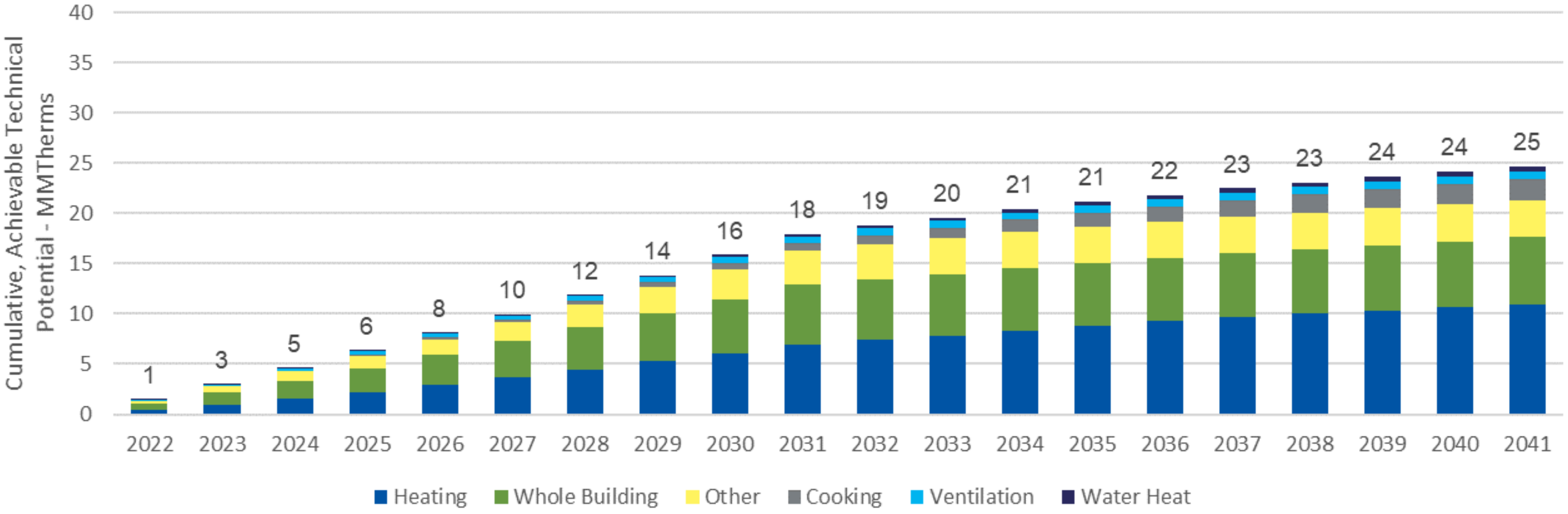
Commercial Gas Supply Curve

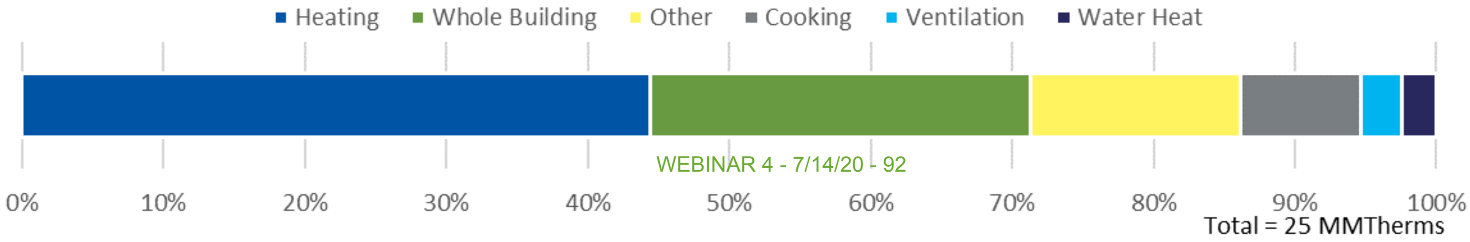


- Cumulative, 20-Year achievable technical potential is 25 million therms
- Commercial accounts for 14% of the total, 20-year achievable technical potential
- About 47% (12 MM therms) of commercial gas potential costs less than $0.22/therm, levelized
- About 79% (20 MM therms) costs less than $0.70/therm, levelized

Commercial Gas Potential Summary

Natural Gas Energy Efficiency Potential – by End Use





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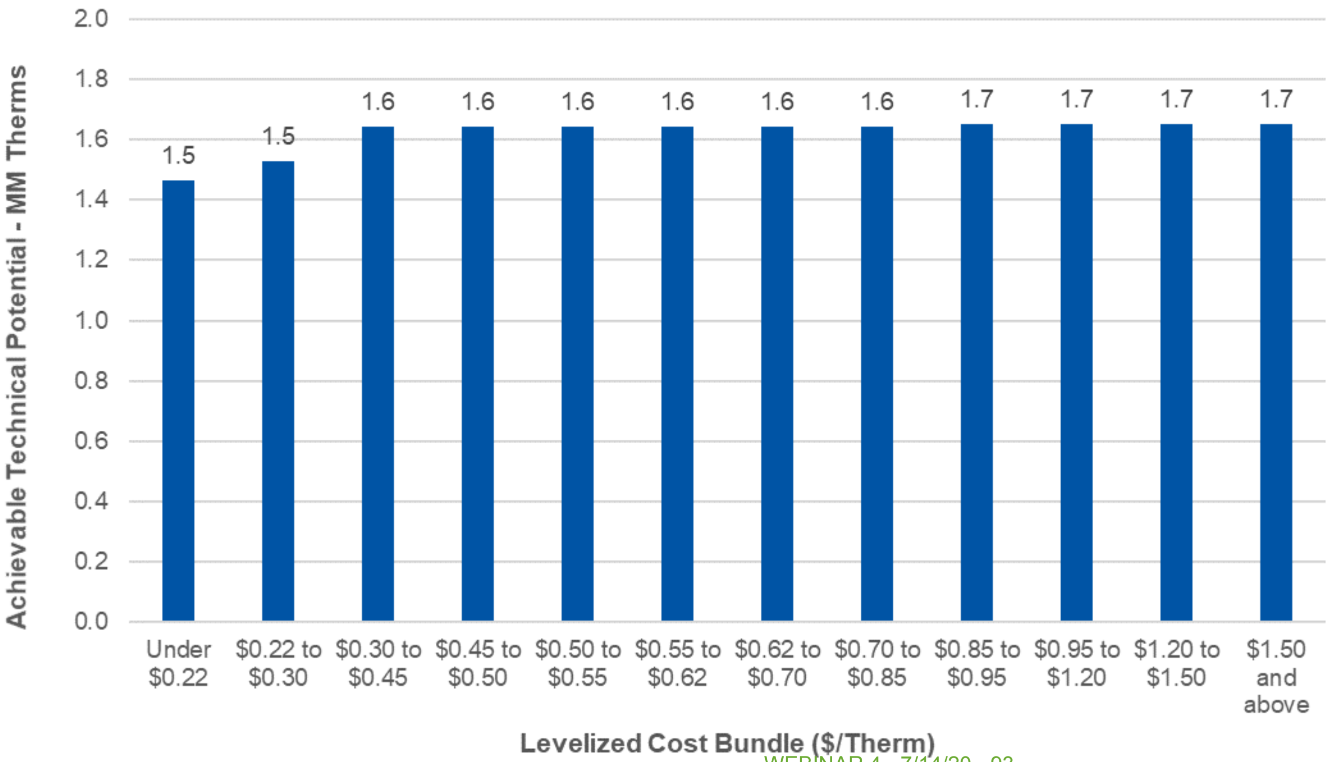
Industrial Gas Potential Summary

Industrial Gas Supply Curve



- Cumulative, 20-Year achievable technical potential is about 1.7 million therms
- Industrial accounts for 1% of the total, 20-year gas achievable technical potential
- About 89% (1.5 MM therms) of commercial gas potential costs less than $0.22/therm, levelized

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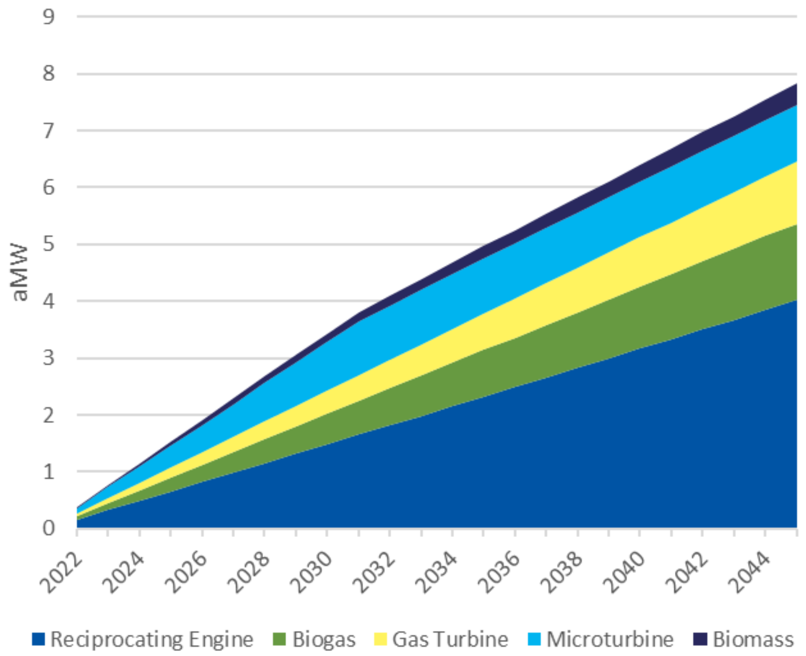
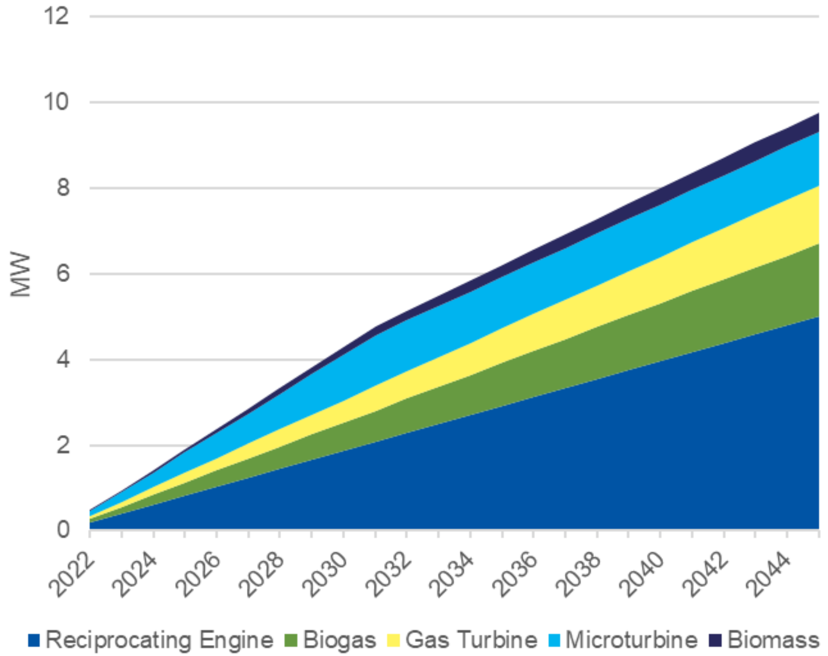
Achievable Potential Results

2045 Achievable Potential – Energy

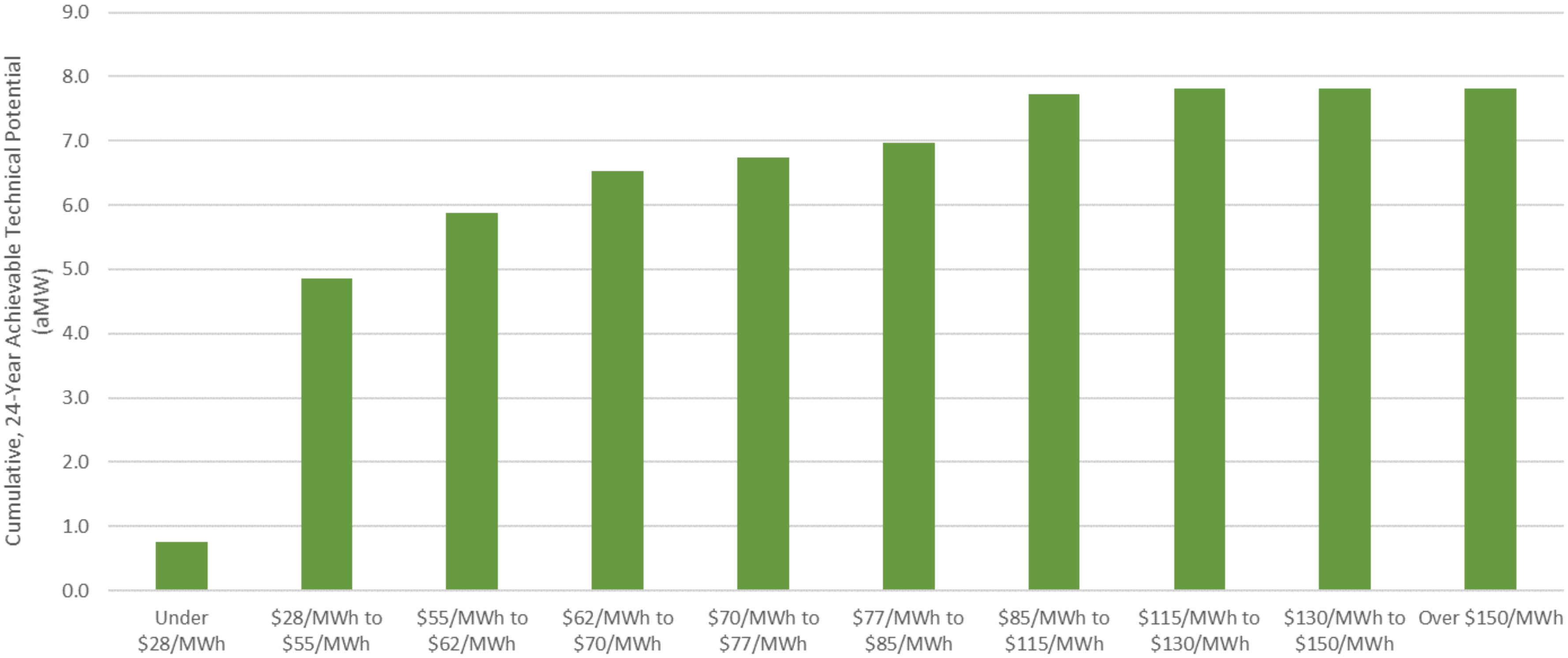


2045 Achievable Potential – Capacity



Achievable Potential Results

Supply Curve



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Solar PV Key Data Inputs

Technical Potential

Total Available Roof Area	• Building square footage (RBSA & CBSA) • Number of floors • Customer counts
Adjusted Available Roof Area	• Adjustment factor from LIDAR or other data source • Accounts for orientation, shading, and obstructions • International Fire Code Article 605.11.3
Module Power Density	• Derived from regional datasets • Forecast future model power density from International Technology Roadmap for Photovoltaic
Electricity Generation	• Capacity factor value • PSE-specific data
Annual Production Degradation	• Applied annually • 2012 NREL study

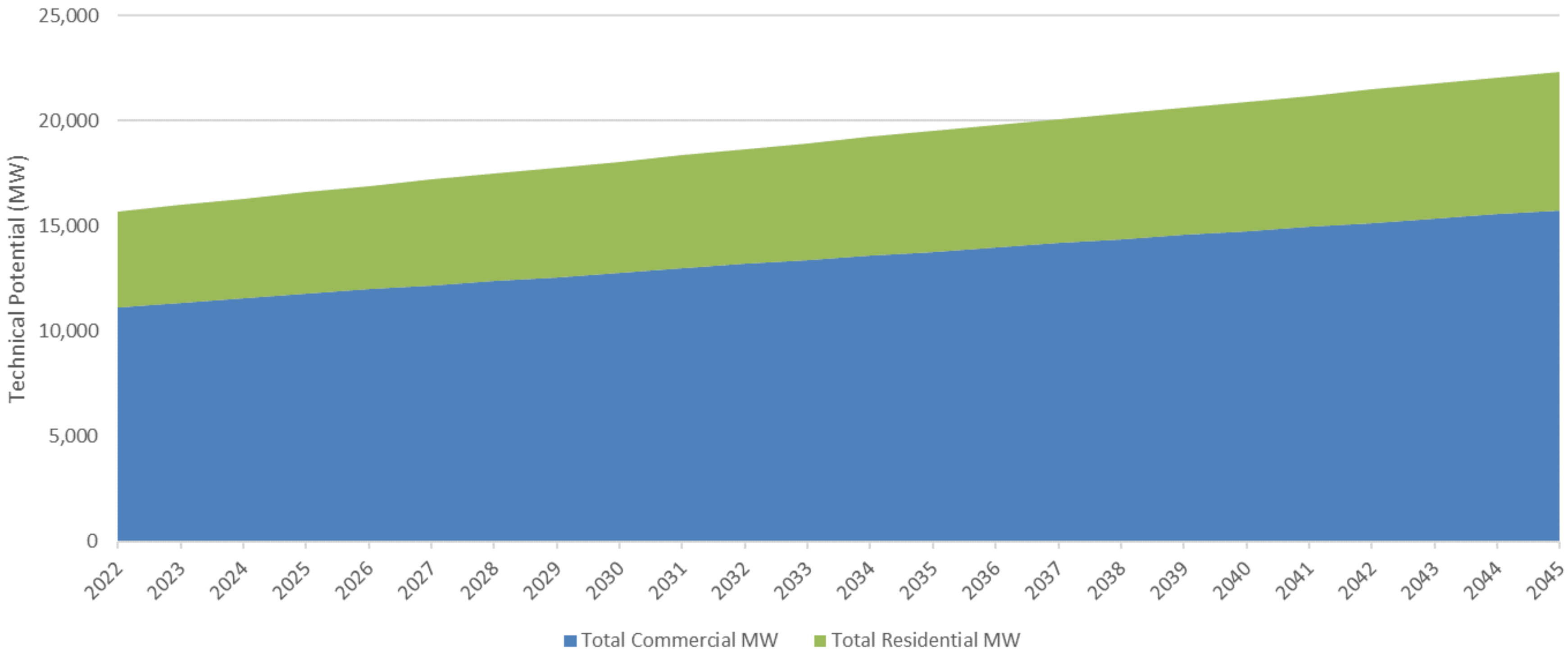
Solar PV Key Data Inputs

Achievable Potential

Electric Retail Rates	• PSE electric res and com general service rates • Rate escalation factors calculated from historical NREL data • Customer counts
Solar System Costs	• Regional installation data • Other sources include Wood Mackenzie and EnergySage • Future cost estimates based on data collected from NREL
Average System Capacity	• Derived from PSE-specific data
Achievable Potential Scenarios	• Business as usual • Utility incentive scenario
Cash Flow Calculation	• Projected retail rates, system install costs, and federal and state incentives • Derive a simple payback period for both res and com for each year

Solar PV Technical Potential

Residential and Commercial Sectors



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Achievable Potential Assumptions

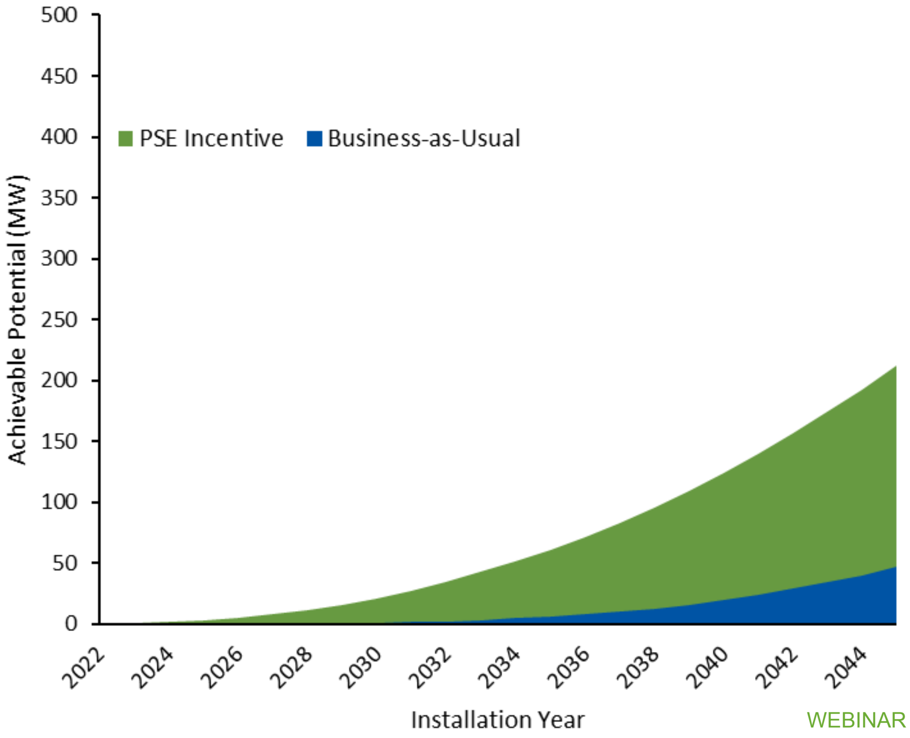
Two Scenarios

Business as Usual	Utility Incentive

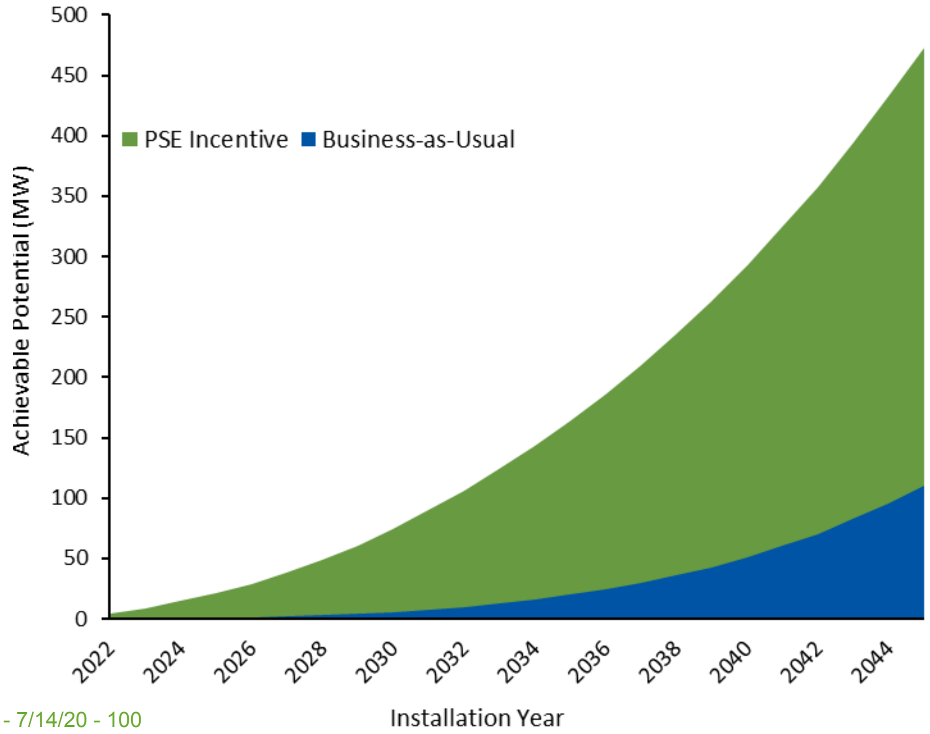
• Continuation of federal ITC in its current form:
  • 0% in 2022 for residential
  • 10% for commercial
• WA RESIP applications ended December 2019
• Net metering
• 5-year MACRS depreciation for commercial
	▪ Business as usual, plus
	▪ Utility incentive equal to \$0.048/kWh
	▪ Calculated from the 2019 IRP as a levelized value of the 2022-2045 electric avoided costs
	▪ Factoring in a 5% assumption for admin costs

Solar PV Achievable Potential

Residential



Commercial



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PSE PUGET SOUND ENERGY

Webinar #4: Demand Side Resources Q&A

7/15/2020

Overview

On July 14, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss demand side resources. Stakeholders shared their input on conservation potential assessment and sensitivities with demand side resources. Additionally, participants were able to ask questions and make comments using a chat box provided by the Go2Meeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 57 stakeholders and PSE staff attended the webinar, plus another 12 attendees who called into the meeting and did not identify themselves (69 people total).

Attendees included: Anika Arugunta, Aron Jarr, Anne Newcomb, Brian Grunkemeyer, Cody Duncan, Corey Corbett, Dan Kirschner, David Meyer, David Tomlinson, Don Marsh, Doug Howell, Eddie Webster, Eli Morris, Elyette Weinstein, Fred Heutte, Jeff Tripp, Jennifer Mersing, Jennifer Snyder, James Adcock, Jane Lindley, John Ollis, Joni Bosh, Justin Moffett, Kassie Markos, Kate Maracas, Kathi Scanlan, Katie Ware, Kevin Jones, Kyle Frankiewich, Larry Becker, Lori Hermanson, Lorin Molander, Mark Sellers-Vaughn, Michael Laurie, Michael Noreika, Michelle Wildie, Mike Hopkins, Nathan Gagnon, Philip Puzon, Rachel Brombaugh, R. C. Olson, Rahul Venkatesh, Robert Briggs, Sarah Laycock, Stephanie Chase, Stephanie Price, Ted Drennan, Therese Miranda-Blackney, Thomas Anderson, Virginia Lohr, Warren Halverson, Willard (Bill) Westre, and Zacarias Yanez.

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 1:30 PM PDT and ended at 4:59 PM PDT.

Name	Time Sent	Comment
Alison Peters	**1:22 PM**	Welcome everyone. We will be starting the webinar at 1:30pm.
Alison Peters	**1:26 PM**	Just a friendly reminder as folks are joining to mute yourself.
Alison Peters	**1:37 PM**	You are encouraged to type in your name to the chat box so that folks know who is here. Share with "Everyone." Thank you.
Michael Laurie	**1:37 PM**	Michael Laurie
Brian Grunkemeyer	**1:38 PM**	Question queued up for slide 36: I don't see anything about Demand Flexibility approaches. Specifically, there's no EV load management measure, and it's unclear whether the Heat Pump Water Heater measure is taking advantage of all the great work the BPA has been doing on aggregating water heaters as Demand Flexibility devices.
Doug Howell	**1:39 PM:**	Would please speak a little louder?
Joni Bosh	**1:39 PM:**	Any way to make Gurvinder's voice clearer? He is hard to hear
Kyle Frankiewich	**1:39 PM**	Kyle Frankiewich, UTC staff
Brian Grunkemeyer	**1:40 PM**	Perhaps the answer to my question is slide 43, but Demand Response leaves something on the table vs. Demand Flexibility. We should be modelling resources that can be called every day, not 6 times per year.
Kyle Frankiewich	**1:41 PM**	slide 10: How does the zip code level overlay with PSE's distribution-level planning and with PSE's efforts regarding CETA's equity requirements?
Jane Lindley	**1:42 PM**	What level of International Association for Public Participation (IAP2) engagement will be used in the meeting today? Inform, Consult, Involve or a combination? Thanks!
Irena Netik	**1:44 PM**	This topic is a combination of inform and consult.
Virginia Lohr	**1:44 PM**	Can the slide be shown as a slide, not within PPT, so it is bigger?
Joni Bosh	**1:45 PM**	What other kind of benefits does Plexos provide, specifically?
Kate Maracas	**1:46 PM**	To Gurvinder - does your Plexos flexibility model distinguish between dispatchable DR and those resources that are responsive in real-time? I'm thinking of resources like EV charging vs. real time pricing products.
Doug Howell	**1:47 PM**	How will EE estimates be adjusted once social cost of carbon is accounted for?
Don Marsh	**1:47 PM**	Is local energy storage included in both the Resource Adequacy Model and the Plexos Flexibility Model? It seems that energy storage would provide benefits that would be valuable in both models.
Joni Bosh	**1:50 PM**	Slide 13 What deferral amount did PSE use in the prior IRP? The Power Council value?
Fred Heutte	**1:53 PM**	comment on slide 13: we have provided input to the NW Council that their new value for T&D deferral (lower now than PSE's) needs further review

Don Marsh	**1:54 PM**	What is the effect of the changed T&D number? Does it make transmission more or less costly compares to NWAs? I'm confused because I missed part of Gurvinder's commets because the audio was too distorted.
Kyle Frankiewich (	**1:54 PM**	slide 13 will we see the inputs and calculations for PSE's updated estimates?
Doug Howell	**1:54 PM**	SLide 14. Is there a complete description of the wiggle room that PSE to depart from the NPCC model?
James Adcock	**1:55 PM**	Slide 13 -- I don't understand the large T&D difference between the Power Council 2021 plan vs. 7th plan?
Don Marsh	**1:56 PM**	Can we see the conservation forecast values by zip code?
Don Marsh	**1:57 PM**	Can we also see how the conservation forecast per zip code has changed during recent years?
Brian Grunkemeyer	**1:58 PM**	To extend on Don's questions, have you thought about producing a Locational Marginal Value of Conservation? Kinda like LMP, but annual for directing upgrades to individual substations.
Doug Howell	**2:00 PM**	Louder pleas
Doug Howell	**2:00 PM**	GUrvinder, you are disappearing again
Don Marsh	**2:00 PM**	Can't easily understand Gurvinder, unfortunately.
kevin jones	**2:00 PM**	Could you ask if Gurvinder is using a headset, and if he can try calling on a direct line? The audio is often muffled.
Joni Bosh	**2:02 PM**	Sorry, I cannot hear Gurvinder's answers
R. C. Olson	**2:02 PM**	Gurvinder is sounding very garbeled again.
R. C. Olson	**2:03 PM**	He is still very hard to understand. Elizabeth comes in clear, but Gurvinder fades in and out in clarity.
R. C. Olson	**2:04 PM**	Please share the forumula (equation) used to calculate cost effectiveness.
Joni Bosh	**2:04 PM**	COuld someone please repeat Gurvinder's answers?
Don Marsh	**2:07 PM**	Recommend that Gurvinder try phoning the audio in. The current garbled audio is very taxing on participants.
	2:07 PM	Sorry, I did not get the answer to Kyle's question on slide 13
Doug Howell	**2:07 PM**	I think I got. The methodology is largely the same.
Doug Howell	**2:07 PM**	The measures, values and assumps can be slightly diff
R. C. Olson	**2:13 PM**	I did not gete an answer to my question. Please provide the formula that is in the portfolio model.
Don Marsh	**2:13 PM**	Thanks, Gurvinder. Audio is MUCH better!
Joni Bosh	**2:13 PM**	Thanks
Doug Howell	**2:13 PM**	Gurvinder - you are much clearer now. Thank you.
Elyette Weinstein	**2:15 PM**	Doug you asked a question about values used.

Don Marsh	**2:17 PM**	Documentation of PSE's models and assumptions is so important because some of the conclusions PSE comes to seem to be at variance with what is happening with other utilities across the country. For example, Pacificorp is going much more for battery storage than PSE is. Why is that? Is there something different about PSE's service territory? We need to understand.
Kyle Frankiewich	**2:21 PM**	slide 18 - Not sure CPA would be the logical place for it anyhow, but time-of-use or dynamic rate structures can prompt load-shifting that shares a lot of similarities with DR and other flexible load programs. How will PSE explore those options?
Don Marsh	**2:22 PM**	Slide #18: We haven't seen PSE's load forecast yet. What level of growth was Cadmus provided for its analysis?
Joni Bosh	**2:22 PM**	If load forecasts are complete for this analysis, can you provide those? Slide 18
Michael Laurie	**2:22 PM**	Do the load forecasts take into account the likelihood that commercial building occupancy will be significantly less than it was pre-COVID and that overall demand will likely be less was expected 6 months ago.
Don Marsh	**2:24 PM**	Slide #19: Five sources - why not consider energy storage? This seems like a significant omission.
Alison Peters	**2:25 PM**	Joni, to your question about the forecasts. This will be the topic of the webinar on Sept. 1.
Michael Laurie	**2:25 PM**	Do any of the efficiency and renewables estimates take into account that we may likely have a Democrat president and Democrate controlled Congress which will likely lead to significant federal incentives for more efficiency and renewables?
kevin jones	**2:26 PM**	In the 2019 PSE IRP it was mentioned that the utilty had a gas demand response pilot program. UTC Kathi Scanlan asked for details of this program. Could you explain why your analysis did not contain DR for gas?
Michael Laurie	**2:27 PM**	How is PSE estimating the non-PSE programmatic conservation that will occur due to the new energy codes, C--PACER law, CETA, and the commercial building performance standard law?
Doug Howell	**2:27 PM**	Slide 20. Once the IRP defines "achievable economic" are PSE implementers required to achieve all of this?
Willard (Bill) Westre	**2:29 PM**	Raise hand #13
Don Marsh	**2:29 PM**	Deferring the load forecast until September makes it so hard to judge all these analyses that use the load forecast as an input.
kevin jones	**2:30 PM:**	Why were the load forecasts not reviewed in this forum prior to them being used in the CADMUS analysis?
R. C. Olson	**2:32 PM**	How is the growing trend to switch from gas to heat pump heating being included in this analysis?
kevin jones	**2:32 PM**	Could you tell us the duration of the gas DR pilot?
Rachel Brombaugh	**2:34 PM**	CPACER was signed into law
Doug Howell	**2:36 PM**	Follow up on Slide 20. How do implementers set the EE target from the 'economic achievable?"

kevin jones	**2:39 PM**	WIll the CADMUS analysis be re-done if there are signficant issues with the PSE load forecast? Technical advisors have typically raised concerns about PSE load forecast. How are these results valid?
R. C. Olson	**2:40 PM**	We would like to know when we can plan on hearing a new analysis that includes the heating fuel switching trend that is growing. This is a big flaw in the analysis. What future session will this be presented in?
Michael Laurie	**2:41 PM**	Could you show us the calculations and inputs used to estimate the non-PSE programmatic conservation that will occur due to Washington legislation that has passed recently. This is critical because if this is underestimated it could lead to overbuilding supply side resources. It is not helpful to anyone to know that you will include it in the modeling. Please show us the numbers and details even if that means showing us a simplification of how the model will deal with it. Thanks
Doug Howell	**2:41 PM**	Follow up on slide 20: How can we ensure oversight of this EE target setting? Seems like this is where the rubber meets the road.
R. C. Olson	**2:43 PM**	On slide 21 please provide details on how the distiction is being made between technically feasible and achieveable options?
Joni Bosh	**2:44 PM**	Slide 23 - What is the source for saturation rates? How does the applicability factor differ from ramp rate
R. C. Olson	**2:47 PM**	For deep energy efficiency work on a buliding, a unique set of measures should be used. These vary from building to building in my experience. The results are not typically calculatable by summing the individual measures used. How does the Camus analysis take this realilty into account?
kevin jones	**2:48 PM:**	WIll PSE provide the customer and load forecast used in the CADMUS analysis?
Joni Bosh	**2:49 PM**	Slide 23 - What is the source and the values of these input values? What is included in non-energy benefits? Sorry that should be for slide 14. Slide 24
Warren Halverson	**2:49 PM**	I, too, am disappointed that load forecasts are to be discussed so late in the process. Aren't loads and customers a primary driver. My question about Step 2 is how do you weight the degree of significance of each of these factors?
Alison Peters	**2:50 PM**	Michael, for the question you asked, would you kindly submit a Feedback Form so PSE can provide the level of detail you are asking for? Thank you.
Doug Howell	**2:50 PM**	Slide 24. Does the Total Resource Cost test have the effect of leaving lost energy efficiency opportunity behind?
Michael Laurie	**2:51 PM**	Alison, Thank you. Where or how do I obtain a Feedback Form? Do you have a link to it?
Willard (Bill) Westre	**2:51 PM**	Slide 24 - What discount rate is used for LCOE?
James Adcock	**2:51 PM**	Jim Adcock Raise Hand
Kyle Frankiewich	**2:51 PM**	slide 24: Do CBSA and RBSA data allow for zip code / census tract tailoring based on local building footprints? IE if neighborhood has more MF housing, then MF EEMs will have a greater impact. May link to highly impacted communities and NEIs.

Alison Peters	**2:52 PM**	Yes. PSE will answer questions in writing when folks submit a Feedback Form. Here is the link: https://pse-irp.participate.online/feedback-form
R. C. Olson	**2:53 PM**	How does the Cadmus efficiency modeling calculation figure the building envelope air leakage reduction plays in the reduction of energy conservation due to heating load reduction? It will vary from building to building.
Alison Peters	**2:53 PM**	For this webinar, please submit your form by July 21 and the answers will be posted online by July 28.
	2:54 PM	Slide 26. what is included in "discretionary measures" and what portion is this of the total EE budget?
R. C. Olson	**2:54 PM**	In slide 26, How is the potential long-term economic value calculated? What is the formula used?
Doug Howell	**2:54 PM**	Slide 26 - Please explain "lost opportunity measure?"
Michael Laurie	**2:55 PM**	Alison, Got it thanks
Doug Howell	**2:57 PM**	Slide 26 - Why is ramp rate only 10 years?
Warren Halverson	**2:58 PM**	I, too, am disappointed that load forecasts are to be discussed so late in the process. Aren't loads and customer accounts primary drivers? My question about Step 2 is how do you the degree of signficance of each of these factors?
R. C. Olson	**2:59 PM**	For many efficiency enhancements, impact continues well beyond ten years. Can we get this time frame extended through the full IRP period of 20 years?
Joni Bosh	**3:00 PM**	If measures are bundled by levelized costs, how do you plan to reflect/capture peak energy values? By measures? By bundles? Slide 27
Kyle Frankiewich	**3:00 PM**	+1 for Joni's question
Doug Howell	**3:01 PM**	Will we have time to offer sensitivities on Slide 69?
Willard (Bill) Westre	**3:03 PM**	Ramp rates - Have other utiliities used shorter ramp rates?
Michael Laurie	**3:04 PM**	Have you looked at the case study of the major retrofit of the Empire State Building to include the measures they implemented in your analysis of what is technically feasible?
Elyette Weinstein	**3:08 PM**	What percentage of annual contriubtions does PSE contribute to the NW Energy Efficiency Alliance?
	3:12 PM	How is the unique efficiency impact for an aggregation of measures going to be used to adjust the PSE future efficiency forecast? This is important as future CETA deadlines and C-PACER programs ramp up and deep efficiency improvements catch on in the buildings market place. The 2021 IRP must take this into account, so when will we see appropriate revised efficiency forecasting?
Michael Laurie	**3:15 PM**	What is the relaationship between the CPA and IRP effort versus program implementation? Are the program implementers at PSE required to show a good faith effort to carry out what the IRP concludes is cost effective? If so is there a publicly available report where the implementers document that?

kevin jones	**3:18 PM**	Gurvinder - you did not really answer my question - would PSE provide the load data used in the CADMUS analysis? Will this be the same or different than the load forecast provided in September? If different we would like to understand the differences. If the same, why will PSE not provide the data now?
R. C. Olson	**3:20 PM**	We would like our questions addressed in real time as slides are being presented and as we have multiple PSE people available to answer. Please delay the presentation accordingly!
Don Marsh	**3:20 PM**	+1 for Kevin's load forecast question. At least tell use what rate of growth is being assumed. We can delve into the details in September, but there is no reason to hide the ball today, especially on such a crucial assumption.
R. C. Olson	**3:23 PM**	You missed the legislating update for HB2405 which put C-PACER into law. This needs to be included in your analysis. When will your analysis be adjusted accordingly?
Don Marsh	**Slide #30**	How do the 2023 values compare to NWPCC assumptions? How do they compare to assumptions for neighboring utilities, like Seattle City Light? They seem a little low to me.
Joni Bosh	**3:26 PM**	repeating my question from slide 24 here again - If measures are bundled by levelized costs, how do you plan to reflect/capture peak energy values? By measures? By bundles? Slide 27
R. C. Olson	**3:27 PM**	Your commentary thus far indicates that several things were overlooked and not included in estimating the achievable energy efficiency over the next twenty years. When will these projections be revised to include the increasing trend of deep efficiency improvements which we expect over the next twenty years?
James Adcock	**3:27 PM**	Slide 31 -- There is no "2019 IRP" -- because Puget canceled it. Please fix this.
kevin jones	**3:30 PM**	Slide 33: Is the 26% to 8% drop in achieveable Industrial technical potential due to industrial to commercial reclassification?
Don Marsh	**3:33 PM**	Slide 34: I think you're saying that most of the drop in electric potential is because of lower growth in various categories. So the load forecast should be significantly lower than we saw in 2019. But for now, we just have to guess. Like blind men describing an elephant.
Fred Heutte	**3:33 PM**	Actually, the NW Council has shown some interest in enterprise class data center EE and DR, and even if no such facilities locate in PSE territory (which can't be ruled out), facilities in smaller categories can add up to considerable new load
R. C. Olson	**3:34 PM**	Slide 34 seems to only consider new construction. Some of us expect an increasing likelihood of retrofitting existing buildings. It appears that you are missing this likely occurence over the next 20 years which will likely eclipse the savings impacts from more efficient new buildings. When will your forcast be adjusted to accomodate this likely future trend?

R. C. Olson	**3:38 PM**	To follow up on my question on air leakage consideration, please provide the data source for the detailed envelope factors that Camus says that they use. Thanks.
Doug Howell	**3:41 PM**	Slide 26. That does not answer the question about why can't PSE further accelerate the ramp rate from 10 years to six or eight years.
R. C. Olson	**3:44 PM**	The answer to my question on the 10 year life for measures rather than 20 years, the assumption that measures will only have a weighted average of 10 years is incorrect in my experience. This needs to be revised. When can we expect to see this impact period extended from 10 years to 20 years?
Michael Laurie	**3:45 PM**	Slide 36 includes one measure called "Whole Home". Whole home what? What is that?
Kyle Frankiewich	**3:46 PM**	hand raised - slide 36
James Adcock	**3:48 PM**	Raise Hand -- general question.
Michael Laurie	**3:50 PM**	Slide 39 Back to my point about a likely Democratic federal administration, I think it is critical to consider that there will be a lot more new federal standards when and if that happens.
Kyle Frankiewich	**3:58 PM**	slide 42: what's the difference betwen CPP and behavior DR? If behavioral DR is similar to home energy reports, is it effectively just asking / informing customers of the benefit of shifting load?
R. C. Olson	**3:58 PM**	Where are slides 41 & 42? One was missed and one that appeared wasn't numbered.
Kate Maracas	**3:58 PM**	Slides 24-43: To what extent does PSE rely on demand response aggregators to deploy the the DR products? Could broader use of aggregators increase customer adoption?
Don Marsh	**3:59 PM**	Disappointed the Cadmus didn't include time-of-use rates as a Demand Response product. Although Critical Peak Pricing can help alleviate maximum peaks, a daily TOU rate would make customer batteries more economical, with potentially attractive environmental benefits.
Kate Maracas	**3:59 PM**	Sorry - the above reference was meant to be slides 42-43.
Don Marsh	**4:00 PM**	Slide 44, Cadmus again mentions PSE's 2045 load forecast, which we are not allowed to know for months. This is not acceptable.
Fred Heutte	**4:01 PM**	slide 47: I have a comment on the residential water heat DR potential.
Don Marsh	**4:01 PM:**	Slide 45, does "behavioral load response" = time of use rates? Or is this just critical peak pricing?
Kate Maracas	**4:02 PM**	Slides 42-44: do many of these programs rely on AMI (automated metering infrastructure)? If so, is investment in AMI an impediment to broader customer adoption?
kevin jones	**4:02 PM**	Slide 45: Is uncertain customer acceptance a CADMUS or PSE assumption and what is the basis for the assumption?
Doug Howell	**4:03 PM**	Demand Response: Do the DR benefits include: avoided generation and TX upgrades; avoided distribution upgrades; storage function; line loss reduction from energy savings; ancillary services at generation level such as frequency regulation and spinning reserve; and ancillary services for distribution of voltage control?

Don Marsh	**4:03 PM**	Slide 45 - "uncertainties regarding customer acceptance" is PSE's standard explanation. However, many utilities find customers love demand response programs that provide lower monthly bills. PSE is using assumptions that are decades out of date.
R. C. Olson	**4:04 PM**	Not including the potential for demand control on smart appliances misses a DR potential. Can this potental be included in a revision to the DR calculations?
Michael Laurie	**4:05 PM**	Slide 45 - Agree with Don Marsh's point. PSE please explain what thinking and evidence led to reach a different conclusion than other utilities reached.
Don Marsh	**4:07 PM**	Slide #46, Critical Peak Pricing seems pretty wimpy if only 15% of customers are eligible. Time of use rates could apply to nearly 100% of customers. PSE's reluctance to study time of use is based on one bad experience more than two decades ago. Technology has changed, the industry has learned.
kevin jones	**4:07 PM**	What is the basis of the assumption that energy efficiency occurs before Demand Response? What is your estimate of delayed DR employment while waiting for EE upgrades?
R. C. Olson	**4:08 PM**	Where to you get your PV market penetration function for each year?
Don Marsh	**4:12 PM**	Slide 51. Solar prices are decreasing pretty fast. Does your forecast anticipate cheaper and more efficient solar panels? Most customers will find it's financially attractive to install panels. The adoption rate in that scenario could be higher than your forecast shows.
Fred Heutte	**4:15 PM**	Comment: because the Bass diffusion model relies so much on first-cost for solar market penetration, the future cost estimates for rooftop PV are absolutely pivotal to the outcome, and as we previously said, even the NREL 2019 ATB medium estimates are probably too high and a midpoint between medium and low is more credible.
Fred Heutte	**4:16 PM**	Also, the new 2020 ATB data has just been put online and we are looking through it now. The website is: atb.nrel.gov
R. C. Olson	**4:17 PM**	Could you please define what you mean by combined heat and power?
R. C. Olson	**4:18 PM**	Are you projecting a decline in natural gas use due to switching to heat pumps? If not, when will you adjust your calculations to include this trend?
Michael Laurie	**4:20 PM**	Have you considered the possibility of some uses of natural gas will be banned in new construction as has happened in a number of jurisdictions in California?
Kyle Frankiewich	**4:23 PM**	raised hand for slide 66
Doug Howell	**4:24 PM**	Raised hand for slide 69
Fred Heutte	**4:25 PM**	for slide 63: is there an effective difference between volt/var optimization (VVO) and conservation voltage reduction (CVR), if so has PSE looked specifically at CVR
Fred Heutte	**4:27 PM**	a general comment: NWEC requests that the workbooks for the EE and DR assessments be made available and sufficient time (5 business days at a bare minimum) provided for stakeholder feedback on the CPA after they are made available

Doug Howell	**4:30 PM**	Slide 69 - Raised hand for a recommended sensitivity
James Adcock	**4:32 PM**	Slide 69 -- Distributed Solar pV -- with 3rd party ownership and PSE financial support -- especially in low income communities.
Don Marsh	**4:33 PM**	Slide 69: Like the PSE incentive, but why $0.048 / kWh? I'd like to see a sensitivity with a higher incentive. I think that could make a big difference. Also, I'd love to see what paired batteries could do. How about some incentive on that?
Don Marsh	**4:34 PM**	+1 on a sensitivity on shorter ramp rates, like Doug suggested! A 6 or 8-year ramp rate would be very interesting.
Don Marsh	**4:35 PM**	It is extremely likely that solar panel efficiency will increase during the next 20 years, making panels cheaper. I don't think PSE is taking that likelihood into account.
Michael Laurie	**4:39 PM**	Could you do a sensitivity analysis of conservation achievable if conservation can be done without a loss of revenue to PSE. And a sensitivity analysis of conservation potential if conservation spending was recognized as capital spending, thus allowing PSE to make a profit on conservation spending.
Kate Maracas	**4:41 PM**	+1 to Don Marsh. Also, the increased capabilities of grid-forming inverters that will inevitably be deployed after implementation of IEEE 1547 standards will have a significant impact on solar PV's (distributed and utility scale) ability to provide flexibility and ancillary services. How is PSE considering both the cost reductions and advanced technical capabilities?
Warren Halverson	**4:56 PM**	It seems like resource alterntives -DR, Solar, Batteries. Water heaters etc etc - are only considered on a total market or company basis.
Warren Halverson	**4:59 PM**	I would like to see a more niche approach to using a combination of these solutions, particularly in transmission planning. It seems to me that there are many applications of these solutions in combination to meet residential and/or commercial needs .... let's add some creativity and options to our customers. Thank you.

PSE IRP Feedback Report
Webinar 4: Demand Side Resources
July 14, 2020

7/28/2020

The following stakeholder input was gathered through the online Feedback Form, from July 7 through July 21, 2020. PSE's response to the feedback can be found in the far right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on August 4, 2020.

Feedback Form Date	Stakeholder	Comment	PSE Response
7/8/2020	James Adcock	It is very difficult to read the Draft Demand Side Resources document due to the very large use of TLAs -- Three Letter Acronyms -- which are unexplained in the document. There is also the use of unexplained "random" numbers, such as "8760" Don't use Three Letter Acronyms without giving definition to those acronyms in the document that uses them. Don't use unexplained "random" numbers, such as "8760" without explaining them in the document. Perhaps prior to the meeting you can send out to participants a temporary "dictionary of acronyms and magic numbers" that explains what all your TLAs and "random" numbers in this document? -- So that we don't spend all the meeting time just asking and answering questions like "What does 'GSHP' Mean" and "What does the number '8760' mean?" And then in the final document you can include this "dictionary of acronyms and magic numbers" in that final document.	Thank you for the suggestion. Concerning your examples, 8760 is the hours in a (non-leap) year and used in modeling. GSHP stands for ground source heat pumps.
7/14/2020	Doug Howell, Sierra Club	Please run two sensitivities: 1. Slide 26. Run two more sensitivities on the ramp rate from 10-years to 8-years and 6-years. 2. Non-energy benefits for energy efficiency. Run a sensitivity to show what is the value of non-energy benefits from energy efficiency. The recent EPA study shows that these benefits are about 2 cents/KWh.	Thank you for the suggestions concerning sensitivities. Your three suggested sensitivities have been added to the list of sensitivities for further discussions at the August 11 webinar. Your suggestion of bundling less cost-effective measures with more cost-effective ones to achieve deeper penetration into the market is a

Feedback Form Date	Stakeholder	Comment	PSE Response
		In addition, PSE needs to provide assurance that the CRAG and the implementation team are maximizing EE potential for each building such that you still have greater benefits than costs so that you are not just swapping out light bulbs but bundling that with other measures and still come out cost effective.	valid argument. The conservation resource advisory group (CRAG) is a separate process than the IRP public participation process. They work directly with PSE's implementation team to approve their program portfolio. Your suggestion would be something the CRAG process would address.
7/14/2020	Brian Grunkemeyer FlexCharging	I'd like to better understand the cost of your Residential EV direct load control conservation measure. If you're installing hardware in the home, I understand that's not cheap. However, $362/kW-yr seems a little high to me. At FlexCharging, we have a software-only vehicle telematics solution where we can provide managed charging based on the driver's schedule first, then fall back on the utility's needs. This should lead to better customer acceptance and higher adoption. We may be able to provide services for around $250/car/year for the service, plus $50/car/year for driver incentives and some program marketing & administration costs. We believe we can get more than 1 kW-yr per vehicle. I'd like to see how this lines up with your numbers. I'm happy to walk through the numbers with someone.	Cadmus can estimate the levelized cost using the values provided by FlexCharging and compare those to the values we used in a side-by-side comparison. PSE and Cadmus will be reaching out to follow-up with you and will report progress in the Consultation Update.
7/14/2020	James Adcock	We really do need PSE to "vet" their audio systems, and all other aspects of their meeting presentation technology, prior to the start of the meeting so that we don't waste the time and effort of 60+ participants. Unfortunately, this continues to be an on-going problem for many years, where PSE "audio" system continue to fail during IRP meetings.	Thank you for your comments.
7/16/2020	Elaine Armstrong, Citizen's Climate Lobby	What is PSE doing, in good faith and at all speed, to reduce their greenhouse gas emissions, reduce reliance on fossil fuels and create a 100% green and reusable energy sources? What you are doing now is increasing reliance on natural gas. There should be no more new plants that use fossil fuels. You need to create ways to use solar, wind, geothermal etc. Entire nations are able to do this. Surely PSE can.	PSE is modeling 80% renewable resources by 2030 and 100% by 2045 to meet the Washington Clean Energy Transformation Act (CETA). PSE is also modeling portfolio sensitivities around different clean energy futures which will be discussed at the August 11, 2020 webinar on scenarios and sensitivities.

Feedback Form Date	Stakeholder	Comment	PSE Response
		Build no new fossil fuel plants. Create clean energy sources with the eye to be entirely greenhouse gas emission-free by 2040. Do more to support homeowners to overcome the giant cost of installing solar on their homes.	
7/19/2020	Willard Westre, Union of Concerned Scientists	Slide 19 – At 2:29pm in the webinar I asked verbally two questions that were not documented in the Q&A report, nor the responses to them. My first question was directed to Lakin Garth with regard to his extensive experience in working with other utilities. I asked him if, in addition to Electric and Gas sources of conservation there was another source, namely, fuel switching between Gas and Electric (e.g. replacing gas furnaces with electric heat pumps). His answer was yes, that this was another viable source. My second question was why wasn't this data included in the presentation. His answer was to refer to PSE staff, implying that the decision was made by PSE. Fuel switching as a conservation resource should not be off-the-table for PSE as this represents a very substantial percentage of the residential and commercial conservation that can be achieved. The use of gas for heating is a major component of PSE's total. Switching to electric heat pumps results in an energy saving of up to 75% and is not costly when timed with end-of-life-replacement. PSE does not effectively offer rebates for this conservation. That was not always the case – in 2010 I received a $1500 rebate for replacing my gas furnace with an electric heat pump. That rebate is not available now. Sometime since 2010, PSE has dropped this major future source of conservation from its plan, significantly reducing its overall conservation effort. Recommendation: PSE develop an aggressive fuel-switching component to its conservation plan, including replacement of gas heating systems with heat pumps. This would help PSE bolster its conservation resources and reduce	PSE responses by paragraph and referenced slide numbers: Fuel conversion from gas to electric is a combination of a gas savings measure and an electric load building measure. This is not a true conservation measure and PSE would not characterize it resulting in 75% energy savings. Fuel conversion is mostly driven by carbon reduction objectives, assuming that the electric supply would be non-emitting. PSE would not generally characterize these measures as low cost since adding electric space heating equipment will likely result in upgrades to the electrical circuits and more expensive heat pump equipment. PSE will be considering a sensitivity where some amount of gas loads are converted to electric. Further discussions will occur at the August 11 webinar on scenarios and sensitivities. The rebate of $1500, that PSE used to offer, was not for converting to electric, but rather for choosing a more efficient electric system, like a high efficiency ductless heat pump, which has a higher cost. The incentive encouraged customers to adopt a more efficient system. In other words,

Feedback Form Date	Stakeholder	Comment	PSE Response
		its requirement for new CETA-required generation resources. Additionally, it would reduce PSE's overall carbon emissions which is critical to achieving zero emissions by 2040. Slide 35 – This slide shows a cumulative achievable technical efficiency potential of 142MW for the year 2026. The Dec 11 presentation Slide 21 shows 336Mw for 2026. Can you explain the reduction in potential efficiency?	if you converted to electric but chose an inefficient electric system you would not have qualified for the rebate. Slide 35: The slide from the December 11, 2018 presentation included all demand side resources including codes and standards. Please also note that for 2026 of the previous study, there were 6 years of conservation since the study started in 2020 (2020-2026), and the current study has only four years of conservation since its starts in 2022 (2022-2026).
7/19/2020	Anne Newcomb	Thank you for including me in the PSE IRP! I will be on a backpacking trip :-) for July 21st but I look forward to participating in the rest! Having lived in Puget Power and PSE territory most of my life I greatly appreciate your track record of offering energy efficiency programs to your customers. Considering it is estimated energy efficiency can reduce demand between 5-30% and possibly more, I highly recommend significantly increasing your investments in energy efficiency programs over the next 5-10 years and include these specific offerings: ○ Fully-subsidized and high-quality energy audits including calibrated blower door tests and thermographic inspections. ○ Well-subsidized window replacements. ○ Well-subsidized resilient and long lasting insulation. Spray foam has the highest R-value and may never need replacement which makes for a great investment too! In addition to energy efficiency, smart grid AI and machine learning technology is the way of the future. BPA has investing in and is using Auto Grid (https://www.auto-grid.com/) to help balance demand. I can see PSE is also working to create a smarter grid including the newly installed smart meters. What smart grid technology is PSE using now and what is your	Thank you for your thoughts and suggestions! PSE is taking a holistic approach to grid modernization that includes several smart grid technologies in addition to traditional infrastructure improvements. Examples of our investments in smart technologies include substation SCADA (Supervisory Control and Data Acquisition), distribution automation, and an Advanced Distribution Management System (ADMS). Substation SCADA is a program that enhances PSE's telecommunications infrastructure to remotely monitor and control our substation equipment in real time. PSE is planning for all substations to be equipped with SCADA improvements by 2025. Distribution Automation (DA) – often described as a "self-healing grid" – is technology that provides monitoring and control of our distribution circuits to help us detect outages more quickly and address them faster and more effectively. Advanced Distribution Management System (ADMS) is a computer-based platform that will enable an integrated real-time approach

Feedback Form Date	Stakeholder	Comment	PSE Response
		roadmap/plan for utilizing this technology to help achieve a clean energy future?	to distribution grid management and optimization, and for the integration of more distributed energy resources. The ADMS platform is currently in deployment and is expected to be complete in 2022. These technologies will help achieve a clean energy future.
7/19/2020	Rob Briggs, Vashon Climate Action Group	Comment #1 – Evaluate higher ramp rates for energy efficiency programs I strongly support Doug Howell's suggestion that the IRP evaluate the option of accelerating the ramp rate to 6 and 8 years for efficiency measures rather than 10 years. Doing so will evaluate a policy capable of reliably delivering early emissions reductions that have been consistently shown to be effective employment generators. Doing so would also balance other emissions reduction policies and measures that inherently have longer lead times and entail greater technical risk and/or economic uncertainty.	Response #1: Thank you for this comment. Modeling accelerating ramp rates as additional sensitivities is being considered and will be discussed at the August 11 webinar on scenarios and sensitivities.
		Comment #2 – Evaluate gas to electricity fuel switching programs The IRP needs to include the assessment of measures that entail switching loads from natural gas to electricity. While this may not have been included in previous IRPs, the writing is clearly on the wall that fossil methane use will be greatly curtailed or eliminated for climate reasons in the future. While one can imaging future power plant technology that could capture and sequester carbon, there is no plausible technology that could do that for distributed uses of natural gas. Washington State has committed to decarbonize its economy, and in California some regulations have already been enacted to shift loads from gas to electricity and many more are now being proposed. The IRP process was created to prevent egregious errors from being made in infrastructure spending, like Washington Public Power System. Rate payers continue to pay millions of dollars per year for mistakes made nearly 40 years. It would be utter folly to fail to include this inevitable and enormously consequential process of curtailing use of fossil methane through fuel	Response #2: PSE will be considering a sensitivity where some amount of gas loads are converted to electric. This will be further discussed at the August 11 webinar on scenarios and sensitivities.

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		switching in a process mandated to plan energy systems 20 years into the future.	
		Comment #3 – Excessive use of acronyms and abbreviations and poor graphic presentation If the purpose of the IRP webinars is to inform stakeholders and field their input, then it would behoove PSE and its contractors to decrease the use of acronyms, particularly those that are not explained. When participants' attention is consumed attempting to parse specialized abbreviations or language, they are not able to attend to the substance of what is being communicated. Slide 44 is a good example of excessive use of unexplained abbreviations and poor graphic design. I note that none of the abbreviations are explained at the bottom of the page, as would be appropriate. Use of these abbreviations in oral presentation, as was done extensively in this last webinar, is doubly problematic because of the near impossibility of both listening and at the same time searching the presentation document to see if the abbreviation was explained. Slide 44 attempts to do too much and as a result doesn't effectively communicate any of the things the audience might reasonably want to know. Any comparison between IRPs doesn't work because the measures don't align. What measures were added or subtracted for 2021? On which measures have assumptions changed? What measures are most impactful? What measures were most cost-effective? Answers to all these questions are hidden by poor presentation.	Response #3: PSE notes that use of acronyms and abbreviations and graphics can be a barrier to understanding and will make efforts to improve meeting materials for all audiences as we are able. Slide 44: The following list defines the abbreviations: ▪ EV: electric vehicle ▪ DLC: direct load control ▪ HPWH: heat pump water heater ▪ C&I: commercial and industrial ▪ DR: demand response ▪ ERWH: electric resistance water heater ▪ CPP: critical peak pricing ▪ BYOT: bring-your-own-thermostat In terms of measures that were added for 2021, slide 45 notes that behavioral demand response, electric vehicle service equipment direct load control, and both grid-enabled and switch technologies were applied to both electric resistance and heat pump water heaters. No measures were removed. The most impactful measures are shown on slide 46.

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			Slide 44 shows each demand response product's levelized cost from lowest to highest from top-to-bottom. The cost-effective amount of conservation will be determined from the IRP portfolio analysis.
		Comment #4 – Better evaluation of electric vehicle load management Interestingly, the measure on the graph on page 44 that appears to be the least cost-effective and to have only very modest impact—residential electric vehicle direct load control—is one that I would have assumed would be among the most cost effective and most impactful. It appears to have an associated cost of $362/kW-yr. Electric vehicles using level 2 chargers pose large loads—larger than residential water heaters and comparable to central air conditioners and heat pumps. Yet charging vehicles in most cases is not time dependent, hence customers likely need little incentive to shift the time at which they charge. Would you please provide the data sources that were used to establish the very high cost for load management for EV charging. There is enormous up-side potential in using the charging of electric vehicles to improve the efficiency and reduce emissions from the electric power sector and also large down-side risk if those loads occur at the wrong times. This seems like a critical assumption to get right, because public policy is likely to shift radically in the coming years to favor EVs, and it seems critical that PSE have a plan in place to manage them. Would you please provide references for the data sources that were used to establish the very high cost for load management for EV charging.	Response #4. Cadmus will provide the assumptions used for residential electric vehicle charging DLC in the consultation update.
7/20/2020	Virginia Lohr, Vashon	I have reviewed Webinar #3: Transmission Constraints Q&A. It states that all questions were answered. I do not recall hearing an answer to my question:	The level of public participation per IAP2 is available in the IRP schedule filed with the WUTC and posted on pse.com:

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	Climate Action Group	"Was there a way for us to know PSE's level of public engagement intended for this meeting before the meeting?" I now have 2 questions: 1. Was my question actually answered during the webinar? 2. What is the answer to my question?	https://oohpseirp.blob.core.windows.net/media/Default/PDFs/UE-200304-UG-200305-PSE-Appendix-A-(07-08-2020).pdf PSE has routinely defined the level of public engagement at the beginning of the presentation and will consider adding the level more prominently on the website in the future. 1. PSE acknowledges that the question was asked in the chat and the response was not documented in the chat. 2. The IAP2 level of public participation for the July 14 webinar was Consult.
7/20/2020	Joni Bosh, NWEC	NW Energy Coalition (NWEC) appreciates the opportunity to provide feedback on the presentation on demand side resources of July 14th, 2020. We start with three general points on the presentation. 1. It was unfortunate that there was not enough time to discuss stakeholders' questions for four of the five topics; it may be worth considering having fewer topics per session and adding sessions. 2. Please explain the process and schedule for completing the 2021 IRP Conservation Potential Assessment. How will the CPA be adjusted when the final load forecast for the 2021 IRP is available? 3. NWEC requests that the workbooks related to the July 14 presentation be made available via the 2021 IRP web site. Once posted, we request sufficient time to review the material with a comment form deadline of at least 5 working days, and preferably 10 working days. It is particularly important to have access to the Demand Side Resource workbooks and any related materials. Other information and data used for IRP inputs, such as generation cost estimates, typically rely on national assessments such as the NREL Annual Technology Baseline, or generic assumptions from public data compiled by PSE staff and consultants.	Response #1. Thank you for this suggestion. Response #2: The CPA was started in January and the webinar was the culmination of that work. The company F2020 load forecast was simultaneously under development during this time. The load forecast informs the new construction measures based on the customer growth, and not the retrofit measures. A draft was available in late May and it was used to estimate the new construction opportunities in the CPA. The final load forecast did not change much from the draft: the annual energy loads did not change, and the peaks are a little lower than the draft peaks used in the CPA, by 0.30%. These changes are not material and will not change the results of the CPA. More details of the load forecast will be presented at the September 1, 2020 meeting. Response #2. Response included in above response.

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		However, demand side resource estimates must be localized and depend on the specific characteristics of PSE's customer base and the historic, current and projected costs and other factors involved in acquiring these resources. For that reason, it is particularly important to review the detailed data underlying the conclusions of the July 14 presentation and eventual inclusion of inputs into the IRP modeling going forward. As a result, the comments here are provisional responses to the material presented on July 14, and we reserve the right to provide further comments after reviewing the supporting material. Our comments and requests are presented by slide below, identified by page number and title.	Response #3. PSE can provide some workbook components that have measure details and assumptions used in the CPA. PSE will reach out to NWEC to discuss this request further.
		Slide 14 - Updates in 2021 CPA: T&D deferral benefit The deferral amount has substantially changed. Please provide the specific assumptions that have altered since the last IRP when the value used was $64.77/kW-yr.	Slide 14: PSE updated the analysis for the 2021 IRP and is currently assessing what information can be made public. Additional information may be provided in the Consultation Update.
		Slide 20 - Types of Energy Efficiency Potential One of the most important reasons for our request to review the workbooks and related materials for the energy efficiency analysis is to be able to trace the process from assessment of technical potential for measures and programs to the achievable technical potential and then the achievable economic potential. Among other things, this will enable comparison to the NW Council's analysis and other utility IRPs in the region.	Slide 20: PSE acknowledges and will be reaching out to you to discuss.
		Slide 27 – Step 6. Develop Supply Curves for IRP Modeling If measures are bundled by levelized cost ranges, please explain how PSE will capture and reflect peak energy values for each measure? An illustrative example might help with that explanation.	Slide 27: The levelized costs currently include the peak demand benefits of deferred T&D. The avoided generation capacity benefits are applied within the portfolio model.
		Slide 30 – Electric Energy Efficiency Potential Please provide the worksheets behind this summary. NWEC also requests an explanation of when and how the assessment of the social cost of greenhouse gases required by CETA is included in this analysis, and how	Slide 30: The SCGHG will be an input in the portfolio model and will be applied to all resources including demand side resources. The effect of SCGHG is to increase the cost of fossil

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		that will be reflected in changes to achievable economic potential for energy efficiency at later stages of the IRP process.	fuel based resources and thus would favor more conservation. Eventually, the avoided cost that are developed from the post IRP process for use in conservation program planning will include the SCGHG adder.
		Slide 31 – Comparison to 2019 CPA The difference between 2019 and 2021 is a 20% reduction in Total Achievable technical potential. While most of this is explained as changed in commercial forecasts, please explain in detail the assumptions behind the reduced potentials for industrial and residential as well.	Slide 31: Overall residential potential is largely unchanged between the 2019 CPA (306 aMW) and 2021 CPA (314 aMW through 2041). Industrial potential is lower due to re-classification of some commercial customers from the industrial sector in the 2019 study.
		Slides 36, 37, 38 – Top Residential/Commercial/Industrial Electric Measures NWEC is concerned with the context and some of the specific detail in these tables. The second column is "Weighted Average Levelized Cost ($/kWh)" but the time period is not indicated, nor whether these are cumulative costs. It is difficult to interpret the sign and scale of many of the indicated values, for example, $0.40/kWh for residential windows, a negative value (-$0.064) for clothes washers, but a positive value ($0.275) for clothes dryers.	Slide 36, 37, and 38: The measure categories in the tables on slides 36, 37, and 38 are comprised of many individual measure applications. These are aggregated into measure categories to ease reporting. Because every individual measure includes its own levelized cost, we created savings-weighted levelized cost at the measure category level. These costs are levelized over the 24-year electric study horizon. Residential windows are a relatively expensive efficiency measure; clothes washers have a negative levelized cost, primarily because of the relatively high value of the non-energy impact of water savings, whereas clothes dryers do not accrue any NEIs and have a relatively higher incremental cost than clothes washers.
		Slide 42 – Demand Response Projects NWEC requests that PSE include in the IRP some discussion of the additional benefits of aligning programmatic DR with effective time of use rate design. There has been considerable analysis of these interactive effects,	Slide 42: PSE will add a discussion on time of use rate in the draft IRP report.

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		and current program efforts, for example the Portland General Electric DR Testbed, are assessing the overall gain from a coordinated approach rather than having program and rate design be developed separately.	
		Slide 44 – Comparison to the 2019 CPA We refer to our earlier comments about the importance of reviewing the underlying workbooks for this analysis, in particular for demand response. That proved to be important in the work of the NW Council's Demand Response Advisory Committee in reviewing inputs for the 2021 Northwest Power Plan, based on a template system for DR analysis provided by Cadmus. At this time, we provide initial comment on one DR measure, grid-enabled water heaters, while reserving the right to provide further comment on this and other measures after reviewing the DR workbooks and supporting materials. The grid-enabled water heater measure has rapidly emerged to be a leading DR resource for PSE. The recent adoption of the CTA-2045 interface module requirement for all new electric water heaters in Washington by January 2022 elevates the importance and availability of this measure even higher. The July 14 presentation indicates a total peak reduction potential of over 60 MW. There is no indication of time duration for the supply curve, but we assume that to be through 2041. As a result of the CTA-2045 requirement, NWEC assumes a much higher resource potential and much faster realization. Taking a very simple approach, we assume 600,000 electric water heaters currently for PSE residential customers and a 12-year resource life, with 50,000 replacements per year. Using the NW Council estimate of 0.5 kW average peak reduction per unit (assuming 4.5 kW demand per unit and a coincidence factor of about 12%), that equates to a technical potential of 25 MW per year and a total potential of 300 MW. This is far greater than the 60+ MW indicated on Slide 44. We recognize that achievable economic potential will be affected by customer acceptance and other reasons, but additional factors also should be	Slide 44: This slide shows 71 MW of residential water heat direct load control. The 71 MW are achievable technical potential which includes an assumption that program participation is equal to 25% of the eligible customer population (i.e. residential customers with electric water heating). This program participation value is the same assumption employed by the Council in its draft 2021 Plan demand response supply curves. Dividing the 71 MW by 25% equals about 284 MW of technical potential, a value similar to NWEC's estimate.

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		considered. For example, a recent report for the Northwest Energy Efficiency Alliance (screen shot below) indicates that about 70% of water heaters are replaced for burnout, but another 30% are purchased for other reasons. New residential units should also be accounted for. Because of the magnitude and favorable cost of the grid-enabled water heater resource, it is important to refine the analysis before setting the inputs for the 2021 IRP. Water Heater Market Characterization Report, #E18-305, April 2018, prepared for NEEA by Russell Research:	

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		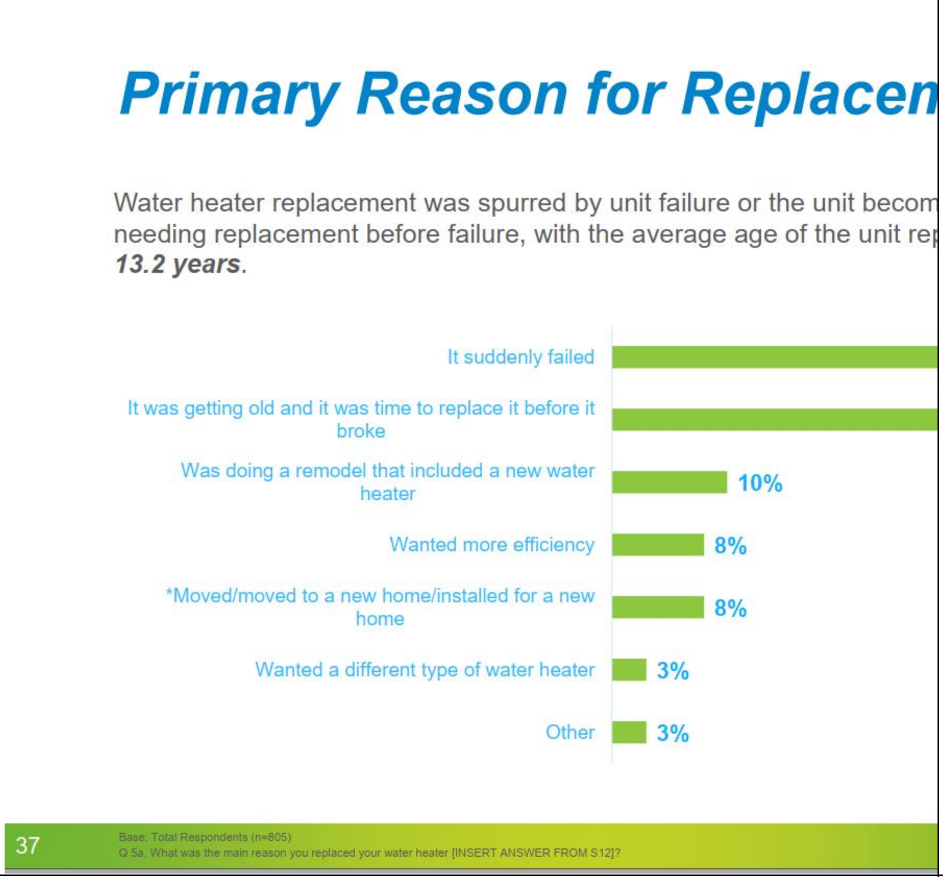	
		Slide 45 – Comparison to the 2019 CPA One point on the slide indicated “Lowered space heating DLC per unit kW impacts.” Please describe the previous and current values and what led to this result.	Slide 45: The previous study used a value of 1.74 kW, which was derived from a PSE pilot in a very specific part of its service territory (Bainbridge Island) that is over a decade old. The new value, 1.09 kW, is the same value used by the Council in its draft 2021 Plan’s demand response supply curves and originates from a

<table>
<tr><th>Feedback Form Date</th><th>Stakeholder</th><th>Comment</th><th>PSE Response</th></tr>
<tr><td></td><td></td><td></td><td>more recent evaluation of PGE’s program. We believe this value is more appropriate and applicable to PSE’s service territory than the Bainbridge Island pilot value.</td></tr>
<tr><td></td><td></td><td>Slide 49 – Distributed PV Methodology
While the Bass diffusion model is widely used, we have three concerns. First, it may not fully capture the anticipated value perceived by customers of hedging against future rate increases.
Second, it may not account for non-price factors driving customer adoption, for example, environmental responsibility. And third, because it is based on an annualized simple payback calculation, first-cost plays a deciding role.
We are unclear whether the methodology incorporates the NREL Annual Technology Baseline (ATB) values for future PV costs, or it relies on the previous Annual Energy Outlook estimates.
We have reviewed the recently issued 2020 ATB, and find that significant cost reductions have occurred compared even to the 2019 ATB for residential solar at their Seattle standard location.
The following table shows the life cycle cost of energy (LCOE $/MWh) values for 2020, 2025 and 2030. The cost decline trend throughout the decade is substantial, and as previously stated, we believe the midpoint between the Low and Mid-range (2019 ATB) or Advanced and Moderate range (2020 ATB) is the most appropriate for modeling purposes.
<table>
<tr><th></th><th>2020</th><th>2025</th><th>2030</th></tr>
<tr><td>2019 Low</td><td>117</td><td>77</td><td>39</td></tr>
<tr><td>2019 Mid</td><td>134</td><td>103</td><td>72</td></tr>
<tr><td>2020 Advanced</td><td>117</td><td>76</td><td>37</td></tr>
<tr><td>2020 Moderate</td><td>119</td><td>84</td><td>50</td></tr>
<tr><td>NWEC Proposed</td><td>118</td><td>79</td><td>44</td></tr>
</table></td><td>Slide 49: Due to the uncertainty regarding future incentive and tax credit availability, PSE plans to model several solar PV sensitivities, including the potential estimated by the Bass diffusion curve, as shown in slide 49 of the presentation.
Regarding the NREL price forecast, the results presented are based on the 2019 ATB cost forecast; the 2020 ATB data set was not yet publicly available at the time of our analysis; however, Cadmus proposes to update the BAU scenario to the 2020 NREL ATB moderate forecast and run a separate sensitivity using the 2020 advanced forecast.</td></tr>
<tr><td></td><td></td><td>Slide 49 – Achievable Potential Assumptions</td><td>Slide 49: This incentive is mostly energy value as solar pV does not contribute to PSE winter</td></tr>
</table>

Feedback Form Date	Stakeholder	Comment	PSE Response
		Please explain the choice of the $0.048/kWh incentive for the subsequent analysis. This amount appears to provide only capacity value and should also include energy value.	system peak. PSE will address this further with a sensitivity requested using an updated 2020 ATB data in place of the PSE incentive.
		Slide 51 – Distributed Solar PV Achievable Potential This chart only addresses the amount of potential new PV going forward. It would be helpful to provide additional information about what PSE has already attained over the last 20 years and adoption trends to date	Slide 51: The requested data will be included in the Consultation Update.
		Slide 66 – Distribution Efficiency Potential Is there an effective difference between volt/var optimization (VVO) and conservation voltage reduction (CVR)? What have been the results from pursuing CVR programmatically?	Slide 66: VVO has a mechanism to dynamically maintain the set point for the conservation voltage reduction even when growing number of distributed energy resources on the circuit. Whereas CVR was a more static system setting and the savings could be reduced with the penetration of more distributed energy resources which impact the electrical characteristics of the distribution system. So far, the CVR is working but looking into the future, VVO will likely become more important.
		Slide 69 – Stakeholder Feedback on DSR Sensitivities Proposed sensitivity 2 is for "Distributed Solar PV – with PSE ownership." Since this would be a new program with many important elements and issues, please explain the basic concept and whether it would expand solar access to low and moderate income and other disadvantaged segments that would expand DSR resource potential.	Slide 69: PSE will include your suggestion provided during the webinar for a sensitivity with a lower cost curve. PSE will likely propose to replace the PSE incentive sensitivity with the lower cost curve sensitivity. The Clean Energy Implementation Plan (CEIP) would allow for discussions on how best to offer programs to disadvantaged segments of PSE customers.
7/20/2020	Michael Laurie, Watershed LLC	Do the load forecasts take into account the likelihood that commercial building occupancy will be significantly less than it was pre-COVID and that overall demand will likely be less for several years into the future because of	PSE responses by paragraphs and referenced slide numbers:

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		the economic impact of COVID and because many more people will be working from home permanently? If not why not? Do any of the efficiency and renewables estimates take into account that we may likely have a Democrat president and Democrat controlled Congress which will likely lead to significant federal incentives for more efficiency and renewables? Biden has put together a major Green New Deal Plan that significantly eclipses the federal spending on efficiency after the housing crash in 2008. If you have not taken this into account, what is your justification for ignoring what could be a huge impact on efficiency starting next year? Could you show us your calculations, inputs, and assumptions that you used to estimate the non-PSE programmatic conservation that will occur due to Washington legislation that has passed recently including new energy codes, C-PACER, CETA, commercial building performance standard, and more. This is critical because if this is underestimated it could lead to overbuilding supply side resources. It is not helpful to anyone to know that you will include it in the modeling. Please show us the numbers and details even if that means showing us a simplification of how the model will deal with it. To me a simplification means at least at Excel workbook that makes estimates of the efficiency savings that will occur due to each program and it documents what those assumptions are based on. Ideally a 3rd party should carry out energy modeling of base case energy use and reduced energy use due to these programs for several representative building types as was done in the study linked below on the energy code impacts. https://www.sbcc.wa.gov/sites/default/files/2020-04/SBCC-BaselineStudy_FinalReport-APPENDIX%20E_Part-2_2-20200323.pdf Have you looked at the Rocky Mountain Institute's case study of the major retrofit of the Empire State Building to include the measures they implemented in your analysis of what is technically feasible? And are you working to ensure that the measures implemented in that building are studied and encouraged in the commercial buildings of PSE customers. And if not,	Per our economic forecasts based on Moody's and other regional sources (which include assumptions about the effects of the pandemic), we anticipate slower commercial customer additions and a small shift of load from the commercial class to the residential class due to unemployment and employment contractions in the medium term (i.e., people spending more time at home). The load forecast is based on the assumption that the pandemic state is temporary (resolved before 2022), however, we acknowledge there may be permanent behavioral changes, post-pandemic, and will adjust the forecast when legitimate steady state becomes more clear. The load forecast details will be further discussed at the September 1 webinar. The IRP is an iterative, long term planning process. Changes to federal standards will be adopted in the assumptions when passed into law. The draft report will include a more detailed accounting of non-programmatic conservation that will occur from Washington State energy legislation. PSE is familiar with the major retrofit of the Empire State. Our study is focused on PSE service area conditions, fuel mix, building & system vintages, labor costs, etc. PSE implementers are required by state law (Energy Independence Act) to implement cost

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		why are you leaving so much conservation on the table when others like in New York are taking action on it? https://www.esbnyc.com/sites/default/files/ESBOverviewDeck.pdf What is the relationship between the CPA and IRP effort versus program implementation? Are the program implementers at PSE required to show a good faith effort to carry out what the IRP concludes is cost effective? If so, is there a publicly available report where the implementers document that? If not why not?	effective amount of conservation coming out of the IRP. They work with a stakeholder group called the conservation resource advisory group (CRAG) to set the targets using the IRP cost effective conservation results, and they file the Biennial Conservation Plan with the WUTC, which is available to the public.
		Slide 36 includes one measure called "Whole Home". Whole home what? What is that?	Slide 36: The Whole Home measure applies to new single family and manufactured home and is an incentive based on achieving 20-30% energy efficiency over the state energy code baseline.
		Slide 39, Back to my point about considering a likely Democratic federal administration in your analysis, I think it is critical to consider that there will be a lot more new federal standards when and if that happens. Why aren't you including this in one of your options going forward?	Slide 39: Typically, most conservation potential assessments, including those performed by the Northwest Power and Conservation Council, do not attempt to predict the impact of non-existent future federal standards or state and local building codes.
		Slide 45 - Agree with Don Marsh's point. PSE please explain what thinking and evidence led to you reaching a different conclusion than other utilities reached on this subject.	Slide 45: The explanation regarding customer acceptance was listed solely with respect to smart appliance direct load control. We are not currently aware of any secondary research that indicates customers' acceptance of having smart appliances controlled by their local utility. The most recent Smart Electric Power Alliance 2019 Utility Demand Response Market Snapshot included a survey question that indicated 0% of 95 utility survey respondents indicated that voice-enabled smart home devices have been integrated into new or existing demand response programs.

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		Have you considered the possibility of some uses of natural gas will be banned in new construction as has happened in a number of jurisdictions in California? If not why not? Could you do a sensitivity analysis of conservation achievable if conservation can be done without a loss of revenue to PSE. I am thinking here about the MEETS approach. (Metered Energy Efficiency Transaction Structure): This is efficiency that also does not have to meet PSE's cost effectiveness bar because it is not PSE paying for it as an alternative to a gas plant or renewables. It is a private investor group doing it to make money from efficiency with no loss of revenue to PSE. After a quick review of the PSE July 14th presentation this looks to be one of the Achilles heals of PSE's effort because they are focused on carrying out cost effective, technically feasible conservation that does not have barriers. But MEETS includes conservation that does not have to meet their cost-effectiveness criteria and that will not be up against the typical barriers that most conservation is limited by. Why isn't PSE willing to at least carry out a pilot project of this deep retrofit approach like Seattle City Light is currently doing? And a sensitivity analysis of conservation potential if conservation spending was recognized as capital spending, thus allowing PSE to make a profit on conservation spending. Some people have proposed the idea that conservation spending be considered capital expenditures because that would allow PSE that make a profit on it. How would this impact conservation spending? I think it could have a huge impact leading to so much conservation spending that the case for new natural gas plants would be unnecessary. Thank you for your time on these important issues. All the best.	PSE is considering a fuel conversion sensitivity from gas to electric. The possible scenarios and sensitivities will be discussed at the August 11 webinar. PSE already has a decoupling mechanism is place: https://www.utc.wa.gov/docs/Pages/PSEDecouplingUE121697.aspx It is primarily a delivery mechanism for conservation measures and this discussion belongs in the design and implementation of programs. Concerning the idea to run a sensitivity on earning a return on conservation, we can discuss this during the August 11 webinar on scenarios and sensitivities (electric and gas).
7/21/2020	Kyle Frankiewich, WUTC	**Commission Staff Feedback for Puget Sound Energy 2021 IRP Webinar #4: Demand Side Resources – July 14, 2020** Questions and comments from presentation:	PSE responses to questions and comments by referenced slide number:

Feedback Form Date	Stakeholder	Comment	PSE Response
		• Slide 11: Elizabeth explained that one advantage of Plexos is that the program is open-source, so all resources are visible and able to be coded in. Accurately representing these unique resources - coding these inputs - then becomes critical. Please share the parameters used for the various DR resources, as well as any documentation used to support the parameters used.	Slide 11: PSE has not finished setting up the Plexos model and the DR programs have not been coded yet. The information will be available at a later date.
		• Slide 13: Where did PSE's figures come from? What went into them? Are they stale or is this a fresh analysis for the 2021 IRP? Please provide the work papers supporting PSE's deferral benefit estimates.	Slide 13: PSE updated the analysis for the 2021 IRP and is currently assessing what information can be made public. Additional information may be provided in the Consultation Update.
		• Slide 18: It appears that CCP is the only type of alternative rate design approach explored within CADMUS's CPA. This may be acceptable if PSE intends to fully explore the potential for TOU and dynamic rates elsewhere in the IRP. What aspect of PSE's work plan includes this piece?	Slide 18: We don't test rate designs in the IRP. The CPP program assumes that the company will attain a time differentiated rate in the near future. That is an assumption upon which the CPP is based in the IRP. The CPP program may or may not be the driver for a future change to a time differentiated rates.
		• Slide 27: Are all costs and benefits levelized by PSE's WACC? If so, it may be more appropriate to model the carbon emissions cost (and carbon emission reduction benefits) using a 2.5% discount rate to align with U-190730. (may be covered in 7/21 meeting)	Slide 27: Yes all costs are levelized using the WACC. U-190730 relates to the use of inflation factors in adjusting the SCGHG. We have done a sensitivity in the past using the social discount rate and we can consider one in this IRP. The scenarios and sensitivities will be discussed at the August 11 meeting.
		• Slide 29: Baselines should rightly be adjusted for new water heater standards; does the EE and DR program implementation side of PSE have the capability to acquire these opportunities?	Slide 29: PSE needs clarity concerning this question. PSE will be reaching out to WUTC to gain some insight.
		• Slide 35: Please describe the whole home measure category. What is weighted average levelized cost? What is being weighted and averaged? Does this imply a market forecast with hourly prices? I didn't get to ask in the interest of time.	Slide 35: The whole home measure relates to whole building performance incentive to build 20-30% above the WA state energy code. Built Green program: The table on slide 36 presents the results for different residential measure categories, some of which are comprised of

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			many different individual measure applications; for the whole home measure category, this would include new single family and manufactured homes that are either 20% or 30% better than code. Therefore, we also created weighted average levelized costs, which is an average levelized cost for each individual measure application, weighted by that application's total achievable technical potential.
		• Slide 42: Please describe the difference between CPP and behavioral DR. Is behavioral DR simply asking/informing?	Slide 42: Critical peak pricing (CPP) is typically included in a tariff whereas behavioral demand response, which is neither time of use nor critical peak pricing, is a demand response program that notifies customers day-ahead via text or email of an upcoming event and encourages them to save energy during a specific time horizon.
		• Slide 44: This is a very useful graph. What are kW-yr costs like on supply side, generally? For peaker / CCCT / 10 MW battery? How do these kw-yr figures compare to the $/kWh measures above? Or is that EE apples and DR oranges? (see recommendation about Pacific Power's aborted idea on calculating the capacity value of EE)	Slide 44: PSE does not have the levelized cost of supply resources, it is calculated at the end of the process using the model outputs.
		• Slide 46: Why limit CPP participation? Can residential customers with gas space heat provide value through a DLC program?	Slide 46: Cadmus is not aware of any gas CPP program. Part of the limitation is that the two primary gas end uses (water and space heating) can also be directly controlled whereas CPP is not a firm resource. Another part of the limitation is that gas is traded on a daily basis and system peaks are daily. If a CPP program is applied to end users, the daily use may not change. The gas use after the CPP event may be higher to bring the space or water temperature back to the set point.

Feedback Form Date	Stakeholder	Comment	PSE Response
		• Slide 49: Does PSE intend to generate other components of the DER assessment required under CETA? Do empirical data support the use of a homo economicus assumption about customer adoption of solar? What is a Bass diffusion model function? A key input to this analysis is the falling cost of solar. Does that input align with PSE's supply-side solar assumptions? Does PSE intend to explore the value of customer-sited (and possibly customer cost-shared) energy storage, especially paired with solar? This seems like an important DER to fully understand. The impact of alternative rate design paired with DERs must also be fully analyzed.	Slide 49: PSE will discuss distributed energy resources (DER) at the August 11 meeting. Depending upon the study, empirical data likely indicate a number of factors influencing both commercial and residential customer solar adoption, including estimated payback. The Bass diffusion model function is a Bass diffusion model variant that models customers' sensitivity to payback and the annualized simple payback for each year of the study horizon. Utility-scale and customer-sited solar PV costs vary widely and are not the same; customer-sited PV costs also vary between residential and commercial customers. In both cases, the PV analysis includes a forecast of future solar PV prices, which do decline substantially over the study period.
		• Slide 50: Where does $0.048/kWh rate come from? Does changing this rate yield dramatically different adoption rates? Does this rate align with the company's PURPA rates? If not, what is included here that is not included within the company's PURPA avoided costs?	Slide 50: We have estimated the avoided cost based on the draft 2019 IRP work we did. This lines up more with cost effectiveness used for customer programs. This is not seen as a PURPA avoided cost. Based on feedback from you and NWEC during the webinar, we will eliminate this PSE incentive sensitivity and consider a lower cost curve sensitivity in its place.
		• Slide 60: Seems gas EE costs have come down while total potential has grown. Why?	Slide 60: The potential has gone up due to market changes that impacted couple measures. Gas potential is lumpy in that changes in one or two measures can have an impact on the supply

Feedback Form Date	Stakeholder	Comment	PSE Response
			curve. The lower gas costs don't affect the measures costs, but will come into play when we run the IRP model to determine the cost effective amount of conservation.
		• Slide 61: As with EE, please explain what is being weighted and averaged in the levelized cost column. Do these calculations include all quantifiable non-energy benefits? Appears so given that aerators have a negative cost. What NEIs were included?	Slide 61: Individual measure applications are being weighted within large measure categories. For example, individual measures may have varying incremental costs and/or energy savings depending on which housing segment is being treated or the baseline measure it is replacing. The individual measure levelized costs are weighted by each measure's total achievable technical potential. These calculations do include all quantifiable non-energy impacts; measures with low incremental costs but significant NEIs, like aerators, may have negative levelized costs.
		• Slide 66: How long did it take for first 17 substations? What controls are being adopted in 2022? Is the tech not ready to be adopted now or in 2021? Has PSE estimated the added cost of pulling these projects forward in time, i.e. to get 24 aMW of savings before 2026 instead of by 2034? Is that option (and the corresponding added cost) selectable by the resource optimization model? Do these upgrades also enable more solar and other DER resources?	Slide 66: The Advanced Distribution Systems Management (ADSM) system will be installed in 2022 and it will ensure stability and accommodate more DERs on the system, and will allow additional savings in the distribution efficiency measures. No, early completion is not adjustable inside the IRP model.
		• Slide 67: why is levelized price the appropriate way to bundle? What does 20yr vector mean? is a 'bundle' of subsidized private solar at small cost the best way to model distributed PV as a selectable resource? What does 'applied in the portfolio models' mean?	Slide 67: The levelized cost is standard industry practice for creating supply curves. A vector is a 20 or 24-year stream of savings that is used as the input in the portfolio model and it is a resource option available in the first year of the study. Distributed solar is a must take resource and is not being "selected." The application of SCGHG in the IRP models was addressed at the July 21 webinar.
		• Slide 68: It seems like there is a lot of analysis that is being described in these bullet points. How is a DR program group's ELCC	Slide 68: PSE will discuss the resource adequacy model and the effective load carrying

Feedback Form Date	Stakeholder	Comment	PSE Response
		determined? Are other resources also decremented based on an ELCC analysis? What is the ramp-up time for a DR program? What are the DR program sizes available to the portfolio model? How did PSE determine that these sizes are appropriate?	capacity (ELCC) of demand response (DR) and other resources at the September 1 meeting. The ramping and quantity is shown and discussed on slide 44 and additionally on slide 84 in the appendix. The amount of DR is the result of the potential assessment.
7/21/2020	Kyle Frankiewich, WUTC	Recommendations:	PSE responses concerning recommendations by number:
		1. Equity analysis in IRP: CETA requires an equity assessment within the IRP, as described in RCW 19.280.030(1)(k). This requirement is not waivable, and is not on hold while rulemakings and Department of Health's cumulative impact analysis work is ongoing. Modeling is a decision support tool, and system needs should consider all constraints and requirements, including equity needs. At the very least, PSE needs to assess whether it's selected portfolio increases or decreases disparities in the geographic distribution of system benefits and burdens. This is a very different challenge from past IRPs, which is why it seems like a good idea to discuss how to approach this new challenge early and often. How does PSE plan to countenance this equity constraint? Please consider adding a separate IRP meeting to discuss equity issues and the company's proposed approach for assessing equity impacts.	1. Thank you for the recommendation. PSE is still assessing the best process to ensure that equity is appropriately addressed through the 2021 IRP.
		2. CPA before load forecast: Many participants expressed concern about this topic. To assuage these concerns, PSE should compare the preliminary load forecast used as a CPA input with the finalized forecast to see whether the CPA results are reasonable. a. We also agree with commenters that changes from 2019 CPA to 2021 CPA are hard to understand if most of the shifts in conservation potential are brought about by changes in the load forecast. b. Also, we want to recognize the unavoidable bind PSE is in – if PSE had started with imperfect load forecast that didn't	2. (a) The impact from the changes to the load forecast are relatively small. The major changes were due to updates to the measures themselves, and their savings assumptions. Three of the major changes were discussed on slide 34. (b) PSE used a draft version of the 2020 load forecast in the results presented on July 14th. We expect the final will be the same as the draft and if not, then very close to it. In the event that

Feedback Form Date	Stakeholder	Comment	PSE Response
		include finished CPA figures, participants may wonder why preliminary figures were being presented when they aren't fully baked.	there is a major change in the final we will inform the stakeholders of the change. In either case, Cadmus will update its analysis based on the final load forecast and we will detail the changes to the potential based on the final forecast.
		3. Ramp rate for discretionary EEMs: Some commenters have noted that the 10 year ramp for discretionary EEMs is arbitrary. I don't know that it's wrong, but it would be good to hear why 10 yrs is more appropriate than 4 or 6 yrs, especially knowing that the value of conservation may (or may not!) jump in 2026 and 2031 due to CETA's restrictions on fossil-based supply-side resources. Some sensitivities to see the impact of adjusting these ramp rates would also be helpful.	3. The 10 year ramp was determined around the 2007 IRP. PSE will consider the faster ramp rates of 6 years and 8 years as sensitivities. This topic will be discussed further at the August 11 webinar.
		4. Uncertainties regarding customer acceptance (of DR, CPP, solar): these assumptions are soft and fungible; PSE could shift perceptions of programs if it decided it was worth the time and investment. Should vet these assumptions based on empirical data elsewhere and assumptions of other utilities.	4. The major customer uncertainty for demand response listed was that of smart appliance direct load control. We are unaware of any fully implemented program or evaluation of customer acceptance of this control technology. For other demand response products, the program participation rates – which account for likely customer acceptance – are all based on secondary research of similar programs from other utilities and have been checked against regional assumptions on the Council's 2021 Plan draft demand response supply curves and other recent, NW utility IRPs.
		5. Sensitivities around private solar: install price; incentive offering; including knock-on effects	5. PSE will be doing a sensitivity with a lower cost curve of solar PV. Additional discussion regarding the sensitivities will occur at the August 11 meeting.
		6. Scenario banning new gas use: I'm not expecting the company to plan around this possibility, but understanding how the plan would have to pivot if a ban or partial ban was put in place can only be helpful.	6. PSE will be discussing portfolio sensitivities at the August 11 webinar and stakeholders will have an opportunity to provide feedback regarding the sensitivities that should be

Feedback Form Date	Stakeholder	Comment	PSE Response
			included. One of the sensitivities is a fuel conversion from gas to electric, we are not looking at a gas ban scenario.
		7. TOU and dynamic rates: Please clarify when and where these options will be analyzed.	7. These options are analyzed outside the IRP in the rates and regulatory group of the company.
		8. DR water heaters: Fred with NWEC's observations on the rough scale of this potential resource are persuasive. Please reconcile the forecast in this CPA of about 60 MW total over 20 yrs with his back-of-the-envelope estimate of about 25 MW a year.	8. Slide 44 shows 71 MW of residential water heat direct load control. The 71 MW are achievable technical potential which includes an assumption that program participation is equal to 25% of the eligible customer population (i.e. residential customers with electric water heating). This program participation value is the same assumption employed by the Council in its draft 2021 Plan demand response supply curves. Dividing the 71 MW by 25% equals about 284 MW of technical potential, a value similar to NWEC's estimate.
		9. DR and conservation capacity cost as net of energy savings: In its 2019 IRP, Pacific Power briefly proposed a novel way to derive the capacity cost of EE and DR resources. They used a 20yr hourly energy price forecast and an EEM's load curve to project whether the EEM was cost-effective purely on an energy basis. When it was not, they took the incremental $/MWh cost relative to their energy price forecast and paired that with the EEM's load curve again to determine a $/kW-yr price for the capacity component of an EEM's benefit. I don't want to see this implemented as a way to determine cost-effectiveness, but as a way to value the capacity value of an EEM, it may be useful. Would the company be willing to explore this approach?	9. We input the conservation supply curve as an hourly load shape and the portfolio model takes into account both the capacity and energy value of the energy efficiency in selecting resources. The demand response is input as a capacity resource and its primary value is due to capacity. The ancillary benefit streams will be netted out of the cost.

Feedback Form Date	Stakeholder	Comment	PSE Response
Questions not answered during the webinar			
7/14/2020	Brian Grunkemeyer, FlexCharging	Question queued up for slide 36: I don't see anything about Demand Flexibility approaches. Specifically, there's no EV load management measure, and it's unclear whether the Heat Pump Water Heater measure is taking advantage of all the great work the BPA has been doing on aggregating water heaters as Demand Flexibility devices.	Slide 36 presents the energy efficiency potential results for the residential sector. It does not include load management; however, slides 41 through 47 cover the demand response portion of the potential assessment, which includes electric vehicle service equipment direct load control. Slide 46 shows that residential water heating direct load control is the single largest end use resource for demand response potential and includes both grid-enabled electric resistance water heaters and heat pump water heaters, both of which are ANSI/CTA-2045 capable. The underlying analysis uses per unit kW impact assumptions from the BPA/PGE study.
7/14/2020	Don Marsh	Documentation of PSE's models and assumptions is so important because some of the conclusions PSE comes to seem to be at variance with what is happening with other utilities across the country. For example, Pacificorp is going much more for battery storage than PSE is. Why is that? Is there something different about PSE's service territory? We need to understand.	PacifiCorp service area is very different than PSE's service area. Their plan shows utility scale battery storage which is also included as a front of the meter option in the 2021 IRP.
7/14/2020	Kevin Jones	Will the CADMUS analysis be re-done if there are significant issues with the PSE load forecast? Technical advisors have typically raised concerns about PSE load forecast. How are these results valid?	If errors are found that need to be corrected, then PSE will make best efforts to make those corrections.
7/14/2020	Court Olson	We would like to know when we can plan on hearing a new analysis that includes the heating fuel switching trend that is growing. This is a big flaw in the analysis. What future session will this be presented in?	Fuel switching is being included as a sensitivity and will be discussed at the August 11 webinar on scenarios and sensitivities.
7/14/2020	Bill Westre	Ramp rates - Have other utilities used shorter ramp rates?	PSE is not aware of shorter ramp rates being used.
7/14/2020	Michael Laurie	Have you looked at the case study of the major retrofit of the Empire State Building to include the measures they implemented in your analysis of what is technically feasible?	PSE is familiar with the major retrofit of the Empire State and our study is focused on local

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			NW (actually PSE service area) conditions, fuel mix, building & system vintages, labor costs, etc.
7/14/2020	Elyette Weinstein	What percentage of annual contributions does PSE contribute to the NW Energy Efficiency Alliance?	According to the filing with the WUTC (Docket Number: EES0012019), PSE paid approximately $7.2 million to NEEA in 2019 and their total utility contributions were approximately $40 million (https://neea.org/annual-report/2019
7/14/2020	Court Olson	How is the unique efficiency impact for an aggregation of measures going to be used to adjust the PSE future efficiency forecast? This is important as future CETA deadlines and C-PACER programs ramp up and deep efficiency improvements catch on in the buildings market place. The 2021 IRP must take this into account, so when will we see appropriate revised efficiency forecasting?	PSE appreciates your observation that we are not using bundling of measures in the CPA. The conservation supply curve is ordered lowest cost to highest cost so we can test the marginal cost resource to determine the cost effective amount of conservation. We will not have a forecast with these bundles in the CPA. However, what you are suggesting can be considered on the implementation level with programs, and the CPA does not prevent this in any way. Programs can be designed to include highly cost-effective measures with hard to reach measures or deep measures.
7/14/2020	Michael Laurie	What is the relationship between the CPA and IRP effort versus program implementation? Are the program implementers at PSE required to show a good faith effort to carry out what the IRP concludes is cost effective? If so is there a publicly available report where the implementers document that?	PSE implementers are required by state law (Energy Independence Act) to implement cost effective amount of conservation coming out of the IRP. They work with a stakeholder group called the conservation resource advisory group (CRAG) to set the targets using the IRP cost effective conservation results, and they file the Biennial Conservation Plan with the WUTC, which is available to the public.
7/14/2020	Kevin Jones	Gurvinder - you did not really answer my question - would PSE provide the load data used in the CADMUS analysis? Will this be the same or different than the load forecast provided in September? If different we would like to	The load forecast was provided as a draft as it takes a lot of effort to get the forecast completed, so there is a small chance that the load forecast may see some minor changes from what was

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		understand the differences. If the same, why will PSE not provide the data now?	used in CPA versus what is finally approved. But the load forecast change will not and does not have a material impact on the CPA numbers. If there is a change in the load forecast from the one used in the CPA, we will inform you of that.
7/14/2020	Don Marsh	Slide #30. How do the 2023 values compare to NWPCC assumptions? How do they compare to assumptions for neighboring utilities, like Seattle City Light? They seem a little low to me.	These values have to be compared within context. A high number can also indicate that the utility has not being engaged in aggressive conservation in the past and thus a lot of conservation still remains. The numbers for Seattle City Light are at the technical potential level, and if one uses the 85% achievability factor assumed in the SCLs numbers for achievable technical potential are as follows: Residential = 21%, Commercial = 20%, and Industrial = 7%. PSE's corresponding numbers are 18%,18% and 8%.
7/14/2020	Court Olson	You missed the legislating update for HB2405 which put C-PACER into law. This needs to be included in your analysis. When will your analysis be adjusted accordingly?	Thank you for bringing this to our attention, the next legislation seems to have passed this spring. Any impacts will be reviewed and PSE will provide a discussion in the IRP book of the implication to the next CPA.
7/14/2020	Joni Bosh	Repeating my question from slide 24 here again - If measures are bundled by levelized costs, how do you plan to reflect/capture peak energy values? By measures? By bundles? Slide 27	The measures are shaped using 8760 hourly shapes before they are bundled. The region has been relying on ELCAP data library and some shapes from the RBSA. Thus the bundles are also an aggregated 8760 hourly shape, where the peak is part of the shape.
7/14/2020	Court Olson	Your commentary thus far indicates that several things were overlooked and not included in estimating the achievable energy efficiency over the next twenty years. When will these projections be revised to include the increasing trend of deep efficiency improvements which we expect over the next twenty years?	The CPA has a comprehensive look at all possible measures that could be done. The idea of deep retrofits belongs in the implementation side, whereby the aggregation of very cost-effective measures with not so cost-effective

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			ones can lead to more comprehensive retrofits. The programs teams are working with pay for performance measures and engaging with them may answer the questions you are posing here.
7/14/2020	Kevin Jones	Slide 33: Is the 26% to 8% drop in achievable Industrial technical potential due to industrial to commercial reclassification?	Yes.
7/14/2020	Don Marsh	Slide #34: I think you're saying that most of the drop in electric potential is because of lower growth in various categories. So the load forecast should be significantly lower than we saw in 2019. But for now, we just have to guess. Like blind men describing an elephant.	The load forecast is not the major driver in the reduced conservation on slide 34. It is not a factor in the items discussed on this slide. Load forecast will be discussed at the September 1 webinar.
7/14/2020	Court Olson	Slide 34 seems to only consider new construction. Some of us expect an increasing likelihood of retrofitting existing buildings. It appears that you are missing this likely occurrence over the next 20 years which will likely eclipse the savings impacts from more efficient new buildings. When will your forecast be adjusted to accommodate this likely future trend? To follow up on my question on air leakage consideration, please provide the data source for the detailed envelope factors that Camus says that they use. Thanks.	PSE appreciates your observation that we are not using bundling of measures in the CPA. The conservation supply curve is ordered lowest cost to highest cost so we can test the marginal cost resource to determine the cost effective amount of conservation. So we will not have a forecast with these bundles in the CPA. However, what you are suggesting can be considered on the implementation level with programs. Programs can be designed to include highly cost effective measures with hard to reach measures, or deep measures. The underlying air leakage assumptions were derived from various Regional Technical Forum unit energy savings workbooks including, for example, the Residential Single Family Weatherization workbook, v4.1: https://nwcouncil.app.box.com/v/ResSFWeatherization-v4-1
7/14/2020	Doug Howell	Slide 26. That does not answer the question about why can't PSE further accelerate the ramp rate from 10 years to six or eight years.	You have requested 6 and 8 year ramping as sensitivities and PSE has included your request

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			in the list of sensitivities. Further discussion will occur at the August 11th meeting.
7/14/2020	Court Olson	The answer to my question on the 10 year life for measures rather than 20 years, the assumption that measures will only have a weighted average of 10 years is incorrect in my experience. This needs to be revised. When can we expect to see this impact period extended from 10 years to 20 years?	The CPA uses standard measure life data for equipment, as used by the regional technical forum (RTF), NWPCC, NEEA, etc. You are correct that often the equipment is used beyond its useful life. In those cases the efficiency also degrades over time. The CPA assumes that equipment is replaced at the end of its life with same efficiency as was installed in the first year.
7/14/2020	Michael Laurie	Slide 36 includes one measure called "Whole Home". Whole home what? What is that?	The whole home measure relates to whole building performance incentive to build 20-30% above the WA state energy code. Built Green program. https://www.pse.com/rebates/new-construction-grants/high-performance-homes
7/14/2020	Michael Laurie	Slide 39 Back to my point about a likely Democratic federal administration, I think it is critical to consider that there will be a lot more new federal standards when and if that happens.	The IRP is an iterative, long term planning process. Changes to federal standards will be adopted in the assumptions when passed into law.
7/14/2020	Kyle Frankiewich	slide 42: what's the difference between CPP and behavior DR? If behavioral DR is similar to home energy reports, is it effectively just asking / informing customers of the benefit of shifting load?	Critical peak pricing (CPP) is typically included as a tariff whereas behavioral demand response, which is neither time of use nor critical peak pricing, is a demand response program that notifies customers via text or email of an upcoming event and encourages them to save energy during a specific time horizon.
7/14/2020	Kate Maracas	Slides 42-43: To what extent does PSE rely on demand response aggregators to deploy the DR products? Could broader use of aggregators increase customer adoption?	At the present, PSE has only conducted pilots demand response programs. PSE will use a request for proposals (RFP) process to solicit the best offerings and programs for its customers, and bidders will have the opportunity to aggregate their DR offerings.
7/14/2020	Don Marsh	Slide 45, does "behavioral load response" = time of use rates? Or is this just critical peak pricing?	Slide 45 mentions behavioral demand response, which is neither time of use nor critical peak

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			pricing. Rather, it is a type of demand response program that notifies customers day-ahead via text or email of an upcoming event and encourages them to save energy during a specific time horizon.
7/14/2020	Kate Maracas	Slides 42-44: do many of these programs rely on AMI (automated metering infrastructure)? If so, is investment in AMI an impediment to broader customer adoption?	Some do rely on AMI, but AMI helps in the measurement and communication for all programs. AMI deployment is not an impediment. PSE is expected to complete its AMI deployment by 2023, one year into the start of this CPA study period. https://www.pse.com/pages/meter-upgrade
7/14/2020	Kevin Jones	Slide 45: Is uncertain customer acceptance a CADMUS or PSE assumption and what is the basis for the assumption?	Thank you for your comment. The explanation regarding customer acceptance was listed solely with respect to smart appliance direct load control. We are not currently aware of any secondary research that indicates customers' acceptance of having smart appliances controlled by their local utility. The most recent Smart Electric Power Alliance 2019 Utility Demand Response Market Snapshot included a survey question that indicated 0% of 95 utility survey respondents indicated that voice-enabled smart home devices have been integrated into new or existing demand response programs.
7/14/2020	Doug Howell	Demand Response: Do the DR benefits include: avoided generation and TX upgrades; avoided distribution upgrades; storage function; line loss reduction from energy savings; ancillary services at generation level such as frequency regulation and spinning reserve; and ancillary services for distribution of voltage control?	Yes. Please refer to the pie chart from Brattle group's presentation at the UTC DR workshop on slide 68. The majority, as in more than 95%, of the savings from demand response accrue from capacity, avoided transmission and distribution, and energy savings. Then there are the other benefits you mention: ancillary services, which include regulation and spinning reserves. In this IRP we will use the Plexos flexibility model to

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			estimate the ancillary benefits associated with the DR programs being considered in the IRP.
7/14/2020	Court Olson	Not including the potential for demand control on smart appliances misses a DR potential. Can this potential be included in a revision to the DR calculations?	No. See below response to Michael Laurie's question reference slide 45.
7/14/2020	Don Marsh	Don Marsh Comment: Slide 45 - "uncertainties regarding customer acceptance" is PSE's standard explanation. However, many utilities find customers love demand response programs that provide lower monthly bills. PSE is using assumptions that are decades out of date.	Thank you for your comment. The explanation regarding customer acceptance was listed solely with respect to smart appliance direct load control. The sixteen demand response products included in the study all explicitly assumed some level of customer acceptance, typically reflected in program participation assumptions that are included in the achievable potential estimation.
7/14/2020	Michael Laurie	Slide 45 - Agree with Don Marsh's point. PSE please explain what thinking and evidence led to reach a different conclusion than other utilities reached.	We would welcome any additional information regarding utilities currently offering demand response programs for smart appliances and/or any evaluations of these programs. The most recent Smart Electric Power Alliance 2019 Utility Demand Response Market Snapshot included a survey question that indicated 0% of 95 utility survey respondents indicated that voice-enabled smart home devices have been integrated into new or existing demand response programs.
7/14/2020	Kevin Jones	Slide 38: What is the basis of the assumption that energy efficiency occurs before Demand Response? What is your estimate of delayed DR employment while waiting for EE upgrades?	Whether we do demand response first or energy efficiency, there is an interaction between the two. So we have to account for it. Even if demand response takes place before, during or after (as assumed here) energy efficiency we need to account for the reduced load due to the interaction.
7/14/2020	Court Olson	Slide 49: Where to you get your PV market penetration function for each year?	It is a relatively, commonly-used Bass diffusion model function that measures a customer's

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			sensitivity to payback and the annualized simple payback for each year of the study.
7/14/2020	Court Olson	Slide 59: Could you please define what you mean by combined heat and power?	Combined heat and power (CHP) is when a customer installs a generation system whose waste thermal heat is recovered for use to serve thermal load on site. By recovering the waste heat from the generation process, you increase the overall efficiency of the CHP.
7/14/2020	Court Olson	Slide 60: Are you projecting a decline in natural gas use due to switching to heat pumps? If not, when will you adjust your calculations to include this trend?	We have not included this. It is not cost effective to convert to heat pumps, unless one is doing an end of life replacement, in which case the incremental costs associated with equipment and electrical service upgrades may or may not be cost effective. We are keeping an eye on this conversion, but don't see much natural conversions to date that will have a meaningful impact on our gas loads. A major shift will likely be affected through legislative mandates, which are not presently on the books and have not been included in the forecasts. Finally, we are considering a sensitivity at the August 11th webinar.
7/14/2020	Michael Laurie	Slide 62: Have you considered the possibility of some uses of natural gas will be banned in new construction as has happened in a number of jurisdictions in California?	We include codes and standards that in the books at the time of the CPA. At the moment we don't have any laws banning natural gas, now or to go into effect in the future. Thus, we have not included anything presently. We will do this again in a couple years and have the chance to review any legislation updates that ban natural gas and can include that accordingly.
7/14/2020	Fred Huette	for slide 63: is there an effective difference between volt/var optimization (VVO) and conservation voltage reduction (CVR), if so has PSE looked specifically at CVR	Yes, PSE has typically just done CVR, but now with the Advanced Distribution Systems Management (ADSM) infrastructure roll out, CVR is done in combination with the reactive power

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			management on the circuit. Since we are now doing both volts and vars, it's called VVO.
7/14/2020	Kate Maracas	+1 to Don Marsh. Also, the increased capabilities of grid-forming inverters that will inevitably be deployed after implementation of IEEE 1547 standards will have a significant impact on solar PV's (distributed and utility scale) ability to provide flexibility and ancillary services. How is PSE considering both the cost reductions and advanced technical capabilities?	The analysis currently does not consider the capability of grid-forming inverters; however, PSE and its contractor are monitoring the implementation of IEEE 1547 interconnection standards and may consider inclusion of the impact of these technologies in the next IRP.

PSE IRP Consultation Update
Webinar 4: Demand-side resources
July 14, 2020

8/04/2020

The following consultation update is the result of stakeholder suggestions gathered through an online Feedback Form, collected between July 7 and July 21, 2020 and summarized in the July 28 Feedback Report. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

PSE also thanks Joni Bosh, Fred Huette and Amy Wheeless of Northwest Energy Coalition (NWEC) for meeting with PSE staff on Juy 29 to help further clarify their questions and suggestions.

Electric Vehicles – Demand Response Program

PSE received feedback from Brian Grunkemeyer and Rob Briggs (Vashon Climate Action Group) concerning the high levelized cost assumption of the DR program for electric vehicles and requested Cadmus to provide more details on their estimate.

Cadmus' EV estimate of $300 from the Regional Technical Forum (RTF) study is reasonably close to the cost data that Brian provided on July 31, 2020 of $250 per participant. The other costs that are included in the $362 levelized cost are detailed in the table below:

Parameters	Units	Values	Notes
Setup Cost	$	DLC: $150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per year	DLC: $150,000	Assuming 1 FTE.
Equipment Cost	$ per new participant	$300	The Regional Technical Forum's researched incremental equipment cost of networked 240V level 2 charger compared to non-networked level 2 charger is $287 (Shum 2019).
Marketing Cost	$ per new participant	DLC: $30	Assuming this product requires higher marketing cost than the BPA assumption (Cadmus 2018a) for DLC products: $25 per new participant.
Incentives (Annual)	$ per new participant	DLC: $25	In line with incentives for residential DLC space heat products.
Attrition	% of existing participants per year	5%	In line with BPA assumption (Cadmus 2018a) for DLC products.
Eligibility	% of segment/	36%	The number of EV owners is aligned with the study's assumptions for energy efficiency. The proportion of EV owners that already have a residential 240V AC level 2 charger (64%) is based on research by the Regional Technical Forum (Shum 2019).
Peak Load Impact	kW per participant (at meter)	0.34	Based on 2021 Plan Workbook "Inputs_Product_ResEVSEDLC-Winter" peak load impact assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655868985770
Program Participation	% of eligible segment/end-use load	DLC: 25%	In line with assumptions for DLC products.
Event Participation	%	0.95	Based on 2021 Plan Workbook "Inputs_Product_ResEVSEDLC-Winter" event participation assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655868985770

Transmission & Distribution Deferral Cost Update

PSE received feedback from Kyle Frankiewich (WUTC) and Fred Heutte (NWEC) requesting more details behind the numbers on slide 13: "Updates in 2021 CPA: T&D deferral benefit." The costs that the Power Council is using in their 2021 Plan is significantly lower that the ones used in the 7th Plan[1]. The Council updated its assumptions for the 2021 Plan: no new T&D development projects were included in the update, and for T&D upgrade projects, only capacity related costs were included. In past IRPs, PSE has used the Council's T&D deferral numbers. Since the costs came down substantially in the Council's 2021 plan, PSE decided to update their own system related costs. The PSE system estimates came close to the updated Power Council estimates, these were presented on slide 13 of the July 14 Webinar.

PSE reviewed projects going back to 2010 and included projects or portions of the projects that were related to the capacity upgrades on the T&D systems. The costs for reliability projects and routine O&M were excluded as conservation will not impact these costs.

Details of the projects used to estimate the new T&D deferral costs are in Appendix A.

Fuel Conversion from Gas to Electric

PSE received feedback from Kyle Frankiewich, Willard Westre, Rob Briggs and Court Olson concerning inclusion of measures or sensitivities to test the impact of converting some end uses from gas to electricity use. PSE has added fuel conversion as a sensitivity for further discussion with stakeholders at the August 11 webinar.

Distributed Solar pV

PSE received feedback from Fred Heutte (NWEC) and Kyle Frankiewich (WUTC) that the cost curve was not up to date, and that a sensitivity should be considered with a lower cost curve. Fred referenced to the recently released (July 2020) 2020 ATB data from NREL.

[1] https://www.nwcouncil.org/sites/default/files/2019_0312_p3.pdf

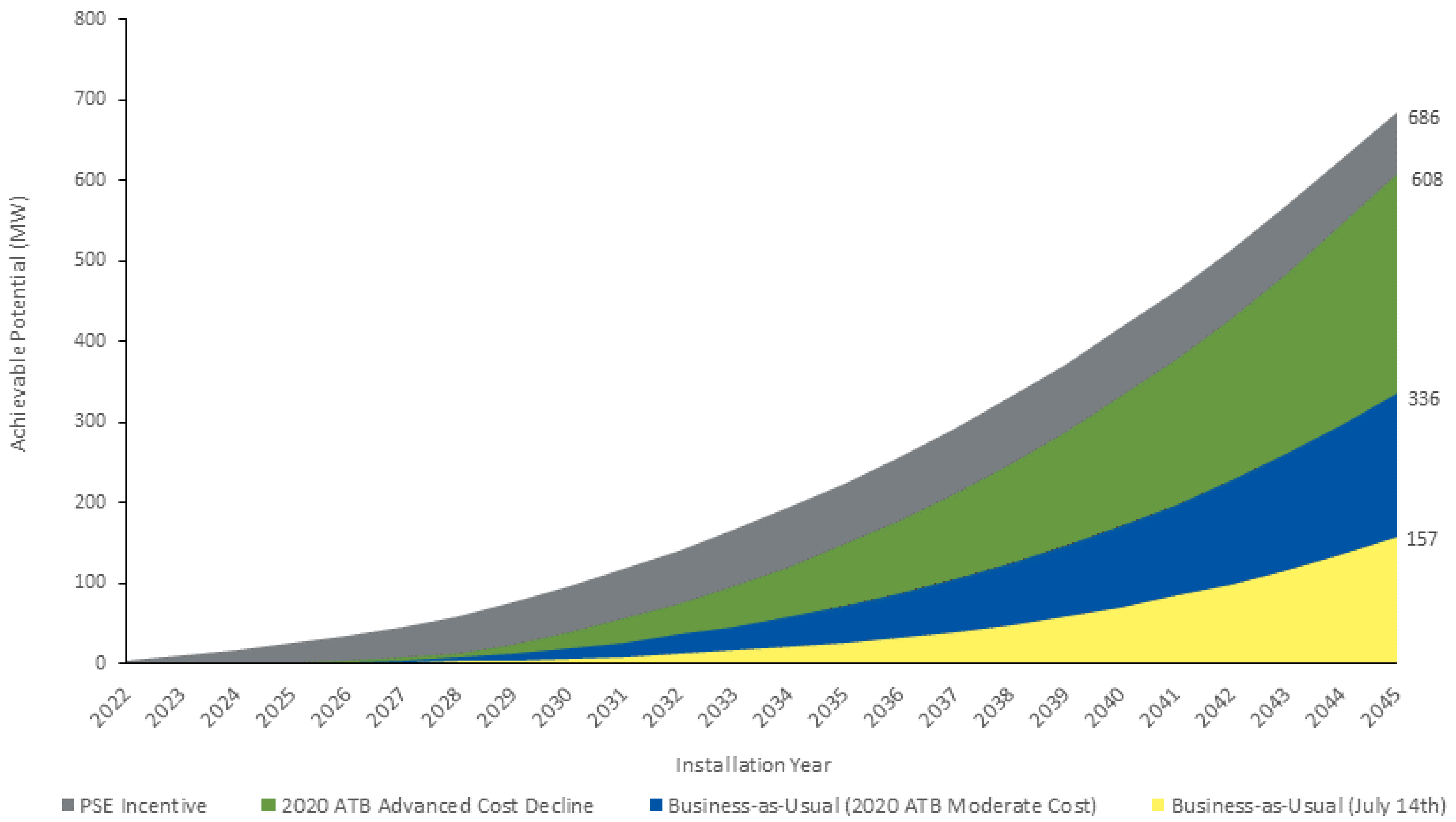
Cadmus had used the 2019 ATB data in their webinar slide, and has since updated the distributed solar pv market potential using the 2020 ATB data. As NWEC had suggested the costs are lower.

The figure below shows the results. The business as usual (BAU) case, which represents the current net metering program, updated with the 2020 MTB *Moderate* Cost forecast, now shows 24-year cumulative potential of 336 MW, which is about 10% higher than the program's straight line projection of 300 MW, which was shown in the August 14 webinar.

Furthermore, the 2020 ATB *Advanced* Cost Decline forecast shows 24-year cumulative potential of 608 MW.

Based on these results and feedback from the stakeholders, PSE will:

1. Update the business as usual (BAU) case to the 2020 ATB *Moderate* Cost forecast, and
2. Replace the PSE incentive sensitivity with the 2020 ATB *Advanced* Cost decline as the sensitivity



There was also a request for historical acheivements to date with respect to PSE's distributed solar pv program. The following is the historical data for all customer classes, including a breakdown by sector:

Total historical installations:

Year installed	Number of Systems	kW AC	kW DC
2000	1	4	1
2001	3	7	4
2002	7	15	12
2004	12	42	34
2005	8	34	30
2006	39	238	236
2007	85	438	409
2008	84	405	399
2009	157	818	814
2010	199	1,148	1,169
2011	227	1,447	1,532
2012	405	2,429	2,627
2013	572	3,913	4,123
2014	691	4,731	5,176
2015	1363	9,907	10,619
2016	1245	10,497	11,659
2017	1009	8,072	9,200
2018	1590	13,688	15,695
2019	1535	14,301	16,215
2020	**605**	**6,189**	**6,859**
Grand Total	**9837**	**78,322**	**86,813**

Installations by customer class:

Sector	Percent Share	
	Systems	kW AC
Commercial	5%	14%
Industrial	0.03%	0.17%
Residential	95%	85%

Equity in the IRP

PSE has scheduled a discussion with WUTC staff regarding an equity assessment in the IRP. Further details will be available by the end of September.

Load Forecast in the CPA

PSE received feedback from several stakeholders expressing concerns that the load forecast used to develop the CPA was a draft and what might happen if the final load forecast is considerably different. There was also a general perception that the changes in load forecast have a major impact on the conservation savings.

Changes in load forecast have a relatively minor impact on the total acehievable potential. The CPA will be updated with the final load forecast.

Demand Side Resource Sensitivities

PSE received feedback from several stakeholders to consider several sensitivities – see section below on "Summary of all updates" for details. All stakeholder suggested sensitivities have been added to the August 11 webinar for further discussion.

Summary of all updates

PSE appreciates the feedback provided by stakeholders. In summary, the following changes will be implemented:

- Workbooks requested by NWEC – PSE is working with Cadmus to provide a measure details workbook for their review. This will be provided towards the end of August.
- T&D deferral cost update details – details of the updated T&D numbers are presented in Appendix A below.
- PSE will include a discussion and provide historical data on acheivements to date for PSE's net metered distributed solar pV program in the demand side resources report.
- Electric Vehicle levelized cost for the DR program is summarized on page 1 of this report.
- Several sensitivities listed below were suggested by stakeholders. PSE will review the list of proposed portfolio sensitivities with stakeholders at the August 11, 2020 webinar and will seek feedback around the details of these sensitivities and additional sensitivities:
    - PSE will remove the PSE incentive and PSE ownership sensitivities and instead consider the one proposed by the stakeholders: sensitivity with a lower cost curve using the 2020 ATB *Advanced* scenario.
    - Accelerated DSR 6 year ramp for discretionary measures
    - Accelerated DSR 8 year ramp for discretionary measures
    - Non Energy impacts using EPA estimates
    - Social discount rate of 2.5% consistent with the social cost of carbon from the technical support document
    - Fuel conversion gas to electric
- PSE will update the CPA with the final load forecast and a discussion of the changes will be provided in the demand side report.

Appendix A: T&D Cost update details

PSE T&D Deferral Cost Summary:

PSE deferral costs	$/kW-yr	$/kW-yr 2020$
Transmission	$ 5.22	$ 5.22
Distribution	$ 7.40	$ 7.40
T&D Deferral Costs	$ 12.61	**$ 12.61**

Power Council deferral costs 2021 Plan	$/kW-yr 2016$	$/kW-yr 2020$
Transmission	$ 3.08	$ 3.35
Distribution	$ 6.85	$ 7.45
T&D Deferral Costs	$ 9.93	**$ 10.79**

Power Council deferral costs 7th Plan	$/kW-yr 2012$	$/kW-yr 2020$
Transmission	$ 26.00	$ 29.55
Distribution	$ 31.00	$ 35.23
T&D Deferral Costs	$ 57.00	**$ 64.77**

PSE TRANSMISSION SYSTEM PROJECTS DATA:

Project	Capital Investment 2020$	Capacity Gained (MW)	Power Factor	Discount rate	Asset lifetime	Result $/kW-yr
Alderton Substation Project Totals	$ 28,277,441	1021	0.98	6.97%	35	2.18
Sedro - Horseranch Project Totals	$ 43,651,437	1203	0.98	6.97%	35	2.85
Juanita Substation Upgrade Project Total	$ 6,969,792	25	0.98	6.97%	35	21.90
Greenwater Upgrade Project Total	$ 7,638,716	15	0.98	6.97%	35	40.00
Cumberland Substation Rebuild Project Total	$ 7,900,038	0	0.98	6.97%	35	0.00
Thorp Substation Rebuild Project Total	$ 3,545,756	0	0.98	6.97%	35	0.00
Sedro - Baker #2 Reconductor Project Total	$ 27,628,881	330	0.98	6.97%	35	6.58
Spurgeon Substation Project Total	$ 1,895,271	339	0.98	6.97%	35	0.44
Maxwelton Substation Project Total	$ 7,869,250	1046	0.98	6.97%	35	0.59
Sedro - Fredonia T-Line Uprate	$ 6,929,378	94	0.98	6.97%	35	5.79
Mt. Si Substation Project Total	$ 16,012,300	25	0.98	6.97%	35	50.31
Port Madison Substation Project Total	$ 18,206,586	252	0.98	6.97%	35	5.68
Sterling Substation Project Total	$ 30,909,684	45	0.98	6.97%	35	53.96
Spurgeon Substation Project Total	$ 32,515,004	45	0.98	6.97%	35	56.76
Blackburn Substation Project Total	$ 43,823,648	45	0.98	6.97%	35	76.50
Ardmore Substation Project Total	$ 24,951,787	261	0.98	6.97%	35	7.51
Semiahmoo Substation Project Total	$ 6,599,786	0	0.98	6.97%	35	0.00
Total/Average	$ 315,324,755	4746	0.98	6.97%	35	5.22

PSE DISTRIBUTION SYSTEM PROJECTS DATA:

Project	Capital Investment 2020$	Capacity Gained (MW)	Power Factor	Discount rate	Asset lifetime	Result $/kW-yr
New OH FDR addition	$ 1,451,190	13.96	0.98	6.97%	35	$ 8.16
New UG FDR addition	$ 938,758	9.05	0.98	6.97%	35	$ 8.15
New OH FDR addition	$ 327,970	13.96	0.98	6.97%	35	$ 1.84
New FDR WCA	$ 2,420,732	13.96	0.98	6.97%	35	$ 13.62
New UG FDR addition	$ 2,153,063	9.05	0.98	6.97%	35	$ 18.69
New UG FDR addition	$ 1,081,724	9.05	0.98	6.97%	35	$ 9.39
New UG FDR addition	$ 379,362	9.05	0.98	6.97%	35	$ 3.29
New UG FDR addition	$ 209,939	9.05	0.98	6.97%	35	$ 1.82
Repl 1-ph lateral w/OH FDR	$ 1,470,663	13.96	0.98	6.97%	35	$ 8.27
Extend UG FDR	$ 238,033	9.05	0.98	6.97%	35	$ 2.07
UG FDR tie	$ 275,575	9.05	0.98	6.97%	35	$ 2.39
UG FDR extension	$ 1,351,231	9.05	0.98	6.97%	35	$ 11.73
UG FDR extension	$ 2,185,186	9.05	0.98	6.97%	35	$ 18.97
Extend UG FDR in existing conduit	$ 282,905	9.05	0.98	6.97%	35	$ 2.46
Upgrade 3-167 auto to 7.5 MVA	$ 2,642,984	7.00	0.98	6.97%	35	$ 29.66
Extend UG FDR	$ 449,758	9.05	0.98	6.97%	35	$ 3.90
UG FDR extension	$ 760,693	9.05	0.98	6.97%	35	$ 6.60
Reconductor from #6CU to OH FDR 397.5	$ 162,528	10.57	0.98	6.97%	35	$ 1.21
New OH FDR TW Extention	$ 602,496	13.96	0.98	6.97%	35	$ 3.39
OH FDR 397.5	$ 294,938	15.20	0.98	6.97%	35	$ 1.52
OH FDR 397.5	$ 1,403,819	10.65	0.98	6.97%	35	$ 10.35
new FDR breaker &UG FDR	$ 937,867	9.05	0.98	6.97%	35	$ 8.14
Repl 3.75 MVA trf with 20 MVA	$ 70,953	16.25	0.98	6.97%	35	$ 0.34
Add two addional #2 ACSR conductors	$ 1,374,218	3.23	0.98	6.97%	35	$ 33.46
Recond 2/0 to 397.5, 5.91, added capacity	$ 1,542,684	7.92	0.98	6.97%	35	$ 15.29
Recond 2/0 to 397.5, 5.91, added capacity	$ 472,612	7.92	0.98	6.97%	35	$ 4.69
Recond 1-ph #6 CU to 336.4 TW FDR	$ 725,016	12.83	0.98	6.97%	35	$ 4.44
OH FDR 397.5	$ 1,908,196	11.24	0.98	6.97%	35	$ 13.34
Add I -ph #2 ACSR	$ 55,644	1.61	0.98	6.97%	35	$ 2.71
Recond 4/0 ASCR to 397.5 FDR	$ 736,591	5.59	0.98	6.97%	35	$ 10.36
Recond 2/0 CU to 397.5 FDR	$ 223,865	5.72	0.98	6.97%	35	$ 3.08
Recond 2/0 CU to 397.5 FDR	$ 253,699	5.72	0.98	6.97%	35	$ 3.49
OH FDR 397.5	$ 445,011	15.20	0.98	6.97%	35	$ 2.30
Recond #2 ACSR to 397.5 FDR	$ 330,543	10.44	0.98	6.97%	35	$ 2.49
Recond #4 CU to 397.5 FDR	$ 585,694	10.65	0.98	6.97%	35	$ 4.32
Recond #4 CU to 336.4 TW FDR	$ 1,282,001	9.42	0.98	6.97%	35	$ 10.69
Recond #6 CU to 397.5 FDR	$ 632,575	11.80	0.98	6.97%	35	$ 4.21
Recond #6 CU to 397.5 FDR	$ 737,312	11.80	0.98	6.97%	35	$ 4.91
Recond #2/0 CU to 397.5 FDR	$ 168,986	5.72	0.98	6.97%	35	$ 2.32
New UG FDR Extension	$ 1,190,576	9.05	0.98	6.97%	35	$ 10.33
New UG FDR Extension	$ 1,496,886	9.05	0.98	6.97%	35	$ 12.99
Recond #4 ACSR to FDR TW	$ 228,706	10.33	0.98	6.97%	35	$ 1.74
UG FDR 750	$ 4,020,530	9.05	0.98	6.97%	35	$ 34.90
UG FdDR	$ 178,224	9.05	0.98	6.97%	35	$ 1.55
UG FDR Extension	$ 384,637	9.05	0.98	6.97%	35	$ 3.34
UG FDR Extension	$ 391,211	9.05	0.98	6.97%	35	$ 3.40
New 750 UG Fdr, 1/0 UG, FDR TW	$ 3,007,573	9.05	0.98	6.97%	35	$ 26.11
Extend new 750 UG Fdr, new 1/0 UG section	$ 132,136	9.05	0.98	6.97%	35	$ 1.15
New 750 UG Fdr; new OH FDR TW	$ 442,187	9.05	0.98	6.97%	35	$ 3.84
New 750 UG Fdr	$ 2,107,015	9.05	0.98	6.97%	35	$ 18.29
new 750 UG Fdr, new 1/0 3-ph	$ 265,951	9.05	0.98	6.97%	35	$ 2.31
Recond 2/0 with 336.4 ACSR TW and 397.5 FDR	$ 290,545	7.92	0.98	6.97%	35	$ 2.88
Recond 1- ph #6 CU with 336.4 TW FDR	$ 366,913	12.83	0.98	6.97%	35	$ 2.25
Add new FDR 336.4 TW	$ 1,509,437	13.96	0.98	6.97%	35	$ 8.49
Recond 1-ph #6 CU with 397.5 FDR	$ 383,763	14.07	0.98	6.97%	35	$ 2.14
Recond 2-ph #4 ACSR with 336.4 FDR	$ 1,588,710	11.39	0.98	6.97%	35	$ 10.95
Recond 3-ph #2 ACSR to 397.5 FDR	$ 2,346,705	7.92	0.98	6.97%	35	$ 23.26
Recond 2-ph #2 ACSR to 336.4 FDR TW	$ 888,821	10.59	0.98	6.97%	35	$ 6.59
Recond 1-ph #6 CU with 336.4 TW	$ 628,079	12.83	0.98	6.97%	35	$ 3.84
Repla 2/0 CU with 397.5 FDR	$ 131,277	5.72	0.98	6.97%	35	$ 1.80
Repl 1-ph #2 ACSR with 3-ph #2 ACSR TW	$ 738,696	2.76	0.98	6.97%	35	$ 21.02
Repl 2-ph #2 ACSR with 3-ph #2ACSR TW	$ 777,704	1.15	0.98	6.97%	35	$ 53.21
New 336.4 FDR TW	$ 393,919	13.96	0.98	6.97%	35	$ 2.22
New UG 1/0	$ 355,356	3.64	0.98	6.97%	35	$ 7.68
New FDR DUV-16	$ 1,091,254	9.05	0.98	6.97%	35	$ 9.47
New UG FDR	$ 2,355,496	9.05	0.98	6.97%	35	$ 20.45
New 750 UG Fdr	$ 124,622	9.05	0.98	6.97%	35	$ 1.08
Reconductor #2 ACSR to 397.5 FDR	$ 98,862	10.35	0.98	6.97%	35	$ 0.75
new UG FDR	$ 2,068,257	9.05	0.98	6.97%	35	$ 17.95
10 new UG FDRs	$ 7,025,651	90.50	0.98	6.97%	35	$ 6.10
Totals/Average	$ 70,576,718	749.61	0.98	6.97%	35	**$ 7.40**

Webinar 5, July 21, 2020

Social Cost of Greenhouse Gases (SCGHG) and Natural Gas Upstream Emissions

PUGET SOUND ENERGY

Webinar #5: Social Cost of Carbon
July 21, 2020 from 1:30 p.m. to 4:30 p.m. PST

Virtual webinar link: https://global.gotomeeting.com/join/899706621
Access code: 899-706-621
Call-in telephone number (audio only): +1 (872) 240-3412

Topic	Lead
Welcome • Agenda review • Safety moment • How to participate • Speaker introductions	EnviroIssues
Social cost of carbon (SCC)/social cost of greenhouse gases (SCGHG) in CETA	Elizabeth Hossner, Manager Resource Planning & Analysis, PSE
SCC in the IRP models	Elizabeth Hossner, Manager Resource Planning & Analysis, PSE
5-minute break	
Upstream natural gas emission methodology	Keith Faretra, Senior Resource Scientist, PSE
Feedback and final Q&A • More participant questions • Using the Feedback Form	Facilitated by EnviroIssues
Wrap up and next steps • Next steps • Upcoming meeting schedule • Thank you's	EnviroIssues

2021 IRP Webinar #5: Social Cost of Carbon

Planning Assumptions & Resource Alternatives
Electric Portfolio Model

PUGET SOUND ENERGY

July 21, 2020

Agenda

- Safety moment
- Social cost of carbon (SCC) in the Washington Clean Energy Transformation Act (CETA)
- SCC in the IRP models
- Upstream natural gas emissions

Safety Moment: Bike Safety

- Always wear a properly-fitted **helmet** that meets the Consumer Product Safety Commission (CPSC) standards.
- **Check your bike equipment** before heading out: check for proper fit and function, including tires, brakes, handlebars and seats.
- **Ride in the same direction as traffic**, as a vehicle on the road.
- **Obey traffic signs**, signals, and lane markings; signal all turns; and follow local laws.
- **Be predictable**; ride in a straight line and use hand signals when changing lanes or turning.
- **Stay focused**; look ahead for traffic and obstacles in your path.
- **Be visible**: wear bright colors, reflective materials and lights on your bicycle at night and in low light conditions.
- **Stay alert**: don’t use electronic devices.
- **Ride safe**; riding impaired by alcohol or drugs affects your judgment and skill; it affects your safety and others on the road

PUGET SOUND ENERGY

Today’s Speakers

Elizabeth Hossner

Manager Resource Planning & Analysis, PSE

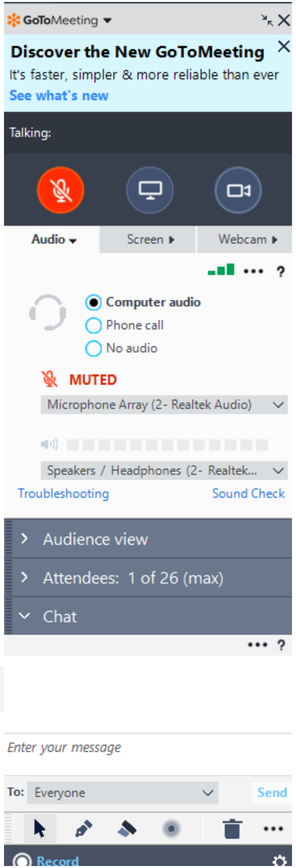
Keith Faretra

Senior Resource Scientist, PSE

Penny Mabie & Alison Peters

Co-facilitators, EnviroIssues

Welcome to the webinar and thank you for participating!



Virtual webinar link: https://global.gotomeeting.com/join/899706621

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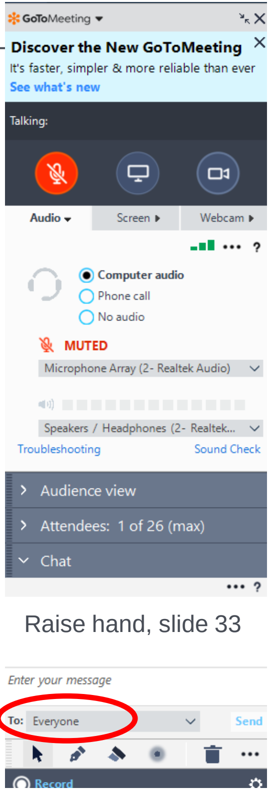
  - **In writing:** your question will be read
  - **Verbally:** type "Raise hand" and slide #, share with "Everyone"; please wait to be called on to ask your question
- Be considerate of others waiting to participate
- We will try to get to all questions



PUGET SOUND ENERGY

Participation Objectives

- PSE will inform stakeholders of the methodology used to model the social cost of carbon in the 2021 IRP analysis
- Stakeholders to share input on possible scenarios or sensitivities around the social cost of carbon

The Social Cost of Carbon in CETA

PUGET SOUND ENERGY

SCC vs. SCGHG

- During the 2019 IRP process, many people used the terminology social cost of carbon (SCC). This term was carried over to the 2021 IRP.
- The new terminology is the social cost of greenhouse gases (SCGHG).
- SCC and SCGHG are interchangeable and refer to the same thing.
- For the purposes of this presentation, PSE will continue to use the term social cost of carbon (SCC).

The Social Cost of Carbon, According to CETA

"NEW SECTION. Sec. 15. A new section is added to chapter 80.28 RCW to read as follows:

*For the purposes of this act, the cost of greenhouse gas emissions resulting from the generation of electricity, including the effect of emissions, is equal to the cost per metric ton of carbon dioxide equivalent emissions, **using the two and one-half percent discount rate, listed in table 2, technical support document: Technical update of the social cost of carbon for regulatory impact analysis under Executive Order No. 12866**, published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016. The commission must adjust the costs established in this section to reflect the effect of inflation."*

- Section 15, Page 35

The Social Cost of Carbon, According to CETA

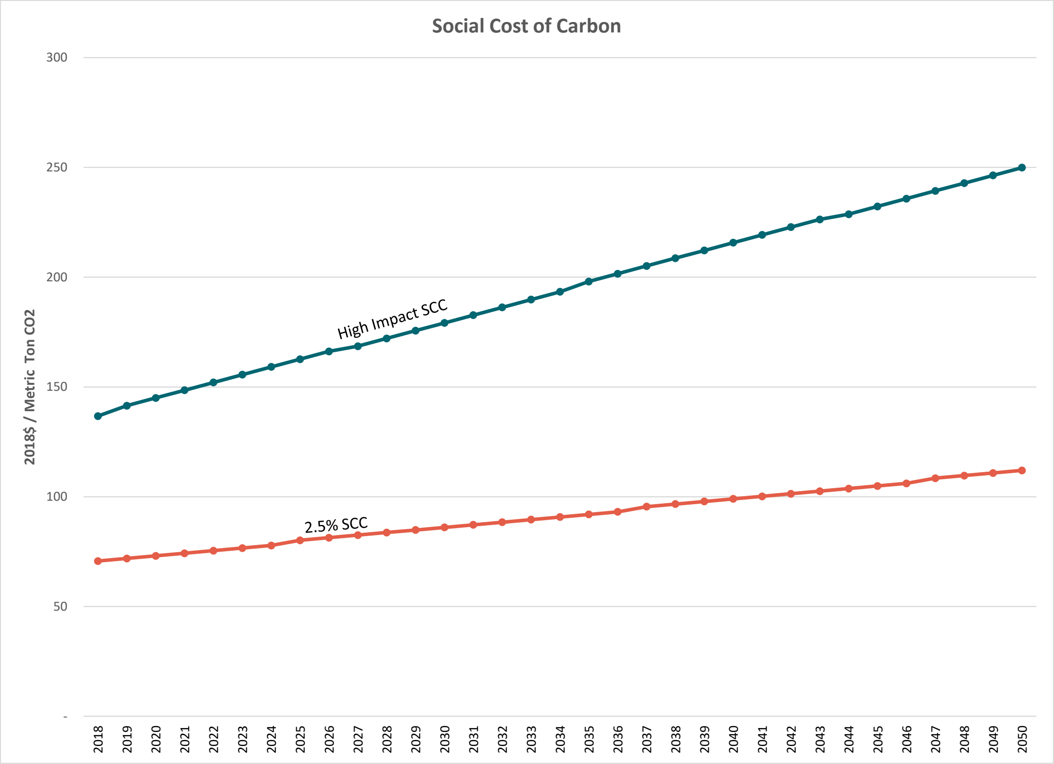
- CETA provides a SCC value published by an interagency working group of the federal government in August, 2016.

- For PSE, this is what must be applied as the SCC for planning decisions and final portfolio recommendations.

Year	Social Cost of Carbon Dioxide* (in 2007 dollars per metric ton)	** GDP Index (2007)	** GDP Index (2018)	Adjusted Social Cost of Carbon Dioxide* (in 2018 dollars per metric ton)
2010	50	92.498	110.382	*60*
2015	56	92.498	110.382	*67*
2020	62	92.498	110.382	*74*
2025	68	92.498	110.382	*81*
2030	73	92.498	110.382	*87*
2035	78	92.498	110.382	*93*
2040	84	92.498	110.382	*100*
2045	89	92.498	110.382	*106*
2050	95	92.498	110.382	*113*

https://www.utc.wa.gov/regulatedIndustries/utilities/Pages/SocialCostofCarbon.aspx

The Social Cost of Carbon Over Time



- The SCC rises steadily over time, tracking with inflation.
- Here, the CETA SCC is compared to a "high impact" SCC figure used in PSE sensitivity modeling.
- All figures are in 2018$/metric ton
- SCC prices available in this spreadsheet

Using the Social Cost of Carbon, According to CETA

Where the SCC must be applied

(3)(a) An electric utility must incorporate the social cost of greenhouse gas emissions as a cost adder when:

(i) Evaluating and selecting conservation policies, programs, and targets;

(ii) Developing integrated resource plans and clean energy action plans; and

(iii) Evaluating and selecting intermediate term and long-term resource options. p. 33 E2SSB 5116.S

(b) For the purposes of this subsection (3):

(i) Gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anaerobic digesters must be considered a non-emitting resource; and

(ii) Qualified biomass energy must be considered a non-emitting resource.

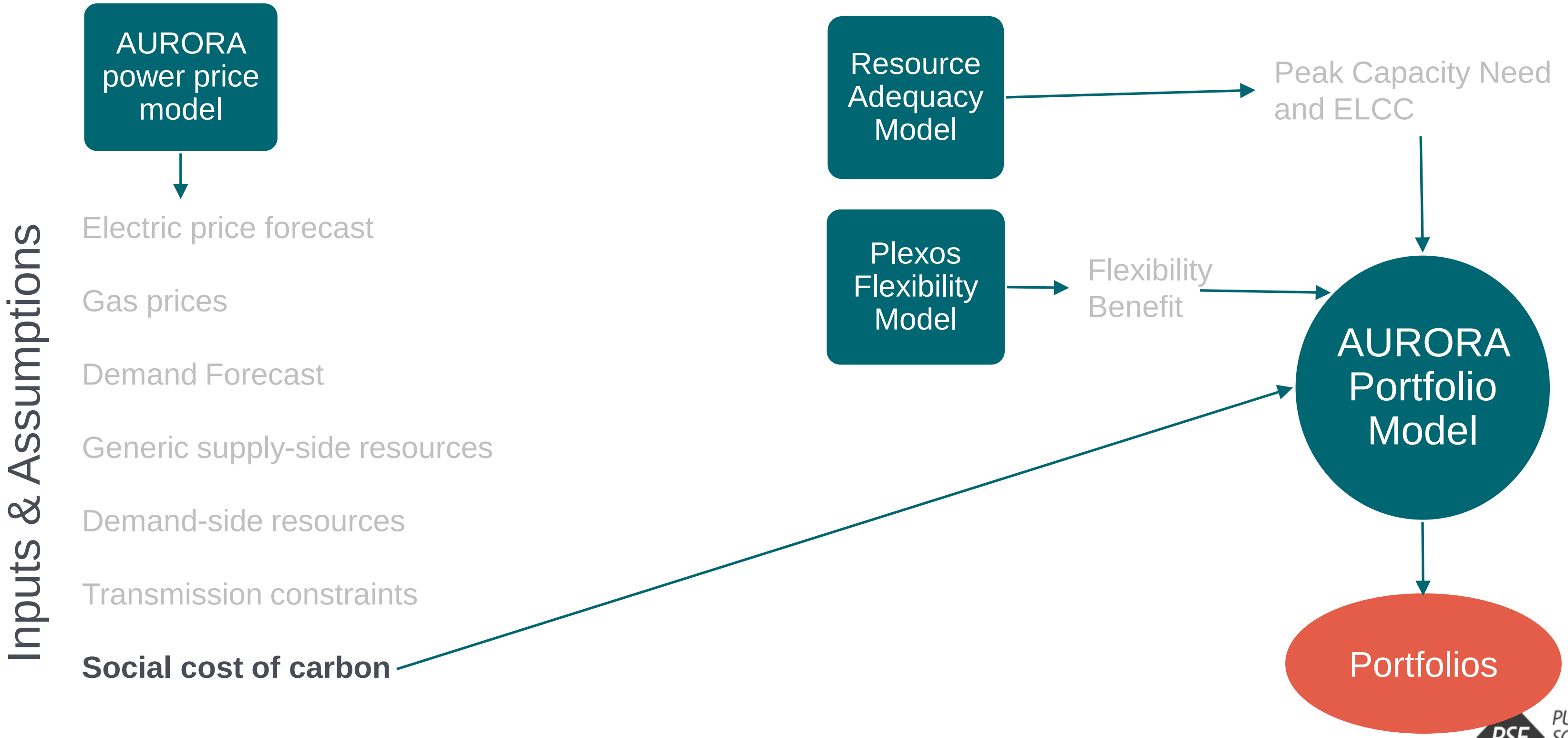
- Section 14, Page 33

Using the Social Cost of Carbon, According to CETA

- CETA explicitly instructs utilities to use the SCC as a cost adder when evaluating conservation and resource additions, and making the IRP or CEAP.
- PSE understands this “cost adder” to mean that the SCC is included in resource planning decisions as a part of the Fixed O&M costs of that resource.
- The SCC is not included in resource dispatch costs.
- The SCC is accounted for post-economic dispatch in order to evaluate competing resource portfolios as they would function in the real world.

The SCC in PSE Models

Electric IRP Models



SCC as a cost adder vs. SCC as a tax

- PSE is required by law to produce electricity at the lowest cost possible to ratepayers. The IRP process is a part of demonstrating the least-cost portfolio for PSE.

- By using the SCC as a planning adder in resource build decisions, PSE factors in the price impact of the SCC to build decisions.

- This cost adder provides an economic disincentive for building thermal plants without artificially increasing the price of electricity for ratepayers.

Applying the SCC as a cost adder

- For thermal plants:
  - Step 1: Run the dispatch of plant over its lifetime.
  - Step 2: Calculate the emission cost for each year:

    CO_2 emissions (tons) * SCC ($/ton) = emission cost ($)
  - Step 3: Add the emission cost ($) from Step 2 to fixed resource costs.
  - Step 4: Re-run the portfolio model for optimal portfolio results

- Unspecified market purchases

  SCC ($/ton) * emission rate (ton/MWh) = adder ($/MWh)

PSE is using the 0.437 metric tons CO2/MWh for unspecified market purchases from Section 7 of E2SSB 5116, paragraph 2.

Applying the SCC as a cost adder – example using a peaker

	Tons CO2	SCC ($/ton)	Total Emission Cost ($)	$/kw-yr
2022	32,409	75	2,445,142	23.51
2023	39,897	77	3,057,055	29.39
2024	30,983	78	2,410,580	23.18
2025	13,393	80	1,073,571	10.32
2026	17,948	81	1,459,883	14.04
2027	22,998	83	1,897,758	18.25
2028	22,498	84	1,883,057	18.11
2029	26,157	85	2,220,107	21.35
2030	20,800	86	1,789,982	17.21
2031	21,508	87	1,876,205	18.04
2032	28,197	88	2,492,937	23.97
2033	28,360	90	2,540,811	24.43
2034	23,974	91	2,176,167	20.92
2035	27,195	92	2,500,563	24.04
2036	29,054	93	2,705,789	26.02
2037	29,024	95	2,771,354	26.65
2038	27,492	97	2,657,497	25.55
2039	25,237	98	2,469,328	23.74
2040	25,835	99	2,558,268	24.60
2041	26,837	100	2,689,103	25.86
2042	28,190	101	2,857,859	27.48
2043	24,806	103	2,544,081	24.46
2044	23,788	104	2,467,700	23.73
2045	22,546	105	2,365,429	22.74
2046	22,635	106	2,401,499	23.09
2047	20,501	108	2,223,375	21.38
2048	24,808	110	2,719,725	26.15
2049	22,857	111	2,532,752	24.35
2050	22,110	112	2,476,141	23.81
2051	22,321	113	2,526,028	24.29

Emissions costs added to the cost of the peaker in the portfolio model during the resource selection for the portfolio

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Note: This is an example and meant for illustrative purposes. Actual costs for 2021 IRP will be calculated later.

Applying the SCC as a cost adder

- How is social cost of carbon being modeled as a cost adder different than a CO_2 tax?
  - Modeling the SCC as a CO_2 tax would understate the costs and emissions associated with the plant. The model is set to optimize the dispatch of the plant including an emission price.

	SCC as a CO_2 tax	SCC as a cost adder
Annual capacity factor from economic dispatch	30%	70%
Annual CO2 emissions	400,000 tons	1,000,000 tons
Total cost of CO2 emissions	$32 Million	$80 Million

- The higher cost associated with the cost adder will make baseload gas plants less economic.

IRP electric portfolio model process

Inputs

- Variable operations & Maintenance (VOM)
- Fixed operations & Maintenance (FOM)
- Plant operating characteristics
- capital costs
- PSE monthly load forecast
- hourly load shape
- Normal Peak Load
- Planning Margin (peak need)
- Peak capacity credit (ELCC)
- Renewable need
- Transmission constraints
- Decommissioning cost for existing resources
- Flexibility Benefit

Social cost of carbon added to existing and new thermal resources and market purchases as a cost adder

Mid-C power prices → Long term capacity expansion for PSE only → **New builds and retirements** → Hourly dispatch for PSE only → **Portfolio dispatch & cost**

AURORA

AURORA

SCC as a cost adder in AURORA

Long Term Capacity Expansion

SCC Included

Existing Thermal

Existing Renewable Resources

Electric and gas price forecasts

Load, Peak need, Renewable need

Generic Renewables

Generic Non-Renewables

SCC Included

Resource builds & retirements

Hourly Dispatch Run

Resource builds & retirements

Hourly Dispatch

No SCC

Final portfolio dispatch & cost

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SCC in the scenarios and portfolio sensitivities

- **PSE will apply the SCC as a post economic dispatch fixed cost adder.**

- **Portfolio sensitivity: High impact SCC**
  - Washington State passes a law or amendment that increases the SCC, or
  - Washington State rulemaking specifies that upstream emissions are to be included in SCC considerations.

- **Scenario: WECC-Wide federal CO_2 tax**
  - Across the WECC, uniform CO2 pricing is implemented as a federal tax
  - States in the WECC: WA, OR, CA, ID, MT, WY, NV, UT, CO, NM, and AZ

Conclusions from 2019 IRP process December 2019 webinar on SCC

1. Renewable resources required to comply with CETA is the key constraint driving the new portfolio resource additions.

2. With the CETA renewable requirement, the application and the value of **social cost of carbon** has little to no effect on portfolio resource additions.

Where we are looking for feedback?

- **Scenarios and sensitivities to model the SCC**
  - PSE is in the process of deciding which scenarios and sensitivities to model.
  - Scenarios and sensitivities will be discussed at the August 11 IRP webinar.

5-minute Break

Upstream natural gas emission methodology

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Participation Objectives

- PSE will inform stakeholders of the methodology used to calculate upstream natural gas emissions

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Social cost of upstream natural gas emissions

Electric utility planning

- CETA does not include references to upstream emissions, but PSE will include upstream emissions in the 2021 IRP

Gas utility planning

- HB 1257, section 15, requires upstream emissions for conservation planning, and PSE will also apply it on the supply side resource planning for the 2021 IRP

Upstream gas emission rate data sources

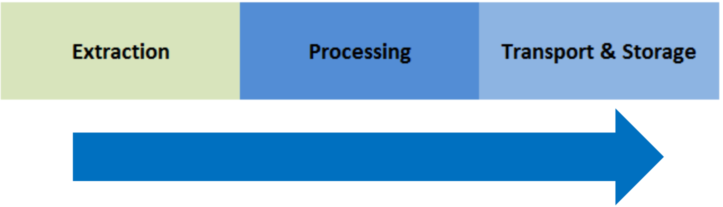
Reliance on data published by the Puget Sound Clean Air Agency (PSCAA)

- PSCAA commissioned an independent lifecycle analysis for the Tacoma LNG Project
- Emissions of carbon dioxide, methane and nitrous oxide are quantified and reported on a CO_2 equivalent basis by applying the 100-year global warming potential (GWP) factors from the Intergovernmental Panel on Climate Change Fourth Assessment Report (AR4, IPCC 2007), which is currently the accepted international reporting standard and the method for the State of Washington and U.S. Environmental Protection Agency GHG reporting. The AR4 100-year GWP is the widely used default metric to weigh GHG emissions and is consistent with the goals of the the Paris Accord and the Kyoto Protocol.

- Two models considered which rely on respective national inventory data from each segment along the natural gas supply chain
  1. **GHGenius** – Canadian model used to examine all stages of natural gas pathways for life cycle assessments
     - Used for baseline sensitivity in PSCAA analysis
  2. **GREET** (Greenhouse gases, Regulated Emissions, and Energy use in Transportation) – Argonne National Lab model, also used for life cycle assessments
     - Used for upper bound sensitivity in PSCAA analysis

Upstream gas emission rate components from lifecycle

- Emission rate associated with extraction, processing and transport of natural gas along the supply chain
- Natural gas supply chain includes:
  1. Extraction & Production – the extraction of raw natural gas from underground formations
  2. Processing - the removal of impurities
  3. Transport & storage – the delivery of natural gas from the wellhead and processing plant to city gate transfers
  4. Fuel - energy required to move the gas (in gas driven compressors)
  5. Distribution – delivery of natural gas from the major pipeline (city gate) to the end users



GHGenius upstream emission rate

GHGenius

- Uses v4.0a (2016)
- Newer version is available (v5.0c, 2018); however, upstream emissions are lower so values in v4.0a are more conservative
- Regionally specific (by Province)
- Includes all stages of the natural gas supply chain
- Emissions data sourced from Pollutant Inventories and Reporting Division of Environment Canada
- Gas statistics sourced from Statistics Canada and the Canadian National Energy Board
- Most widely adopted protocol for Canada

GREET upstream emission rate

GREET

- Updated October 2018
- US specific
- Includes all stages of the natural gas supply chain
- Emissions data sourced from EPA GHG Inventory
- Gas statistics sourced from US Energy Information Administration
- Most widely adopted protocol for United States

Published emission rates

Natural Gas Supply Chain Upstream Life Cycle Emission Rates

Supply Chain Segment		GHGenius (Baseline Sensitivity), g/MMBtu				GREET (Upper Sensitivity), g/MMBtu			
		Carbon Dioxide	*Methane*	*Nitrous Oxide*	*Carbon Dioxide Equivalent*	*Carbon Dioxide*	*Methane*	*Nitrous Oxide*	*Carbon Dioxide Equivalent*
Natural Gas Extraction	**Extraction**	2,303.16	25.05	0.110	2,962.2	2,153.87	8.04	0.019	2,360.5
Extraction Fugitive		2.69	115.53	0.000	2,890.9	0.00	137.87	0.000	3,446.6
Natural Gas Processing	**Processing**	2,325.46	10.35	0.040	2,596.1	1,665.98	5.94	0.013	1,818.3
Processing Fugitive		1,101.04	0.00	0.000	1,101.0	702.06	6.17	0.000	856.3
Transmission - Distribution	**Transport & Storage**	1,192.80	2.29	0.009	1,252.8	1,650.74	63.04	1.385	3,639.4
Total		6,925.14	153.21	0.160	**10,803.0**	6,172.66	221.05	1.417	**12,121.1**

Source: Puget Sound Clean Air Agency, Final Supplemental Environmental Impact Statement (March 29, 2019)

Upstream Emission Rate - Sum of All Segments Expressed in CO2equivalent (CO2e)

Canadian vs. US gas in IRP models

- Electric IRP assumes all new gas from BC
  GHGenius: 10,803 g/MMBtu = 23 lbs/MMBtu
    Upstream emissions added to emission rate of NG plants
    Example:

New NG plant emission rate:	117 lbs/MMBtu
Upstream emission rate:	23 lbs/MMBtu
Total emission rate:	140 lbs/MMBtu

  Example on slide 19 for SCC calculation includes the higher emission rate with upstream emissions for total tons of CO_2

- Gas IRP assumes different rates for the US and Canadian supply hubs and then the gas model (Sendout) optimizes between the different supply hubs
  - GHGenius used for Canadian supply hubs
  - GREET used for US supply hubs

Questions & Answers

Feedback Form

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Resource planning

Home | 2021 IRP | Get Involved | Consultation Updates | Past IRPs | Sign Up

Establish Resource Needs	Planning Assumptions & Resource Alternatives	Analyze Alternatives & Portfolios
Analyze Results	Develop Resource Plan	Clean Energy Action Plan

Planning Assumptions & Resource Alternatives

PSE will analyze potential futures through scenarios and sensitivities that will have different gas prices, electric prices, electric demand, environmental policies, and supply-side and demand-side resource alternatives. Sensitivities determine how different potential futures and factors affect resource strategies, costs, emissions, and risks. This IRP steps defines the inputs and assumptions to be used in the various IRP models.

- Social Cost of Carbon +
- Upstream Emissions +
- Generic Resource Assumptions +
- Transmission Constraints +
- Natural Gas Price Forecast +
- Electric Price Forecast +
- Demand Side Resources (Conservation) +
- Demand Side Resources (Demand Response) +
- Clean Energy Transformation Act +
- Delivery System Planning +

Meetings

- May 28, 2020: Generic Resource Assumptions +
- June 10, 2020: Electric Price Forecast +
- June 30, 2020: Transmission Constraints +
- July 14, 2020: Demand Side Resources +
- July 21, 2020: Social Cost of Carbon –

7/21/2020 | 1:30 - 4:30 PM

Overview

On July 21, 2020 PSE will host a webinar on the social cost of carbon. At this meeting, stakeholders will share input on why PSE should be utilizing the high social cost of carbon and understand PSE's upstream emissions calculations.

Feedback forms can be used to submit your questions before the meeting and to provide feedback after the meeting.

Please register for the meeting using the link at the bottom of this page. You can join the meeting from your computer.

Share your feedback with PSE

May we post these comments to the IRP webpage?

- Yes
- No

Please keep my comments anonymous

First Name* | Last Name*

Organization

Email Address* | Phone Number

Address | City

State (Select a State) | Zip Code

Please select the topic you would like to provide feedback on: *For general comments, please select "General" from the list.*

Select a topic

Respondent Comment*

Attach a file: Choose File | No file chosen

Recommendations

Submit

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Feedback Form

- An important way to share your input
- Available on the website 24/7
- Comments, questions and data can be submitted throughout the year, but timely feedback supports the technical process
- Please submit your Feedback Form within a week of the meeting topic

Feedback Form → **Feedback Report** → **Consultation Update**

Next steps

- Submit Feedback Form to PSE by **July 28, 2020**
- A recording and the chat from today's webinar will be posted to the website **tomorrow**
- PSE will compile all the feedback in the Feedback Report and post all the questions by **August 4, 2020**
- The Consultation Update will be shared on **August 11**

Details of upcoming meetings can be found at pse.com/irp

Date	Topic
August 11, 8:30 am – 12:30 pm	Portfolio sensitivities development (electric & gas) CETA assumptions Distributed energy resources
September 1, 1:00 – 5:00 pm	Demand forecast (electric & gas) Resource adequacy Resource need: peak capacity, energy & renewable energy need
October 20, 1:30 – 4:30 pm	Portfolio sensitivities draft results Flexibility analysis
November 4, 1:00 – 4:30 pm	Clean Energy Action Plan 10-year Distribution & Transmission Plan
December 9, 1:00 – 4:30 pm	Portfolio draft results Stochastic analysis Wholesale market risk

Thank you for your attention and input.

Please complete your Feedback Form by July 28, 2020

We look forward to your attendance at PSE's next public participation webinar:

Portfolio sensitivities development (electric & gas)

CETA assumptions

Distributed energy resources

August 11, 2020

Appendix

PSE Conversion

- In order to input the SCC into AURORA models, PSE converts the final SCC numbers into 2012$/short ton.

- To do so, the CETA GDP conversions are used to change to 2018$, and a 2.5% inflation rate is used to convert to 2012$ for the AURORA model.

Annual SCC
(2007$ / metric ton)

CETA GDP Conversion

Annual SCC
(2018$ / metric ton)

2.5 % Inflation Rate

$$\frac{\text{1.10231 US Ton}}{\text{Metric Ton}}$$

AURORA Input
Annual SCC
(2012$ / short ton)

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IRP EMMISION PRICE CALCULATIONS

EXCEL SPREADSHEET

Click this link to download the spreadsheet:

https://oohpseirp.blob.core.windows.net/media/Default/documents/2021_PSE_IRP_Emission-Price-Calculations.xls

EMMISION PRICE CALCULATIONS WORKBOOK (INFLATION UPDATE)

Click this link to download the workbook:

https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/July_21_webinar/Emission_Price_Calculations_workbook_2019_(Inflation-Update).xls

Webinar #5: Social Cost of Carbon Q&A

7/22/2020

Overview

On July 21, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss the social cost of carbon. PSE informed stakeholders of the methodology used to model the social cost of carbon in the 2021 IRP analysis and the methodology used to calculate upstream natural gas emissions. Stakeholders shared their input on possible scenarios or sensitivities regarding the social cost of carbon. Additionally, participants were able to ask questions and make comments using a chat box provided by the Go2Meeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 47 stakeholders and PSE staff attended the webinar, plus another seven attendees who called into the meeting and did not identify themselves (54 people total).

Attendees included: Amy Wheeless, Ashton, Bill Pascoe, Brian Grunkemeyer, Brian Robertson, Charlie Black, Cody Duncan, Dan Kirschner, Don Marsh, Doug Howell, Edward Finklea, Elyette Weinstein, Fred Heutte, James Adcock, Jane Lindley, Jennifer Mersing, Jim Loring, Joni Bosh, Kary Buri, Kathi Scanlan, Katie Ware, Kevin Jones, Kyle Frankiewich, Liz Klumpp, Devin McGreal, Michael Laurie, Michael Noreika, Mike Hopkins, Ned Whiting, R. C. Olson, Richard Sawyer, Robert Briggs, Sarah Laycock, Sophia Spencer, Stephanie Chase, Ted Drennan, Virginia Lohr, Vlad Gutman-Britten, and Willard (Bill) Westre.

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 1:30 PM PDT and ended at 4:29 PM PDT.

Name	Time Sent	Comment
Alison Peters	**1:35 PM**	Hello to everyone joining the webinar today. Just a couple of friendly reminders to stay muted until we stop for questions. You are also welcome to type in your name to let the group know who is here today.
ET69	**1:36 PM**	To be really safe…don't ride a bike in cities. 😉
Kyle Frankiewich	**1:39 PM**	Hello all, Kyle Frankiewich with WUTC staff here
Jane Findley	**1:42 PM**	What level of International Association for Public Participation (IAP2) engagement will be used in the meeting today? Inform, Consult, Involve or a combination? Thanks!
Penny Mabie	**1:44 PM**	Thank you for your question. As mentioned, this webinar will be at Inform and Consult on the IAP2 Spectrum.
Virginia Lohr	**1:45 PM**	What are the levels of public participation anticipated for the methane portion of the presentation? You only told us about the participation for the SCC portion of the talk. It would be helpful to have this information clearly communicated to us before a meeting.
Joni Bosh	**1:46 PM**	Question slide 11 and appendix - Why go through the elaborate conversion from metric tons to short tons?
Doug Howell	**1:47 PM**	I'm hearing an echo from Elizabeth
James Adcock	**1:47 PM**	Does one of the facilitators still have their mic on? Please *everyone* except of Elisabeth make sure your mic is muted so we can try to get rid of the echo.
Kevin Jones	**1:48 PM**	Slide 12: Will that SCC value be static over the entire analysis period or will the values "escalate" over the analysis period?
Kevin Jones	**1:50 PM**	Slide 12: - Will PSE adjust the SCC value to "then year dollars" in their analysis?
Doug Howell	**1:50 PM**	Slide 12 - applies to EE. Doesn't applying scc to dispatch model affect how it impacts energy efficiency.
James Adcock	**1:50 PM**	Jim Adcock Raise Hand Slide 14
Doug Howell	**1:50 PM**	In the real world model, there is no carbon tax. But in the real world, the are very real carbon impacts.
Charlie Black	**1:51 PM**	Disagre with characterization of including SCC at dispatch as a "tax". It is not a tax, it is an environmental externallity.

Kathi Scanlan	**1:51 PM**	Staff recommends an update and annual adjustment (from 2018 to 2019 dollars per metric ton); the Commission's website table should be updated by the end of July (for its calculation, staff uses BEA GDP Table 1.1.4 Annual Price Indexes Line 1, last revised May 28, 2020
Fred Huette	**1:51 PM**	Why is PSE using a 2.5% inflation rate? Most estimates (for example US Bureau of Economic Analysis) tend to be around 2.1%. This won't make much difference in the short run but can have an effect over 10+ years.
Joni Bosh	**1:54 PM**	Question Slide 14 - This slide says SCC is added to conservation, but where is that demonstrated in these slides? Excluding SCC from dispath modelint makes it more likely that new thrmal resources will run more; we would urge you to run the SCC as a variable cost.
Charlie Black	**1:56 PM**	There is nothing in CETA that precludes a utility from using SCC as a cost adder at time of dispatch in its IRP modeling or resource acquisition evaluation. To be clear, PSE is proposing to treat SCC as a tax, which it is not.
Irena Netik	**1:56 PM**	Response to Virginia Lohr's question: Upstream emissions which will be discussed later in this meeting is inform on the IAP2 spectrum. Thank you.
Charlie Black	**1:58 PM**	I suggest that PSE review the concept of environmental externmalities and how they are properly used to reflect costs that are not priced in the marketplace.
James Adcock	**2:00 PM**	Slide 14 -- If the resource decision has already been made, then for what reason are you running a subsequent resource dispatch model?
Michael Laurie	**2:01 PM**	To follow on Doug's question about slide 13. I see that SCC plays a role in deciding to select conservation at the front end but we all know that how things play out from year to year will always vary from the the expectations in planning and IRP efforts. So when there is a greater demand for energy than planned for and if that demand exceeds what conservation and renewables were assumed to be sufficient it appears that you would be in a situation where you will be making energy resource decisions that no longer include SCC.
Kyle Frankiewich	**2:04 PM**	Slide 14: To echo Joni's question, I'm not tracking on how the fixed-cost approach to SCC impacts the portfolio optimization. Does the model 'know' that dispatching a gas plant is adding more costs to the total portfolio than are shown in dispatch? Happy to wait til later slides
Kyle Frankiewich	**2:06 PM**	I understood Elizabeth's use of the word 'tax' as specifying how it would be added to the dispatch model.
Doug Howell	**2:07 PM**	+++ to Charlie Black's statement

James Adcock	**2:09 PM**	Re Charlie's concerrns -- IRPs are a "public process" and I would like to see Charlie's concerns in this area (as long as everyone else's) discussed, in a discussion, in a public IRP forum.
Kevin Jones	**2:10 PM**	- Slide 17: Lowest REASONABLE cost
Kevin Jones	**2:11 PM**	Slide 18: Step 1: How does PSE determine the dispatch plan for thermal plants? What is the dispatch schedule for other PSE assets? What is the capacity factor used for wind and solar during this part of the analysis? Slide 18: Step 4: What is determined when you “re-run the portfolio model”? Slide 18: How is SCC applied to fuel sources, including upstream methane leaks?
Joni Bosh	**2:12 PM**	+++to kevin's clarification that is lowest REASONABLE cost
Bill Westre	**2:15 PM**	S-19 What is the source of Tons CO2 - MW? Dispatch %?
Kyle Frankiewich	**2:16 PM**	I'm understanding the figures in slide 20 as an illustrative example of how SCC out of dispatch lets thermal plants run more, which in turn runs up their total cost relative to alternatives.
Charlie Black	**2:16 PM**	Does this aproach for treating SCC as a "tax" assume that the SCC is a dollar cost that flows through to PSE ratepayers? If so, that is not a proper way to apply SCC as an environmental externality.
Doug Howell	**2:20 PM**	Slide 20. How will this affect operations and dispatch of peaker plants?
Katie Ware	**2:17 PM**	Slide 20: The numbers in the table appear to be round estimates to illustrate the initial principle that SCC-as-adder will result in higher carbon-related costs for a resource, without going into that final round of optimization. Does PSE think the CF difference would be as extreme as 30% v 70%, or did PSE pick a relatively extreme example to help illustrate the idea?
Joni Bosh	**2:20 PM**	Slide 20 - all else being equal, the SCC as a cost adder increases capacity, which would lead to LCOE going down. Even if LCOE is not the only factor considered, doesn't this lead to dispatch picking the less costly thermal plant more and more frequently in Aurora?
Charlie Black	**2:21 PM**	In actuality, since the SCC is an environmental externality that is not explicitly priced in the wholesale power market, it is not a dollar cost that would affect PSE's revenue requirements or its retail electric rates under EITHER approach to incorporating SCC. So this calls into question the validity of PSE's analytical approach, including treating SCC as a fixed cost adder OR as a "tax".

James Adcock	**2:22 PM**	Did Puget ever figure out whether their "80 Year Hydro" include the BPA "fixes" related to the change of BPA dispatch protocols back in the 80s -- i.e. has older Hydro data been corrected to account for current dispatch protocols?
Charlie Black	**2:23 PM**	However, since the environmental damages caused by GHG emissions are real (albeit unpriced) costs, they should be included in ecnomic dispatching decisions. Another way to say this is that economic dispatch decisions should include all real costs, including both priced and unpriced costs.
Fred Huette	**2:26 PM**	referring to my previous comment about inflation rate, the NW Council is currently using an average rate of about 2.095% for 2021-40 -- see https://nwcouncil.app.box.com/v/StandardInfoWorkbookv4-2
Kyle Frankiewich	**2:27 PM**	I'm confused about how this wouldn't change the dispatch. Presumably each iteration will prompt AURORA to select a different proxy resource, which will change the dispatch and cause thermals to run differently from the first iteration of the determinative run.
Kevin Jones	**2:28 PM**	Regarding inflation rate - is this a PSE decision or is this a UTC decision that is incorporated into the SCC "costs" they publish on their website?
Kyle Frankiewich	**2:29 PM**	Does the 2nd iteration then take the plant, fully laden with SCC as a fixed cost, and set its dispatch as modeled in the 1st iteration (which would be something other than optimized)?
James Adcock	**2:29 PM**	I know that PSE doesn't want to include SCC in their modeling of dispatch, but doesn't CETA require in the "must" expression that utlities, including PSE, "must" include SCC in all aspects of modeling for IRP development?
Bill Westre	**2:29 PM**	S-19 What causes the drop in Tons CO2 in 2025
Vlad Gutman-Britten	**2:30 PM**	Dispatch is based on marginal cost, not LCOE.
Vlad Gutman-Britten	**2:33 PM**	How does SCC impact amount of conservation selected? Is EE selected as part of the Aurora portfolio runs?
James Adcock	**2:36 PM**	How does your modeling model the problem of "once in 20 years extended winter drought" in the decision to (possible) retire existing combined cycle plants?
Charlie Black	**2:37 PM**	I have a question about the format for these feedback sessions. Is the primary form of "feedback" supposed to just be clarifying questions? Is less opportunity being provided for stakeholders to provide comments and suggestions?

Joni Bosh	**2:37 PM**	Question slide 21 - In the oval, what is the basis of the "cost adder"? also, the content of the green circle changed a bit since it was presented in december - does that mean some of the data input to the model has changed as well?
James Adcock	**2:38 PM**	Slide 22 -- for what purposes does PSE use the "Final portfolio dispatch & cost" ?
Michael Laurie	**2:41 PM**	In comparing conservation to other resources is the loss of revenue from conservation included or ignored?
Joni Bosh	**2:41 PM**	Where is the SCC value of the DSR added?
Charlie Black	**2:47 PM**	Thanks for your ressponse. I hope we can put that approach into practice.
Joni Bosh	**2:48 PM**	To clarify previous question, I understand your explanation of comparing costs of demand and supply side resources, but I am still not clear how the value of SCC is applied to say an individual efficiency measure.
Vlad Gutman-Britten	**2:49 PM**	But SCC creates a relative benefit for EE as a result.
James Adcock	**2:55 PM**	How about a Scenario of: West-Coast CO2 tax -- WA, OR, CA ?
Kevin Jones	**2:55 PM**	Slide 23: What does your statement about upstream emissions mean?
Katie Ware	**2:58 PM**	Slide 23 suggests upstream emissions will not be included in the base, but (jumping forward) slides 29 et seq suggest PSE will include upstream emissions. Could you please clarify?
Joni Bosh	**3:01 PM**	We would like to see a scenario that applies the SCC to the variable costs to allow comparisons of the two approaches.
Doug Howell	**3:02 PM**	+++ on a dispatch scenario
Kevin Jones	**3:02 PM**	+++ Joni's suggestion for scenarios looking at application of SCC to dispatch
Kyle Frankiewich	**3:08 PM**	keith's connection is not as good as it could be
Fred Huette	**3:10 PM**	AR4 is out of date and AR5 should be used, among other things it predates the Paris Agreement. The methane emissions factors were significantly refined in AR5.
Doug Howell	**3:10 PM**	Slide 30. Have you addressed the complaints raised by the Stockholm Environment Institute about the GREET and GHGenius models?

Robert Briggs	**3:12 PM**	Slide #30 - Upstream gas emission rate data sources Excuse me if I missed it, but would you please tell us the rates of upstream life-cycle methane leakage that are being assumed as a percentage of methane delivered for both power generation and direct customer use?
Fred Huette	**3:13 PM**	I will have a comment on the PSCAA and Canadian metrics used in the GHGenius model.
Doug Howell	**3:13 PM**	Slide 32. How can you focus on gas supply from Canada? This avoids the fundamental climate principle of "leakage"
Don Marsh	**3:13 PM**	+++ Robert's question. I'm also interested in the methane leakage rate.
Kevin Jones	**3:14 PM**	Slide 30: Could you provide your rationale for PSE plans to use the 100 vs 20-year GWP for the CO2 equivalent of various GHG's
Doug Howell	**3:14 PM**	Slide 34. What is the total percentage of leakage from wellhead to end use?
Doug Howell	**3:15 PM**	Hand raised
Kevin Jones	**3:15 PM**	Slide 35: Will PSE consider a sensitivity that varies the source of gas (instead of just assuming that all new gas will come from BC)?
Fred Huette	**3:16 PM**	I will be summarizing a comment NWEC submitted to the NW Council (the doc also includes staff presentation on upstream methane and NWGA letter): https://www.nwcouncil.org/sites/default/files/2020_0616_2.pdf
Robert Briggs	**3:19 PM**	Keith did not answer my question.
Vlad Gutman-Britten	**3:20 PM**	Slide 34 I believe is on a CO2 basis, not on a volume basis. Can you please clarify that and provide it on a volume basis?
Robert Briggs	**3:22 PM**	Slide #34 The GREET model includes data from a robust up-to-date meta-study of methane leakage in the US that found methane leakage rates more than twice as high as those you show on slide #34. Those results were summarized in a 2018 paper by Alverez et al. in Science. Do you intend to use those data in the 2021 IRP? If not, why not?
Kevin Jones	**3:23 PM**	Please reply to Fred's comments.

Robert Briggs	**3:23 PM**	Please explain your justification for using the 100-year GWP value for methane for methane when the IRP study period is limited to 20 years for all other costs and the UN has declared we have just ten years to make major reductions in greenhouse gas emission before causing irreversible damage. AR4 values are out of date. AR5 provides values reflecting current science Please explain you justification using these obviously flawed values in this forward-looking IRP process.
Jane Lindley	**3:23 PM**	+++ Fred Huette's comment outmoded data - it's critical to have current science/numbers to measure upstream emissions.
Robert Briggs	**3:25 PM**	Slide #30 - Upstream gas emission rate data sources In the gas section of the 2017 IRP, PSE stated that the percentage of methane leaked by PSE (as distinct from upstream emissions) was 0.5%. a) Is the assumption 0.5% methane leakage on PSE's watch also being assumed for the 2021 IRP? b) Is that leakage included in the values shown for upstream methane emissions? c) What is the basis for the in-house leakage assumptions? d) Is methane leakage by your end-use gas customers included in PSE's greenhouse gas emissions or are they ignored?
Doug Howell	**3:27 PM**	AR4 is old data. You can go better than that.
Doug Howell	**3:28 PM**	+++ Yes, do a sensitivity using AR5
Don Marsh	**3:29 PM**	Ouch. PSE asked for consultation on sensitivities. A reasonable suggestion was just rejected. Disappointed.
ET69	**3:30 PM**	Agreed!
Kyle Frankiewich	**3:31 PM**	raised hand
Dan Kirschner	**3:34 PM**	I will point out that the most recent (2020) EPA emissions rate estimate is 1.0%, not 1.4% as suggested by Mr. Gutman Britten. 1.4% was from the 2018 EPA Inventory.
Fred Huette	**3:34 PM**	See slide 12 of the NW Council staff presentation for a comparison of estimated upstream methane emission rates. Among them: EDF median 2.84%, EPA median 1.82%.
Dan Kirschner	**3:36 PM**	The EPA median rate offered by Mr. Huette is from the 2018 invnetory and includes both oil and gas systems. The current inventory (2020) estimates 1.0% methane emissions from natural gas systems.

Robert Briggs	**3:40 PM**	I have attempted to look at the assumptions in GHGenius v4.0a (2016). The documentation is not available. Can you help me gain access to the documentation for this version of the progam that has been supplanted? The issue is important because without it we can not tell whether recent research with much higher leakage rates have been included.
Virginia Lohr	**3:47 PM**	I thought the law said something like "least REASONABLE cost" as what you are to pursue for customers, not just least cost or lowest cost. Is this true? If so, why do you consistently drop the word "reasonable"? This was raised this repeatedly during the last IRP, yet your language didn't seem to change. It's hard to trust you on the important things we can't see, such as what you are actually putting in your models, when we are constantly frustrated by these simple obvious things we can see and have brought up so often, including Kevin Jones' comment earlier in the chat.
Robert Briggs	**3:48 PM**	Question for Elizabeth, can you explain one more time what questions are answered by the final portfolio dispatch and cost runs?
Don Marsh	**3:51 PM**	Where does the CETA 2% annual cost premium get factored in? In other words, if a low-emission solution is within 2% of the cost of a higher-emission solution, doesn't CETA mandate the lower emission solution? Or perhaps I don't understand CETA?
Kevin Jones	**3:52 PM**	One of the objectives of this meeting was to solicit scenario suggestions from the public. Several have been suggested. Could you summarize the suggestions you will consider and pose an open question to others on the call to provide their thoughts?
Robert Briggs	**3:52 PM**	Another question for Elizabeth: Is SCC not used in the dispatch runs because there is a computational problems in doing so or because you don't belive it belongs there? I'm very sceptical of analyses that treat costs that need to be analyzed at the margin as fixed costs.
Kyle Frankiewich	**3:59 PM**	I've heard the company say that they will be running SCC in dispatch as a sensitivity, followed by some participants asking for such an analysis. Can the company clarify that this will be done as a sensitivity, at least, so participants can understand the impacts of this modeling decision? Ah, i think Elizabeth said it again.
Kyle Frankiewich	**4:01 PM**	Q about retirements - hand raised
James Adcock	**4:02 PM**	Raise Hand.
Charlie Black	**4:02 PM**	PSE has said a number of times that it thinks it is not appropriate to include SCC in dispatch under CETA. Can PSE please provide a written rationale explaining the basis for its position on this, including citing relevant sections of CETA that support its position?
Kyle Frankiewich	**4:07 PM**	it would be reflected in a higher overall portfolio cost as well, yes?

Kevin Jones	**4:11 PM**	raise hand
Joni Bosh	**4:12 PM**	my connection has gone scratchy - would you write up the explanation that Kyle and Elizabeth just discussed, as I could not hear it. Thanks
Fred Huette	**4:12 PM**	We will submit the SEI comments in a meeting comment.
Virginia Lohr	**4:14 PM**	Is it prudent to go with the values of the Agency when so many questions have been raised. Wouldn't the prudent thing to do to be to follow up with what was raised? Pugent Soung Clean Air Agency
ET69	**4:16 PM**	What is PSE’s biggest concern relative to this process?
Joni Bosh	**4:21 PM**	Please identify yourself
Joni Bosh	**4:22 PM**	Thank you
Kyle Frankiewich	**4:25 PM**	I'd encourage participants to make use of the feedback forms, and would encourage the company to make sure to offer an explanation when the company decides not to adopt a suggestion.

PSE IRP Feedback Report
Webinar 5: Social Cost of Carbon
July 21, 2020

8/04/2020

The following stakeholder input was gathered through the online Feedback Form, from July 14 through July 28, 2020. PSE's response to the feedback can be found in the far-right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on August 11, 2020.

Feedback Form Date	Stakeholder	Comment	PSE Response
7/16/2020	Elaine Armstrong, Citizens Climate Lobby	What is PSE doing, in good faith and at all speed, to reduce their green house gas emissions, reduce reliance on fossil fuels and create a 100% green and reusable energy sources? What you are doing now is increasing reliance on natural gas. There should be no more new plants that use fossil fuels. You need to create ways to use solar, wind, geothermal etc. Entire nations are able to do this. Surely PSE can.	PSE is modeling 80% renewable resources by 2030 and 100% by 2045 to meet the Washington Clean Energy Transformation Act (CETA). PSE is also modeling portfolio sensitivities around different clean energy futures which will be discussed at the August 11, 2020 webinar on scenarios and sensitivities.
7/16/2020	Elaine Armstrong, Citizens Climate Lobby	Build no new fossil fuel plants. Create clean energy sources with the eye to be entirely green house gas emission-free by 2040. Do more to support homeowners to overcome the giant cost of installing solar on their homes.	Thank you for your comment, thoughts and suggestions.
7/20/2020	James Adcock	Page 14 of 2021 IRP Webinar #5: Social Cost of Carbon Planning Assumptions & Resource Alternatives Electric Portfolio Model Using the Social Cost of Carbon, According to CETA I would like to have time allowed for a robust discussion of Puget's four positions expressed on this page, because they are interpretations of CETA that I, and I believe many other people, would disagree with. For example, I believe "cost adder" means logically an added cost proportional to the actual fuel being consumed, not a fixed cost that is somehow decoupled from the amount of fuel actually being used. For example, an NG plant actually dedicated to rare "reliability" concerns, such as "once in 20 years winter drought" should have very low emissions, and therefor should have very low SCC costs. Please allow robust time for discussion and possible disagreement, allowing stakeholders to fully understand, agree, or disagree, with PSE's four stated positions on this page, representing PSE's interpretation of CETA SCC "cost adder" requirements. CETA Quote: An electric utility must incorporate the social cost of greenhouse gas emissions as a cost adder when: (ii) Developing integrated resource plans and clean energy action plans; End-quote. Must" means "must" -- it does not mean that a utility can pick and choose when to turn on or to turn off SCC in their modeling.	Thank you for your comment. PSE will run several sensitivities and scenarios, requested by stakeholders, around the different ways to model the social cost of carbon. Further discussion will occur at the August 11 stakeholder meeting.
7/20/2020	James Adcock	Page 43 of 2021 IRP Webinar #5: Social Cost of Carbon Planning Assumptions & Resource Alternatives Electric Portfolio Model Please explain why PSE needs to: "In order to input the SCC into AURORA models, PSE converts the final SCC numbers into 2012$/short ton."	AURORA uses US tons (short tons) instead of metric tons. PSE converts from metric tons to short tons for the model.
7/21/2020	James Adcock	Given that PSE keeps complaining that they run out of time before answering all of the questions, could we "waste" less time on the PSE "Safety Issues" -- which have nothing to do with IRPs in any case.	Thank you for your comment.
7/22/2020	Vladimir Gutman,	Please see attached memo.	Thank you for your comments and questions. PSE responses by referenced numbers in the memo:

Feedback Form Date	Stakeholder	Comment	PSE Response
	Climate Solutions		1. PSE will work on creating a write-up of the AURORA portfolio model to include in the 2021 IRP. 2. PSE will run several sensitivities and scenarios, requested by stakeholders, around the different ways to model the social cost of carbon. Further discussion will occur at the August 11 stakeholder meeting.
7/22/2020	Kevin Jones, Vashon Climate Action Group	During the July 21 PSE IRP meeting I posted this question: Could you provide your rationale for PSE plans to use the 100 vs 20-year GWP for the CO2 equivalent of various GHG's. To which you replied that using the 100-year GWP allows you to remain consistent with your regulatory reporting requirements. When I asked would you consider this as a sensitivity, you answered "no". The Governor's Directive 19-18 requires consideration of both the 100 and 20-year GWP, saying in part: I hereby direct the Department of Ecology to adopt rules by September 1, 2021, to strengthen and standardize the consideration of climate change risks, vulnerability, and impacts in environmental assessments for major projects with significant environmental impacts. Such rules should be based on the most current climate change science, consistent with the findings of recent international and national assessments and the Department's recommendations under RCW 70.235.040. The rules should be uniform and apply to all branches of government, including state agencies, political subdivisions, public and municipal corporations and counties. The rules should cover major industrial projects and major fossil fuel projects; and establish uniform methods, processes, procedures, protocols or criteria that ensure a comprehensive assessment and quantification of direct and indirect greenhouse gas emissions resulting from the project. Rules for cumulative environmental assessments and reporting should include: • 20-year and 100-year global warming potentials for all greenhouse gases attributable to the project, as provided by the most recent international assessment Given the Governor's Directive, will you reconsider your position and include GWP variation as a sensitivity in the 2021 IRP? If not, please provide rationale.	See Final Supplemental Environmental Impact Statement of the Proposed Tacoma Liquefied Natural Gas Project, pages 4-5 and Appendix B pages 5-7, 91-93. See PSE letter to PSCAA dated November 21, 2018, pages 22-25.
7/26/2020	Virginia Lohr, Vashon Climate Action Group	Please see attached file.	Thank you for your comments. Concerning PSE's decision to present upstream emission as an "inform" level of public participation per IAP2, this is the appropriate level for an input to the 2021 IRP.
7/27/2020	Rob Briggs, Vashon Climate Action Group	Methane Releases by PSE I asked during the webinar if the values PSE is using from the GHGenius and GREET models for methane leakage rates include leakage that occurs while the gas is in PSE's custody and downstream while the gas is the custody of PSE's customers. Keith Faretra's response was "yes they do." Would you please verify formally and on the record that Keith's response is correct and that PSE stands behind that answer.	Yes, PSE stands behind that answer. PSE is using the GHGenius and GREET models to define upstream, midstream and downstream emission rates. This includes fugitive methane that occurs while the gas is in PSE's custody prior to delivery to a metered customer. Emissions from all the defined segments of the natural gas supply chain are included in the IRP analysis. The emission rates are itemized in the summary table on slide 34. Upstream of PSE's control includes extraction, processing, and transportation. Midstream is represented by the distribution segment. This is gas delivered to customers under PSE's control. Downstream emissions are those emissions associated with the end-use combustion of natural gas by PSE customers. The end use combustion rate is defined by EPA and is equal to 54,400 gCO2/MMBtu.
7/27/2020	Rob Briggs, Vashon	Slide #32 – GHGenius upstream emission rate The slide indicates that you are using GHGenius V4.0a (2016).	Thank you for your comments.

Feedback Form Date	Stakeholder	Comment	PSE Response
	Climate Action Group	When I go to the Natural Resources Canada web site and follow the GHGenius link, I find that V4.0a (2016) is not available. In September 2019 when I did a similar search to obtain GHGenius V4.0a program documentation to answer questions I had about the data sources that it uses, my effort was thwarted by this message: "The Government of Canada and S&T Squared no longer have an agreement to distribute the older versions of the model. If you need an old version please e-mail us and we can direct you to who to ask within the Government of Canada." I noted this problem in a letter sent to Irena Netik dated September 18, 2019. I am seeking the program documentation for GHGenius V4.0a (2016), so that I can examine the research documents that were used as the basis for that version of the program. During the webinar, Keith Faretra offered to provide me documentation for GHGenius V4.0a. I would appreciate being sent the GHGenius V4.0a documentation using the email address that you have on file for me. However, I am concerned that the documentation that Keith has available is not the documentation I need to answer critical questions about the underlying assumptions in the program. I do not believe it is appropriate for PSE to be using data from a program for which full documentation is not available. If the IRP process is to effectively protect the public interest, it must be open and transparent. That is particularly true for assumptions like upstream methane leakage with large and far-reaching impacts on IRP results. Research published after the 2016 that was conducted using new and more accurate measurement technologies found significantly higher levels of methane releases than those previously assumed.[1] As it currently stands, we are presented with a black box containing old data with very large impacts on IRP results and are told to simply accept its output. This is not acceptable in the context of the IRP process, in which public review is legally mandated. David Suzuki Foundation, New science reveals climate pollution from B.C.'s oil and gas industry is more than double what government claims, April 26, 2017, https://davidsuzuki.org/press/new-science-reveals-climate-pollution-b-c-s-oil-gas-industry-double-government-claims/. Make available the requested documentation or Update IRP data sources to those that are current and supported.	
7/27/2020	Rob Briggs, Vashon Climate Action Group	Slide #30 and 34 – GREET upper sensitivity rate The GREET model contains multiple data sources with a range of methane leakage rates. The value shown on slide #34 as "Upper Sensitivity" does not reflect the higher end of the values contained in GREET. In fact, the most recent and most robust methane leakage research in GREET shows a leakage rate more than twice as high as that buried in the 12,121.1 g/MMBtu displayed on slide #34. If you go to the GREET web site at Argonne National Laboratory, and look at the GREET Manual entitled Updated Natural Gas Pathways in the GREET1_2018, you encounter this: "...we added the option to use emissions data from Alvarez et al. (2018) for GREET1_2018. The data from Alvarez et al. (2018) is referred to as EDF 2018 in GREET." [1] If you have any doubt about the quality of this research, consider this passage from the GREET manual: "From 2013 to 2018, a collaboration of the Environmental Defense Fund (EDF), universities, research institutions, and companies have completed 16 projects to collect data on methane emissions from the natural gas supply chain (EDF 2018). The EPA has incorporated data from these efforts, (e.g. updated emission factors for production, processing, transmission and distribution equipment) to improve its GHGI (Burnham et al. 2015). In 2018, EDF and many of its collaborators published an analysis synthesizing data collected across the 16 projects (Alvarez et al. 2018). The researchers, similar to Brandt et al. (2014) but with updated data, used a bottom-up analysis supplemented by a top-down analysis (covering 30% of U.S. gas production) to estimate national CH_4 emissions from natural gas and oil supply chains. Their facility-based estimate of 2015 NG and oil supply chain emissions is ~60% higher than the U.S. EPA GHGI estimate. Alvarez et al. (2018) facility-based methodology uses downwind measurements which, unlike solely relying on component-based calculations as done in the GHGI, can capture emissions released during abnormal operating conditions." [2]	Thank you for your comments.

Feedback Form Date	Stakeholder	Comment	PSE Response
		It appears that PSE has within the trusted GREET data source, ready access to improved, up-to-date data on upstream fugitive emissions rates but has chosen not to use them. Please tell me why PSE has chosen to use a value for methane leakage of approximately 1% of methane delivered as an upper sensitivity when the source for that data contains highly credible research showing a 2.3% rate as the national average. During the 2019 IRP process, we were told PSE was using these same suspect values because PSE was new at accounting for upstream emissions and that we should not expect PSE to get it right the first time. That line of argument no longer works. Please consider using the leakage values in GREET labeled "EDF 2018" in a sensitivity analysis. Andrew Burnham, Updated Natural Gas Pathways in the GREET1_2018, October 2018, p. 2, pdf available here: Modelhttps://greet.es.anl.gov/publication-update_ng_2018. Ibid. Please consider using the leakage values in GREET labeled "EDF 2018" in a sensitivity analysis.	
7/27/2020	Rob Briggs, Vashon Climate Action Group	Slide #30 - Upstream gas emission assumptions The Puget Sound Clean Air Agency's report has been widely discredited, so it is disappointing to see PSE using it here as though it is capable of serving as a primary reference. It is highly counterproductive for PSE to be using data from 2007 (AR-4) when more up-to-date data from 2014 (AR-5) are available. Similarly, citing justification from the Kyoto Protocol adopted in 1997, while ignoring the UN IPCC Special Report [https://www.ipcc.ch/sr15/], released in October 2018, makes it clear that PSE does not intend to base the IRP on sound, up-to-date science. The IPCC Special Report Global Warming of 1.5 ºC stated we have (now) just ten years to make massive and unprecedented changes to global energy infrastructure to limit global warming to moderate levels. "There is no documented historic precedent" for the action needed at this moment, the report says. In this context, it is wildly inappropriate to be using a GWP 100-year value for methane for an IRP with a 20-year analysis period, in a state that has legislatively mandated rapid decarbonization of its electric utilities, and in a global environment in which approaching two thousand governments in 30 countries have declared climate emergencies over the past two years. GWP 100-year values dramatically understate the importance of near-term climate forcing from methane by averaging those impacts into the next century. It is reckless and irresponsible to continue to use GWP100 for methane. The magnitude of the errors that PSE is designing into the IRP from these upstream emission rate inputs is quite large. I and others have shown that using the low values PSE proposes leads to errors in levelized cost that are larger than the $3.56/MMBtu that PSE has been assuming as its cost of gas once those emissions are fully burdened using social cost carbon. [1] Errors of this magnitude rob the IRP analyses of any analytical value. Failure to correct the problems with these data inputs will ensure that PSE 2021 IRP is obsolete before it has even been completed. It is doubly disturbing that PSE refuses to discuss alternatives to using these erroneous values, even in sensitivity analyses. Sensitivity analyses are used to assess the impact of assumptions on which there is uncertainty. Given that these errors are both egregious and willful, the UTC would be justified in rejecting PSE 2021 IRP on the basis of these errors alone. September 19, 2019 TAG #8, Slide 15. Use the 20-year GWP for methane at the very least in a sensitivity analysis.	Thank you for your comment. See Final Supplemental Environmental Impact Statement of the Proposed Tacoma Liquefied Natural Gas Project, pages 4-5 and Appendix B pages 5-7, 91-93. See PSE letter to PSCAA dated November 21, 2018, pages 22-25.

Feedback Form Date	Stakeholder	Comment	PSE Response
7/27/2020	Virginia Lohr, Vashon Climate Action Group	PSE plans to use the upstream greenhouse emissions analysis method from the Proposed Tacoma Liquefied Natural Gas Project Final Supplemental Environmental Impact Statement prepared by Ecology and Environment, Inc. for the Puget Sound Clean Air Agency (PSCAA). This analysis is found in Appendix B: PSE Tacoma LNG Project GHG Analysis Final Report and was conducted by Life Cycle Associates. My understanding is that PSE currently proposes to consider no alternatives to this method. Is it prudent to rely solely on a consultant's report with a prominent disclaimer with the following statement? "No warranty or representation, express or implied, is made with respect to the accuracy, completeness, and/or usefulness of information contained in this report." TAG members and stakeholders raised questions about PSE's proposed use of these methods for calculating upstream greenhouse gas emissions during the 2019 PSE IRP process. Questions were again raised in the 2021 IRP webinar on this topic. One concern with the method PSCAA and PSE have adopted is its use of out-of-date science, such as the IPCC's 4th annual assessment (AR4) from 2007. Much newer science is available, including the IPCC's 5th Assessment Report from 2014 and research showing that methane is much more damaging than previously thought. While some agencies still use AR4, does that mean that PSE must also use this out-dated science? If PSE must use AR4 or choses to use out-dated science, is there any reason why PSE could not add a sensitivity based on more current science, such as AR5? Governor Inslee published Directive 19-18 on December 19, 2019. It requires the Department of Ecology to develop rules regarding greenhouse gas emissions based on "the most current climate change science," and to adopt the new rules by September 1, 2021. While the final rules will not be available for PSE to use in 2020, the fact that AR4 will no longer be acceptable in 2021 is clear. Is it prudent to refuse to use current science in the 2021 IRP, at least as a sensitivity, in light of this Directive? PSE should abandon their sole reliance on the PSCAA methods. At the very least, PSE should add a sensitivity that uses current science and addresses concerns raised in the 2019 and 2021 IRP processes, including using global warming potential values for methane from AR5 and adding a sensitivity analysis using the 20-year global warming potential for methane, which the Governor's Directive specifically mentions should be part of the new rules. Getting these calculations correct is critical to getting the right answer on what is reasonable, wise, and prudent for PSE to do for their investors, for rate-payers, for people living near their polluting facilities, and for the future of humanity.	See Final Supplemental Environmental Impact Statement of the Proposed Tacoma Liquefied Natural Gas Project, pages 4-5 and Appendix B pages 5-7, 91-93. See PSE letter to PSCAA dated November 21, 2018, pages 22-25.
7/28/2020	Rob Briggs, Vashon Climate Action Group	Slide #14 - Using the Social Cost of Carbon, According to CETA 'PSE understands this "cost adder" to mean that the SCC is included in resource planning decisions as a part of the Fixed O&M costs of that resource.' The social costs of greenhouse gas emissions are a function of the quantity emitted. Therefore, the social cost of carbon must be treated as a variable cost in portfolio optimizations. Treating SCC as a fixed cost dramatically lowers the apparent marginal cost of fossil-fuel use and represents an implicit subsidy for fossil-fuel use in the planning model. Please explain clearly why PSE proposes to include SCC as part of the fixed costs when it properly should be treated as a variable cost. If PSE contends that their approach grows out of specific language in CETA, please cite that specific language.	Thank you for your comment. PSE will run several sensitivities and scenarios, requested by stakeholders, around the different ways to model the social cost of carbon. Further discussion will occur at the August 11 stakeholder meeting.
7/28/2020	Rob Briggs, Vashon Climate Action Group	Treat SCC as a variable cost. Abandon all use of it as a fixed cost, which it is not.	Thank you for your comment. PSE will run several sensitivities and scenarios, requested by stakeholders, around the different ways to model the social cost of carbon. Further discussion will occur at the August 11 stakeholder meeting.

Feedback Form Date	Stakeholder	Comment	PSE Response
7/28/2020	Rob Briggs, Vashon Climate Action Group	Slide #14 – Including SCC in dispatch costs 'The SCC is not included in resource dispatch costs.' My understanding is that CETA's scope covers planning and acquisition decisions by utilities but not their operations. It remains unclear to many of us stakeholders why PSE intends to include the costs of greenhouse gas emissions in some phases of the planning process but not in others. Failure to include significant cost factors in any phase of the IRP analysis process would lead to distorted results. a) Please explain PSE's rationale for omitting this very large cost component from the dispatch modeling, if that is in fact what is being proposed. b) If this remains an unresolved issue with stakeholders, I recommend PSE run the IRP analyses with SCC consistently included throughout IRP analyses and again as a sensitivity as PSE proposes. c) If the problem PSE has with consistently including SCC in the IRP relates to discordance with real-world dispatch decisions, would not the best solution be for PSE to include SCC in their actual real-world dispatch decisions as well? Doing so would be consistent with the intent of CETA and with its long-term mandatory decarbonization benchmarks.	Thank you for your comment. PSE will run several sensitivities and scenarios, requested by stakeholders, around the different ways to model the social cost of carbon. Further discussion will occur at the August 11 stakeholder meeting.
7/28/2020	Orijit Ghoshal, Invenergy	Please see attached	Thank you for your comments. PSE has reached out to you and Charlie Black to follow-up with you and will report progress in the Consultation Update.
7/28/2020	Orijit Ghoshal, Invenergy	Invenergy encourages PSE to recognize that GHG emissions produced by its electric generating resources are environmental externalities and to treat them as such in the portfolio modeling analyses for the 2021 IRP. Invenergy encourages PSE to include the SCC in the variable dispatching costs of its GHG-emitting resources when modeling its resource portfolio for the 2021 IRP. As part of PSE's resource portfolio modeling, Invenergy encourages PSE to track and report environmental externality costs (i.e., quantities of GHG emissions multiplied by the SCC of its resources' GHG emissions), and to separately track and report the resource portfolio costs that actually go into its revenue requirements. Decisions about PSE's portfolio resource mix should be made on the basis of the sum of revenue requirements plus GHG externality costs. This will be a more realistic method for applying the SCC than either of PSE's proposed approaches. Reporting both of types of costs will also make PSE's analysis more transparent.	Thank you for your comment. PSE will run several sensitivities and scenarios, requested by stakeholders, around the different ways to model the social cost of carbon. Further discussion will occur at the August 11 stakeholder meeting.
7/28/2020	Doug Howell, Sierra Club	We should be assuming that there will not be an increase in overall gas use over the next 10 years. And there is no gas production in Washington. All gas comes from out of state or Canada. PSE asserts that all their gas comes from Canada. If so, they are pushing other buyers to other suppliers such as the Rocky Mountain states. Methane emissions from Canada have the same climate impact as methane emissions from the Rockies. As a result, PSE needs to analyze the total regional supply chain of gas that comes into Washington to fully account for upstream methane emissions. We request that PSE run a scenario (or at least a sensitivity) assessing the regional impacts of upstream methane from all gas fuel supplies into Washington. If PSE does not agree with running this scenario, then they have to explain how their gas supply is affecting the overall supply chain of gas into Washington.	Thank you for your comment.
7/28/2020	Doug Howell, Sierra Club	Run a scenario on upstream leakage rates of methane from all gas supplies into Washington.	Thank you for your comment.
7/28/2020	Joni Bosh, NW Energy Coalition	NWEC comments and suggestions. Evidently, four supporting documents will have to be submitted separately. Those follow this submission.	Thank you for your comment.
7/28/2020	Joni Bosh, NW Energy Coalition	See Four supporting documents.	Thank you for the four supporting documents. All four documents are provided as part of the Webinar 5 Feedback Form upload package on pse.com.
7/28/2020	Doug Howell, Sierra Club	We do not agree that the social cost of carbon (SCC) should be treated as a "cost adder" or as "fixed" cost. Climate impacts have long been an environmental externality and now with CETA we can internalize this damage in the planning and acquisition processes. As such, PSE needs to treat this externality for what it is: a variable cost. As a variable cost, it needs to be included in PSE dispatch modeling. We do not agree that PSE should characterize this as a carbon tax. Just because you are treating SCC as a variable cost for dispatch modeling, does not make it a tax. It would be tax if it showed up in your annual revenue requirement, which it will not.	Thank you for your comment. PSE will run several sensitivities and scenarios, requested by stakeholders, around the different ways to model the social cost of carbon. Further discussion will occur at the August 11 stakeholder meeting.

Feedback Form Date	Stakeholder	Comment	PSE Response
7/28/2020	Doug Howell, Sierra Club	Incorporate SCC in the dispatch model. Explain why you are not treating this as a variable cost. Explain the calculations for Slide 20, and provide all the data inputs that lead to the results on Slide 20.	Thank you for your comment. PSE will run several sensitivities and scenarios, requested by stakeholders, around the different ways to model the social cost of carbon. Further discussion will occur at the August 11 stakeholder meeting.
7/28/2020	Kyle Frankiewich, WUTC Staff	Questions and comments from presentation: • Slide 18: It seems that the iterative / cyclical / recursive approach to SCC-as-adder might hobble the ability of the portfolio optimizer to 'see' and avoid these costs. I think I'm mostly confused about how the company iterates its carbon emissions estimates to get the $/kw-yr fixed costs correct, and how or whether a thermal plant's run rate is fixed or able to be optimized somewhat by the model. At some point, dispatch must be affected, either through the SCC-in-dispatch or through gas resources becoming too expensive in an after-the-model-run adjustment. • Slide 21: How do SCC-as-adder costs get figured into an optimized retirement plan for existing thermal plants? Are existing plants added as selectable, with increasing kW-yr SCC O&M costs for each iteration of a plant to be retired in, say, 2030 vs 2035 vs 2045? Or, is the fact that the O&M is paid for within the model on a year-to-year basis means that the model can see the SCC-related difference between retiring sooner vs later? • Slide 35: Does the assumption that all gas used for electric generation is from BC align with PSE's historical purchasing patterns for its existing plants?	PSE responses referenced slide numbers: Slide 18: The plants dispatch to gas and electric prices. Using SCC as a fixed cost adder does not affect dispatch since we are not changing gas or electric prices. Running the cyclical process will not change dispatch of the thermal plants. Slide 21: PSE will work on creating a write-up of the AURORA portfolio model to include in the 2021 IRP. Slide 35: PSE's assumption that all gas used for electric generation is from BC does align with historical purchasing. The natural gas for power generation portfolio does not have pipeline capacity from the (US) Rockies.
7/28/2020	Kyle Frankiewich, WUTC Staff	Recommendations: 1. SCC as dispatch cost: I appreciate the discussion around whether SCC should be included outside of dispatch or within dispatch. I agree with Mr. Adcock's question about whether excluding SCC as a 'carbon tax' means PSE is ignoring carbon costs imposed by CETA starting in 2030. Elizabeth stated that the company is modeling CA's carbon tax, and can constrain its fleet by emissions or energy. I also understood that the 80% renewables requirement starting in 2030 is implemented in the model as an RPS standard modeling constraint, rather than the administrative penalty for emitting resources. Please provide some additional explanation on how (or whether) PSE's modeling tools optimize around these constraints. I worry that the constraints may have unintended impacts, and may nudge the optimization in a direction that is, well, suboptimal. I am glad to hear that PSE will be doing some extra test runs to understand the impacts of each approach. 2. WUTC and SCC: Staff recommends using the updated figures on the Commission's website; the table should be updated by the end of July (for its calculation, staff uses BEA GDP Table 1.1.4 Annual Price Indexes Line 1, last revised May 28, 2020). 3. SCC and existing plants – modeling for optimized retirement date: Suggestion more than recommendation – I would encourage PSE to review how plant closures are modeled. I am not sure if I have it right, but I understood from Elizabeth's explanation that PSE's portfolio generation tools will optimize for the closure dates of existing thermal resources. The optimization will solve to the lowest-cost portfolio, and SCC is included in a $/k-/yr fixed cost that changes each year based on the forecasted capacity factor of a thermal plant. This means the optimizer will 'see' costs in each year, and can choose to avoid those costs by closing the plant. 4. Upstream gas emissions – AR4 vs AR5: PSE stated that PSCAA's study and the company's reporting requirements both use 100-yr GWP factors and inputs/assumptions contained in the IPCC's Fourth Assessment Report (AR4), published in 2007, and that the company intends to use these assumptions and inputs for the IRP analysis of upstream emissions. The IPCC released AR5 in 2014, and other scientific studies on this topic have been published in the last few years. The company must support all modeling decisions, including the decision to use either AR4 or AR5 to estimate upstream emissions. Staff recommends a sensitivity comparing estimates calculated using AR4 with those calculated using AR5, so the company and stakeholders can better understand the impacts of this modeling decision. 5. Renewable natural gas / hydrogen – selectable option in model: These resources are clearly not as commonplace as mature products like recips or even batteries, but it's been demonstrated by other utilities (NextEra, NW Natural) that the technology is proven enough to be explored in both integrated planning and through pilots. NW Natural's last IRP (pg 6.30) should provide a good starting point. I see that the company heard feedback from stakeholders on this issue during its first IRP meeting. I look forward to continued discussion when we reach the portfolio modeling phase.	PSE responses by referenced numbers: 1. PSE will be running sensitivities around SCC and possible dispatch limits around plant emissions. Further discussion will occur at the August 11 stakeholder meeting. 2. When the updated numbers are available, PSE will update to the new price index. 3. Yes, the model runs simulations using perfect foresight. Knowing what costs will be in the future, the model looks at the economics of retiring a plant earlier and replacing it so that it does not incur more costs in the future versus maintaining the plant for a higher cost. 4. PSE will include a sensitivity for AR5. Further discussion will occur at the August 11 stakeholder meeting. 5. PSE is researching RNG and hydrogen as a fuel source. 6. The complete list of scenarios and sensitivities will be available for the August 11 webinar and will revised with stakeholder feedback. 7. PSE will run several sensitivities and scenarios around the different ways to model the social cost of carbon. PSE filed comments with the Washington Utilities and Transportation Commission (WUTC) under UE-191203, https://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=191023. Comments on the social cost of carbon begin on page 17, question 9. A discussion of the SCC modeling will also be included in the IRP book.

Feedback Form Date	Stakeholder	Comment	PSE Response
		6. Catalogue of scenarios and sensitivities: This might already be part of the company's plan, but if not, Staff recommends that the IRP contain a narrative description of scenarios and sensitivities the utility used, including those informed by the public participation process. 7. Written rationale on SCC modeling decision: Not a recommendation, but a suggestion to invest the time necessary to fully explain, either in the consultation update or the IRP itself, why the company is using the SCC-as-adder approach. A useful write-up would include an analysis the pros and cons for the company's implementation of SCC as a fixed cost rather than as a dispatch cost, for example, and would clearly specify how, in the company's view, this implementation meets CETA's requirements for resource planning and conservation. This explanation would be augmented by a comparison of the company's main model outputs with the SCC-at-dispatch scenario, which should show the relative impact of this modeling decision. If the company plans on compiling the list of scenarios and sensitivities, I hope this explanation and comparison of the two model runs would be a manageable lift.	

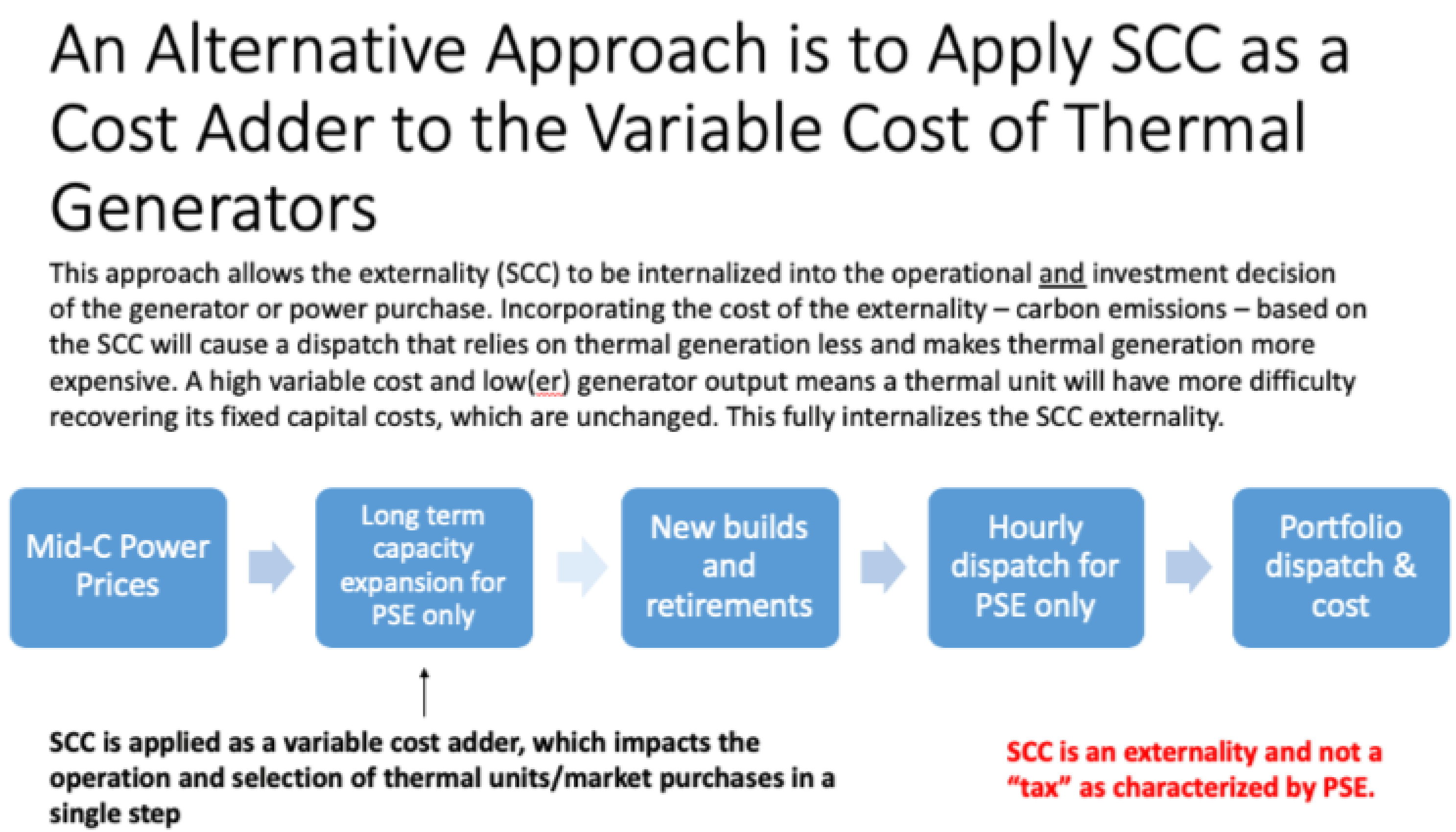
PSE IRP Feedback Report
Webinar 5: Social Cost of Carbon
July 21, 2020 – Addendum for NWEC comments

8/25/2020

The following stakeholder input was provided from NWEC on July 28, 2020.

Note – this is an addendum to the feedback report published August 4, 2020. All four documents NWEC provided as part of the Webinar 5 Feedback Form upload package on pse.com were read by the IRP team and uploaded. However, the formal letter was missed by PSE, and the material content is in the below table. An update to the consultation report dated August 11 is not needed. NWEC's comments are consistent with the consultation update. Further, NWEC was involved with an August 10 consultation meeting with PSE. PSE responses to NWEC's questions are below.

Feedback Form Date	Stakeholder	Comment	PSE Response
7/28/2020	Joni Bosh and Fred Heutte, NW Energy Coalition	Slide 14 – first point – While it was explained the SCC is provided to program staff who apply that value to conservation measures that come out of the RFP at the time when the measures are being screened for the IRP, we would appreciate a more detailed written explanation of the methodology. Demand side resources are often bundled into groups by costs so that the SCC must be reflected in the individual price as the model is selecting those resources. It was also stated during the presentation that the SCC is not applied to any demand side resource such as conservation of efficiency in either the long-term capacity expansion analysis or in Aurora modeling. Are other measures, such as grid controlled hot water heaters, treated the same way? How does this ensure that the DSP are fairly considered compared to other choices?	For the IRP models, the SCC is added to thermal emitting resources. This ensures that the emitting resources are being penalized and that no bias is being created towards renewable resources or demand-side resources. If the SCC were added to demand-side resources as a benefit, then it would create a bias towards demand-side resources over renewable resources which are also qualifying resources under CETA law.
7/28/2020	Joni Bosh and Fred Heutte, NW Energy Coalition	Slide 14 – points 2 and 3 – We appreciate the explanation why PSE has decided to apply the SCC as a fixed cost in the resource planning, but we respectfully disagree with this approach. The purpose of requiring the SCC as a planning price is to internalize into planning decisions the external cost of emitting CO2. The SCC does not function as a tax that is passed through to customers, but as an external cost that must be incorporated in resource investment decisions. If dispatch modeling informs resource investment choices in any way, the SCC must be included in the dispatch analysis to prevent distortions. While LCOE is not the only factor considered in choosing resources, it is an important one; accounting for SCC in dispatch modeling will reduce a NGCC's capacity factor (all else being equal), which will increase overall cost on a levelized basis. On a per MWh basis, including the SCC in only the investment analysis and not in modeled dispatch will skew the economics of two identical resources. This is illustrated by using the chart PSE provided on Slide 20 [graphic provided and available here – https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/July_21_webinar/Attachment_9_NWEC_Comments_on_SCC_in_IRP.pdf]. Treating SCC as a fixed cost may raise the capital cost of the certain thermal resources, but may well lower levelized costs (a per MWH measure). The model's economic "incentive" is to add thermals and run them more because they become more economic the more they run, as their upfront fixed cost is spread over more and more MWhs. By excluding SCC from dispatch modeling, it is more likely that certain new and existing thermal resources will run more than if the SCC was accounted for in their dispatch costs As a result, the incorrect price signal is being sent to the model, especially when selecting against demand-side resources. Consequently, there will be no way to test if higher amounts of demand-side resources will result in a lower cost/lower risk portfolio. PSE's agreement to run a scenario incorporating the SCC in dispatch will allow a comparison between treating SCC as a fixed cost and treating SCC as a variable cost to see if that makes a difference in the resources chosen for the portfolio. This is how we understand PSE's [graphic provided and available here – https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/July_21_webinar/Attachment_9_NWEC_Comments_on_SCC_in_IRP.pdf]. We suggest the following as an alternative to the methodology depicted in Slide 21:	Thank you for your feedback and providing the alternative methodology and the graphic. A clarification meeting was held on August 10 between PSE, Joni Bosh of NWEC, Charlie Black and Orijit Ghosal of Invenergy, Rob Briggs of Vashon Climate Action Group, and Eleanor Bastion of Washington Environmental Council. PSE will complete a modeling sensitivity where the SCC is modeled as a variable cost (dispatch cost).

Feedback Form Date	Stakeholder	Comment	PSE Response
			
7/28/2020	Joni Bosh and Fred Heutte, NW Energy Coalition	Slide 17 – first point – this needs to be corrected to state "….at the lowest REASONABLE cost possible to ratepayers." Least cost is not defined as singularly the lowest cost, but the lowest cost considering a number of factors, per 19.280.020(9) and (11).	PSE acknowledges your suggested correction. Thank you.
7/28/2020	Joni Bosh and Fred Heutte, NW Energy Coalition	Slide 18 – Instead of adding the SCC to the fixed plant costs, we would argue that SCC should be added to variable costs, dispatch modeling and unspecified market purchases. We will trust that is what the second scenario PSE committed to run will do.	PSE will complete a modeling sensitivity where the SCC is modeled as a variable cost (dispatch cost).
7/28/2020	Joni Bosh and Fred Heutte, NW Energy Coalition	Slide 19 – out of curiosity, is there some reason the results in the fourth column do not match what the results would be multiplying the tons of CO_2 times the SCC in \$/ton? They are not far off, so is the difference due to rounding?	Thank you for your comment on this slide, we appreciate the attention paid to the details of our presentation and the accountability it brings. The difference in the fourth column is due to the rounding of values in the second and third columns. In the future, PSE will include the additional digits if possible.
7/28/2020	Joni Bosh and Fred Heutte, NW	Slide 21 – it is still not clear how DSR are incorporated into this methodology. Please explain more fully.	DSRs are incorporated into this methodology as a resource in the Long Term Capacity Expansion (LTCE) model.

Feedback Form Date	Stakeholder	Comment	PSE Response
	Energy Coalition		The price of different DSR options are included as inputs into the LTCE. The AURORA model has an option to select a DSR as it would a supply-side resource. Once the selected DSR options are included in the portfolio, it has an effect on the forecasted load of the service territory during the hourly dispatch.
7/28/2020	Joni Bosh and Fred Heutte, NW Energy Coalition	Slide 24 – the conclusions listed on this slide are described as the conclusions that were presented in the December 11, 2019 Power point. However, this list leaves off the third conclusion 3. "With the CETA renewable requirement, significantly more conservation is added than the 2017 IRP. " Please explain why this conclusion was not included in the current presentation. While we would generally agree that an RPS standard is an effective driver of change, it seems a well-designed methodology for applying the social cost of carbon could have a significant effect on resource choices, especially of demand side resources and conservation.	This conclusion was not included because portfolio results for the 2021 IRP have not yet been modeled. This intent of the July 21 Social Cost of Carbon webinar was to explain and garner feedback on PSE's modeling strategy for the SCC.
7/28/2020	Joni Bosh and Fred Heutte, NW Energy Coalition	Upstream Emissions Slides 29-35 – NWEC believes that PSE should use the most current and well documented scientific and technical analysis of upstream methane emissions. Concerning the sources cited by PSE, neither the Canadian analysis using the GHGenius model, nor the EPA analysis for the US using GREET, are consistent with current observational data and analysis, and almost certain to understate the upstream emissions rate by a considerable margin. Our concerns are fully documented in a recent letter to the Northwest Power and Conservation Council (attached). In particular, we are concerned that the Canadian values greatly understate the upstream emissions for development and production areas in northeast British Columbia and northwest Alberta region that are the source for much of the natural gas used in Puget Sound region power plants as well as direct use. Several recent peer-reviewed studies cited in our letter summarize both field surveys and summaries of data provided to provincial regulators. Further, in the regulatory review of both the Tacoma LNG project and the proposed Kalama methanol facility, several organizations with significant expertise have reviewed the analysis by PSCAA relying on the same Canadian provincial sources and submitted extensive comments. In that regard, we attach a December 2018 letter from the Stockholm Environment Institute (SEI) US Center summarizing concerns about the vintage and limitations of the data and analytical methods used in the Canadian provincial assessments. The PSCAA values referenced on Slide 34 are 153.21 g/mmBtu for GHGenius (Canadian gas) and 221.05 g/mmBtu for GREET (US gas). According to the lookup table in the NW Council staff analysis (attached) at Tab 1, line 54, this approximates emissions rates of 0.85% and 1.25% respectively. In comparison, the EPA mid estimate is 1.82% (Council analysis, Tab 1, cell W24), and the EDF mid estimate is 2.84% (cell W23) and low estimate is 2.47% (cell X23). We recommended, and the NW Council staff proposed, to use the EDF low estimate for US gas (2.47%) because the EDF-led methane emissions study is by far the most substantial and extensive ever conducted. It involves a wide range of engineering, gas chemistry and atmospheric science experts, extensive use of direct and indirect data acquisition, and integrated analysis with results presented in numerous peer reviewed publications. While the project is continuing, the summary publication by Alvarez et al. ("Assessment of methane emissions from the U.S. oil and gas supply chain," Science, doi: 10.1126/science.aar7204, also attached) provides a comprehensive assessment including the recommended emissions metrics mentioned above. In conclusion, we recommend that PSE use the EDF low emissions rate of 2.47% as the most supportable overall value for aggregate upstream methane emissions from both US and Canadian sources. We also recommend that the Canadian values be further refined going forward, through consultation with relevant experts, especially those conducting the peer reviewed studies of Canadian methane emissions, to gain a consensus expert view on an appropriate upstream emissions rate for natural gas sourced in British Columbia and Alberta.	Thank you for your suggestions and providing background information. The NWPCC is recommending a derived rate upstream rate equivalent to 8,336 gCO2e/MMBtu in its modeling. PSE will use the derived rates from PSCAA. The PSCAA rates are 10,803 gCO2e/MMBtu for Canadian gas and 12,121 gCO2e/MMBtu for US gas. Concerning emission rate, assuming 1 MMBtu of natural gas contains 16,939 g of methane, the upstream fugitive rate will range from 0.90 to 1.31%. Thank you for your recommendation.

Invenergy Comments on Puget Sound Energy's Integrated Resource Plan Stakeholder Presentation on Social Cost of Carbon on July 21, 2020

Summary of PSE's Proposed Treatment of the Social Cost of Carbon in its 2021 IRP

The Clean Energy Transformation Act (CETA) requires PSE to incorporate the Social Cost of Carbon (SCC) for greenhouse gas (GHG) emissions in its integrated resource plans (IRPs). PSE has described two alternative approaches that it intends to use to apply the SCC in modeling its electric resource portfolio for the 2021 IRP.

PSE's preferred approach is to deliberately exclude the SCC from the variable costs of dispatching its GHG-emitting resources. Under this first approach, PSE's GHG-emitting resources would be allowed to dispatch unconstrained by the SCC, and the resulting GHG emissions would be accumulated on an annual basis. Then the annual GHG emissions would be multiplied by the SCC, and the result would be treated as an annual "fixed cost". This cost would be included in total annual costs for PSE's resource portfolio.

As a second approach, PSE proposes to perform a sensitivity analysis that would treat the SCC as if it were a carbon "tax". Under this approach, the SCC would be included as a variable cost of dispatching its GHG-emitting resources.

Under both of these approaches, it appears that PSE intends to treat the GHG emissions costs as if they are hard-dollar costs, including the costs in its calculations of the revenue requirements associated with its electric resource portfolio.

PSE's Preferred Approach Misapplies the SCC

PSE's first approach is inconsistent with the definition and intended use of the SCC.

The SCC was developed by the federal Interagency Working Group to estimate the *incremental cost* of the *economic damages* that result from the emission of one carbon-dioxide metric ton-equivalent amount of GHG emissions. Because the SCC is an incremental cost, portfolio modeling for IRP should include the SCC in the variable dispatch costs for GHG-emitting resources. PSE's first approach to exclude the SCC from variable dispatch costs is thus inconsistent with the Interagency Working Group's use of the SCC.

In addition, the SCC was specifically designed to enable the economic costs of GHG emissions to be included and reflected in cost-benefit analyses of decisions that would increase or decrease GHG emissions. PSE's IRP is a clear example of this type of cost-benefit analysis. It also seems clear that the intent of CETA is to require utility IRPs portfolio modeling analyses to recognize the SCC as an incremental cost. Thus, PSE's first approach is also inconsistent with the purpose behind SCC.

As a result, PSE's approach of ignoring the SCC when modeling economic dispatching of its resources, and then treating its GHG emissions as an annual fixed cost, conflicts with the purpose and use of the SCC as an incremental cost of economic damages. This approach undermines the intent of CETA as well.

PSE's Integrated Resource Planning Under CETA Should Treat the SCC as an Environmental Externality

PSE has argued that the SCC should not be included in variable dispatching costs for IRP modeling because the SCC is not required to be included in wholesale market prices for electricity. Invenergy agrees that wholesale market prices for electricity do not currently fully reflect the economic damage costs associated with GHG emissions. However, this fact actually demonstrates why the SCC should be included in variable dispatch costs for GHG-emitting resources for IRP portfolio modeling.

GHG emissions are environmental externalities. This is because GHG emissions create actual, incremental environmental costs that are not borne by the entity that produces the emissions, and the costs are not included in the market price paid by purchasers of electricity.

Since GHG emissions are an environmental externality, they should be treated as such in utility IRPs and RFPs under CETA. Invenergy supports doing this using generally accepted practices for internalizing externality costs. Specifically, utility IRP and RFP analyses should internalize the incremental environmental damage cost (as represented by the SCC) caused by each incremental decision to emit CO_2, including at the point of each hourly dispatch decision.

Suggesting that the SCC should be treated as a fixed cost because it is not reflected in the so-called "real world" of competitive wholesale markets is a false diversion. GHG emissions are a real-world cost, but because their costs are not fully recognized in the competitive marketplace, they are externalities that can and should be addressed as incremental costs in IRP portfolio modeling. Even if PSE was correct that costs that are not imposed in the “real world” should not be imposed in their IRP modeling, it does not follow that adding those costs after-the-fact as an annual fixed cost somehow comports with the “real world.” The “real world” simply does not include these costs, either as fixed or variable, so they should be imposed according to how the costs are incurred and according to the purpose and intent of CETA.

Treating SCC as a “Tax” is Also Inaccurate

As noted above, PSE is offering to perform a sensitivity analysis that treats the SCC as an incremental cost by including it in the variable costs of dispatch for its GHG-emitting resources. PSE has also stated that it intends to treat the resulting SCC emissions costs as a “tax”.

However, neither PSE nor its retail electric customers are subject to a dollar-per-ton tax on GHG emissions produced by PSE’s electric resources. Thus, PSE’s proposed approach to sensitivity analysis of the SCC as a “tax” is also unrealistic.

Invenergy Recommendations for PSE Analysis of the SCC in the 2021 IRP

Invenergy encourages PSE to recognize that GHG emissions produced by its electric generating resources are environmental externalities and to treat them as such in the portfolio modeling analyses for the 2021 IRP. Invenergy encourages PSE to include the SCC in the variable dispatching costs of its GHG-emitting resources when modeling its resource portfolio for the 2021 IRP.

As part of PSE’s resource portfolio modeling, Invenergy encourages PSE to track and report environmental externality costs (i.e., quantities of GHG emissions multiplied by the SCC of its resources’ GHG emissions), and to separately track and report the resource portfolio costs that actually go into its revenue requirements. Decisions about PSE’s portfolio resource mix should be made on the basis of the sum of revenue requirements plus GHG externality costs. This will be a more realistic method for applying the SCC than either of PSE’s proposed approaches. Reporting both of types of costs will also make PSE’s analysis more transparent.

Date: **July 22, 2020**
From: **Vlad Gutman-Britten, Climate Solutions**
To: **Puget Sound Energy Integrated Resource Plan Team**
RE: **July 21, 2020 Social Cost of Carbon Presentation Responses and Feedback**

Climate Solutions appreciates the opportunity to comment on the July 21st Social Cost of Carbon presentation. A key principle for Climate Solutions that has been articulated to both the UTC and the Department of Commerce as part of CETA rulemaking is that the SCC application methodology must accurately reflect how a plant will operate in the real world in order to properly evaluate the impact of the full projected emissions a facility will be responsible for. We articulated this position to the UTC in our comment letter date December 20, 2019 and in more detail to the Department of Commerce on June 15, 2020, from which we quote below:

> Incorporating the social cost of greenhouse gas emissions should strive to reflect how generating stations and resource portfolios will operate in real-time after the planning process is complete…In order to accurately understand the greenhouse gas impacts of specific utility choices, a utility's resource plan should reflect the state of the grid, the costs of dispatch, and the competitive standing of various resources as accurately as possible and *as they would function in reality*. Doing this accurately enables a utility, its customers, and the public to understand the import of differing choices and the social costs being imposed by those choices.
>
> If a utility incorporates the social cost of greenhouse gas emissions into the input cost of fossil fuel resources, this assumes that in real-time, the social cost of greenhouse gas emissions will impact dispatch and operations. Doing this will artificially suppress the dispatch of fossil fuel resources in a utility's system simulation and create the impression of a portfolio that is lower-emitting than said portfolio would be in actuality. In practice, this means that a substantial share of emissions the portfolio would generate would not be covered by the social cost of greenhouse gases as required in statute, and lead to utility resource decisions that are not reflective of real-world greenhouse gas impacts of specific resource selections. Utilities should only be permitted to incorporate the social cost of greenhouse gas emissions pre-economic dispatch if in real-time, utilities plan to incorporate these costs into operational decisions.

It is of paramount importance that *all* the emissions from an evaluated portfolio be priced with SCC, which would require simulating an accurate capacity factor for all selected resources. Furthermore, artificially suppressing the dispatch of a thermal resource under consideration would yield an increased energy gap that would need to be filled by other resources, resulting in builds that are not necessary given the actual higher level of dispatch that a facility would experience.

Nonetheless, we agree with other stakeholders that there is an opaqueness in how:

1. SCC impacts resource portfolios. This is because of the factor that PSE has identified—resource choices are being driven principally by portfolio requirements and not SCC.
2. SCC impacts on conservation and demand side resource selection.

We recommend that PSE provide more background on point 2—explaining how the proposed SCC impacts the cost-effective level of conservation and other demand side resources selected and how this selection is and is not informed by metrics like LCOE. On the call, presenters explained that the avoided carbon emission value of these resources is reflected in their selection by providing a relative cost advantage for them when minimizing total portfolio cost, but more clarity on this point would be beneficial.

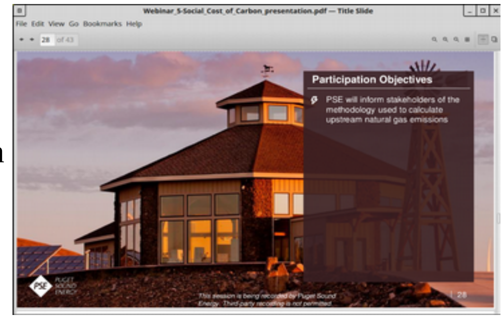
To address point 1, we agree with other stakeholders that a scenario with SCC applied as an adder and another with SCC applied during dispatch would be helpful. As the company has pointed out, the 2019 IRP included such runs and concluded that SCC largely doesn't impact resource selection, so in addition we'd suggest running these scenarios *in absence* of the CETA portfolio requirements. Ultimately, depending on how rule-making settles on this question, this scenario could be useful for establishing the baseline for the purposes of incremental cost calculation.

In addition, we have concerns with the emissions leakage rate selected by the company for upstream methane sources. While we recognize that the company is suggesting using an agency figure selected by PSCAA, numerous recent peer-reviewed studies have indicated that this level may be too low. A recent example published by a team led by Ramon Alvarez, who has a long history of examining leakage rates and impacts, indicates that US leakage rate could be 60% higher than the EPA currently estimates for example. We urge the company to reexamine the leakage level selected for its natural gas sources and consider adjustments to reflect recent research. At minimum, a sensitivity that includes higher leakage estimates should be conducted to address whether such an adjustment impacts the company's preferred portfolio. Doing so would help elucidate the impact of this specific figure in making resource choices.

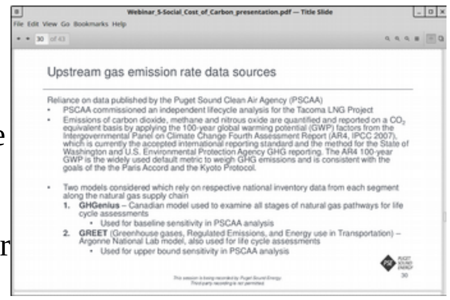
Thanks again for providing an opportunity to comment on the company's 2021 IRP, and we look forward to continued engagement with your team.

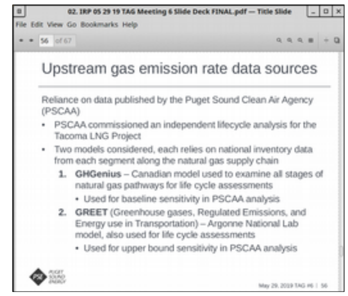
Feedback questions regarding the level of public participation PSE selected for Webinar 5

For the section of Webinar 5 on upstream natural gas emissions methodology, PSE chose the lowest level of public participation possible: "**inform**" only (Webinar 5, Slide 28).

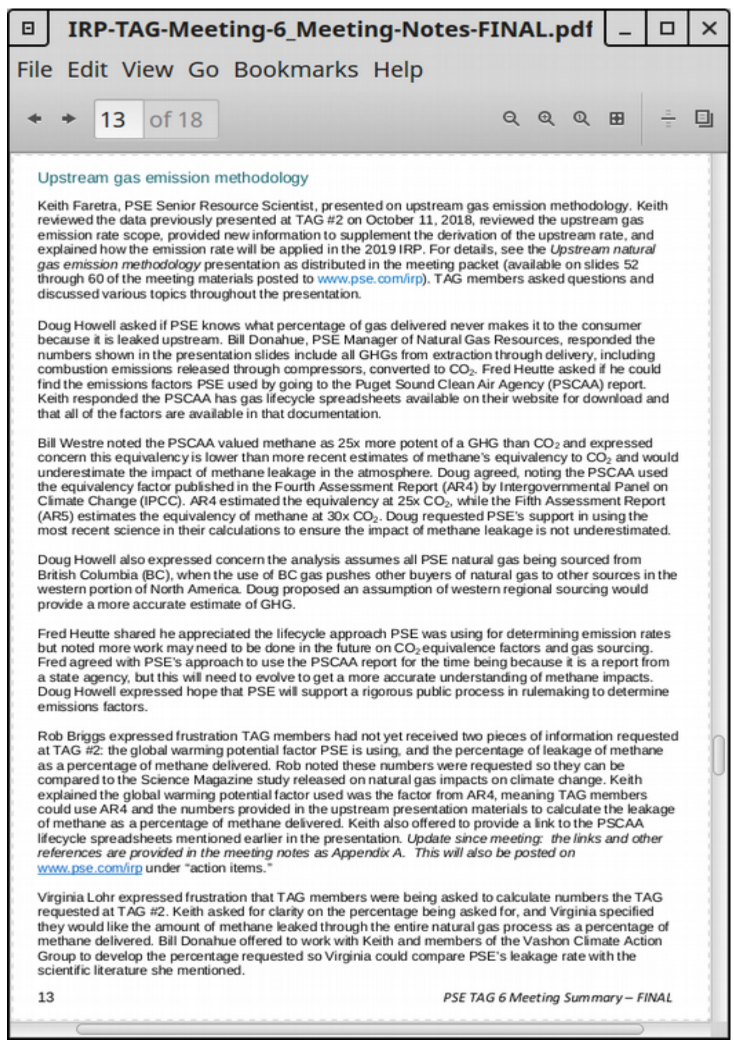


During Webinar 5, PSE informed us they would use the same emissions methodology (Webinar 5, Slide 30) they had proposed during the 2019 IRP process (TAG 6, Slide 56). In fact, all but one slide used for presenting this information for the 2019 IRP were the same as those in the 2021 IRP, so many stakeholders present at the 2021 IRP webinar were already informed of the proposed method.





During the 2019 IRP process, lively discussion ensued when PSE's proposed method was presented (TAG 6, Final notes, pg 13), so in addition to knowing that most stakeholders were already informed about the method, PSE should have known that stakeholders would be expecting to participate at a level higher than "inform."



Upstream gas emission methodology

Keith Faretra, PSE Senior Resource Scientist, presented on upstream gas emission methodology. Keith reviewed the data previously presented at TAG #2 on October 11, 2018, reviewed the upstream gas emission rate scope, provided new information to supplement the derivation of the upstream rate, and explained how the emission rate will be applied in the 2019 IRP. For details, see the *Upstream natural gas emission methodology* presentation as distributed in the meeting packet (available on slides 52 through 60 of the meeting materials posted to www.pse.com/irp). TAG members asked questions and discussed various topics throughout the presentation.

Doug Howell asked if PSE knows what percentage of gas delivered never makes it to the consumer because it is leaked upstream. Bill Donahue, PSE Manager of Natural Gas Resources, responded the numbers shown in the presentation slides include all GHGs from extraction through delivery, including combustion emissions released through compressors, converted to CO_2. Fred Heutte asked if he could find the emissions factors PSE used by going to the Puget Sound Clean Air Agency (PSCAA) report. Keith responded the PSCAA has gas lifecycle spreadsheets available on their website for download and that all of the factors are available in that documentation.

Bill Westre noted the PSCAA valued methane as 25x more potent of a GHG than CO_2 and expressed concern this equivalency is lower than more recent estimates of methane's equivalency to CO_2 and would underestimate the impact of methane leakage in the atmosphere. Doug agreed, noting the PSCAA used the equivalency factor published in the Fourth Assessment Report (AR4) by Intergovernmental Panel on Climate Change (IPCC). AR4 estimated the equivalency at 25x CO_2, while the Fifth Assessment Report (AR5) estimates the equivalency of methane at 30x CO_2. Doug requested PSE's support in using the most recent science in their calculations to ensure the impact of methane leakage is not underestimated.

Doug Howell also expressed concern the analysis assumes all PSE natural gas being sourced from British Columbia (BC), when the use of BC gas pushes other buyers of natural gas to other sources in the western portion of North America. Doug proposed an assumption of western regional sourcing would provide a more accurate estimate of GHG.

Fred Heutte shared he appreciated the lifecycle approach PSE was using for determining emission rates but noted more work may need to be done in the future on CO_2 equivalence factors and gas sourcing. Fred agreed with PSE's approach to use the PSCAA report for the time being because it is a report from a state agency, but this will need to evolve to get a more accurate understanding of methane impacts. Doug Howell expressed hope that PSE will support a rigorous public process in rulemaking to determine emissions factors.

Rob Briggs expressed frustration TAG members had not yet received two pieces of information requested at TAG #2: the global warming potential factor PSE is using, and the percentage of leakage of methane as a percentage of methane delivered. Rob noted these numbers were requested so they can be compared to the Science Magazine study released on natural gas impacts on climate change. Keith explained the global warming potential factor used was the factor from AR4, meaning TAG members could use AR4 and the numbers provided in the upstream presentation materials to calculate the leakage of methane as a percentage of methane delivered. Keith also offered to provide a link to the PSCAA lifecycle spreadsheets mentioned earlier in the presentation. *Update since meeting: the links and other references are provided in the meeting notes as Appendix A. This will also be posted on* www.pse.com/irp under "action items."

Virginia Lohr expressed frustration that TAG members were being asked to calculate numbers the TAG requested at TAG #2. Keith asked for clarity on the percentage being asked for, and Virginia specified they would like the amount of methane leaked through the entire natural gas process as a percentage of methane delivered. Bill Donahue offered to work with Keith and members of the Vashon Climate Action Group to develop the percentage requested so Virginia could compare PSE's leakage rate with the scientific literature she mentioned.

13 *PSE TAG 6 Meeting Summary – FINAL*

Is this the first time in the 2021 IRP process that PSE has used a level of "inform" only? If it was used for a previous topic, why was it deemed appropriate for that topic? Also, why did PSE decide to go with "inform" only for this topic?

Thank-you for your attention to these questions.

Virginia Lohr
Vashon Climate Action Group
July 25, 2020

NW Energy Coalition
for a clean and affordable energy future

June 15, 2020

Richard Devlin, Chair
Northwest Power and Conservation Council
851 SW Sixth Avenue, Suite 1100
Portland, OR 97204

Dear Chair Devlin and Council members:

The NW Energy Coalition (NWEC) is pleased to write in support of the staff recommendation – with one exception as described below – for the assessment of upstream methane emissions for the 2021 Northwest Power Plan. We appreciate the review of the Natural Gas Advisory Committee and the work by staff member Steve Simmons to prepare a thorough and well documented methodology.

NWEC is committed to achieving the vision of a reliable, clean and affordable Northwest power system, and considers the work of the Council to have even more importance from this point onward in providing clear guidance for the rapid transformation needed to achieve our region's climate, clean energy, reliability, economic and environmental protection goals.

Identifying and rapidly reducing greenhouse gas emissions attributable to the power sector is a crucial aspect of that effort. While the role of carbon dioxide (CO_2) as the "control knob for the climate" with atmospheric and climate system effects for thousands of years is relatively well understood, methane (CH_4) is another very important greenhouse gas with climate impact on relatively short time scales of up to 20 years. The primary locus of emissions for CO_2 is combustion – and indeed, natural gas, primarily composed of methane, creates substantial CO_2 on combustion, as already accounted for in the Council's assessment and methods.

The key concern for methane, however, is emissions in the supply chain prior to combustion in natural gas power plants and otherwise. As staff's report indicates, assessing upstream methane emissions is a complex undertaking, and considerable research is ongoing to acquire more observational data and develop more robust assessment methods.

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Given the relevance and magnitude of methane emissions related to the Northwest electric power system, NWEC believes it is very important to take the initial steps outlined by staff to include upstream methane assessment in the 2021 Plan. We recommend that the Council:

- Take an evidence-based approach to upstream methane emissions, recognizing rapid advances being made in data acquisition, refinement and assessment, but also recognizing the remaining areas of uncertainty and data gaps.

- Focus on data and assessments most relevant for the primary supply basins for Northwest power system use, particularly northeast British Columbia, Alberta, and the Rockies.

- Also fully consider national assessments in providing guidance.

- Invite scientific experts in the field of methane emissions, atmospheric chemistry and climate science to provide views and advice to the Council on the complex data and assessment issues involved.

- Take a flexible and incremental approach to avoid significant under or overestimation of upstream methane emissions and to incorporate new relevant information on an ongoing basis.

- Include one or more elements in the Action Plan for the 2021 Plan to facilitate additional progress on this important topic.

NWEC also supports the efforts by environmental regulators and the natural gas industry to mitigate upstream methane emissions through improved monitoring, reporting, leak detection and response (LDAR) programs, regulatory compliance and other efforts. As verifiable evidence of those efforts develops, that should also be folded into the Council's analysis.

Turning to the specific approach recommended by staff for the 2021 Plan, the key metric is L_d, the aggregate upstream methane emissions rate. The staff methodology is appropriate overall, and we support the recommendation to adopt the EDF Low L_d value for upstream emissions for US sourced natural gas used by the Northwest power sector, primarily from the Rockies region.

The EDF managed research program, which has now been running for a decade, is supported across many relevant sectors, involves rigorous field research protocols and scientific review, assesses emissions from many US supply basins, especially the Rockies, and has resulted in numerous peer reviewed publications.

However, we do not support the staff's recommendation for Canadian natural gas sources based on provincially adopted L_d values. Because Canadian gas, primarily from northeast British Columbia but also various parts of Alberta, comprises about two-thirds of Northwest gas supply, this is an important issue to consider as the Council finalizes the 2021 Plan.

NWEC believes that while the provincial values for upstream emissions have been widely cited, they are based on earlier baseline assessments that have not been updated for many years.

However, quite a lot of new research is now available, and below we provide a capsule summary of several relevant publications:

- Atherton et al. (2017)[1] conducted an extensive field survey of gas and oil production areas in northeastern British Columbia, covering more than 1,600 well pads and processing facilities. They conclude: "Our calculated emission frequency values, combined with estimated and pre-established emission factors for wells and facilities, provided a CH4 emission volume estimate of more than 111 800 ± 15 700 t per year for the BC portion of the Montney. This value exceeds the province-wide estimate provided by the government of BC even though the Montney only represents about 55 % of BC's total natural gas production."

- Wisen et al. (2020)[2] reviewed natural gas well leakage data from the British Columbia Oil and Gas Commission. They found that about 11% of over 21,000 wells reported leakage during their lifetime, twice the rate indicated from earlier research in Alberta, and highlighted that both BC and Alberta have almost no leakage reporting from abandoned or retired wells.

- Ravikumar et al. (2020)[3], as part of a field study of leak detection and response (LDAR) efforts, reviewed emissions studies in both Alberta and British Columbia and likewise concluded: "Both ground-based and aerial-measurements in Alberta showed higher vented and total methane emissions compared to provincial regulatory estimates. Similarly, mobile measurements using truck-mounted sensor systems in British Columbia and Alberta have consistently shown that a majority of the emissions are dominated by a small number of high-emitting sites, often identified as 'super-emitters.'"

- O'Connell et al. (2019)[4] surveyed 1,299 oil and gas well pads and 2,670 unique wells and facilities in Alberta, and found: "As a result of measured emissions being larger than those reported in government inventories, this study suggests government estimates of infrastructure affected by incoming regulations may be conservative. Comparing emission intensities with available Canadian-based research suggests good general agreement between studies, regardless of the measurement methodology used for detection and quantification."

[1] Atherton et al., 2017, "Mobile measurement of methane emissions from natural gas developments in northeastern British Columbia, Canada," *Atmospheric Chemistry and Physics*, 17, 12405–12420, 2017, DOI: 10.5194/acp-17-12405-2017.
[2] Wisen et al., 2020, "A portrait of wellbore leakage in northeastern British Columbia, Canada," *Proceedings of the National Academy of Sciences*, 117 (2) 913-922; DOI: 10.1073/pnas.1817929116
[3] Ravikumar et al., 2020, "Repeated leak detection and repair surveys reduce methane emissions over scale of years," *Environmental Research Letters* 15 (2020) 034029, DOI: 10.1088/1748-9326/ab6ae1
[4] O'Connell et al., 2019, "Methane emissions from contrasting production regions within Alberta, Canada: Implications under incoming federal methane regulations. *Elementa* 7: 3. DOI: 10.1525/elementa.341

After our review of the literature, including the examples cited here, NWEC believes the Canadian L_d upstream emissions metric should be updated to a higher value reflecting the more recent research.

To summarize, the Canadian L_d value proposed by staff is a methane loss rate of 0.77%. In comparison, that is about two-fifths of the EPA rate of 1.82%, and less than one-third of the EDF Low rate of 2.47%. We conclude the Canadian value is out of date and implausibly low given the results of numerous peer-reviewed studies in British Columbia and Alberta.

We recommend that the Natural Gas Advisory Committee be reconvened later this year to review the upstream methane emissions rate for Canadian supply areas, including presentations from experts having direct experience with these issues. It may be appropriate as a starting point to consider the EDF Low rate and adjust from there.

NWEC again thanks Council staff and the NGAC for close attention to this important issue and urges the Council to move forward with the staff recommendation to include the assessment of upstream methane emissions for the 2021 Plan, with an upward adjustment for the Canadian emissions rate.

Sincerely,

Fred Heutte
Senior Policy Associate
NW Energy Coalition
fred@nwenergy.org

1402 Third Avenue, Suite 900
Seattle, WA 98101

December 27, 2018

Ann Farr
Port of Kalama
110 W. Marine Drive
Kalama, WA 98625
Via email to: SEIS@KalamaMfgFacilitySEPA.com

Dear Ms. Farr:

In February this year, we published a discussion brief in which we examined the climate implications of the proposed Kalama methanol facility. The brief, titled "Towards a climate test for industry: Assessing a gas-based methanol plant", has since been cited in the media and by other commenters on the Kalama facility.

Further, the new, Draft Supplemental Environmental Impact Statement (DSEIS) responds (indirectly) to the major critiques we had advanced in our discussion brief – critiques that were directed at the prior, Final Environmental Impact Statement (FEIS). In particular, the DSEIS, unlike the FEIS, now estimates upstream, fugitive methane losses associated with the gas supplied to the facility.

Because of these developments, we now find ourselves compelled to submit our own comments, attached, in order to help evaluate the improvements in the DSEIS.

Herein, we find that the DSEIS treatment of fugitive methane losses, though more comprehensive than in the FEIS, is still not credible. We also make further critiques, including related to the misplaced confidence that the DSEIS places in drawing a direct, causal connection between the planned production of the Kalama facility's methanol and the displacement of coal-based methanol in China.

We are grateful for the opportunity to provide these comments, and would be happy to answer any questions about them.

Sincerely,

Peter Erickson and Michael Lazarus
Senior Scientists
Stockholm Environment Institute, U.S.

SEI comments on Kalama DSEIS

Peter Erickson and Michael Lazarus, Stockholm Environment Institute (SEI) U.S. Center
December 27, 2018

In February this year, we published a discussion brief in which we examined the climate implications of the proposed Kalama methanol facility. The brief, entitled "Towards a climate test for industry: Assessing a gas-based methanol plant"[1], presented an approach for assessing whether the construction and operation of the facility would be consistent with internationally-agreed goals of keeping global temperature rise "well below 2 degrees C."[2]

We found that the facility's 2016 "Final" Environmental Impact Statement (FEIS)[3] provided an incomplete and deeply flawed analysis of GHG emissions associated with the facility. In our assessment, correcting these errors would increase the facility's annual emissions by a factor of two to six relative to the estimates in the FEIS. We also found that, even with these corrections, the facility could still reduce global GHG emissions if were to displace coal-based methanol, as proponents, Northwest Innovation Works (NWIW), have claimed.

However, we also found that other more widely used technologies can produce olefins – the precursor to plastics that proponents claim will be the ultimate (and only) destination for the facility's methanol output – would result in lower global emissions. Overall, our analysis suggested that the facility would be inconsistent with a deeply low-carbon future, risking the long-term lock-in of a technology (natural gas-to-methanol-to-olefins) that does not represent a low-emission means of producing plastics. It found the claims that the facility would only displace coal-based methanol less than compelling.

Since our discussion brief, a new Draft Supplemental EIS (DSEIS) was submitted by the Port of Kalama and Cowlitz County,[4] and additional information and studies relevant to the proposed Kalama methanol facility have been released.[5–8] Further, the project developer – Northwest Innovation Works – has disputed our report,[9] and an analysis they commissioned, by the Low Carbon Prosperity Institute, has commented on our findings.[5]

We have reviewed the new DSEIS, and make six observations below. The first three of these relate to "upstream" methane losses, since the DSEIS, though more comprehensive than in the FEIS, is still not credible in this regard. We then remark on the misplaced confidence that the DSEIS places in drawing a direct, causal connection between the planned production of the Kalama facility's methanol and the displacement of coal-based methanol in China. Our final two observations concern the consistency of the Kalama facility with a deeply low-carbon transition in line with the globally agreed goal to limit warming to 'well below 2 degrees C".

1 The DSEIS analysis of upstream natural methane loss rate is not credible.

In 2016, the FEIS made the serious error of assuming that the Kalama facility would lead to *no* upstream methane emissions from the production, gathering, processing, and transportation of natural gas. In doing so, the FEIS defied common practice.

Now, in 2018, the DSEIS has sought to remedy this error by including estimates of upstream methane emissions, but does so, once again, in a flawed manner that significantly underestimates these emissions.

Namely, the DSEIS uses outdated and inaccurate information for its assessment of the GHG emissions associated with the production, gathering, processing, and transportation of natural gas. As the DSEIS notes, the process of producing and transporting natural gas leads to GHG emissions – both methane

(CH_4) and carbon dioxide (CO_2) – from "fugitive losses" as well as ongoing emissions from operating the wells and gathering and processing infrastructure.

However, the DSEIS relies on the GHGenius model, which, according to the DSEIS, uses an implausibly low methane loss rate of 0.32% for gas from British Columbia.[i] That rate was self-reported by the Canadian Association of Petroleum producers in the year 2000 and was calculated using an incomplete bottom-up method that does not count all methane losses[10] – especially not those from irregular operations or accidental releases, which have since been found to be a substantial source of emissions from natural gas production.[11]

Further, both of the other sources of methane loss estimates listed in the DSEIS for B.C. gas suffer from similar limitations. The "G7 Study" is also a bottom-up analysis, has not yet undergone peer review, was conducted in Alberta (not BC as claimed in the DSEIS), and looked at a set of unique conditions that cannot be extrapolated to any other operator or region. Similarly, the DSEIS cites the B.C. government inventory – but this too uses a bottom-up method that misses large quantities of fugitive methane.[12]

By contrast to these bottom-up methods, more comprehensive and modern estimates of methane losses from the natural gas supply chain are much higher, about 2%, and are informed by top-down techniques, such as airplanes equipped with sensors that can capture the full range of operating conditions at gas extraction fields.[7,13]

In summary, we see little reason why methane loss rates from the gas provided to the Kalama facility (whether from Canada or the U.S.) would be lower than the current most comprehensive (yet still incomplete) estimate of 2.2%,[ii] published in the journal *Science* in 2018.[6]

2 The DSEIS choice of global warming potential for natural gas does not reflect recent science

Furthermore, the DSEIS uses an outdated figure for how methane contributes to global warming. Specifically, they use a value for methane's "global warming potential" of 25. (The number indicates how much more a molecule of methane contributes to warming over 100 years than does carbon dioxide). That value of 25 is from the Intergovernmental Panel on Climate Change (IPCC)'s 2007 *Fourth Assessment Report*,[14] but the IPCC has since updated the potential to 34 in its 2013 *Fifth Assessment Report*.[15] Government agencies may still use the 2007 value for reporting their GHG emissions to national or international bodies that require consistency over time and across reporting jurisdictions. However, what governments use for reporting to such bodies need not constrain their use of more accurate values in environmental assessments. In sum, we see no legitimate reason not to use the latest science in assessing the Kalama facility's GHG emissions effect.[16]

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[i] Though the DSEIS reports using GHGenius version 4.03 and that GHGenius uses a leakage rate of 0.32% (Table B.3 of Appendix A to the DSEIS), the data the DSEIS reports in Table B.4 of 104 g CH_4 per mmBtu of gas suggest a methane loss rate of between 0.6% and 0.7%. We are not sure how to account for this discrepancy.

[ii] Here we use Alvarez *et al.*'s (2018) estimate of 2.2% methane loss rate (expressed as a function of methane produced) through gas transmission; the rate would be 2.3% if local gas distribution were also included.

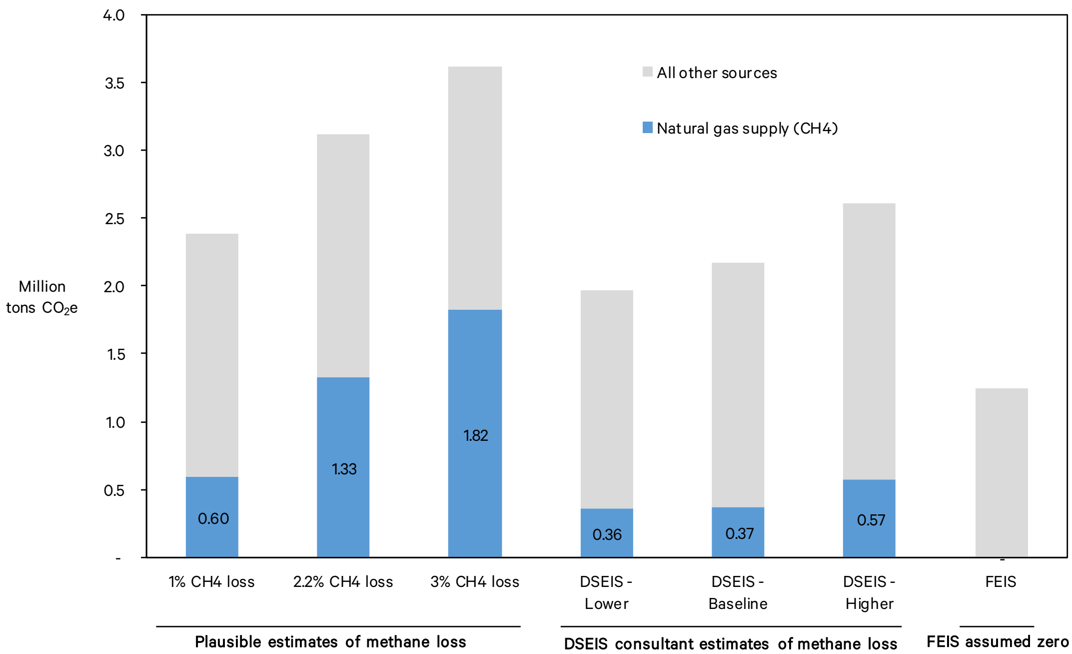
3 Correcting for these errors in the DSEIS methane loss analysis alone increases total facility GHG emissions by 10-70%

Correcting for the under-estimate of methane losses (point 1 above) and the incorrect use of an outdated global warming potential (point 2 above) in the DSEIS would substantially increase the estimate of the Kalama facility's annual GHG emissions.

Figure 1 shows the total GHG emissions associated with producing methanol at the Kalama refinery, under a range of plausible long-term methane loss rates of 1 to 3% (but with the DSEIS estimates of all other emissions), and including the current "best" estimate of 2.2%[iii]

We estimate that, in total, production and delivery of methanol from the Kalama refinery to Chinese ports would lead to 2.4 million to 3.6 million tons CO_2e annually, assuming a 100-year Global Warming Potential (GWP). These estimates are 10% to 70% higher than the DSEIS baseline estimate of 2.2 million tons CO_2e. (Figure 1 compares our three scenarios to those in both the DSEIS and the prior FEIS). The only difference between our estimates and those in the DSEIS is the amount of methane losses from natural gas supply and how much that contributes to the proposed facility's total GHG emissions.

Figure 1. Greenhouse gas emissions associated with the proposed Kalama facility under alternative assumptions about methane (CH_4) loss, as compared to EIS estimates



Source: SEI Analysis based on the Kalama DSEIS and FEIS, supplemented with a new, best estimate of current methane loss of 2.2%, plus a wider, plausible range of future methane loss of 1% to 3% based on a literature review, and with global warming potentials (GWP) for methane of 34 times higher than CO_2 over a 100-year timeframe, based on IPCC.[15] For the three bars on the left, we assumed the same emissions from other sources as in the DSEIS baseline case.

It is also important, in our view, to be simple and transparent about assumptions, such as methane loss rate, that have such a large influence on the emissions estimates. By contrast, the DSEIS cites a model,

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[iii] The 1 to 3% range was also used in another recent study comparing the lifecycle emissions of power plants. We adopt the Kalama DSEIS baseline estimates for all other sources for simplicity, not necessarily because we agree with them. In particular, the DSEIS presents a confusing and misleading representation of marginal power resources that ignores the Northwest Power and Conservation Council's analysis of marginal CO_2 emissions rates.

GHGenius version 4.03, which – when it comes to methane loss rate – appears not really to be a model at all, but primarily a single assumption drawn from an industry study 18 years ago, as described above.

The math for estimating methane emissions attributable to the Kalama facility is not complicated, and need not be spread out over multiple tables as in the DSEIS. Our estimate of the methane emissions attributable to the project, 1.33 million tonnes CO_2e, is calculated as follows in Table 1.

Table 1. Calculation of methane loss associated with the Kalama facility

Parameter	Value	Source	Notes
Gas delivered	107 Tera BTU	DSEIS	Calculated as 29.6 mmBtu/tonne from DSEIS Appendix A Table 3.9 multiplied by 3.6 million tonnes methanol as on DSEIS page 3-32
Divided by	/		
Gas energy content	23,180 BTU per pound	DSEIS	This value from the DSEIS is about 10% higher than imputed from a heat content of 1049 BTU/ft as in the DSEIS Appendix A Table C.1 and an imputed gas density of 22.3 g/ft^3 from PSE. We aren't sure how to explain the difference.
Divided by	/		
English to metric conversion	2,205 pounds per metric tonne	Unit Conversion	
Multiplied by	X		
Methane content, by weight	83.1%	Puget Sound Energy	Methane content of delivered gas by volume is 91.3%, as reported in Table 2.5 of the DSEIS for the Tacoma LNG project where it is attributed to PSE. Considering the molecular weight of methane relative to other gas components (e.g., ethane and propane), this is about 83.1% by weight.
Multiplied by	X		
Methane loss as a fraction of methane delivered	2.25%	Alvarez et al 2018	Alvarez reports methane loss of 2.2% as a function of methane *produced*, not *delivered*; we convert between those here as 0.022/(1-0.022)
Multiplied by	X		
Global Warming Potential (100 year)	34	IPCC 2013 (Myhre et al 2013)	This is the value including climate feedbacks.
Equals	=		
Annual GHG emissions	1.33 million tonnes CO_2e	Arithmetic	

4 The DSEIS is far too confident that Kalama methanol will displace coal. Still, the possibility does exist.

As the DSEIS points out, the GHG emissions of producing methanol from coal in China are far higher than producing methanol from gas. Therefore, *if* methanol and olefin markets were restricted to China and the country were otherwise likely to commit to intensive coal use (despite its Paris Agreement commitment) for another 3 decades, then indeed gas-based methanol from Kalama could directly displace the production of methanol from coal, and GHG savings could be quite significant. However, methanol and olefin markets are complex and global, and it is difficult to be certain what Kalama methanol would displace.

In particular, we see several problems with DSEIS market analysis of the displacement of coal-based methanol.

First, the DSEIS market analysis, i.e. Figures 4.16 and 4.17 in DSEIS Appendix A, constrains the analysis to just the methanol producers that can access China's methanol-to-olefin market. Because methanol and olefin markets are global, as the DSEIS acknowledges, we see no good reason to limit the scope in this way. The practical implication of the DSEIS constraining the market this way is to exclude, inappropriately, a large number of international, gas-based methanol producers from consideration for what may be displaced by Kalama methanol.

Second, the DSEIS market analysis assumes that demand for methanol is fixed. But as the DSEIS notes elsewhere, demand for methanol from the olefin market is highly dependent on oil price. If oil prices are low, olefin producers would favor naphtha-based routes, and have less demand for methanol-based-routes, especially for new, coal-based methanol. The DSEIS does not report what oil prices they assume, and so we cannot know what underlies their anticipated demand. There is some reason to believe that oil prices could be low in the future, and not exceed, e.g. $60 per barrel, for extended periods. This could occur, for example, if the global market for electric vehicles and commitments to address climate change cut into future oil demand.[17,18] Oil prices at that level could make other olefin routes more cost competitive, reducing the demand for methanol; in that case, methanol-to-olefin facilities (fed by coal-based methanol) may not actually be the marginal producer that the DSEIS assumes they are.

Third, and relatedly, the DSEIS projects far too much confidence in the future of coal-to-methanol in China. The DSEIS relies on a proprietary forecast from China's chemical industry, but it is common in China for announced facilities to never be built. For example, analysis has shown that a significant fraction of announced coal-based power plants in China are cancelled or shelved rather than proceed to construction and operation.[iv] Cancellation of potential coal-based facilities could well occur for methanol, too, especially if China expands its carbon pricing and other climate policy efforts to the industrial sector. Already, China has taken important steps to curb coal, both in response to air pollution concerns and its own commitments to address climate change, including a national emission trading system. Indeed, some analysts believe that coal consumption in China, which in recent years was increasing rapidly, has entered a plateau phase and will soon begin a long decline.[19,20]

Lastly, the DSEIS makes the argument that the Kalama facility will displace other methanol producers based on cash costs of production of $150/tonne, but these costs are not spelled out or justified, nor sensitivities examined. Were methanol demand to be lower (as described above) and the many other global gas-to-methanol-facilities not excluded (as also described above), it is conceivable that, were the

[iv] According to the CoalSwarm Coal Plant Tracker, 359 GW of announced coal plants in China have been cancelled since 2010, as compared with 431 GW that went into operation and 126 GW currently under construction. (See www.coalswarm.org) In addition, in 2016 and 2017, the Chinese government suspended another 444 GW of coal plants at various stages of development. (Shearer, C. *et al.* Boom and Bust 2018: Tracking the Global Coal Plant Pipeline, CoalSwarm, Greenpeace USA, and Sierra Club (2018)).

capital costs of the Kalama facility to also be included, that the facility may not be in the strong economic position it claims to be. For example, a $2 billion capital cost, financed over the 40-year facility lifetime at 7% cost of capital, would amount to about $42 per tonne, assuming 3.6 million tonnes methanol produced per year. Adding this $42 per tonne to the facility's stated cash costs of $150/tonne would potentially place it in range – especially if gas prices are not as low as envisioned – of being economically vulnerable to reduced methanol demand.

Nevertheless, despite these problems, the possibility remains that Kalama could displace a substantial amount of coal-based methanol. An analysis by the Low Carbon Prosperity Institute (LCPI)[5] introduces a useful concept – a ratio of how much the Kalama facility would displace coal-based methanol (with substantial GHG *reductions*) relative to naphtha-based olefins (with smaller GHG *increases*) to render the net effect on emissions neutral.

However, though innovative, even that LCPI analysis may give too much weight to coal-based methanol. As Figure 4.15 in DSEIS Appendix A shows, globally, there is even more gas-based-methanol available than coal-based methanol, so other gas-to-olefin facilities should also be considered as possible sources displaced (with little effect on GHG emissions either way).

Similarly, on the downstream end (meaning, what the methanol is used for), it is not just other olefin routes that may be displaced (they are a relatively small share of the methanol market), but also vehicle fuel, formaldehyde, and other chemical products, as Figure 4.5 in Appendix A to the DSEIS shows, all of which themselves also have GHG implications. For example, blending gasoline with gas-derived methanol would increase GHG emissions: an 85% blend of gas-derived methanol would yield life-cycle GHG emissions 15% to 19% higher than conventional gasoline.[21] In addition, the market effects of inducing additional liquid fuel consumption could also increase emissions by up to 20-60% on top of that.[22]

Taking the LCPI innovation of assessing relative likelihood further – to look, probabilistically, at how new gas-to-methanol may displace *multiple* ways of both producing and consuming methanol – would be a useful contribution. Unfortunately, it is beyond the scope of what we can do in this limited comment window. Regardless, it is clear that the approach taken in the DSEIS's central results (e.g., Table 6.1 of Appendix A of the DSEIS) – of assuming it is *only* coal that is displaced -- is tenuous, at best.

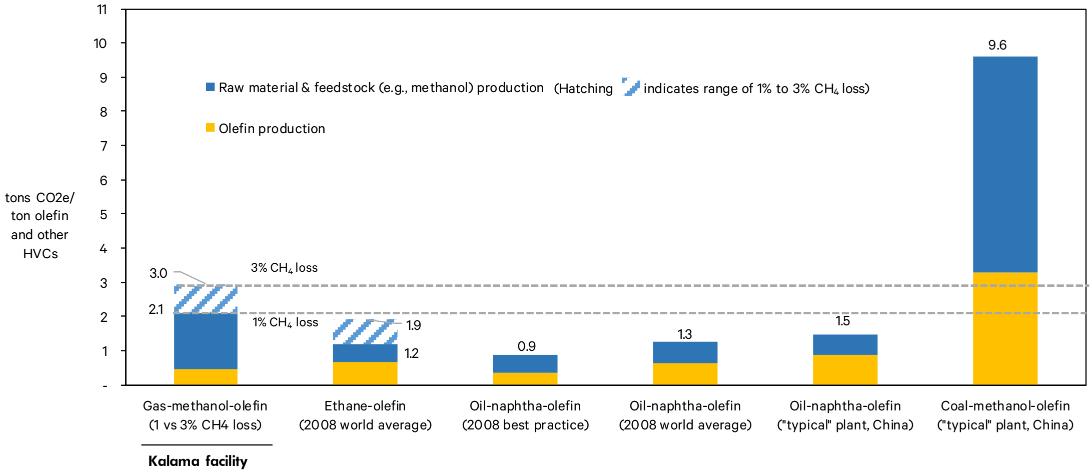
5 New, long-lived industrial infrastructure should manufacture products (here, olefins) with very low life-cycle emissions. The Kalama methanol facility does not.

Our discussion above recognized the possibility that the Kalama facility may displace coal-based methanol. Still, even if the facility *were* to reduce emissions relative to coal-based methanol, its construction and operation might not be consistent with long-term climate goals. A low-carbon transition – in line with the globally-agreed guardrail of keeping warming "well below 2" degrees Celsius – might call for investment in even lower-emitting production processes. In other words, comparing against a "business-as-usual" technology – regardless of whether that technology is coal-based methanol or instead a more common naphtha-based route – may simply be inadequate for assessing whether a facility "makes sense" in light of the need to steeply reduce global emissions.

Several technologies produce olefins and related chemicals. The predominant technology globally has been steam cracking of naphtha (a product of crude oil refining) and, to a lesser extent, ethane (a co-product of natural gas production).[23] For example, in 2016, 82% of ethylene capacity was naphtha and ethane based, and only 2% was methanol based.[24]

Figure 2 shows the GHG emissions implications of these and other alternative pathways to making olefins and the related high-value chemicals that are often minor co-products of olefin refining. As shown, producing a ton of these chemicals from naphtha would result in 0.9 to 1.3 tons CO_2e, depending on whether best or average practice is followed. That is about half the GHG emissions as a facility using natural-gas-based methanol from Kalama (2.1 to 3.0 tons CO_2e, depending on methane loss rates). (Appendix E to Appendix A of the DSEIS reports a higher estimate for the GHG-intensity of naphtha-based chemicals – equivalent to 1.9 t CO_2e per tonne of HVCs, which it acknowledges is higher than in the peer-reviewed literature.[v] Even this value is lower than the corrected Kalama estimate, however.)

Figure 2. Greenhouse gas intensity of alternative olefin production pathways



Source: SEI Analysis based on the following sources. GHG emissions intensity of methanol production at the proposed Kalama facility is drawn from the DSEIS, adjusted to account for a range of methane loss rates of 1% to 3%. GHG emissions intensity of olefin and other HVC production from the Kalama facility's methanol is assumed to be 2008 best practice from Ren et al 2008.[25] GHG emissions intensity of the ethane-olefin and oil-naphtha-olefin routes are 2008 values for CO_2 intensity drawn from Ren et al 2008,[25] supplemented with a range of methane loss for ethane production of 1 to 3% (same as for gas-methanol-olefin) and a methane intensity for naphtha from Xiang et al 2015.[26] GHG emissions intensity of the oil-naphtha-olefin and coal-methanol-olefin pathways in China are based on current plants of "typical" capacity as drawn from Xiang et al 2014.[25,27] This chart is updated from our prior discussion brief in two additional ways: (1) to take a more conservative approach to estimating methane emissions from the world average and best practice ethane and naphtha-based routes (increasing those estimates); (2) correcting the "functional unit", or denominator, for all pathways to be "high value chemicals" (olefins and other high value byproducts, such as aromatics) using the approach in Ren et al 2008, which discounts the non-olefin byproducts for naphtha and ethane by 50% relative to olefins. The denominator of our previous chart was a mix of HVCs and true olefins.

Figure 2 suggests that the gas-to-methanol-to-olefin route represented by the Kalama methanol facility is not a low-GHG emission way to make olefins and related high-value chemicals, compared to ethane and naphtha-based routes. This would seem to indicate that the Kalama facility would not meet the industrial sector climate "test" we advanced in our prior discussion brief, and cannot confidently be claimed to be part of a deeply low-carbon future.

A recent report from the International Energy Agency does, however, include an increase in gas-to-methanol-to-olefin in its "Clean Technology Scenario". We address this in the next point.

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[v] Here we adjust the DSEIS estimate of 2.3 tonnes CO2e per tonne olefin (Table 5.12) by the ratio of olefins to HVCs in Table E.1 of 1.21 to reach an estimate of the GHG-intensity of naphtha-based HVCs of 1.9 t CO2e/ t HVC.

6 A recent study by the International Energy Agency includes gas-based methanol in its low-carbon scenario, but that scenario was based on market trends and costs of production, not an analysis of greenhouse gas intensity

A recent study by the International Energy Agency (IEA) suggests that Chinese coal-based methanol (as olefin feedstock) would expand under reference conditions, and its low-emissions ("Clean Technology") scenario foresees some replacement of coal-based methanol by gas-based methanol.[8] As argued by the Low Carbon Prosperity Institute in a recent review, this would appear to indicate that natural gas methanol has a role a low-carbon future.[5] However, the IEA study did not "choose" specific technologies for making olefins and other high-value chemicals in its scenarios based on relative GHG emissions intensity, but instead based on production costs and macroeconomic conditions.[vi] Carbon constraints in its Clean Technology Scenario are instead considered implicitly (aligned with the IEA's Sustainable Development Scenario), but critically the IEA did not consider methane (CH_4) emissions. When methane emissions are considered, as Figure 2 and the analysis above show, there appears to be little if any GHG advantage for gas-to-methanol-to-olefin routes compared to naphtha- and ethane-based routes.

[vi] This is described on page 31 of the IEA study, and confirmed by communication with the authors.

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Assessment of methane emissions from the U.S. oil and gas supply chain

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Methane emissions from the U.S. oil and natural gas supply chain were estimated using ground-based, facility-scale measurements and validated with aircraft observations in areas accounting for ~30% of U.S. gas production. When scaled up nationally, our facility-based estimate of 2015 supply chain emissions is 13 ± 2 Tg/y, equivalent to 2.3% of gross U.S. gas production. This value is ~60% higher than the U.S. EPA inventory estimate, likely because existing inventory methods miss emissions released during abnormal operating conditions. Methane emissions of this magnitude, per unit of natural gas consumed, produce radiative forcing over a 20-year time horizon comparable to the CO_2 from natural gas combustion. Significant emission reductions are feasible through rapid detection of the root causes of high emissions and deployment of less failure-prone systems.

Methane (CH_4) is a potent greenhouse gas, and CH_4 emissions from human activities since pre-industrial times are responsible for 0.97 W m^{-2} of radiative forcing, as compared to 1.7 W m^{-2} for carbon dioxide (CO_2) (*1*). CH_4 is removed from the atmosphere much more rapidly than CO_2, thus reducing CH_4 emissions can effectively reduce the near-term rate of warming (*2*). Sharp growth in U.S. oil and natural gas (O/NG) production beginning around 2005 (*3*) raised concerns about the climate impacts of increased natural gas use (*4*, *5*). By 2012, disagreement among published estimates of CH_4 emissions from U.S. natural gas operations led to a broad consensus that additional data were needed to better characterize emission rates (*4*–*7*). A large body of field measurements made between 2012 and 2016 (table S1) has dramatically improved understanding of the sources and magnitude of CH_4 emissions from the industry's operations. Brandt *et al.* summarized the early literature (*8*); other assessments incorporated elements of recent data (*9*–*11*). This work synthesizes recent studies to provide an improved overall assessment of emissions from the O/NG supply chain, which we define to include all operations associated with oil and natural gas production, processing and transport (Section S1.0) (*12*).

Measurements of O/NG CH_4 emissions can be classified as either top-down (TD) or bottom-up (BU). TD studies quantify ambient methane enhancements using aircraft, satellites or tower networks and infer aggregate emissions from all contributing sources across large geographies. TD estimates for nine O/NG production areas have been reported to date (table S2). These areas are distributed across the U.S. (fig. S1) and account for ~33% of natural gas, ~24% of oil production, and ~14% of all wells (*13*). Areas sampled in TD studies also span the range of hydrocarbon characteristics (predominantly gas, predominantly oil, or mixed), as well as a range of production characteristics such as well productivity and maturity. In contrast, BU studies generate regional, state, or national emission estimates by aggregating and extrapolating measured emissions from individual pieces of equipment, operations, or facilities, using measurements made directly at the emission point or, in the case of facilities, directly downwind.

Recent BU studies have been performed on equipment or facilities that are expected to represent the vast majority of emissions from the O/NG supply chain (table S1). In this work we integrate the results of recent facility-scale BU studies to estimate CH_4 emissions from the U.S. O/NG supply chain, and then we validate the results using TD studies (Section S1). The probability distributions of our BU methodology are based on observed facility-level emissions, in contrast to the component-by-component approach used for conventional inventories. We thus capture enhancements produced by all sources within a facility, including the heavy tail of the distribution. When the BU estimate is developed in this manner, direct comparison of BU and TD estimates of CH_4 emissions in the nine basins for which TD measurements have been reported indicates agreement between methods, within estimated uncertainty ranges (Fig. 1).

Our national BU estimate of total CH_4 emissions in 2015 from the U.S. O/NG supply chain is 13 (+2.1/-1.6, 95% confidence interval) Tg CH_4/y (Table 1). This estimate of O/NG CH_4 emissions can also be expressed as a production-normalized emission rate of 2.3% (+0.4%/-0.3%) by normalizing by annual gross natural gas production (33 trillion cubic feet (*13*), with average CH_4 content of 90 vol%). Roughly 85% of national BU emissions are from production, gathering, and processing sources, which are concentrated in active O/NG production areas.

Our assessment does not update emissions from local distribution and end use of natural gas, due to insufficient information addressing this portion of the supply chain. However, recent studies suggest that local distribution emissions are significant, exceeding the current inventory estimate (*14*–*16*), and that end-user emissions might also be important. If these findings prove to be representative, overall emissions from the natural gas supply chain would increase relative to the value in Table 1 (Section S1.5).

Our BU method and TD measurements yield similar estimates of U.S. O/NG CH_4 emissions in 2015, and both are significantly higher than the corresponding estimate in the U.S. Environmental Protection Agency's Greenhouse Gas Inventory (EPA GHGI) (Table 1, Section S1.3) (*17*). Discrepancies between TD estimates and the EPA GHGI have been reported previously (*8*, *18*). Our BU estimate is 63% higher than the EPA GHGI, largely due to a more than two-fold difference in the production segment (Table 1). The discrepancy in production sector emissions alone is ~4 Tg CH_4/y, an amount larger than the emissions from any other O/NG supply chain segment. Such a large difference cannot be attributed to expected uncertainty in either estimate: the extremal ends of the 95% confidence intervals for each estimate differ by 20% (i.e., ~12 Tg/y for the lower bound of our BU estimate can be compared to ~10 Tg/y for the upper bound of the EPA GHGI estimate).

We believe the reason for such large divergence is that sampling methods underlying conventional inventories systematically underestimate total emissions because they miss high emissions caused by abnormal operating conditions (e.g., malfunctions). Distributions of measured emissions from production sites in BU studies are invariably "tail-heavy", with large emission rates measured at a small subset of sites at any single point in time (*19*–*22*). Consequently, the most likely hypothesis for the difference between the EPA GHGI and BU estimates derived from facility-level measurements is that measurements used to develop GHGI emission factors under-sample abnormal operating conditions encountered during the BU work. Component-based inventory estimates like the GHGI have been shown to underestimate facility-level emissions (*23*), probably because of the technical difficulty and safety and liability risks associated with measuring large emissions from, for example, venting tanks such as those observed in aerial surveys (*24*).

Abnormal conditions causing high CH_4 emissions have been observed in studies across the O/NG supply chain. An analysis of site-scale emission measurements in the Barnett Shale concluded that equipment behaving as designed could not explain the number of high-emitting production sites in the region (*23*). An extensive aerial infrared camera survey of ~8,000 production sites in seven U.S. O/NG basins found that ~4% of surveyed sites had one or more observable high emission-rate plumes (*24*) (detection threshold of ~3-10 kg CH_4/h was 2-7 times higher than mean production site emissions estimated in this work). Emissions released from liquid storage tank hatches and vents represented 90% of these sightings. It appears that abnormal operating conditions must be largely responsible, because the observation frequency was too high to be attributed to routine operations like condensate flashing or liquid unloadings alone (*24*). All other observations were due to anomalous venting from dehydrators, separators and flares. Notably, the two largest sources of aggregate emissions in the EPA GHGI – pneumatic controllers and equipment leaks – were never observed from these aerial surveys. Similarly, a national survey of gathering facilities found that emission rates were four times higher at the 20% of facilities where substantial tank venting emissions were observed, as compared to the 80% of facilities without such venting (*25*). In addition, very large emissions from leaking isolation valves at transmission and storage facilities were quantified using downwind measurement but could not be accurately (or safely) measured using on-site methods (*26*). There is an urgent need to complete equipment-based measurement campaigns that capture these large emission events, so that their causes are better understood.

In contrast to abnormal operational conditions, alternative explanations such as outdated component emission factors are unlikely to explain the magnitude of the difference between our facility-based BU estimate and the GHGI. First, an equipment-level inventory analogous to the EPA GHGI but updated with recent direct measurements of component emissions (Section S1.4) predicts total production emissions that are within ~10% of the EPA GHGI, although the contributions of individual source categories differ significantly (table S3). Second, we consider unlikely an alternative hypothesis that systematically higher emissions during daytime sampling cause a high bias in TD methods (Section S1.6).

Two other factors may lead to low bias in EPA GHGI and similar inventory estimates. Operator cooperation is required to obtain site access for emission measurements (*8*). Operators with lower-emitting sites are plausibly more likely to cooperate in such studies, and workers are likely to be more careful to avoid errors or fix problems when measurement teams are on site or about to arrive. The potential bias due to this "opt-in" study design is very challenging to determine. We therefore rely primarily on site-level, downwind measurement methods with limited or no operator forewarning to construct our BU estimate. Another possible source of bias is measurement error. It has been suggested that malfunction of a measurement instrument widely used in the O/NG industry contributes to underestimated emissions in inventories (*27*); however, this cannot explain the >2x difference in production emissions (*28*).

The tail-heavy distribution for many O/NG CH_4 emission sources has important implications for mitigation since it suggests that most sources – whether they represent whole facilities or individual pieces of equipment – can have lower emissions when they operate as designed. We anticipate that significant emissions reductions could be achieved by deploying well-designed emission detection and repair systems that are capable of identifying abnormally operating facilities or equipment. For example, pneumatic controllers and equipment leaks are the largest emission sources in the O/NG production segment exclusive of missing emission sources (38% and 21%, respectively; table S3) with malfunctioning controllers contributing 66% of total pneumatic controller emissions (Section S1.4) and equipment leaks 60% higher than the GHGI estimate.

Gathering operations, which transport unprocessed natural gas from production sites to processing plants or transmission pipelines, produce ~20% of total O/NG supply chain CH_4 emissions. Until the publication of recent measurements (*29*), these emissions were largely unaccounted by the EPA GHGI. Gas processing, transmission and storage together contribute another ~20% of total O/NG supply chain emissions, most of which come from ~2,500 processing and compression facilities.

Our estimate of emissions from the U.S. O/NG supply chain (13 Tg CH_4/y) compares to the EPA estimate of 18 Tg CH_4/y for all other anthropogenic CH_4 sources (*17*). Natural gas losses are a waste of a limited natural resource (~\$2 billion/y), increase global levels of surface ozone pollution (*30*), and significantly erode the potential climate benefits of natural gas use. Indeed, our estimate of CH_4 emissions across the supply chain, per unit of gas consumed, results in roughly the same radiative forcing as does the CO_2 from combustion of natural gas over a 20-year time horizon (31% over 100 years). Moreover, the climate impact of 13 Tg CH_4/y over a 20-year time horizon roughly equals that from the annual CO_2 emissions from all U.S. coal-fired power plants operating in 2015 (31% of the impact over a 100-year time horizon) (Section S1.7).

We suggest that inventory methods would be improved by including the substantial volume of missing O/NG CH_4 emissions evident from the large body of scientific work now available and synthesized here. Such empirical adjustments based on observed data have been previously used in air quality management (*31*).

The large spatial and temporal variability in CH_4 emissions for similar equipment and facilities (due to equipment malfunction and other abnormal operating conditions) reinforces the conclusion that significant emission reductions are feasible. Key aspects of effective mitigation include pairing well-established technologies and best practices for routine emission sources with economically viable systems to rapidly detect the root causes of high emissions arising from abnormal conditions. The latter could involve combinations of current technologies such as on-site leak surveys by company personnel using optical gas imaging (*32*), deployment of passive sensors at individual facilities (*33*, *34*) or mounted on ground-based work trucks (*35*), and in situ remote sensing approaches using tower networks, aircraft or satellites (*36*). Over time, the development of less failure-prone systems would be expected through repeated observation of and further research into common causes of abnormal emissions, followed by re-engineered design of individual components and processes.

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SUPPLEMENTARY MATERIALS

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Materials and methods
Additional author disclosures
Figs. S1 to S11
Tables S1 to S12
References (*37*–*77*)
Databases S1 and S2

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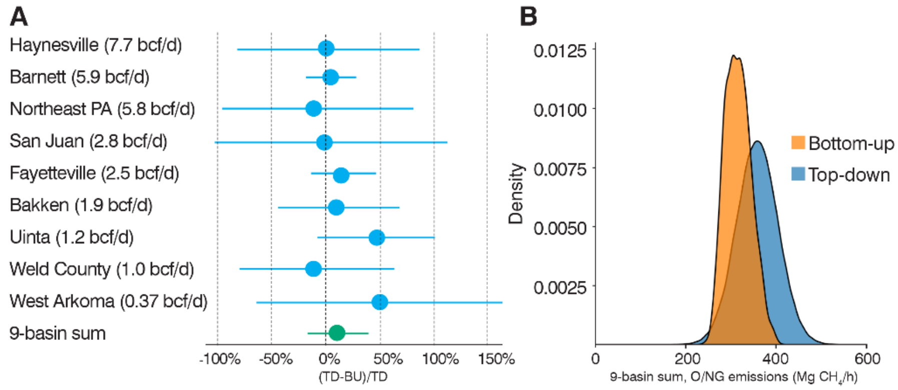

Fig. 1. Comparison of this work's bottom-up (BU) estimates of methane emissions from oil and natural gas (O/NG) sources to top-down (TD) estimates in nine U.S. O/NG production areas. (**A**) Relative differences of the TD and BU mean emissions, normalized by the TD value, rank ordered by natural gas production in billion cubic feet per day (bcf/d, where 1 bcf = 2.8 × 10^7 m^3). Error bars represent 95% confidence intervals. (**B**) Distributions of the 9-basin sum of TD and BU mean estimates (blue and orange probability density, respectively). Neither the ensemble of TD-BU pairs (A) nor the 9-basin sum of means (B) are statistically different (p=0.13 by a randomization test, and mean difference of 11% [95% confidence interval of -17% to 41%]).

Table 1. Summary of this work's bottom-up estimates of CH_4 emissions from the U.S. oil and natural gas (O/NG) supply chain (95% confidence interval) and comparison to the EPA Greenhouse Gas Inventory (GHGI).

Industry segment	**2015 CH_4 Emissions (Tg/y)**	
	This work (bottom-up)	**EPA GHGI** (*17*)
Production	7.6 (+1.9/-1.6)	3.5
Gathering	2.6 (+0.59/-0.18)	2.3
Processing	0.72 (+0.20/-0.071)	0.44
Transmission and Storage	1.8 (+0.35/-0.22)	1.4
Local Distribution*	0.44 (+0.51/-0.22)	0.44
Oil Refining and Transportation*	0.034 (+0.050/-0.008)	0.034
U.S. O/NG total	13 (+2.1/-1.7)	8.1 (+2.1/-1.4)[†]

*This work's emission estimates for these sources are taken directly from the GHGI. The local distribution estimate is expected to be a lower bound on actual emissions and does not include losses downstream of customer meters due to leaks or incomplete combustion (Section S1.5).

[†]The GHGI only reports industry-wide uncertainties.

Science

Assessment of methane emissions from the U.S. oil and gas supply chain

Ramón A. Alvarez, Daniel Zavala-Araiza, David R. Lyon, David T. Allen, Zachary R. Barkley, Adam R. Brandt, Kenneth J. Davis, Scott C. Herndon, Daniel J. Jacob, Anna Karion, Eric A. Kort, Brian K. Lamb, Thomas Lauvaux, Joannes D. Maasakkers, Anthony J. Marchese, Mark Omara, Stephen W. Pacala, Jeff Peischl, Allen L. Robinson, Paul B. Shepson, Colm Sweeney, Amy Townsend-Small, Steven C. Wofsy and Steven P. Hamburg

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UPSTREAM METHANE EMMISION WORKBOOK

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November 21, 2018

BY HAND DELIVERY AND EMAIL

Puget Sound Clean Air Agency
ATTN: Public Comment on DSEIS, Tacoma LNG Project
1904 Third Avenue, Suite 105
Seattle, WA 98101
publiccomment@pscleanair.org

Re: Comments on Tacoma LNG Project Draft Supplemental Environmental Impact Statement

Dear Agency:

Puget Sound Energy, Inc. ("PSE") appreciates this opportunity to comment on the Draft Supplemental Environmental Impact Statement ("DSEIS") prepared by the Puget Sound Clean Air Agency ("PSCAA") and currently in the public notice process.

As the Northwest's largest utility, PSE has been a leader in developing and promoting clean energy and advancing efficiency programs and technologies. In the last decade, PSE has deployed over 770 megawatts of wind generation and other green energy projects and is currently the nation's third-largest utility producer of wind power.

In addition to developing renewables, we have gone above and beyond in our conservation efforts establishing award-winning programs in Energy Conservation and Green Power. PSE has one of our country's best and most comprehensive energy-efficiency programs for helping homes and businesses reduce their energy use. PSE offers our customers financial incentives and technical help to conserve energy, and PSE also promotes the growth of renewable electricity production in its service area through various customer programs. We are keenly aware of our customers' interest in reducing carbon emissions, and we share their concern and commitment to achieving meaningful carbon reduction. At the end of 2017, we announced our TOGETHER commitment to reduce carbon emissions 50 percent by 2040 and have developed a measurable plan with short- and long-term steps to reach this goal while continuing to meet our customers' needs.

If we are going to significantly reduce carbon emissions in our state, however, we have to address transportation. In Washington, nearly half of all carbon emissions come from transportation. PSE has been supporting the market growth of electric vehicles and is working to further expand our efforts through our alternative vehicle strategies and supporting charging stations the region needs to make electric vehicles a central part of our transportation future. At the same time, we have to think of the whole picture and consider commercial and industrial transportation uses.

We have the opportunity to significantly reduce emissions with cleaner alternatives to diesel and other fuels. PSE's partnership with TOTE Maritime will make just this kind of impact. When TOTE's first ship leaves Tacoma for Alaska fueled with LNG, it will result in material reductions of harmful air pollutants, including diesel particulate, sulfur dioxide, oxides of nitrogen and greenhouse gases. In concert with the vessel owners, the Tacoma LNG facility will create the greenest shipping fleet on the West Coast. In short, Tacoma LNG is a critical component of moving to lower carbon and cleaner energy infrastructure.

PSCAA's DSEIS is an integral step in moving this effort forward. As with any draft document, there are inevitably items that merit correction, which is why SEPA provides for public input and comment in the first instance. While the DSEIS text itself is succinct, the life-cycle analysis is broad in reach and quite dense. PSE has given the DSEIS and its referenced materials meticulous review, and we largely concur with its methodology, analysis and conclusions. Consequently, our comments are minor and carefully focused on accuracy and detail, so that the Final Supplemental Environmental Impact Statement ("FSEIS") sets the bar high for other greenhouse gas ("GHG") impacts analyses in the future across Washington. With these thoughts in mind, PSE respectfully submits the following comments to PSCAA for consideration in finalizing the Tacoma LNG DSEIS. We think that you have a quality product based on a reputable consultant that reaches the correct conclusion that the proposed project will result in a net reduction in GHG emissions. Nevertheless, there are specific improvements suggested below that, without changing the conclusion, will enhance the internal consistency and accuracy of the final product. These comments are not necessarily presented in order of importance.

Comment #1: PSE supports the inclusion of a condition in the Tacoma LNG air permit that requires that natural gas come exclusively from British Columbia.

Several commenters have wrongly criticized PSCAA for assuming that the natural gas to be used by the Tacoma LNG facility will come from British Columbia. This criticism is misplaced. PSE has identified from the outset of the PSCAA review process that the natural gas to be used by the Tacoma LNG facility will come from British Columbia. All gas delivered to PSE's gas system flows under firm pipeline capacity contracts on Williams' Northwest Pipeline, LLC ("NWP"). NWP is the only pipeline system for gas to get to PSE's system. NWP is fully contracted and has been since their last expansion in 2003. Each firm pipeline contract has a firm receipt point and a firm delivery point(s). Firm receipts from Sumas can only originate in British Columbia. The firm receipt point on contracts acquired to serve the Tacoma LNG facility is Sumas.

PSE has consistently stated that the gas delivered to Tacoma LNG for liquefaction, storage and subsequent use will originate in British Columbia. For that reason, PSE supports a condition in the air permit to memorialize this commitment and put to rest the factually inaccurate suggestion that natural gas from other regions will be used by the facility.

Comment #2: PSE supports the methodology employed by PSCAA to quantify upstream greenhouse gas emissions associated with extraction and transportation of natural gas.

Several commenters have wrongly criticized PSCAA for relying upon a British Columbia-specific analysis using the GHGenius model. We believe that the estimate of greenhouse gas emissions generated by GHGenius for British Columbia natural gas production is conservative and overstates the upstream greenhouse gas emissions. More accurate information can be obtained from the Canadian National Inventory Report ("NIR") in conjunction with provincial data on how the NIR value (which covers the oil and gas sector broadly) was developed. Both the GHGenius values and the NIR values are widely used and accepted. Although a small number of articles suggest that these values underreport fugitive emissions, general consensus has not been reached on this point and the values in the articles suggesting that underreporting has occurred are speculative. As explained further below, PSCAA must rely on the most recent widely accepted data and not arbitrarily base estimates on isolated studies.

The SEIS should be based on the Provincial data

On May 25, 2018, PSE submitted a Background Information Document ("BID") that assessed the life-cycle greenhouse gas emissions associated with the proposed facility. As part of that analysis, PSE determined emissions for natural gas production in British Columbia based on Province-specific data from the Canadian NIR and British Columbia natural gas production data as reported by the Province in its Natural Gas & Oil Statistics data series. PSE believes that this is the most accurate means of determining greenhouse gas emissions associated with natural gas production in British Columbia. PSE recognizes that there is not a substantial difference between using the Province-specific fugitive emission rate (estimated at 0.2%) and the GHGenius fugitive emission rate (estimated at 0.32%). However, the SEIS should represent the most accurate information available. For that reason, we recommend that PSCAA revise its analysis to use the current British Columbia-specific data presented in the BID rather than relying on the data generated by GHGenius.

The SEIS cannot inflate fugitive emissions based on incomplete studies

Comments that PSCAA should artificially inflate the upstream fugitive emission rates based on limited and problematic mobile studies should be rejected. The primary article that forms the basis for these comments (the Atherton study) was published in October 2017.[1] The Atherton study provided valuable information about the need for increased measures to identify and reduce fugitive methane emissions from specific emission points. As the authors conclude, "Our study highlights the need for emission reduction efforts in the Montney to be focused on the few higher-emitting active gas wells, as well as abandoned, and aging infrastructure."[2] PSE supports this conclusion and notes that, unlike many areas in the U.S., the Canadian and British Columbia governments have implemented extensive measures in the years following the time period when the data underlying the Atherton study were collected (8/14/2015-9/5/2015). For example, in 2016, British Columbia implemented new guidelines eliminating routine flaring.[3] On April 26, 2018, the Canadian national government adopted new regulations that require companies to control methane leaks from equipment and the release of methane from compressors starting on January 1, 2020.[4] The Atherton paper concluded that "compressor stations emitted most frequently" and so the 2018 regulations appropriately target a source that Atherton expressly called out.[5] The 2018 Canadian regulations also limit methane leaks associated with well completion with the requirements taking effect on January 1, 2020.[6] These Canadian regulations also impose limits on methane venting and the release of methane from pneumatic devices starting January 1, 2023.[7] In short, the Atherton study was an important data point about the state of methane fugitive emissions in 2015 and the need for more regulation. Consistent therewith, the Canadian and British Columbia governments have acted since that study was performed, implementing a broad swath of regulations targeting fugitive methane emissions from the oil and gas sector.

It is also important to note that there were significant limitations relating to the Atherton study that call its quantitative conclusions into question. PSE recognizes the value of the Atherton study for qualitatively focusing the provincial and national governments on the need for further regulation of fugitive methane sources. As explained above, however, that has already been

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[1] Atherton et al.; *Mobile measurement of methane emissions from natural gas developments in northeastern British Columbia*, Canada, Atmos. Chem. Phys., 17, 12405-12420, 2017.
[2] *Id.*
[3] https://www.bcogc.ca/node/5916/download.
[4] https://www.canada.ca/en/environment-climate-change/news/2018/04/federal-methane-regulations-for-the-upstream-oil-and-gas-sector.html.
[5] Atherton et al; *Mobile measurement of methane emissions from natural gas developments in northeastern British Columbia*, Canada, Atmos. Chem. Phys., 17, 12405-12420, 2017.
[6] https://www.canada.ca/en/environment-climate-change/news/2018/04/federal-methane-regulations-for-the-upstream-oil-and-gas-sector.html.
[7] *Id.*

accomplished. Nonetheless, there are serious questions regarding the representativeness of the quantitative estimates of methane emissions expressed in the Atherton paper and the limitations of using the study for quantifying methane emission rates. As discussed in the recent paper published by the National Academy of Sciences ("NAS"), methane emissions from gas wells peak during mid-afternoon hours.[8] As described by the NAS authors, "maintenance activities, such as manual liquid unloadings (MLUs) or depressurization of equipment ("blowdowns"), are often triggered by human operators during daytime work-week hours and may produce high emission rates for short durations."[9] As discussed in the 2018 NAS paper, daytime weekday measurements, such as the Atherton study relied upon, should not be used to estimate a methane emission rate as they typically will reflect the absolute peak of emitting activity and can greatly distort the overall inventory.[10] While Atherton's qualitative recommendation that the government focus on "the few higher-emitting active gas wells, as well as abandoned, and aging infrastructure" may have merit, the quantitative component of the paper is highly suspect.

In summary, studies such as the Atherton report help focus regulatory priorities, but cannot be used, nor are intended, to adjust accepted inventory values for methane emission rates. As the Atherton authors themselves stated in response to peer review comments, "The primary purpose of the paper was to determine emission frequencies, not to create a highly accurate volumetric inventory."[11] At this point in time, the most accurate estimate of the emission rate for natural gas production in British Columbia is the Province-specific data from the Canadian NIR and British Columbia natural gas production data previously provided to PSCAA by PSE.

Comment #3: The DSEIS has inconsistencies regarding the TOTE fuel oil terminology.

The DSEIS is internally inconsistent in describing the type of fuel that TOTE currently uses and would continue to use under the No Action Alternative. We suggest that the DSEIS be revised to use a consistent acronym to describe the fuel to be used by TOTE and other ships under the No Action Alternative, and accordingly the emission factors used in the spreadsheets need to reflect the correct fuel.

The DSEIS describes the Proposed Action as a terminal to supply LNG to vessels "replacing the use of marine diesel oil ("MDO") and diesel fuel."[12] Table 3-1 of the DSEIS states that under the No Action Alternative, MDO would continue to be used by TOTE and other potential future customers of the Tacoma LNG facility. This is further discussed in Section 3.3.3 of the DSEIS:

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[8] Vaughn et al.; *Temporal variability largely explains top-down/bottom-up difference in methane emission estimates from a natural gas production region*, Proceedings of the National Academy of Sciences (Nov. 2018) 115 (46) 11712-11717; DOI: 10.1073/pnas.1805687115; http://www.pnas.org/content/115/46/11712.
[9] *Id.*
[10] *Id.*
[11] https://www.atmos-chem-phys-discuss.net/acp-2017-109/acp-2017-109-AR1.pdf
[12] DSEIS Section 1.2.1.

> Under the No Action Alternative, marine engines would continue to operate on MDO. Under the 250,000 gpd scenario, the Proposed Action would displace 21.48 million gallons of MDO used by TOTE marine vessels, and would provide additional capacity to replace another 23.21 million gallons of MDO used by other marine vessels. Under the 500,000 gpd scenario, the expanded capacity would also displace 21.48 million gallons of MDO used by TOTE marine vessels, and would provide additional capacity to replace up to 69.32 million gallons of MDO used by other marine vessels.

As seen in the quote above, the DSEIS repeatedly states that under the No Action Alternative, TOTE will utilize MDO. However, in Appendix C to the DSEIS, LCA states that the fuel used by TOTE is Marine Gas Oil ("MGO"). We recognize that MGO and MDO are very similar distillate fuels that are both referred to in common maritime use as diesel. However, in order to avoid confusion the SEIS needs to consistently describe the fuel used by TOTE. In its May 3, 2018 response to PSCAA's information request, TOTE stated that if the LNG terminal is not constructed, "[t]he current engines would remain and utilize 0.1% Sulphur compliant marine fuel (MGO)."[13] Therefore, we recommend that the DSEIS text be revised to be consistent with the LCA report in Appendix C and identify the fuel that TOTE employs as MGO.

Comment #4: The DSEIS spreadsheets should use marine diesel factors instead of bunker fuel factors to calculate the upstream emissions associated with TOTE's fuel oil.

Comment #3 is about the use of a consistent term to describe the fuel that TOTE uses and would continue to use under the No Action Alternative. Separate from that issue, but related to TOTE's current fuel use, there are calculation issues with the spreadsheets because they are based on the assumption that TOTE burns bunker fuel when in actuality it burns distillate fuel (diesel). The DSEIS calculations rely in many places on assumptions that vary based on the type of fuel employed. Several emission calculation errors derive from the incorrect assumption that the fuel TOTE will utilize under the No Action Alternative is appropriately modeled as residual oil or "bunker fuel for marine vessels" in GREET. As explained above, the appropriate fuel under the No Action Alternative for TOTE vessels is MGO. The MGO fuel that TOTE currently uses and would use under the No Action Alternative is most closely approximated as low sulfur diesel fuel within the GREET model, not bunker fuel. Assuming that TOTE will employ bunker fuel leads to an over-estimation of emissions under both the Action and No Action Alternatives.

[13] Response to Question 8, *Tacoma LNG SEIS Data and Information Request for TOTE Maritime* (May 3, 2018).

This confusion between MGO and bunker fuel does not change the DSEIS conclusions. In fact, the net impact of this misunderstanding, which includes both upstream and downstream inaccuracies, is that the DSEIS underestimates the total GHG benefit associated with the Action Alternative. Nevertheless, the factors should be corrected so the numbers provided in the analysis are accurate. In this Comment #4 and the following Comment #5 we describe specific corrections needed for the upstream and downstream emissions. These comments are made in reference to the Scenario A spreadsheet (250,000 gpd), but apply equally to the Scenario B spreadsheet (500,000 gpd).

The DSEIS spreadsheets contain an error relating to the calculation of the upstream GHG emissions associated with producing TOTE's fuel oil because they use the GREET bunker fuel emission factor instead of the GREET diesel fuel emission factor. This leads to the under-estimation of upstream emissions associated with TOTE's fuel under the No Action Alternative.

The upstream emissions related to TOTE marine diesel production (tonnes/year CO2e) are identified in cell H140 of the "Upstream" sheet. The individual constituent GHGs (CO2, CH4 and N2O) are calculated in cells E140:G140. Each of those three is calculated similarly; the formula for CO2 is as follows:

=$C140*C$87/1000

Where:

C140 = GBtu/year of diesel fuel consumed
C87 = CO2 emission rate for bunker fuel

As you can see from the defined terms, there is an error in the emission rate being used. The purpose of the calculation is to determine the CO2 emissions associated with producing and delivering marine diesel (MGO) and yet the emission rate used is for the less refined bunker fuel. Because the upstream emissions associated with refining an MMBtu of bunker are roughly half the emissions associated with refining an MMBtu of diesel, this error results in the upstream emissions associated with TOTE marine diesel being understated. Table 1 shows how the upstream TOTE marine diesel emissions increase by approximately 12,500 tonnes per year when the appropriate emissions rate is utilized.

Table 1. No Action Alternative: Upstream TOTE Marine Diesel Emissions

	GHG Emissions tonne/year (as proposed)	**GHG Emissions tonne/year** (corrected)
Upstream TOTE Marine Diesel (MGO) Emissions	52,448	64,775

Comment #5: The DSEIS spreadsheets should use diesel fuel factors as opposed to bunker fuel factors to calculate the downstream emissions.

As introduced in Comment #4, the confusion over distillate fuel versus bunker fuel also resulted in errors in the downstream emissions calculations for both LNG and oil-fired vessels. These errors all derive from the incorrect assumption that the fuel TOTE will utilize under the No Action Alternative is appropriately modeled as residual oil or "bunker fuel for marine vessels" in GREET. As explained above, the distillate fuel TOTE vessels use today and will continue to use under the No Action Alternative is most closely approximated as low sulfur diesel fuel within the GREET model. Assuming that TOTE employs bunker fuel leads to over-estimated emissions under both the Action and No Action Alternatives. An example of how this impacts the spreadsheets is presented below.

In response to an information request from PSCAA, PSE provided data on the grams per trip of CO2 and the estimated tonnes of fuel that would be consumed during each trip. The estimated fuel use is calculated from the modeled engine work required over the course of a trip using fuel consumption factors listed in cells C110:C112 of the "EF Marine Vessels spec. TOTE" sheet. These fuel consumption factors are themselves calculated from direct CO2 emission factors for the Main Engine, Auxiliary Engine and Boiler. The formula used for calculating the fuel consumption factor for the Main Engine (cell C110) was:

=Q13*(12/44)/Fuel_Specs!$F$18

Where:

Q13 = the gCO2/kWh for a medium speed diesel.
Fuel_Specs!$F$18 = Carbon percentage by weight <u>for 2.8% sulfur bunker fuel</u>

This generated a fuel consumption factor with reported units of gallons MDO/kWh.

However, the 2.8% sulfur bunker fuel used in the SEIS calculation shown above is both (a) illegal to be used in a TOTE (or equivalent) vessel and (b) not equivalent in carbon content to the correct MGO baseline fuel for TOTE. Thus, the carbon percentage by weight for 2.8% bunker fuel should not be used to generate a 0.1% sulfur MGO fuel consumption factor. This matters because the carbon percentage by weight is lower for low sulfur diesel than that for high sulfur bunker fuel. By using the wrong denominator value, the fuel consumption factor is slightly off. When the proper fuel consumption factor is applied, the amount of distillate fuel consumed per trip changes by 1.5 tonnes per trip for the Main Engine as shown in Table 2 below.

Table 2. Fuel Consumption Estimates

	Fuel Consumption Estimate in Spreadsheet Using Wrong Fuel Consumption Factor	Fuel Consumption Estimate Using Accurate Fuel Consumption Factor
	(MT MGO)	(MT MGO)
Fuel Consumed Within 200 nm	62.0	62.2
Fuel Consumed Outside 200 nm	386.5	387.9
Total Fuel Consumed	448.6	450.1

This technical error is then carried into the calculation of the g/tonne MGO emission rate used to calculate the ultimate g/MMBtu MGO, LHV emission rate that is the foundation of the calculations. For example, the emissions rate (g/tonne MGO) for CO2 is calculated in cell L48 of the “End use TOTE-Fuel Oil Vessel” sheet using the following formula:

=L47*1000000/SUM($D$59:$F$59)

Where:

L47 = total emissions
$D$59:$F$59 = fuel consumption as determined using the fuel consumption factors

With the fuel consumption factors corrected, the emission rates (g/tonne MGO) shown in cells L49:P49 in the “End use TOTE-Fuel Oil Vessel” sheet change as shown in Table 3 below.

Table 3. Emission Rates Under No Action Alternative (g/tonne MGO)

	Emission Rate Estimate in Spreadsheet Using Wrong Fuel Consumption Factor	Emission Rate Estimate Using Accurate Fuel Consumption Factor
	(g/tonne MGO)	(g/tonne MGO)
CO2	3,182,667	3,171,667
NO2	143	152
CH4	49	49
CO2c	3,198,951	3,187,895
CO2e	3,242,897	3,234,406

As you can see, this technical error results in the DSEIS overstating the GHG emission rates (g/tonne MGOe) associated with the No Action Alternative.

Similarly, with the fuel consumption factors corrected, the emission rates (g/tonne MGO) shown in cells L49:P49 in the "End use TOTE-LNG Vessel" change as shown in Table 4 below.

Table 4. Emission Rates Under Action Alternative (g/tonne MGO)

	Emission Rate Estimate in Spreadsheet Using Wrong Fuel Consumption Factor	Emission Rate Estimate Using Accurate Fuel Consumption Factor
	(g/tonne MGOe)	(g/tonne MGOe)
CO2	2,180,117	2,172,582
NO2	153	152
CH4	25,931	25,841
CO2c	2,194,855	2,187,269
CO2e	2,888,582	2,878,599

As you can see, this results in the DSEIS overstating the GHG emission rates (g/tonne MGOe) associated with the Action Alternative.

This technical error is further magnified when the emission rates are divided by the fuel-specific heating value in the "Fuel_Specs" sheet to convert the g/tonne MGO emission rate to a g/MMBtu basis. In cell L49 of the "End use TOTE-Fuel Oil Vessel" sheet, a g/MMBtu MGO emission rate is calculated using the following formula:

=L48/(lbperkg*Fuel_Specs!$P$18)*1000

Where:

L48 = the emission rate in g/tonne MGO
Fuel_Specs!$P$18 = the heating value for 2.8% sulfur bunker fuel

As you can see, cell L49 incorrectly imports the heating value for 2.8% sulfur bunker fuel (i.e., "Fuel_Specs" sheet cell P18) rather than the heating value for a fuel equivalent to MGO such as low sulfur diesel (e.g., "Fuel_Specs" sheet cell P14). Fuel with a 2.8% sulfur level is prohibited from use within an Emission Control Area ("ECA") and is prohibited from use anywhere after January 1, 2020 unless the vessel is operating scrubbers. Therefore, there is no basis for using the bunker fuel heating value. As a result of using the bunker fuel heating value rather than the diesel fuel heating value, the g/MMBtu emission rate calculation is incorrect. In order to calculate an accurate g/MMBtu emission factor, the denominator in cell L49 must be the heating value associated with a low-sulfur diesel (cell C14 in the "Fuel_Specs" sheet). The use of a heating value associated with an obviously wrong fuel type is clearly inappropriate. This same technical error affects both the Action Alternative ("End Use TOTE-LNG Vessel" sheet) and the No Action Alternative ("End Use TOTE-Fuel Oil Vessel" sheet). Comparisons of the erroneous emission rates and the accurate emission rates for each scenario are shown in Table 5 and Table 6 below.

Table 5. Emission Rates Under No Action Alternative (g/MMBtu MGO, LHV)

	Emission Rate Estimate in Spreadsheet Using Wrong Heating Value	**Emission Rate Estimate Using Accurate Heating Value**
	(g/MMBtu MGO, LHV)	**(g/MMBtu MGO, LHV)**
CO2	85,081	78,179
NO2	4	4
CH4	1	1
CO2c	85,517	78,579
CO2e	86,691	79,725

Table 6. Emission Rates Under Action Alternative (g/MMBtu MGO, LHV)

	Emission Rate Estimate in PSCAA Spreadsheet Using Wrong Heating Value	**Emission Rate Estimate Using Accurate Heating Value**
	(g/MMBtu MGO, LHV)	**(g/MMBtu MGO, LHV)**
CO2	58,280	53,552
NO2	4	4
CH4	693	637
CO2c	58,674	53,914
CO2e	77,220	70,995

Ultimately, the values in the two tables above are used to calculate the marine vessel emissions associated with the Action and No Action Alternatives. For example, in cell F59 of the “Direct End use” sheet, methane emissions from LNG combustion are calculated using the following formula:

=$F31*Factors!E$73/1000

Where:

F31 = the annual LNG consumption in GBtu/yr, LHV
Factors!E$73 = the methane emission rate in the table above (693 g/MMBtu LHV, uncorrected; 637 g/MMBtu LHV, corrected)

Because the emissions are calculated by multiplying the LNG consumption by a flawed emission rate, the ultimate result is inaccurate.

Correcting the errors is relatively straightforward and does not result in a material change in the overall conclusions expressed in the DSEIS. Once the emission rates are corrected, the GHG emissions attributable to the upstream and downstream marine use of LNG fuel and MGO decline. As shown in cell H59 of the "Direct End use" sheet, direct end use emissions from LNG drop from 529,859 tonnes/year CO2e to 490,443 tonnes/year CO2e. The GHG emissions attributable to the downstream marine use of MGO (i.e., the No Action Alternative) decrease from 609,291 tonnes/year CO2e to 558,611 tonnes/year CO2e. Tables 7 and 8 below summarize the changes under Scenario A (250,000 gpd) that result from the corrections outlined above.

Table 7. Action Alternative: End Use Emissions

	GHG Emissions tonne/year (as proposed)	**GHG Emissions tonne/year** (corrected)
End Use LNG	**529,859**	**490,443**
On-site Peak Shaving	43,854	43,854
TOTE Marine	225,993	207,659
TOTE Marine Diesel Pilot fuel	7611	7,000
Other Marine LNG (by Bunker Barge)	244,185	224,375
Other Marine Diesel Pilot Fuel	8,216	7,555

Table 8. No Action Alternative: End Use Emissions

	GHG Emissions tonne/year (as proposed)	**GHG Emissions tonne/year** (corrected)
Total End Use Diesel /Fuel Oil/LNG	**602,291**	**558,611**
Diesel Peak Shaving for Power	58,891	58,891
TOTE Marine Diesel	261,325	240,326
Other Marine Diesel (by Bunker Barge)	282,076	259,394

When these corrections are combined with the corrections to the upstream marine diesel emissions rates, total emissions under the No Action Alternative ("Results" sheet, cell E51) decline from 727,536 tonnes/year CO2e to 696,183 tonnes/year. Total emissions under the Action Alternative ("Results" sheet, cell E31) decline from 687,639 tonnes/year to 648,223 tonnes/year. The decline in emissions under the Action Alternative is slightly greater than the decline under the No Action Alternative, thereby modestly improving the GHG reductions for the Action Alternative.

The DSEIS and associated spreadsheets should be revised to correct the errors identified above. Although these corrections do not change the ultimate conclusion expressed in the DSEIS that the Action Alternative results in a net decrease in life cycle GHG emissions as compared to the No Action Alternative, the FSEIS should reflect the accurate fuel assumptions and resulting calculations. We have included as an attachment to this letter a set of revised spreadsheets that reflect the suggested changes discussed in comments 4 and 5. You will see that the revised spreadsheets include toggles ("Input" sheet; cells H32 and H33) that allow you to turn on and off the corrections so as to be able to see the impact of using the correct factors/values.

Comment #6: The DSEIS greenhouse gas calculations should be revised to reflect the greenhouse gas emissions associated with Tacoma LNG's electricity supplier rather than a Washington State average mix.

Section 2.2.3 of the DSEIS accurately describes the specific electric power generation mix serving the facility, but then does not use that mix to calculate the greenhouse gas emissions from the facility's consumption of electricity. Instead the DSEIS imputes to the Tacoma LNG facility GHGs associated with the Washington statewide average for electric generation into the GHG calculations thus overstating emissions. In addition, the text of the DSEIS misstates the greenhouse gas emission rate that is imputed to the facility, by taking into account only the upstream power generation emissions and not the emissions from the generating facility itself. This second error relates only to the text of the DSEIS and not the actual calculations performed in the supporting spreadsheets. Both errors appear to be oversights that should be corrected.

As accurately stated in section 2.2.3 of the DSEIS, the Tacoma LNG facility electricity load will be exclusively served by and sourced from Tacoma Power ("Power would be delivered to the Tacoma LNG facility through the Tacoma Power electrical system."). There is no option for the facility to be served by other suppliers. Section 2.2.3 of the DSEIS also accurately notes that the majority of Tacoma Power's electricity portfolio is generated by hydroelectric, nuclear and non-hydroelectric renewable energy sources. The spreadsheets supporting the PSCAA life cycle analysis identify the combined upstream and power plant emissions associated with the Tacoma Power grid mix as 29.9 g/kWh CO_2e.[14] The same spreadsheets identify the combined upstream and power plant emissions associated with the average Washington grid mix as 215 g/kWh

[14] "Upstream" sheet; sum of cells H29 and H30.

CO_2e.[15] The DSEIS then calculates the greenhouse gas emissions associated with construction and operation of the Tacoma LNG facility using the 215 g/kWh CO_2e emission factor.[16]

The electricity supply for the facility must come from Tacoma PUD, so it is not accurate to use a state-wide grid mix when specific information exists for Tacoma PUD. Tacoma Power generates all the electricity it distributes, including that provided to the facility and has a surplus of power. Tacoma Power has had decreasing load and is forecasting the continuing sale of surplus power to the grid in the future.[17] As a result, there is no basis to assume that the greenhouse gas emissions associated with the generation mix serving Tacoma LNG's load will increase above the current level. Calculating the greenhouse gas emissions associated with Tacoma LNG's electricity consumption based on the Washington average (215 g/kWh CO_2e) as opposed to the emission rate associated with Tacoma Power (29.9 g/kWh CO_2e) is not accurate and should be corrected in the SEIS.

In addition, we believe that the text of the DSEIS needs to be revised to accurately reflect the emission rates used in the spreadsheet calculations for calculating GHGs associated with upstream statewide average electricity generation GHG emissions. Section 2.2.3 of the DSEIS states that "an average emission rate of 18 g/kWh carbon dioxide equivalent (CO_2e), was used to estimate upstream electricity emissions (State Energy Office at the Washington Department of Commerce)." 18 g/kWh CO_2e comes from cell H27 of the "Upstream" sheet in the supporting spreadsheets. We believe that the wrong value was copied out of the "Upstream" sheet and that the sum of cells H27 and H28 (i.e., 215 g/kWh CO_2e) should be referenced for calculations where the Washington average electricity generation GHG emission rate is appropriately employed. As explained above, it is not appropriate to use the Washington average electricity generation GHG emission rate for the Tacoma LNG facility because all of its electricity will be obtained from Tacoma Power. However, to the extent that the Washington average electricity generation GHG emission rate is used for calculations such as upstream refining, the text should accurately reference the emission factors used in the calculations.

In summary, the emission rate associated with Tacoma Power's generation portfolio must be used to calculate greenhouse gases associated with constructing and operating the Tacoma LNG facility. This emission rate must then be reflected in the text of the SEIS. While not changing the conclusion in the DSEIS, accurately characterizing the GHG emissions attributable to the electricity used by the proposed facility will more fully recognize the benefits attributable to the Action Alternative. The spreadsheets placed on public comment as an attachment to the DSEIS include a toggle ("Input" sheet; cell H24) that allows one to correct the generation portfolio to reflect the Tacoma Power generation mix. It may simply have been an oversight that the toggle

[15] "Upstream" sheet; sum of cells H27 and H28.
[16] "Upstream" sheet; cells G42 and G47.
[17] Tacoma Power Integrated Resource Plan, 2017 Update https://www.mytpu.org/file_viewer.aspx?id=64787.

was switched to the state-wide mix given that the text of the DSEIS accurately reflects that electricity for the proposed project would come exclusively from Tacoma Power. This oversight should be corrected in the FSEIS.

Comment #7: The DSEIS should be revised to employ the correct CA_GREET value for liquefaction and storage of LNG and to remove the inaccurate statement that the proposed facility is not energy efficient.

On page 89 of Appendix C of the DSEIS (the LCA report) LCA incorrectly states that "[t]he power consumption of Tacoma LNG is considerably higher than the CA_GREET default value." This misstatement should be corrected because the Tacoma LNG facility is in fact highly energy efficient. The unnumbered table on page 89 of Appendix C states that the electricity consumption for Tacoma LNG is 1,348 kWh/1,000 gal LNG while the CA_GREET value is 43.89 kWh/1,000 gal LNG. Based on these values, LCA reaches the conclusion that the proposed facility is not energy efficient. This conclusion is wrong because LCA uses an incorrect CA_GREET energy consumption value to derive the kWh/1,000 gal LNG power consumption value. LCA employed a Total Energy/Unit LNG value from CA_GREET of 1,607 $Btu_{energy}/MMBtu_{LNG}$. When one performs the unit conversion with a 91 percent efficiency, you get 43.89 kWh/1,000 gal LNG--the figure in the unnumbered table on page 89 of Appendix C. The derivation of this value is shown below.

Incorrect Derivation
Assumes LNG Storage (As a Transportation Fuel)

A	Heating Value	84,820	BTU / gallon	HHV Fuel Spec GREET
B	Conversion BTU to kW-h	3412.14	BTU / kW-h	Constant
C	Total Energy / unit LNG	1,607	BTU_{energy} / $MMBTU_{LNG}$	GREET Value below for Energy Consumption
D	Convert to kW-h / MMBTU(LNG)	0.47	kWh_{energy} / $MMBTU_{LNG}$	= C / B
E	Convert to kW-h / (1) BTU(LNG)	4.71E-07	kWh_{energy} / BTU_{LNG}	= D / 1E6
F	Convert to kW-h / gallon(LNG)	0.04	kWh_{energy} / $gallon_{LNG}$	= E / A
G	Energy / 1000-gallons	**40**	**kWh_{energy} / 1000-$gallon_{LNG}$**	= F * 1000
	Assuming 91% LOSS	**43.89**	**kWh_{energy} / 1000-$gallon_{LNG}$**	= F / 0.91 ← Incorrect

However, 1,607 $Btu_{energy}/MMBtu_{LNG}$ is the CA_GREET default factor for the energy associated with storage of LNG. The CA_GREET default factor for the energy associated with both liquefaction and storage of LNG is 125,772 $Btu_{energy}/MMBtu_{LNG}$. When one performs the unit conversion from the correct energy consumption value, you get 3,623 kWh/1,000 gal LNG.

	Correct Derivation Natural Gas to Liquefied Natural Gas (As a Transportation Fuel)		
A	Heating Value	84,820 BTU / gallon	HHV Fuel Spec GREET
B	Conversion BTU to kW-h	3412.14 BTU / kW-h	Constant
C	Total Energy / unit LNG	125,772 BTU_{energy} / $MMBTU_{LNG}$	GREET Value below for Energy Consumption
D	Convert to kW-h / MMBTU(LNG)	36.86 kWh_{energy} / $MMBTU_{LNG}$	= C / B
E	Convert to kW-h / (1) BTU(LNG)	3.69E-05 kWh_{energy} / BTU_{LNG}	= D / 1E6
F	Convert to kW-h / gallon(LNG)	3.13 kWh_{energy} / $gallon_{LNG}$	= E / A
G	Energy / 1000-gallons	**3,126 kWh_{energy} / 1000-$gallon_{LNG}$**	= F * 1000
	Assuming 91% LOSS	**3,623 kWh_{energy} / 1000-$gallon_{LNG}$**	= F / 0.91 ← Correct

As shown in Table 9 below, a comparison of Tacoma LNG's power consumption value of 1,348 kWh/1,000 gal LNG to the correct CA_GREET derived power consumption value of 3,623 kWh/1,000 gal LNG demonstrates how energy efficient the Tacoma LNG facility will be.

Table 9. Energy Efficiency of the Tacoma LNG Facility

Tacoma LNG (kWh/1,000 gal LNG)	CA_GREET (kWh/1,000 gal LNG)
1,348	3,623

The DSEIS should be revised to accurately reflect the CA_GREET figure for liquefaction and storage as well as to note the high energy efficiency of the proposed facility.

Comment #8: The carbon balance on page 92 of Appendix A to the LCA Report contains errors.

The "Annual Throughput" figure on page 92 (Appendix A) of the LCA Report, which is Appendix C of the DSEIS contains several minor technical errors. Specifically, we have identified the following corrections for PSCAA's consideration:

- The amount of natural gas exiting the LNG Pretreatment system annually should be corrected to 322,354 tonnes, not 315,523 tonnes as shown in the DSEIS mass balance figure. The mass balance shows 326,239 tonnes of natural gas entering LNG Pretreatment and 3,885 tonnes exiting as "Pretreatment fired NG." The difference is 322,354 tonnes, not 315,523 tonnes.
- The amount of LPG produced annually should be corrected to 8,910 tonnes, not 8,722 tonnes as calculated in the DSEIS mass balance figure. Because the mass of natural gas exiting the pretreatment increases by 6,831 tonnes natural gas (322,354 tonne NG –

315,523 tonne NG = 6,831 tonne NG), the amount of LPG production will increase by 188 tonnes.

- The CO_2 produced annually by flaring the LPG should be corrected to 24,083 tonnes, not 23,573 tonnes as calculated in the DSEIS. Using a value of 8,910 tonnes LPG, CO2 emissions will increase by 510 tonnes CO2.
- The CO_2 produced annually for the facility should be corrected to 95,164 tonnes, not 94,654 tonnes as calculated in the DSEIS. Adding 510 tonnes CO2 to the facility total brings the total emissions to 95,164 tonnes.

The corrected values are summarized in Table 10 below.

Table 10. Carbon Balance Corrections

DSEIS Calculated (Incorrect)	Correct Value
315,523 tonne NG	322,354 tonne NG
8,722 tonne LPG	8,910 tonne LPG
23,573 tonne CO2 from flared LPG	24,083 tonne CO2 from flared LPG
94,654 tonne CO2 Facility Total	95,164 tonne CO2 Facility Total

While these are not significant differences, the FSEIS should be revised to reflect accurate values.

Comment #9: Table C.1 in Appendix C incorrectly identifies natural gas data as "placeholder data."

Table C.1 in Appendix C of the LCA Report, which, in turn, is Appendix C of the DSEIS incorrectly suggests that natural gas carbon content, heating value and the CO_2 emission factor are interim "placeholder" values. Our understanding is that the emission factors stated in Table C.1 are never used in the analysis so perhaps this is an editing oversight because this table does not have to be included in the appendix. However, if the table is to be included, there are minor errors that should be corrected. For example, the higher heating value ("HHV") for natural gas stated in Table C.1 is 1,054 Btus/scf. However, the correct value (which is accurately shown in the "Input" sheet of the supporting spreadsheets at cell C90) is 1,090 Btus/scf. Again, if Table C.1 is to be included in the FSEIS, the values should be corrected to reflect the values used in the actual analysis. While not affecting the conclusions in the DSEIS, it is confusing for Table C.1 to inaccurately reference "placeholder data" and to reflect values inconsistent with the DSEIS spreadsheets.

Comment #10: Note "a" in Table C.2 of Appendix C incorrectly states that natural gas properties will be recalculated based on requested data.

Table C.2, Note "a" in Appendix C of the LCA Report, which, in turn, is Appendix C of the DSEIS incorrectly states that "Natural gas properties will be recalculated based on data that has been requested." Note "a" also indicates that the fuel properties in Table C.1 match those on the "Fuel_Specs" sheet in the supporting spreadsheets. However, PSE responded to the PSCAA information requests on May 25, 2018--over four months prior to completion of the LCA Report in Appendix C. Therefore, the language in Note "a" appears to be out of date and should be removed. We also note that the fuel values in Table C.2 should be amended to match the numbers in the "Fuel_Specs" sheet of the underlying spreadsheets.

Comment #11: The DSEIS misstates the amount of LNG that would be gasified during times of peak demand.

There are inconsistencies in the DSEIS about the amount of LNG that would be gasified during peak demand periods. Section ES.2 of DSEIS inaccurately states "During times of peak gas demand, 85,000 dekatherms of NG would be re-gasified and re-injected into PSE's distribution system." However, in Section 2.3.4 the DSEIS accurately states that the vaporization system would have the capacity to deliver 66 MMSCF/day (i.e., 66,000 Dth/day) of natural gas at standard distribution pipeline pressure. We believe that the confusion may stem from language in the FEIS which speaks of the Proposed Action being to "re-inject <u>and divert</u> approximately 85,000 Dth/day." (emphasis added). The FEIS was accurate in this description, but that does not mean the entire 85,000 Dth/day is from re-gasified natural gas. As described in Section 1.3.4.1 of the BID, the Tacoma LNG facility will have the capacity on a peak demand day to re-gasify up to 66,000 Dth/day of gas from storage, but can add additional supply by diverting up to 19,000 Dth of natural gas that would normally be delivered to the facility for liquefaction. Therefore, Section ES.2 of DSEIS should be revised to state "During times of peak gas demand, 66,000 dekatherms of natural gas per day would be re-gasified and re-injected into PSE's distribution system and 19,000 dekatherms of NG per day would be diverted from being routed to the liquefaction plant and be left in the pipeline for consumer use."

Similar to our other comments, this is not a significant error that affects the overall DSEIS conclusions, but nonetheless should be corrected.

Comment #12: Table A.11 in the LCA Report contains values that should be corrected.

Table A.11 in Appendix C of the LCA Report, which, in turn, is Appendix C of the DSEIS includes incorrect values. For example, Table A.11 indicates that 2,299 gallons of LNG are lost per bunkering event. The sheet entitled "PSE_LNG_Operations" in the DSEIS spreadsheet contains the value of 114 gallons per event. The latter value reflects the assumptions built into the DSEIS spreadsheet and the 2,299 gallon value currently in Table A.11 is inconsistent with what is actually used in the DSEIS spreadsheets. Table A.11 appears to have had the wrong data populated into many of the cells in the table and should be corrected to avoid confusion. These corrections to the table do not alter the conclusions of the DSEIS because the spreadsheets are accurate.

Comment #13: Section 2.3.4 of the DSEIS incorrectly suggests that the LNG that is re-gasified and injected into the pipeline during peak demand periods would be used for electricity generation.

Section 2.3.4 of the DSEIS states "GHG emissions would also occur during the combustion of the natural gas in the power generation facility associated with peak shaving." This statement is incorrect. During a peak demand period when the immediately available gas supply is insufficient, PSE's priority is residential and commercial natural gas customers. At such a time, the Tacoma LNG facility would gasify LNG in storage and re-inject this natural gas into the pipeline for use by its residential and commercial natural gas customers. As explained in Section 1.3.6.3 of the BID:

> The Tacoma LNG Facility would also enable PSE to avoid repurposing firm gas transmission from peak period electricity generation to residential gas service. In the absence of the Tacoma LNG Facility, during peak periods PSE would have to use this firm gas transmission to supply gas customers and thus would be required to operate "peaker" dual-fuel combustion turbine electric generating units utilizing fuel oil rather than using natural gas. The additional GHG emissions attributable to use of fuel oil in dual-fuel combustion turbine electric generating units is not quantified in this analysis, but will occur if the Project is not built.

As this provision makes clear, one benefit of the project is that during peak demand periods, PSE has the ability to vaporize LNG and put that natural gas into the pipeline to supply residential and commercial gas service. None of the peak shaving natural gas would be supplied to electricity generation. The natural gas used for electricity generation is in a separate portfolio of gas resources designated for PSE's electricity generation. Tacoma LNG is an exclusively natural gas customer gas supply resource.

Comment #14: The SEIS must accurately calculate emissions of black carbon and organic carbon relative to the Action and No Action Alternatives.

As noted above, the 2018 IPCC Special Report recommended an increased focus on reduction of short-term climate forcers such as black carbon and organic carbon. Black carbon is a component of $PM_{2.5}$ generated primarily by the incomplete combustion of fossil fuels.[18] Black carbon emissions are estimated to be the second or third largest contributor to current warming, after CO_2 and methane. Black carbon influences climate by directly heating surrounding air when suspended in the atmosphere, by reducing the reflectivity of the earth's surface when deposited (an effect particularly strong over snow and ice), and through additional indirect effects related to interaction with clouds. Black carbon has a tremendous impact locally and along the Canadian and Alaska coastlines on snow and ice fields, not to mention on human health.

One of the critical benefits presented by the proposed project is that it will result in a substantial decrease in black carbon emissions from vessels. PSCAA has appropriately included black carbon and organic carbon calculations in the DSEIS spreadsheets. However, those calculations contain errors that we presume are due to incorrect fuel assumptions (in the absence of the Tacoma LNG project TOTE vessels will run on diesel and not bunker fuel).[19] Whatever the reason for the mistakes, the FSEIS should be corrected as outlined below:

1. The "End use TOTE - Fuel Oil Vessel" sheet references incorrect BC/OC ratios for transit, maneuvering and hoteling emissions in cells Q44:R44, Q45:R45 and Q46:R46, respectively. For example, the transit black carbon emissions for the <u>fuel oil vessel</u> are calculated in cell Q44 using the following formula:

   =H44*BC_OC Ratios'!$C$6/100

   Where:
   H44 = PM2.5 emissions
   BC_OC Ratios'!$C$6 = the black carbon percentage for a natural gas fired engine

   The correct "BC_OC Ratios" sheet reference should be to cell O6, for a diesel-fired engine. In other words, the spreadsheet is calculating black carbon emissions for a <u>fuel oil-fired vessel</u> using the black carbon percentage of PM2.5 specific to a <u>natural gas-fired engine</u>. The formula should reference BC_OC Ratios'!$O$6, the correct BC percentage for a diesel-fired engine and consistent with the PM2.5 emissions factors used for an MGO-fueled marine vessel engine.

2. The Emissions Factors tables in rows 63 through 90 of the "End use TOTE - Fuel Oil Vessel" sheet misapply the Fuel Correction Factors. The formulae in these cells use

[18] https://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-4-4-3.html.
[19] See comments 4 and 5 above.

emission factors contained in Table B.2 (cells D8:K17 of the "EF Marine Vessels spec. TOTE" sheet), and reflect emissions of an ocean going vessel operating on 0.1% S MDO as reported in the 2016 Puget Sound Maritime Air Emissions Inventory.[20] The Emissions Factors tables in rows 63 through 90 of the "End use TOTE - Fuel Oil Vessel" sheet then apply Fuel Correction Factors to the 0.1% MGO emissions rates. The Fuel Correction Factors are shown in Table 3.22 (cells B96:L105 of the "EF Marine Vessels spec. TOTE" sheet). However, these Fuel Correction Factors are intended to adjust emissions factors from a baseline of 2.7%S HFO (the baseline in the 2011 Puget Sound Maritime Air Emissions Inventory), not the 0.1% MGO baseline used in the current analysis.[21] By applying these Fuel Correction Factors to the updated baseline emissions factors for 0.1% MGO shown in Table B.2, particulate emissions for the fuel oil-fired vessel are incorrectly reduced by 83%.

3. Cells Q44:Q46 and R44:R46 of the "End use TOTE - Fuel Oil Vessel" and "End use TOTE-LNG Vessel" sheets are intended to represent the tonnes per trip values for black carbon and organic carbon, respectively, for each of the three phases of transportation. The values in cells Q48 and R48 of these two sheets are intended to represent the sum of the values for each of the phases. However, the values in cells Q48 and R48 of both of these two sheets are hard-entered numbers and do not reflect the sum of values above them.

Correcting these errors results in a four-fold increase in black carbon emissions associated with the TOTE Fuel Oil Vessel and a halving of the organic carbon emissions.

It is also noted that Table B.12 (cells B58:K60 of "EF Marine Vessels spec. TOTE") contains an error for the PM10 emissions rate of a fuel oil auxiliary boiler. The listed value is 16 g/kW-hr. The correct value is 0.16 g/kW-hr, as reported in the 2016 Puget Sound Maritime Air Emissions Inventory. Because the PM10 emissions rates of auxiliary boilers are assumed to be the same for fuel oil and natural gas, this error doesn't create a relative emissions difference between the two fuels. However, the error should still be addressed so as to ensure that the SEIS is accurate.

Given the substantial climate forcing impacts of black carbon, PSCAA must accurately address these emissions in the analysis. Failure to do so would cause the FSEIS to understate the life cycle benefits of the Proposed Action. The errors in the spreadsheets identified above should be corrected and the black carbon and organic carbon impacts of the Action Alternative as

[20] htbtps://pugetsoundmaritimeairforum.files.wordpress.com/2018/10/final-2016-psei-report-19-oct-2018-scg.pdf
[21] See, Section 3.6.10, Table 3.22 of the 2011 Inventory ("emission factors were given for engines using residual fuel with an average 2.7% sulfur content.") https://pugetsoundmaritimeairforum.files.wordpress.com/2016/06/2011pseireportupdate_20130523.pdf

compared to the No Action Alternative should be identified. While more commonly considered in the context of the 20-year horizon, it is important that even this 100-year horizon assessment recognize the huge benefit achieved by reducing black carbon emissions and reducing the substantial effects that black carbon has on the glaciers and snow fields that lie in immediate proximity to Pacific Northwest maritime traffic.

We have included as an attachment to this letter a set of revised spreadsheets that include a toggle ("Input" sheet; cells H30 and H31) that allow you to consider the black carbon and organic carbon impacts ("Input" sheet; cell H30) as well as to correct the inaccurate black carbon and organic carbon computations ("Input" sheet; cell H31).

Comment #15: The DSEIS uses an appropriate methane emission rate for marine LNG-fired engines.

Recent data lend further support for the use of the methane emission rate for marine LNG-fired engines that is in the DSEIS. The DSEIS relies upon the June 13, 2017 SINTEF report (Table 7.2) for the methane emission rate value for an LNG-fired LPDF 4-stroke engines. The 5.3 g/kW-hr value was derived from actual tests on two ships equipped with Low Pressure Dual Fuel ("LPDF") engines. Since the time of that report and preparation of the DSEIS, MAN Energy Solutions ("MAN"), the company upgrading the TOTE propulsion system to LNG, has performed its own testing. As described in the attached October 26, 2018 letter, MAN has tested methane emissions for a converted MAN 58/64 engine as part of their engineering development program. This engine is the equivalent of those that will power the MV Midnight Sun and MV North Star on LNG once fully converted. When adjusted for density to match the conditions of the SINTEF report, the emission rate is 5.3 g/kW-hr. Note that MAN compares their tested value to the value reported in the SINTEF report reflecting the average of actual tests and manufacturer testbed data. MAN's value comes out at exactly the same rate (5.3 g/kW-hr) as the other *in situ* tests. This lends tremendous credibility to the value used in the DSEIS.

Comment #16: PSCAA is correct to employ the AR4/100-year assumptions in assessing life cycle GHG emissions under the Action and No Action Alternatives.

At the public hearing held on October 30, 2018, multiple commenters suggested that PSCAA should apply AR5, 20-year average Global Warming Potentials ("GWPs") instead of the AR4, 100-year average GWPs employed in the DSEIS. The stated justification for this shift, which several other commenters acknowledged would put the SEIS at odds with Washington's statutes, rules and policies, was the belief that because a recent IPCC study says significant action must be taken in the next 12 years, that the average GWPs must more closely match this period. This comment reflects a misunderstanding of the SEIS process, what the IPCC report says, and the policy underlying the 100-year GWP horizon.

Focusing on a 20-Year Average GWP as Opposed to a 100-Year GWP Inaccurately Minimizes the Long Term Effect of Carbon Dioxide on Climate Change

GWP is the ratio between the climate warming effect of 1 tonne of a non-CO2 GHG and the climate warming effect of 1 tonne of CO2 had each been emitted on the same day. The IPCC has estimated that the average relative GWP for methane over the first 20 years after it is emitted is 86 (without climate-carbon feedbacks).[22] This means that over 20 years (and with no consideration beyond 20 years) the average relative global warming potential of 1 ton of methane equals that of 86 tonnes of CO2.

Because GWP is a ratio (as opposed to an absolute number) the relative decline in CO2 and methane distort the 20-year average GWP value. Specifically, over the first 3.3 years, the fraction of a tonne of CO2 emitted that remains in the atmosphere declines faster than methane. Thus methane's GWP over the first three years goes up notwithstanding the fact that its levels are declining significantly over that time period. This artificially inflates the global warming effect of methane during that 3.3-year period.

More importantly, half of methane's global warming effect has occurred within 8.6 years of being emitted and 3/4 of its effect has occurred within 17.2 years of being emitted. By 100 years, the direct effect of methane on global warming drops to negligible levels, with the fraction of remaining methane decreasing to 0.000009 percent, while slightly less than 40 percent of the CO2 is still present.[23] As the IPCC has stated, "About half of a CO2 pulse to the atmosphere is removed over a timescale of 30 years; a further 30% is removed within a few centuries; and the remaining 20% will typically stay in the atmosphere for many thousands of years."[24] Climate researcher, David Archer, et al., concluded that "climate effects of CO2 releases to the atmosphere will persist for tens, if not hundreds, of thousands of years into the future."[25] The authors of that paper cautioned against even limiting consideration to the 100-year horizon given the longevity of CO2.

Because methane is reduced by roughly 98 percent within the first 50 years, but it takes tens of thousands of years to reach the same reduction in CO2 stocks, it is bad policy to focus on the 20-year average GWP values. This ignores the much greater long-term impact that an equivalent

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[22] IPCC; Anthropogenic and Natural Radiative Forcing (2013); https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter08_FINAL.pdf

[23] Fugitive Methane and the Role of Atmospheric Half-Life; *Geoinfor Geostat: An Overview 5:3.* https://www.scitechnol.com/peer-review/fugitive-methane-and-the-role-of-atmospheric-halflife-bu53c.php?article_id=6097

[24] IPCC Fourth Assessment Report; TS 2.1.1; https://www.ipcc.ch/publications_and_data/ar4/wg1/en/tssts-2-1-1.html

[25] Atmospheric Lifetime of Fossil Fuel Carbon Dioxide; Annu. Rev. Earth Planet. Sci. (2009); http://climatemodels.uchicago.edu/geocarb/archer.2009.ann_rev_tail.pdf.

amount of CO2 has for centuries into the future. As the IPCC noted, "Adoption of a fixed horizon of e.g., 20, 100 or 500 years will inevitably put no weight on the long-term effect of CO2 beyond the time horizon."[26] Simply ignoring the impacts of CO2 after 20 years, as the 20-year average GWP does, makes no sense from a policy point of view and is why all creditable policy making organizations rely upon the 100-year horizon. The 100-year average GWP still understates the long-term impact of CO2 as opposed to methane, but it gives a more accurate sense of the long-term impacts.

The 2018 IPCC Special Report on the Impacts of Global Warming Does Not Suggest That it is Necessary or Appropriate to Rely on the 20 Year Average GWP

In October 2018, the UN Intergovernmental Panel on Climate Change ("IPCC") released a Special Report on the impacts of global warming exceeding 1.5 degrees Celsius above preindustrial levels. The Paris Climate Accord commits to actions to stay below an increase in global temperatures of 2 degrees Celsius but to also pursue actions that would strive to keep increases in temperature to 1.5 degrees Celsius. The report concludes that to stay below an increase of 1.5 degrees Celsius, greenhouse gas emissions will need to be reduced by 45% from 2010 levels by 2030 and 100% (net zero) below 2010 levels by 2050. Nowhere does that report state that it is appropriate to use the 20-year average GWP in place of the 100-year average GWP as a policy tool. Doing so would mean that climate impacts are only considered for the first 20 years and effects after 20 years are not considered.

The 2018 IPCC Special Report does discuss the need for an increased focus on reduction of short-term climate forcers such as methane and black carbon. Methane reduction through industry and governmental efforts to reduce leakage in natural gas production such as those already underway in British Columbia is identified as a key tool that is highly achievable and has economic benefits as well. Reduction in black carbon emissions through reductions in diesel emissions is also identified as a pathway that not only has highly significant short-term climate reduction potential, but also has significant corollary public health benefits. However, the 2018 IPCC Special Report's focus on addressing short-term climate forcers is distinct from saying that policymakers should stop considering the long-term relative impacts of greenhouse gases. Some greenhouse gases, such as CO2, will be around for millennia, while others, such as methane, will essentially be gone in a few decades or less. There are benefits and tradeoffs related to each. However, governments must make decisions based on the long-term impacts to climate.

The 2018 IPCC Special Report does not specifically recommend a particular pathway or scenario to be followed. However, it does identify the consequences of inaction and identifies a number of methods that can be chosen by policy makers.

[26] IPCC; Anthropogenic and Natural Radiative Forcing (2013); https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter08_FINAL.pdf

In the context of the Tacoma LNG project, use of LNG as a marine fuel is consistent with a number of the identified alternative pathways in the report. Substituting LNG for oil in ship engines reduces climate emissions directly and also reduces black carbon, creating not only long- and short-term climate benefits, but improvements to public health through reduced exposure to diesel particulates. The use of British Columbia natural gas is also consistent with the identified pathways. As part of the Pan-Canadian Framework on Clean Growth and Climate Change, the Canadian government committed to reduce methane emissions from the oil and gas sector by 40 to 45 percent from 2012 levels by 2025. In April 2018, Environment and Climate Change Canada ("ECCC") adopted federal methane regulations to deliver on this commitment.[27] These regulations included the requirement that by January 1, 2020, well completions involving hydraulic fracturing must prevent fugitive releases. British Columbia has charted an even more aggressive course than the Canadian national government by setting its own aggressive targets of reducing Province-wide greenhouse gas emissions by 18 percent (relative to 2007 levels) by 2016, 33 percent by 2020 and 80 percent by 2050.[28] By committing to its natural gas feedstock coming exclusively from British Columbia, Tacoma LNG is supporting responsible development from a region that is aggressively pursuing greenhouse gas reductions. This pathway is consistent with the pathways outlined in the 2018 IPCC Special Report.

Use of AR4/100-year average GWPs is consistent with Washington, PSCAA, and U.S. EPA policy, in addition to that adopted by the Paris Accord

As noted by many commenters at the October 30 hearing, federal and state GHG reporting regulations and all major GHG policy considerations and goals, including those of the State of Washington, U.S. EPA, PSCAA, the Paris Accord and the Kyoto Protocol, are based on the AR4/100-year average GWPs. At page 4-5 of the DSEIS PSCAA states correctly that it is applying the GWP factors because it is the currently accepted international reporting standard and the methodology for State of Washington GHG reporting. Neither the State of Washington, U.S. EPA, PSCAA, the Paris Accord nor the Kyoto Protocol have adopted the AR5 GWPs and it would be inappropriate for PSCAA to adopt those standards here. Emissions are reported using these assumptions and goals are based on these assumptions. As explained above, the basis for this approach is that focusing on the 20-year average GWP eliminates consideration of the long-term impact of CO2 and other GHGs. Maintaining consistency when making policy considerations is key.[29] Also, compelling reasons exist for looking at the long-term impacts of emissions on climate change.

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[27] See, e.g., https://www.canada.ca/en/environment-climate-change/news/2018/04/federal-methane-regulations-for-the-upstream-oil-and-gas-sector.html.

[28] http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/00_07042_01.

[29] We note that even if 20 year average GWP values are assessed, a correct analysis incorporating the impacts of black carbon demonstrates that the Action Alternative results in a substantial net reduction in GHG emissions.

Comment #17: Although PSCAA has not been presented with a permit application for liquefaction of 500,000 gallons of LNG per day, there is no error in assessing that amount in the context of the SEIS.

There was confusion at the October 30 hearing about the end use contemplated for LNG in excess of the amount to be consumed by TOTE, peak shaving and truck transfers (the "unallocated LNG"). The primary purposes of the Tacoma LNG facility would be to provide LNG for marine vessel fuel and to PSE customers by re-gasification during times of peak demand (i.e., peak shaving). A small amount of LNG would be capable of transfer by truck. At either a 250,000 or 500,000 gallon per day production volume, there would be additional unallocated LNG available for maritime use.

PSE has only requested authority from PSCAA to build and operate a facility with the capacity to produce 250,000 gallons per day of LNG. This is based exclusively on the use of the infrastructure proposed in the Notice of Construction ("NOC") application. In order to perform a complete life cycle analysis of the greenhouse gas emissions associated with both a 250,000 and 500,000 gallon per day scenario, it was assumed that all remaining LNG not used by TOTE, for on-road heavy duty trucking or for peak shaving would be combusted in other marine vessels. All of this unallocated LNG was assumed to be transferred into barges on the Blair Waterway; no bunkering could occur in the Hylebos Waterway. Methane losses associated with the bunkering process and emissions associated with marine combustion were calculated and included in the spreadsheets on the "Direct End use" sheet. Different fuel transfer alternatives might be considered in the future if a market is identified. At that time, should modifications to the Tacoma LNG facility be necessary, all appropriate environmental review and permitting processes would be conducted.

As part of the original Proposed Action, the FEIS studied the Tacoma LNG Facility's ability to liquefy between 250,000 and 500,000 gallons per day. The DSEIS prepared by PSCAA to study GHG emissions consistently analyzes the facility's ability to generate up to 500,000 gallons of LNG per day. PSCAA's decision to review the environmental impacts of the Proposed Action at 500,000 gallons per day as studied in the original FEIS is appropriate. However, environmental review and environmental documents such as an FEIS or FSEIS do not constitute permits–they simply inform decision-makers when reviewing permit applications. Here, the NOC permit application submitted by PSE asks PSCAA to approve a facility that is limited to a daily average production capacity of 250,000 gallons. PSE would need to seek additional NOC permitting in the future to modify the 250,000 gallon per day amount of LNG sought by the NOC before PSCAA. There is no error in PSCAA's decision to review the Proposed Action at 500,000 gallons per day of capacity consistent with the FEIS, and there is no bar to PSE's ability to seek approval for a facility that is smaller than the maximum studied.

Comment #18: PSCAA is not reviewing a proposal for export of LNG to foreign markets.

At least one commenter at the October 30 hearing wrongly asserted that PSE is going to use Tacoma LNG for export of LNG to another country. This assertion is incorrect. The Tacoma LNG Project is not and cannot be operated as an LNG export facility. LNG import and export terminals are subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"), which is the only agency in the United States that has authority to certify such facilities. The Tacoma LNG Facility is not a FERC-certificated export terminal.

Beyond the legal inability to operate the Tacoma LNG Facility as an export terminal, the proposal lacks the physical ability to perform as one. The Tacoma LNG Facility is sized only to serve the needs of natural gas customers and TOTE vessels: the project NOC is for authorization to "produce up to 250,000 gallons of fuel-grade (to satisfy PSE's supply agreement with TOTE) LNG per day, and store up to 8 million gallons of LNG on site." Even assuming all 250,000 gallons per day were diverted away from TOTE and natural gas customers (something PSE cannot do legally), it would take six months of round-the-clock daily production at 250,000 gallons per day just to produce enough LNG to fill one LNG export tanker. Beyond PSE's legal and physical inability to produce the volumes necessary for LNG export, there is no existing infrastructure at the Tacoma LNG Facility, and none proposed, that could fuel such a vessel.

PSE appreciates this opportunity to comment on the DSEIS relating to our proposed Tacoma LNG project. We recognize and appreciate the tremendous effort that PSCAA and its contractors have invested in this document. We hope that our comments are accepted in the constructive manner in which they are intended. We believe strongly that the best SEIS is one that is accurate and firmly rooted in established approaches. We recognize that some of our comments are complicated technically and may merit or be best addressed through real-time discussion. As you review our comments if additional information is needed from PSE, as the project applicant, we will make the PSE Team available at any time.

Ultimately, we believe that the DSEIS reached an accurate conclusion in determining that the Action Alternative will result in a net decrease in GHG emissions. This conclusion is reached based on an established approach that is consistent with the procedures adopted by PSCAA, the State of Washington, U.S. EPA and reflected in the Paris Accord and the Kyoto Protocol. We believe that the edits identified in this letter and addressed (in regards to comments 4, 5, 6 and 14) through revisions to the spreadsheets should be incorporated into the FSEIS.[30] These edits

[30] Again, we note that the changes in the spreadsheet needed to address comment #6 simply requires changing a toggle in the spreadsheet version released for public comment to be consistent with the text. There is no dispute that

will make the FSEIS more accurate, but they do not alter the fact that by building and operating the Tacoma LNG facility, PSE will be helping to reduce GHG emissions in addition to helping reduce NOx, SO2 and particulate emissions.

With the conclusion of the comment period, PSE looks forward to expeditious issuance of the Final SEIS so that we can proceed with the application for a minor source Notice of Construction from PSCAA. When it commences operation, the Tacoma LNG project will result in the reduction of criteria pollutants and greenhouse gases. We look forward to being able to recognize those benefits for the community as soon as possible.

Please do not hesitate to contact the PSE team if you have any questions or would like to set up a meeting. The team contact is Keith Faretra who can be reached at keith.faretra@pse.com or (425) 456-2561.

Sincerely,

Steve R. Secrist on behalf of David Mills
Senior Vice-President, Policy and Energy Supply

Attachments:

- October 25, 2018 letter from MAN to TOTE re emissions test results
- Spreadsheets reflecting changes in letter

cc: Craig Kenworthy

---

the sole potential source of electricity for the proposed project is Tacoma Power and that Tacoma Power's generation portfolio is significantly greener than the state-wide average for Washington.

MAN Energy Solutions

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Augsburg, October 26, 2018

MV Midnight Sun & MV North Star

Emission Information regaring Methane after the 58/64 conversion to Dual-Fuel operation.

Dear Ladies and Gentlemen,

Herewith we would like inform you about the requested values regarding the Methane values of the converted 58/64 engine to Dual-Fuel Operation for the vessels MV Midnight Sun and MV North Star.

The provided data from the SINTEF report dated 2017-06-13 have been used for a comparison with the values we have derived in the meantime.

Our provided values are only for information and not binding since we are in the development process according to schedule.

	E2-Cyclus Factor Methane [g/kWh]	Density [kg/m³]
SINTEF Report 2017-06-13	6,9	0,78
MAN Augsburg		
Preliminary 07/2018	4,7 @ 75% only	0,536
Comparable to SINTEF	5,3	0,78

As a result, we are at least 23% of CH_4 below the SINTEF value at a comparable density which has been used as a reference value for the study. The overall GHG should be much better than the stated 13,5%.

We hope that we have provided the requested information. If you should have any questions, please do not hesitate to contact us any time.

Yours sincerely,
MAN Energy Solutions

i.V. Spindler
Dr. Thomas Spindler
Senior Manager
Head of Upgrades & Retrofits
PrimeServ Augsburg

i.V. A. Knafl
Dr. Alexander Knafl
Vice President
Head of Advanced Engineering
& Exhaust Aftertreatment
Engineering 4-Stroke

NW Energy Coalition
Comments on and Requests
regarding the PSE 2021 IRP Webinar #5:
Social Cost of Carbon, July 21st, 2020

July 24, 2020

Elizabeth Hossner
Manager Resource Planning & Analysis

Keith Faretra
Senior Resource Scientist
Puget Sound Energy

Dear Elizabeth and Keith:

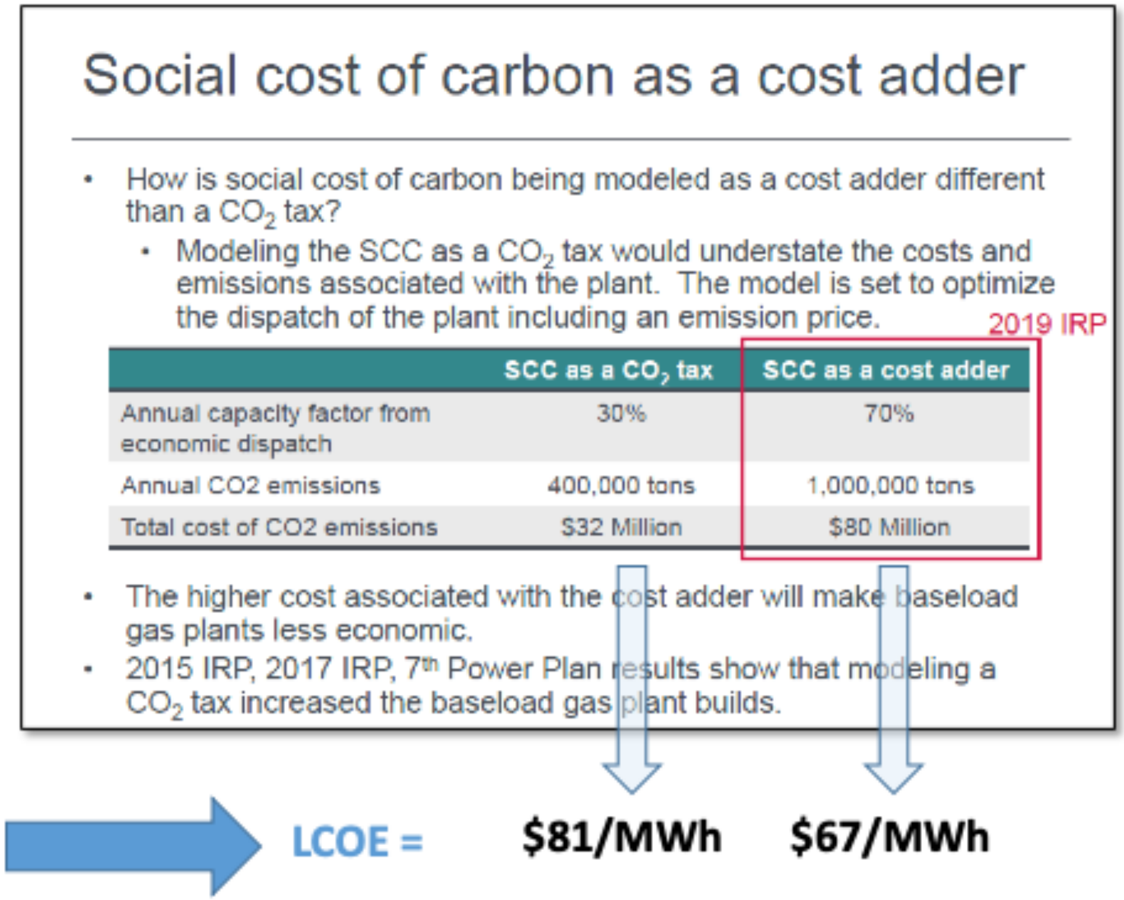
NW Energy Coalition (NWEC) appreciates the opportunity to ask questions about and make suggestions regarding PSE's approach to applying the Social Cost of Carbon (SCC), per the Clean Energy Transformation Act (CETA) and measuring upstream emissions. Our comments generally follow the order of the slides presented in the webinar of July 21st, starting with comments on the SCCC.

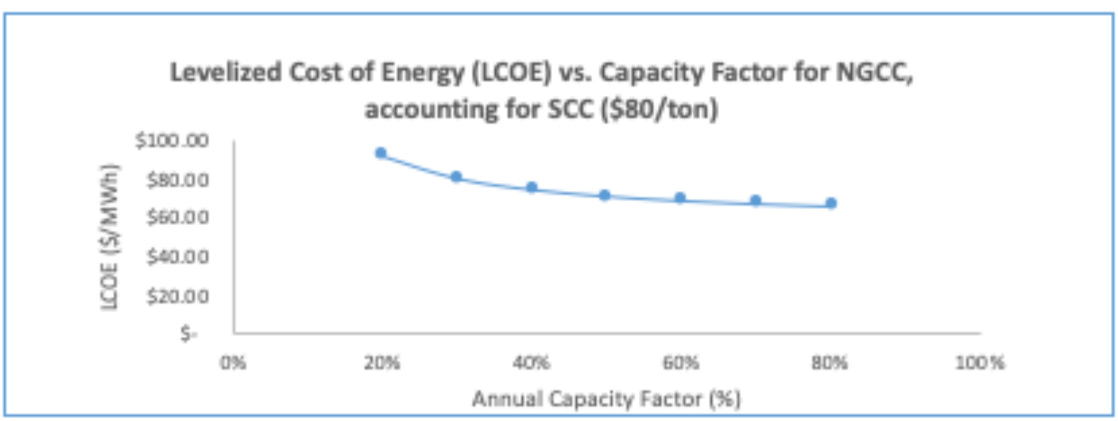
Slide 14 – first point – While it was explained the SCC is provided to program staff who apply that value to conservation measures that come out of the RFP at the time when the measures are being screened for the IRP, we would appreciate a more detailed written explanation of that methodology. Demand side resources are often bundled into groups by costs, so the SCC must be reflected in the individual price as the model is selecting those resources.

It was also stated during the presentation that the SCC is not applied to any demand side resource such as conservation or efficiency in either the long-term capacity expansion analysis or in Aurora modeling. Are other measures, such as grid controlled hot water heaters, treated the same way? How does this ensure that DSR are fairly considered compared to other choices?

Slide 14 – points 2 and 3 – We appreciate the explanation why PSE has decided to apply the SCC as a fixed cost in the resource planning, but we respectfully disagree with this approach. The purpose of requiring the SCC as a planning price is to internalize into planning decisions the external cost of emitting CO_2. The SCC does not function as a tax that is passed through to customers, but as an external cost that must be incorporated in resource investment decisions.

If dispatch modeling informs resource investment choices in any way, the SCC must be included in the dispatch analysis to prevent distortions. While LCOE is not the only factor considered in choosing resources, it is an important one; accounting for SCC in dispatch modeling will reduce a NGCC's capacity factor (all else being equal), which will increase overall cost on a levelized basis. On a per MWh basis, including the SCC in only the investment analysis and not in modeled dispatch will skew the economics of two identical resources. This is illustrated by using the chart PSE provided on Slide 20;





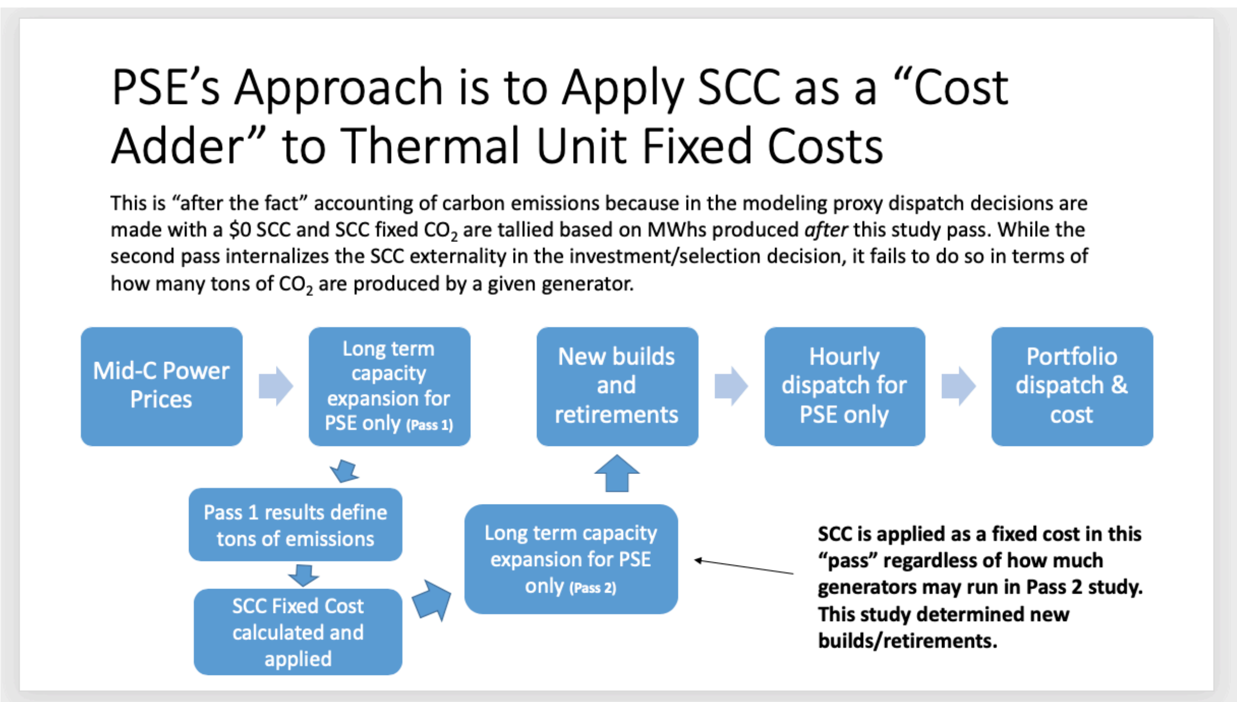
Data sources: NREL 2019 ATB NGCC with adjustments to capacity factor; emission rate = 0.42 metric tons/MWh (based on Goldendale historical operations and EIA)

Confi

Treating SCC as a fixed cost may raise the capital cost of the certain thermal resources, but may well lower levelized costs (a per MWH measure). The model's economic "incentive" is to add thermals and run them more because they become more economic the more they run, as their upfront fixed cost is spread over more and more MWhs. By excluding SCC from dispatch modeling, it is more likely that certain new and existing thermal resources will *run more* than if the SCC was accounted for in their dispatch costs

As a result, the incorrect price signal is being sent to the model, especially when selecting against demand-side resources. Consequently, there will be no way to test if higher amounts of demand-side resources will result in a lower cost/lower risk portfolio.

PSE's agreement to run a scenario incorporating the SCC in dispatch will allow a comparison between treating SCC as a fixed cost and treating SCC as a variable cost to see if that makes a difference in the resources chosen for the portfolio. This is how we understand PSE's proposal:



We suggest the following as an alternative to the methodology depicted in Slide 21:

An Alternative Approach is to Apply SCC as a Cost Adder to the Variable Cost of Thermal Generators

This approach allows the externality (SCC) to be internalized into the operational <u>and</u> investment decision of the generator or power purchase. Incorporating the cost of the externality – carbon emissions – based on the SCC will cause a dispatch that relies on thermal generation less and makes thermal generation more expensive. A high variable cost and low(er) generator output means a thermal unit will have more difficulty recovering its fixed capital costs, which are unchanged. This fully internalizes the SCC externality.

SCC is applied as a variable cost adder, which impacts the operation and selection of thermal units/market purchases in a single step

SCC is an externality and not a "tax" as characterized by PSE.

Slide 17 – first point – this needs to be corrected to state "….at the lowest REASONABLE cost possible to ratepayers."   Least cost is not defined as singularly the lowest cost, but the lowest cost considering a number of factors, per 19.280.020(9) and (11).

Slide 18 – Instead of adding the SCC to the fixed plant costs, we would argue that SCC should be added to variable costs, dispatch modeling and unspecified market purchases. We will trust that is what the second scenario PSE committed to run will do.

Slide 19 – out of curiosity, is there some reason the results in the fourth column do not match what the results would be multiplying the tons of CO2 times the SCC in $/ton? They are not far off, so is the difference due to rounding?

Slide 21 – it is still not clear how DSR are incorporated into this methodology. Please explain more fully.

Slide 24 – the conclusions listed on this slide are described as the conclusions that were presented in the December 11, 2019 Power point. However, this list leaves off the third conclusion

3. "With the CETA renewable requirement, significantly more conservation is added than the 2017 IRP. "

Please explain why this conclusion was not included in the current presentation.

While we would generally agree that an RPS standard is an effective driver of change, it seems a well-designed methodology for applying the social cost of carbon could have a significant effect on resource choices, especially of demand side resources and conservation.

Upstream Emissions:

Slides 29-35 – NWEC believes that PSE should use the most current and well documented scientific and technical analysis of upstream methane emissions. Concerning the sources cited by PSE, neither the Canadian analysis using the GHGenius model, nor the EPA analysis for the US using GREET, are consistent with current observational data and analysis, and almost certain to understate the upstream emissions rate by a considerable margin.

Our concerns are fully documented in a recent letter to the Northwest Power and Conservation Council (attached). In particular, we are concerned that the Canadian values greatly understate the upstream emissions for development and production areas in northeast British Columbia and northwest Alberta region that are the source for much of the natural gas used in Puget Sound region power plants as well as direct use. Several recent peer-reviewed studies cited in our letter summarize both field surveys and summaries of data provided to provincial regulators.

Further, in the regulatory review of both the Tacoma LNG project and the proposed Kalama methanol facility, several organizations with significant expertise have reviewed the analysis by PSCAA relying on the same Canadian provincial sources and submitted extensive comments. In that regard, we attach a December 2018 letter from the Stockholm Environment Institute (SEI) US Center summarizing concerns about the vintage and limitations of the data and analytical methods used in the Canadian provincial assessments.

The PSCAA values referenced on Slide 34 are 153.21 g/mmBtu for GHGenius (Canadian gas) and 221.05 g/mmBtu for GREET (US gas). According to the lookup table in the NW Council staff analysis (attached) at Tab 1, line 54, this approximates emissions rates of 0.85% and 1.25% respectively.

In comparison, the EPA mid estimate is 1.82% (Council analysis, Tab 1, cell W24), and the EDF mid estimate is 2.84% (cell W23) and low estimate is 2.47% (cell X23).

We recommended, and the NW Council staff proposed, to use the EDF low estimate for US gas (2.47%) because the EDF-led methane emissions study is by far the most substantial and extensive ever conducted. It involves a wide range of engineering, gas chemistry and atmospheric science experts, extensive use of direct and indirect data acquisition, and integrated analysis with results presented in numerous peer reviewed publications. While the project is continuing, the summary publication by Alvarez et al. ("Assessment of methane emissions from the U.S. oil and gas supply chain," Science, doi: 10.1126/science.aar7204, also attached) provides a comprehensive assessment including the recommended emissions metrics mentioned above.

In conclusion, we recommend that PSE use the EDF low emissions rate of 2.47% as the most supportable overall value for aggregate upstream methane emissions from both US and Canadian sources. We also recommend that the Canadian values be further refined going forward, through consultation with relevant experts, especially those conducting the peer reviewed studies of Canadian methane emissions, to gain a consensus expert view on an appropriate upstream emissions rate for natural gas sourced in British Columbia and Alberta.

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7.27.2020

PSE IRP Consultation Update
Webinar 5: Social Cost of Carbon
July 21, 2020

8/11/2020

The following consultation update is the result of stakeholder suggestions gathered through an online Feedback Form, collected between July 14 through July 28, 2020 and summarized in the August 4, 2020 Feedback Report. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

PSE thanks Kyle Frankiewich (WUTC) for providing the recently updated inflation adjustment of the social cost of carbon pursuant to docket U-190730 Order 01 referenced below.

PSE also thanks Charlie Black and Orijit Ghosal of Invenergy, Joni Bosh of Northwest Energy Coalition (NWEC), Rob Briggs of Vashon Climate Action Group and Eleanor Bastion of Washington Environmental Council for meeting with PSE on August 10 to help further clarify their questions and suggestions concerning Invenergy's proposal for an environmental externalities approach to the modeling of the social cost of carbon in the 2021 IRP.

Special thanks to Joni Bosh of NWEC who alerted PSE that we missed the feedback form submitted by NWEC in the feedback report. The letter from Joni Bosh and Fred Huette of NWEC has been uploaded to the PSE IRP website and will be addressed separately via addendums to the feedback report and this consultation update. The referenced letter is available here:
https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/July_21_webinar/Attachment_9_NWEC_Comments_on_SCC_in_IRP.pdf

Social cost of carbon inflation adjustment

An inflation adjustment of the social cost of carbon was referenced by Kathi Scanlan of the WUTC at the July 21 meeting. On July 30, the commission published docket U-190730 Order 01 “Adopting an Adjusted Cost of Greenhouse Gas Emissions Reflecting the Effect of Inflation”. The Order is attached to this consultation update. PSE will update the numbers used for the 2021 IRP modeling. The “Emission Price Calculations workbook.xls” spreadsheet has been updated on the PSE IRP website to reflect this latest guidance from the WUTC. The updated spreadsheet name is “Emission Price Calculations workbook (Inflation Update)” and is available here: https://pse-irp.participate.online/meeting/july-21-2020-social-cost-of-carbon-and-upstream-emissions.

Upsteam emissions

PSE received feedback from Rob Briggs and Virginia Lohr of the Vashon Climate Action Group, Joni Bosh and Fred Heutte of NEWC and Doug Howell of Sierra Club concerning PSE’s assumptions around upstream natural gas emissions. PSE appreciated the feedback. The modeling protocols described during the webinar will remain consistent with prior modeling efforts and accepted regulatory criteria, and in addition PSE proposes to model a portfolio sensitivity which utilizes the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5) global warming potential (GWP) for greenhouse gas emissions included in upstream emissions.

Social cost of carbon modeling approach

PSE received feedback from James Adcock, Vlad Gutman-Britten (Climate Solutions), Kevin Jones, Virginia Lohr and Rob Briggs (Vashon Climate Action Group), Charlie Black and Orijit Ghosal (Invenergy), Doug Howell (Sierra Club), Joni Bosh and Fred Heutte (NWEC) and Kyle Frankiewich (WUTC) concerning the social cost of carbon modeling approach.

PSE is modeling the social cost of carbon (SCC) as a post-economic dispatch cost. However, PSE proposes to model several portfolio sensititivites and electric price scenarios modeling the SCC as a variable dispatch cost as requested by stakeholders.

PSE models the SCC as a **fixed cost adder** using the following methodology (also described during the July 30th webinar):

1. A long-term capacity expansion (LTCE) model is run to determine portfolio build decisions over the modeling timeframe. Within the LTCE model, the SCC is applied as a penalty to emitting resources (i.e. fossil-fuel fired resources) during each build decision.
    a. The fixed cost adder is calculated as such:
        i. AURORA generates a forecast of dispatch for the economic life of the emitting resource. This dispatch forecast is not impacted by the SCC to simulate real-world dispatch conditions.
        ii. The emissions of this dispatch forecast are summed for the economic life of the emitting resource and the SCC is applied to the total lifetime emissions.
        iii. The lifetime SCC is then applied as fixed cost amortized over the life of the project.
        iv. A new build decision is made based on the total lifetime cost of the resource.
2. The LTCE model results in a portfolio of new builds and retirements. Since the LTCE runs through many simultions a sampling method is used to decrease run, so the final step is to pass the portfolio to the hourly dispatch model, which is capable of modeling dispatch desisions at a much higher time resolution. The hourly dispatch model is not capable of making build decisions, but will more accurately assess total portfolio cost to rate payers. Since the SCC is not a cost passed to rate payers, the SCC is not included as part of this modelling step.

The strengths of this modeling approach include:

- accurate representation of real-world emitting resource dispatch as defined by current regulation
- accurate representation of cost to customers in the build decision
- inclusion of the SCC in all long-term planning build decisions
- distinction between build decisions and dispatch decisions (SCC is not double counted)

The weaknesses of this modeling approach include:

- emissions from thermal resources are not reduced but total portfolio emissions are reduced by less thermal resource builds

Stakeholders have requested that the SCC be included as a **dispatch cost** at all modeling levels. PSE understands this approach as:

1. A long-term capacity expansion (LTCE) model is run to determine portfolio build decisions over the modeling timeframe. Within the LTCE model, the SCC is applied as a penalty to emitting resources duing each build decision as a dispatch cost.
    a. The variable dispatch cost is calculated as such:
        i. AURORA generates a forecast of dispatch for the economic life of the emitting resource. This dispatch forecast is impacted by the SCC which would increase the cost to dispatch the emitting resource, thereby reducing the number of dispatches of the emitting resource.
        ii. The emission costs of this dispatch forecast which already contain the SCC are summed for the economic life of the emitting resource.
        iii. A build decision is made based on the lifetime cost of the resource.
2. The LTCE model results in a portfolio of new builds and retirements. Since the LTCE runs through many simultions a sampling method is used to decrease run, so the final step is to pass the portfolio to the hourly dispatch model, which is capable of modeling dispatch desisions at a much higher time resolution. The hourly dispatch model is not capable of making build decisions, but will more accurately assess total portfolio cost to rate payers. The SCC can either
    a. be included in dispatch decisions to remain consistent with the LTCE model, or
    b. not be included in the hourly dispatch.

The strengths of this modeling approach include:

- inclusion of the SCC in all long-term planning build decisions

The weaknesses of this modeling approach include:

- possible double counting of SCC as both a build and a dispatch decision
- the dispatch of the resources will be optimized to minimize total costs which will result in a change in dispatch that is lower than expected in the real-world
- not reflective of real-world dispatch decisions which can result in a sub-optimal portfolio by underestimating the resource costs
- increased cost to customers

Given the strengths and weaknesses of each modeling approach PSE proposes to model several sensitivities to diagnose the impact of modeling approach on the social cost of carbon. PSE recognizes that there are several variations on these two general approaches and looks forward to discussion with stakeholders on the August 11th webinar to clarify details various sensitivities.

Summary of all updates

PSE appreciates the feedback provided by stakeholders. In summary, the following changes will be implemented into the portfolio model or included in the proposed portfolio sensitivities with stakeholders at the August 11, 2020 webinar:

- Update inflation adjustment of the social cost of carbon consistent with docket U-190730 Order 01 published by the WUTC on July 30, 2020.
- Proposed inclusion of a portfolio sensitivity to model upstream emissions consistent with AR5.
- Proposed inclusion of several portfolio sensitivities to diagnose impacts of various social cost of carbon modeling approached (e.g. cost adder, dispatch cost, externality, tax).

PSE is committed to keeping our stakeholders informed of our progress toward incorportating feedback into the 2021 IRP process.

Webinar 6, August 11, 2020

Portfolio Sensitivities, CETA, Assumptions, and Distributed Energy Resources

PUGET SOUND ENERGY

Webinar #6: Portfolio Sensitivities & CETA Assumptions
August 11, 2020 from 8:30 a.m. to 12:30 p.m. PST

Virtual webinar link: https://global.gotomeeting.com/join/611496333
Access code: 611-496-333
Call-in telephone number (audio only): +1 (669) 224-3412

Topic	Lead
Welcome • Agenda review • Safety moment • How to participate • Speaker introductions	EnviroIssues
Portfolio Sensitivities	Elizabeth Hossner, Manager Resource Planning & Analysis, PSE
5-minute break	
CETA Assumptions	Elizabeth Hossner, Manager Resource Planning & Analysis, PSE
DER Integration	Jens Nedrud, Manager System Planning, PSE Therese Miranda-Blackney, Manager Distributed Energy Resources, PSE Elaine Markham, Manager Meter Technology, PSE
5-minute break	
Consultation Update briefing	Elizabeth Hossner, Manager Resource Planning & Analysis, PSE
Feedback and final Q&A • More participant questions • Using the Feedback Form	Facilitated by EnviroIssues
Wrap up and next steps • Next steps • Upcoming meeting schedule • Thank you's	EnviroIssues

2021 IRP Webinar #6: Portfolio Sensitivities, CETA Assumptions, and Distributed Energy Resources

PUGET SOUND ENERGY

Analyze Alternatives and Portfolios
Electric & Gas Portfolio Model

August 11, 2020

Agenda

- Electric and gas portfolio sensitivities
- Clean Energy Transformation Act (CETA) assumptions
- Distributed energy resources (DER)
- Consultation update: electric price forecast

Safety Moment: Sun Safety

- Ultraviolet (UV) rays from the sun can damage your skin in as little as 15 minutes.
- When outdoors, use sunscreen with an **SPF of 15 or higher** on any exposed skin.
- Be sure to **reapply sunscreen after 2 hours**, after swimming, or after toweling off.
- Sunscreen usually only has a **shelf life of 3 years**.
- You can also reduce sun exposure by staying in the shade, wearing long pants, wearing long sleeves, and wearing a hat.
- **Sunglasses help protect your eyes** from UV rays, reducing the risk of cataracts and protecting the skin around your eyes.
- When hiking, you are exposed to more UV rays at **higher elevation**.
- You are still exposed to UV rays on cloudy or foggy days, so you should still wear sunscreen.

Today’s Speakers

Elizabeth Hossner
Manager Resource Planning & Analysis, PSE

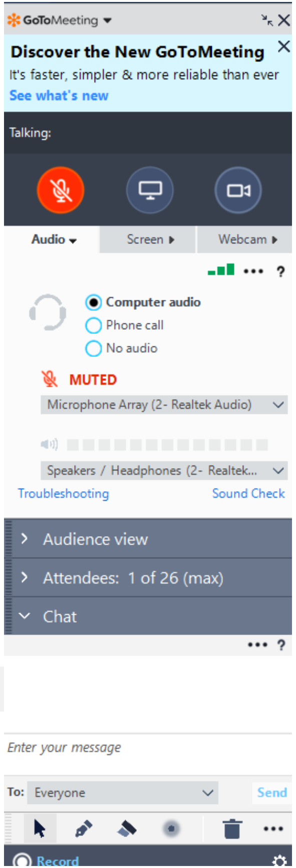
Jens Nedrud
Manager System Planning, PSE

Therese Miranda-Blackney
Manager Distributed Energy Resources, PSE

Elaine Markham
Manager Grid Modernization Strategy and Enablement, PSE

Penny Mabie & Alison Peters
Co-facilitators, EnviroIssues

Welcome to the webinar and thank you for participating!



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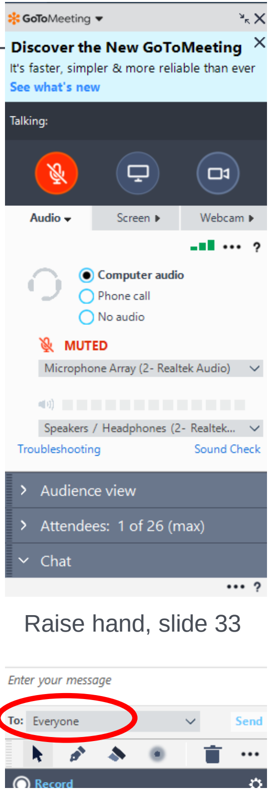
  - **In writing:** your question will be read
  - **Verbally:** type "Raise hand" and slide #, share with "Everyone"; please wait to be called on to ask your question
- Be considerate of others waiting to participate
- We will try to get to all questions



PUGET SOUND ENERGY

Scenarios and Sensitivities

PUGET SOUND ENERGY

Note for the FINAL IRP:
The scenarios and sensitivities detailed in this presentation and the supplemental Excel file prepared for this meeting was updated based on stakeholder
Feedback and the Excel was updated and included in the Final IRP record

Participation Objectives

- PSE will involve stakeholders in planning scenarios and portfolio sensitivities for the 2021 Electric and Gas IRP.

  IAP2 level of participation: INVOLVE

This session is being recorded by Puget Sound Energy. Third-party recording is not permitted.

Portfolio sensitivities overview

- The purpose of a scenario is to create a 20-year electric price forecast.
- The purpose of a portfolio sensitivity is to test how different generating resources, environmental regulations, market conditions, transmission assumptions and other variables change PSE's mix of generating resources to meet electric and gas load.
  - Sensitivities evaluate PSE's place in the market (defined by the 20-year electric price forecast).
- Portfolio sensitivity results are used to inform the forecast of resources to meet the peak capacity, energy and renewable need over the 24-year planning time horizon (2022-2045).
- All portfolio sensitivities will meet the Clean Energy Transformation Act:
  - By 2030: at least 80% of electric sales met by renewable/non-emitting resources
  - By 2045: 100% of electric sales met by renewable/non-emitting resources

Portfolio sensitivities

- PSE will run a set of portfolios using different economic conditions, varying gas prices and demand.
- PSE will then select a reference portfolio to use as the basis to make input changes for each portfolio comparison.
- These changes may include:

Social cost of carbon/CO_2 price	Renewable generation
Demand forecast	Natural gas generation
Gas prices	Energy Storage
Conservation	Transmission constraints/build limits
Demand Response	Market conditions

- Each sensitivity will create a unique set of results to examine how the portfolio changes, such as: generating resource mix, portfolio cost, portfolio emissions, and others.

Key Definitions

- **Scenario** – A consistent set of data assumptions that defines a specific picture of the future; it looks at different economic factors that can change the electric price forecast
- **Sensitivity** - A set of data assumptions based on a reference scenario in which only one input is changed. Used to isolate the effect of a single variable.
- **Power Price** – The wholesale price of power, provided by the Resource Planning team's Electric Price Forecast.
- **Demand** – The demand for electric power and natural gas from PSE's customers.
- **Gas Price** – The price of natural gas (NG), which is used as a fuel in NG generation plants, provided by Wood Mackenzie.
- **CO_2 Price/Regulation** – The price of CO_2 in the model (if applicable), or any other regulation regarding greenhouse gas emissions.
- **RPS/Clean Energy Regulation** – Regulation that dictates the type of generation that must be used to produce electricity.
- **Transmission Build Limits** – Model assumptions about transmission capacity and availability.
- **Market conditions** – This market conditions looks at PSE's connection into the electric power markets

Stakeholder involvement

- PSE would like involvement from stakeholders to create the list of portfolio sensitivities and asks for stakeholders to suggest sensitivities and help to prioritize the analysis.

  1. Are there sensitivities that should be added and/or removed?
  2. Do you have detailed assumptions or criteria that can inform the sensitivities?

- PSE will make best efforts to complete all the requested analysis, however some analysis may take longer than others to complete and it is possible that not everything can be finished to meet the IRP filing date.
  - PSE will start modeling with the highest priority items.

Stakeholder involvement

- The list of sensitivities is the current thinking and includes sensitivities identified so far.
- The list of sensitivities will be finalized after stakeholder involvement is incorporated.
- Multiple sensitivities will be modelled for most themes.
- Details are included in the spreadsheet and on following slides.

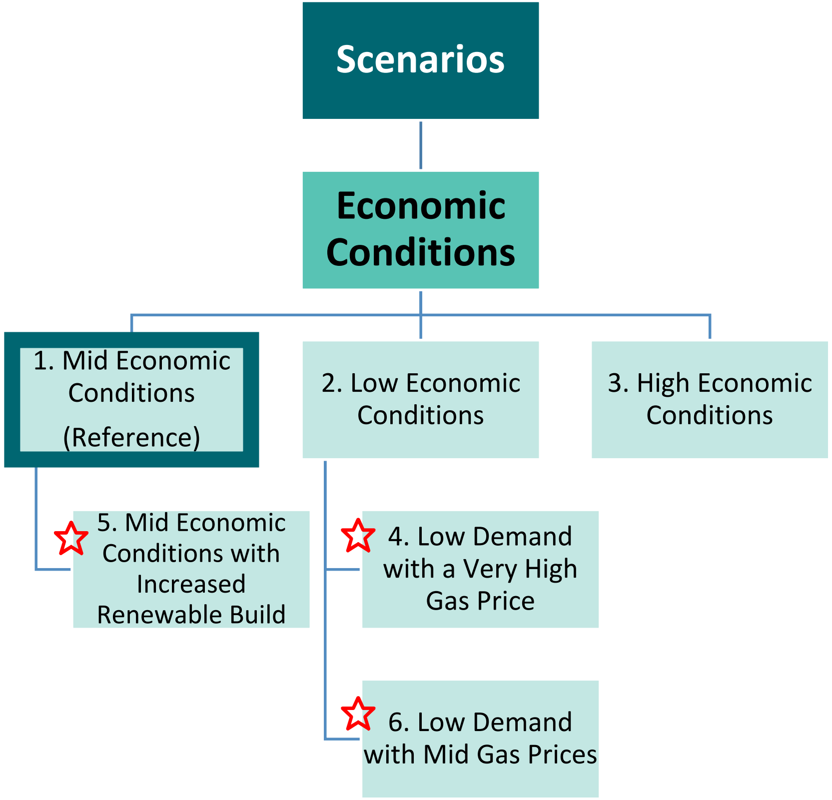
2021 IRP key issues

The following key issues are proposed for analysis:

- Portfolio resources to meet CETA
- Social cost of carbon impact on portfolio modeling
- Conservation impacts from CETA
- Electric vehicle, fuel conversion and temperature impacts on demand forecast
- Early retirement of natural gas generation and switching to alternative fuel sources
- Transmission availability for meeting CETA
- Future market availability

Other issues may be proposed by stakeholders.

Portfolio sensitivities



☆Stakeholder requested

Stakeholder requested

1. Mid Economic Conditions (reference)

Future Market Availability

- 7. Renewable Over-generation Test
- 8. Reduced Market Reliance at Peak

Market Conditions sensitivities help to quantify the effects of the PSE's reliance on power purchases and evaluate possible over generation from renewable resources.

Transmission Constraints and Build Limitations

- 9. Highly Distributed (Tier 1)
- 10. Distributed (Tier 2)
- 11. Highly Centralized (Tier 3)
- 12. Time Delayed
- 13. Firm Transmission as a Percent of Nameplate

Transmission Constrains and Build Limitations sensitivities allow PSE to evaluate the effects on different configurations of transmission capacity on the overall portfolio

Conservation

- 14. 6-yr Ramp Rate
- 15. 8-yr Ramp Rate
- 16. Non-Energy Impacts
- 17. Social Discount Rate for DSR

Conservation sensitivities help to evaluate the effect of different approaches to conservation, including the ramp rate of certain programs, different fiscal models, and what impacts are included in our assessments.

Social Cost of Carbon

- 18. High SCC
- 19. SCC as Dispatch Cost in Portfolio Model Only
- 20. SCC as Dispatch Cost in both Power Price and Portfolio Models
- 21. Modeling AR5 for upstream emissions
- 22. SCC as Fixed Cost, Plus a Federal Carbon Tax
- 23. High Load, SCC as Dispatch Cost in both Power Price and Portfolio Models
- 24. SCC as Tax in WA, OR and CA

Social Cost of Carbon sensitivitie s, including changing the price and application of the SCC, illustrate its effect on the portfolio.

Emissions Reduction

- 25. Biodiesel as a Fuel for Peakers
- 26. No New Gas Generation
- 27. Gas Generation Out by 2045
- 28. Carbon Reduction
- 29. Must-Take DR and Battery Storage

Emissions Reduction sensitivities vary PSE's options in building and operating NG peaker plants, including early retirements and certain emissions-related criteria.

Demand Adjustments

- 30. Fuel Switching for Gas to Electric
- 31. Temperature Sensitivity on Load

Demand Forecast sensitivities make minor adjustments to the demand forecast in order to assess the impact of certain variables, such as temperature and fuel switching rates.

Economic conditions sensitivities

Description	Power Price	Demand	Gas Price	CO_2 price/Regulation	RPS/Clean Energy Regulation
1. Mid economic conditions	Mid	Mid	Mid	2.5% SCC plus upstream natural gas GHG emissions	WA CETA – 80% renewable resources by 2030 and 100% by 2045
2. Low economic conditions	Low	Low	Low	2.5% SCC plus upstream natural gas GHG emissions	WA CETA – 80% renewable resources by 2030 and 100% by 2045
3. High economic conditions	High	High	High	2.5% SCC plus upstream natural gas GHG emissions	WA CETA – 80% renewable resources by 2030 and 100% by 2045

Note: all scenarios include unconstrained transmission (Tier 0), conservation and DR chosen economically, existing natural gas plants allowed to retired economically, and market purchases and sales available up to transmission limit.

PSE PUGET SOUND ENERGY

Economic conditions sensitivities continued

Scenario	Power Prices	Demand	Gas Price	CO_2 price/Regulation	RPS/Clean Energy Regulation
4. Low demand with very high gas price	Low demand + very high gas	Low	Very High	2.5% SCC plus upstream natural gas GHG emissions	WA CETA – 80% renewable resources by 2030 and 100% by 2045
5. Increased Renewable Builds	Mid + increased renewable builds	Mid	Mid	2.5% SCC plus upstream natural gas GHG emissions	WA CETA – 80% renewable resources by 2030 and 100% by 2045, 100% by 2045 in OR plus utility goals
6. Modified low growth	Mid + low demand	Low	Mid	2.5% SCC plus upstream natural gas GHG emissions	WA CETA – 80% renewable resources by 2030 and 100% by 2045

Note: all scenarios include unconstrained transmission (Tier 0), conservation and DR chosen economically, existing natural gas plants allowed to retired economically, and market purchases and sales available up to transmission limit.

PSE PUGET SOUND ENERGY

Future market availability sensitivities

- Market Conditions sensitivities help to quantify the effects of the PSE's reliance on power purchases and evaluate possible over generation from renewable resources.

- The Mid economic conditions is used as the baseline assumptions to make changes.

7. Renewable over generation

- This sensitivity tests for renewable over generation by modeling PSE in isolation

8. Declining market reliance

- This sensitivity reduces the availability of market purchases to meet peak capacity

Distributed generation/transmission constraint sensitivities

- Transmission Constrains and Build Limitations sensitivities allow PSE to evaluate the effects on different configurations of transmission capacity on the overall portfolio

- The Mid economic conditions is used as the baseline assumptions to make changes.

9. Highly Distributed Generation – results in more resources in Western WA
- Tier 1 with increased customer and PSE owned solar PV in Western Washington

10. Distributed Generation – results in more resources in Western WA
- Tier 2 with increased customer and PSE owned solar PV in Western Washington

11. Highly Centralized Generation
- Tier 3 transmission constraint that includes new builds

12. Time delayed transmission constraint
- Time delayed – Tier 1 (2022 – 2025), Tier 2 (2025 – 2030), Tier 3 (2030 – 2035), Tier 0 beyond 2035

13. Firm transmission as a percent of nameplate
- Firm transmission acquired for % of nameplate of renewable resources

4. Conservation sensitivities

- Conservation sensitivities help to evaluate the effect of different approaches to conservation, including the ramp rate of certain programs, different fiscal models, and what impacts are included in our assessments.

- The Mid economic conditions is used as the baseline assumptions to make changes.

14. 6 Year Ramp Rate

- This sensitivity models a 6 year ramp rate for DSR

15. 8 Year Ramp Rate

- This sensitivity models an 8 year ramp rate for DSR

16. Non-Energy Impacts

- This sensitivity includes non-energy impacts

17. Social Discount Rate for DSR

- This sensitivity models a 2.5% social discount rate

Social cost of carbon sensitivities

- Social Cost of Carbon sensitivities, including changing the price and application of the SCC, illustrate its effect on the portfolio.

- The Mid economic conditions is used as the baseline assumptions to make changes.

18. High Social Cost of Carbon

- A higher SCC value that includes upstream emissions

19. SCC as a Dispatch Cost – Portfolio Model Only

- SCC is applied as a dispatch cost to the portfolio model

20. SCC as a Dispatch Cost – Portfolio and Electric Price Models

- SCC is applied as a dispatch cost to the portfolio and electric price models. An updated electric price scenario will be run for this sensitivity

21. Modeling AR5 for upstream emissions

- This sensitivity would model the AR5 report fo upstream emissions instead of the AR4

Social cost of carbon sensitivities continued

- Social Cost of Carbon (SCC) sensitivities, including changing the price and application of the SCC, illustrate its effect on the portfolio.

- The Mid economic conditions is used as the baseline assumptions to make changes.

22. Federal CO_2 Tax

- A federal CO_2 tax of $15/short ton of CO_2 along with the social cost of carbon

23. High Growth and SCC Dispatch Cost

- SCC is applied as a dispatch cost to the portfolio and electric price models. An updated electric price scenario will be run for this sensitivity
- Note: This sensitivity uses the high economic growth and the reference.

24. SCC as a tax in WA, OR, CA

- This sensitivity uses SCC as a CO_2 tax in WA, OR, and CA. An updated electric price scenario will be run for this sensitivity
- Note: This sensitivity can also use the CA carbon price to model a west coast cap & trade. Given that the Mid-C is modeled as one pacific northwest zone, this sensitivity would need to include Idaho and Montana, otherwise there will be leakage into the other states.

6. Emissions reduction resource assumptions sensitivities

- Emissions Reduction sensitivities vary PSE's options in building and operating NG peaker plants, including early retirements and certain emissions-related criteria.

- The Mid economic conditions is used as the baseline assumptions to make changes.

25. Biodiesel as a fuel for peaker plants

- This sensitivity models biodiesel as an option for peaker natural gas plants

26. No new natural gas generation

- This sensitivity models PSE becoming 100% renewable by 2030

27. Natural gas generation out by 2045

- This sensitivity models all natural gas plants retiring by 2045

28. Carbon Reduction

- This sensitivity models a time limitation on any new natural gas builds to limit CO_2 emissions

29. Demand Response and batteries prioritized

- This sensitivity forces the model to maximize demand response and batteries before new natural gas plants are built

7. Demand adjustment sensitivities

- Demand Forecast sensitivities make minor adjustments to the demand forecast in order to assess the impact of certain variables, such as temperature and fuel switching rates.

- The Mid economic conditions is used as the baseline assumptions to make changes.

30. Gas to Electric Conversion

- Demand forecast that includes the electrification of the gas sector

31. Temperature Sensitivity

- Temperature sensitivity demand forecast (increased summer peak)

Stakeholder involvement

- PSE would like involvement from stakeholders to <u>create</u> the list of portfolio sensitivities and asks for stakeholders to suggest sensitivities and <u>help to prioritize</u> the analysis.

  1. Are there sensitivities that should be added and/or removed?
  2. Do you have detailed assumptions or criteria that can inform the sensitivities?

- PSE will make best efforts to complete all the requested analysis, however some analysis may take longer than others to complete and it is possible that not everything can be finished to meet the IRP filing date.
  - PSE will start modeling with the highest priority items.

5-minute Break

CETA: 2030-2045

PUGET SOUND ENERGY

Participation Objectives

- PSE will consult stakeholders on assumptions to use for the alternative compliance as part of the Clean Energy Transformation (Act CETA) for the 2021 Electric IRP.
- PSE will consult with stakeholders about the best way to meet the 20% carbon-neutral method outlined by CETA.

IAP2 level of participation: CONSULT

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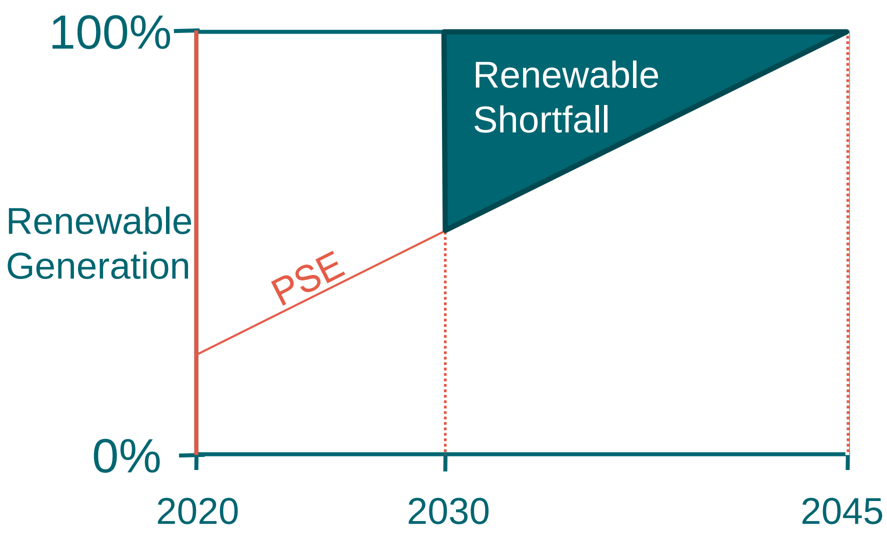
CETA Targets

"With our wealth of carbon-free hydropower, Washington has some of the cleanest electricity in the United States. But electricity remains a large source of emissions in our state. We are at a critical juncture for transforming our electricity system. **It is the policy of the state to eliminate coal-fired electricity, transition the state's electricity supply to one hundred percent carbon-neutral by 2030, and one hundred percent carbon-free by 2045.** In implementing this chapter, the state must prioritize the maximization of family wage job creation, seek to ensure that all customers are benefiting from the transition to a clean energy economy, and provide safeguards to ensure that the achievement of this policy does not impair the reliability of the electricity system or impose unreasonable costs on utility customers."

- CETA Section 1, Subsection 2

Carbon Neutral by 2030, with 80% Renewable Generation

- CETA states that all utilities must be carbon neutral by 2030, and that 80% generation must be renewable.
- CETA provides flexibility with the remaining 20% between the years 2030 and 2045.
- PSE must determine how to best meet the carbon neutral goal until the utility can achieve 100% renewable generation.



Meeting CETA between 2030 and 2045

(b) Through December 31, 2044, an **electric utility may satisfy up to twenty percent of its compliance obligation** under (a) of this subsection **with an alternative compliance** option consistent with this section. An alternative compliance option may include any combination of the following:

(i) **Making an alternative compliance payment** under section 9(2) of this act;

(ii) **Using unbundled renewable energy credits**, provided that there is no double counting of any nonpower attributes associated with renewable energy credits within Washington or programs in other jurisdictions, as follows:

(A) Unbundled renewable energy credits produced from eligible renewable resources, as defined under RCW 19.285.030, which may be used by the electric utility for compliance with RCW 19.285.040 and this section as provided under RCW 19.285.040(2)(e); and

(B) Unbundled renewable energy credits, other than those included in (b)(ii)(A) of this subsection, that represent electricity generated within the compliance period; p. 11 E2SSB 5116.PL

(iii) **Investing in energy transformation projects**, including additional conservation and efficiency resources beyond what is otherwise required under this section, provided the projects meet the requirements of subsection (2) of this section and are not credited as resources used to meet the standard under (a) of this subsection; or

(iv) **Using electricity from an energy recovery facility using municipal solid waste as the principal fuel source**, where the facility was constructed prior to 1992, and the facility is operated in compliance with federal laws and regulations and meets state air quality standards. An electric utility may only use electricity from such an energy recovery facility if the department and the department of ecology determine that electricity generation at the facility provides a net reduction in greenhouse gas emissions compared to any other available waste management best practice. The determination must be based on a life-cycle analysis comparing the energy recovery facility to other technologies available in the jurisdiction in which the facility is located for the waste management best practices of waste reduction, recycling, composting, and minimizing the use of a landfill.

Options for Meeting the Next 20%: Alternative Compliance Payments

- The alternative compliance payment is a base fine of $100 for each MWh of electricity that is not produced by a renewable or non-emitting resource.
  - Coal-fired resources receive a fine of $150/MWh
  - Gas-fired peakers receive a fine of $84/MWh
  - Gas-fired combined-cycle power plants receive a fine of $60/MWh

- These fines are adjusted to inflation every 2 years.

Options for Meeting the Next 20%: Unbundled RECs

- Unbundled Renewable Energy Credits (RECs) are tradeable certificates issued by the EPA that are attached to a single MWh of renewable generation.

- RECs are available nationally, but must correspond to an “eligible period” of generation.

  - For example, PSE could not purchase RECs from 2029 to meet the 2030 CETA requirements.

- “Unbundled” RECs mean that they are sold separately from the electricity that they are tied to.

- What is the price of unbundled RECs?

Options for Meeting the Next 20%: Energy Transformation Projects

- Utilities may also invest in “Energy Transformation Projects” to achieve the “Carbon Neutral” status outlined in CETA
- Energy transformation projects reduce emissions from sectors that are not specifically related to energy production. These reductions can be used to offset emissions from CO_2-generating resources.
- Potential projects include things like:
  - Electrification of the transportation sector (e.g. public transportation, electric vehicles)
  - Investments in hydrogen as a fuel for transportation
  - Distributed Energy resource programs
  - Efficiency and conservation efforts
  - Agricultural emission reduction

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Stakeholder feedback on how PSE should be meeting the 20%

- PSE is seeking feedback from stakeholders if there is any prioritization of the options for the 20% alternative compliance to reach carbon neutral target by 2030 in the 2021 IRP.

- PSE will also analyze a sensitivity to reach 100% renewable resources by 2030 (see Sensitivity 26 No new gas generation)

DER Integration between Delivery System Planning (DSP) and Integrated Resource Planning (IRP)

PUGET SOUND ENERGY

Participation Objectives

- PSE will inform stakeholders on how distributed energy resources are incorporated into the 2021 IRP

IAP2 level of participation: INFORM

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Agenda

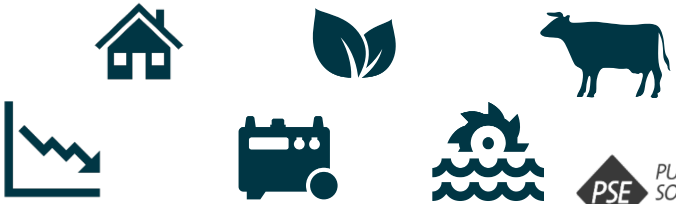
- Distributed Energy Resource (DER) evolution
- Delivery System Planning (DSP) and IRP integration
- DER pilots
- Grid modernization – DER enablement
- DSP Non-wire alternative evaluations
  - Bainbridge example
- DER forecast

Distributed Energy Resources play an important role in PSE's customer future

- Experiencing tremendous change across industry
- Distributed Energy Resources (DERs) solve a resource need
- Non-Wired Alternatives (NWAs) solve a system deficiency and potentially a resource need
- Both are important and can be distribution and/or transmission connected depending upon size / location; either in front or behind the meter
- Non-emitting / renewable
- Sets of technologies used together (such as microgrid) or alone (such as PV)

"Distributed Energy Resources (DERs) and Non-Wire Alternatives (NWAs) are a set of technologies including PV cells, battery storage, fuel cell, wind, thermal, hydro, biogas, cogeneration, compressed air, flywheel, combustion generators, demand response (DR), and energy efficiency"

NY Reform the Energy Vision (REV)



PSE PUGET SOUND ENERGY

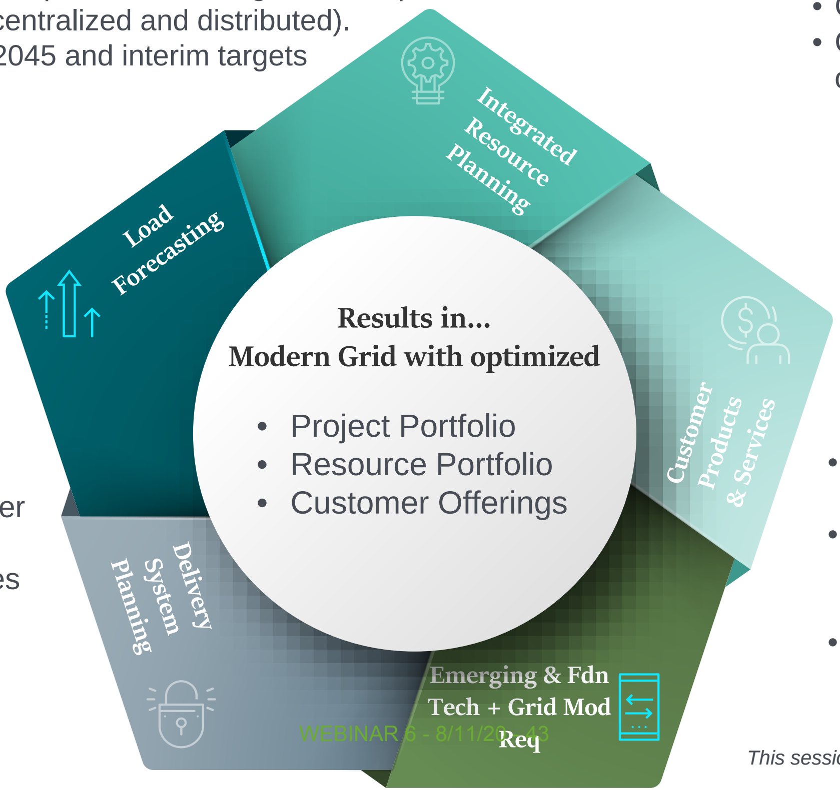
How does it all fit together?

Load Forecasting
- Electricity demand
- System-wide
- Locational
  - End use

Integrated Resource Planning
- Resource portfolio enabling CETA requirements (DER centralized and distributed).
- 2030, 2045 and interim targets

Customer Products & Services
- Customer desires for clean energy
- Customer product and service offerings to:
  - Mitigate upward rate pressure from grid/resource investments
  - Support customer engagement in CETA goals

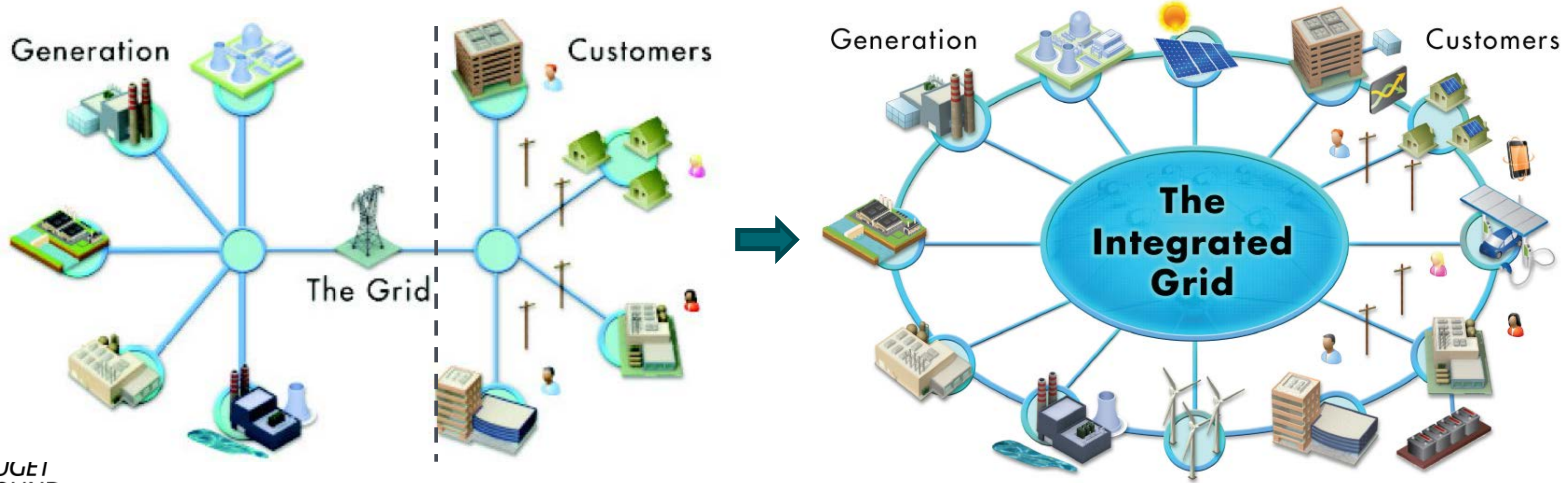
Delivery System Planning
- Infrastructure solutions that:
  - Enable resource portfolio (distributed and centralized)
  - Maintain reliability, resiliency, capacity and power quality
  - Promote customer / stakeholder engagement
  - Consider Non-Wire Alternatives (NWAs)



Emerging & Foundational Technologies + Grid Modernization Requirements
- Smart / flexible capabilities to delivery system
- Systems such as:
  - AMI
  - ADMS
- Pilot technologies such as:
  - Microgrids
  - Storage

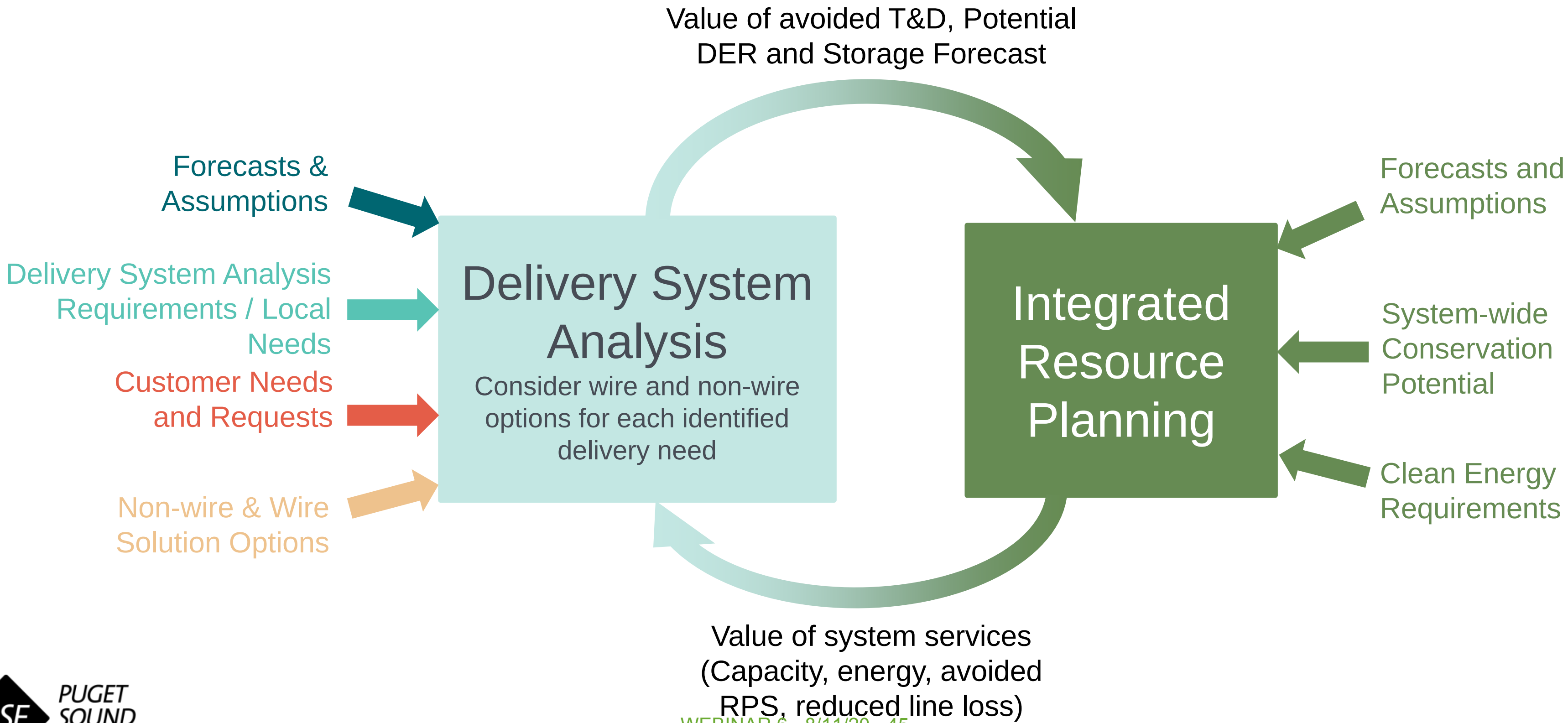
PSE’s IRP and DSP linked closely

- Integrated Resource Planning (IRP) optimizes resources which deliver power to grid.
- Delivery System Planning (DSP) ensures that electricity gets to our customers



Existing grid design – push power to customers
EPRI - 2014

DSP & IRP evolving integration to support DERs

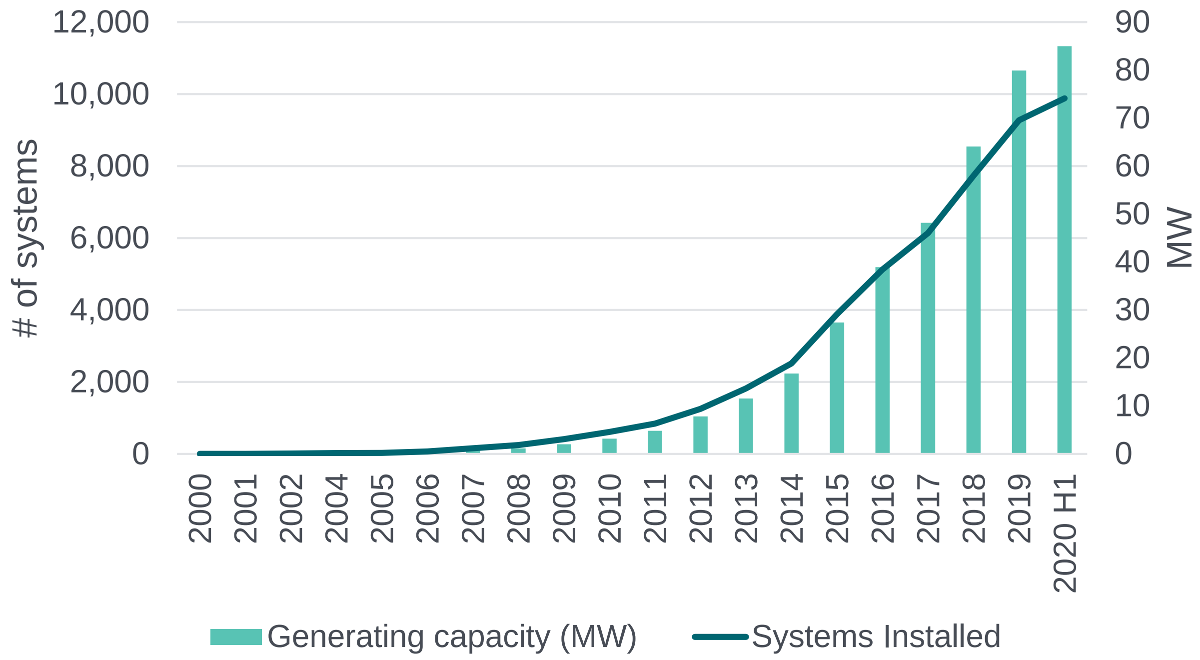


PSE PUGET SOUND ENERGY

Active DERs at PSE today

- Customer connected solar
- Community solar (under development)
- Energy storage

PSE's solar net metering program continues to grow



PUGET SOUND ENERGY

Community solar overview

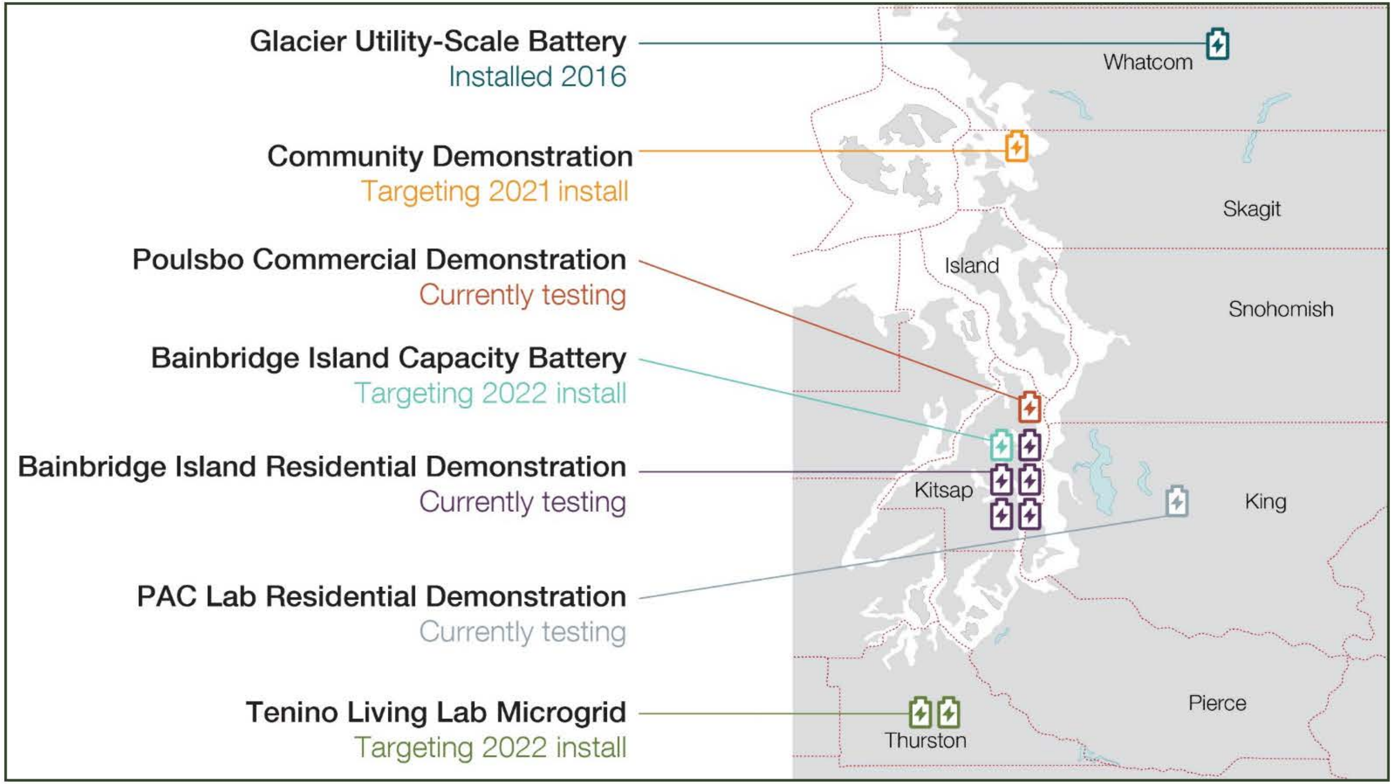
Community solar refers to local solar projects wherein multiple subscribers voluntarily pay a small amount each month and receive credit on their electric bills energy for produced by their share of the project.

Community solar programs can **expand access** to renewable energy to a broader set of customers such as renters, those with shaded roofs, and those who choose not to install a residential system on their home for financial or other reasons.

PRELIMINARY PRODUCT DESIGN

- New, local solar capacity in PSE's electric service territory
- Participants select specific projects to participate in
- Monthly subscription model
- Customers can purchase multiple shares
- Customers sign year-long commitment
- 8-year program length
- Portion of discounted subscriptions dedicated for low-income customers
- Available to residential and commercial customers

PSE’s portfolio of energy storage



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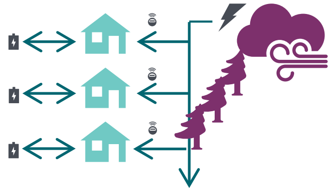
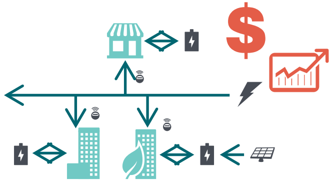
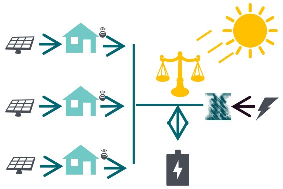
Customer-sited energy storage demos

Project	Primary Use Case	Battery Deployment and Project Scale	On the Grid
1 **Residential Project: Bainbridge Island**	Backup power during grid outage	• Behind-the-Meter (6-units) • Consumer-scale (6kW/15.5kWh) • Proprietary software platform for operation	
2 **Commercial Project: Poulsbo**	Demand (kW) management	• Behind-the-Meter (1-unit) • C&I Building-scale (30kW/183kWh) • Integrated communication and controls	
3 **Community Project: Samish Island**	Balance solar PV backfeed to the grid	• Front-of-Meter (1-unit) • Distribution-scale (~75kW/160kWh) • Controls and grid integration for microgrid	

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Current PSE battery storage projects


Bainbridge Island Residential Demonstration


Bainbridge Island Residential Demonstration

Mobile Battery Trailer


Glacier utility-scale battery

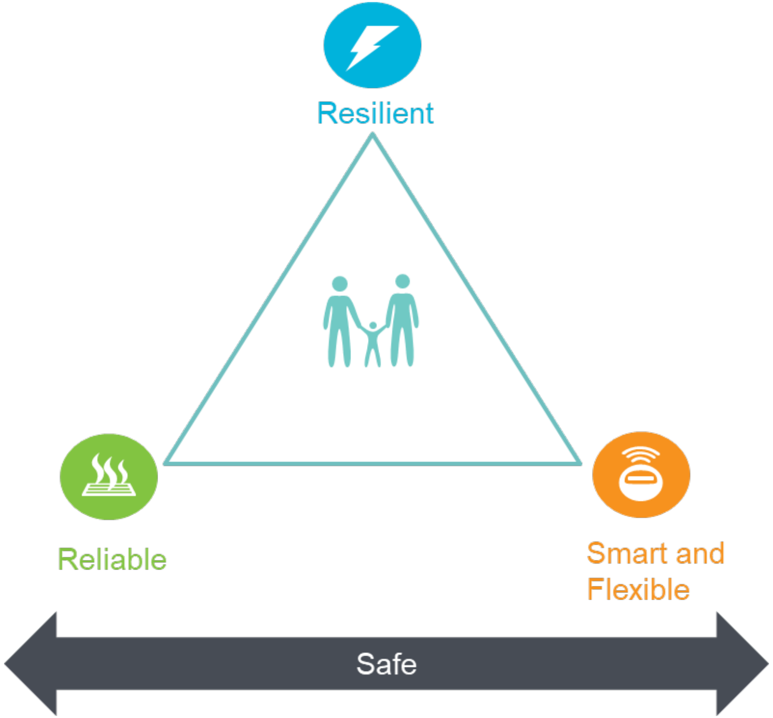

Poulsbo Commercial Demonstration

5-minute Break

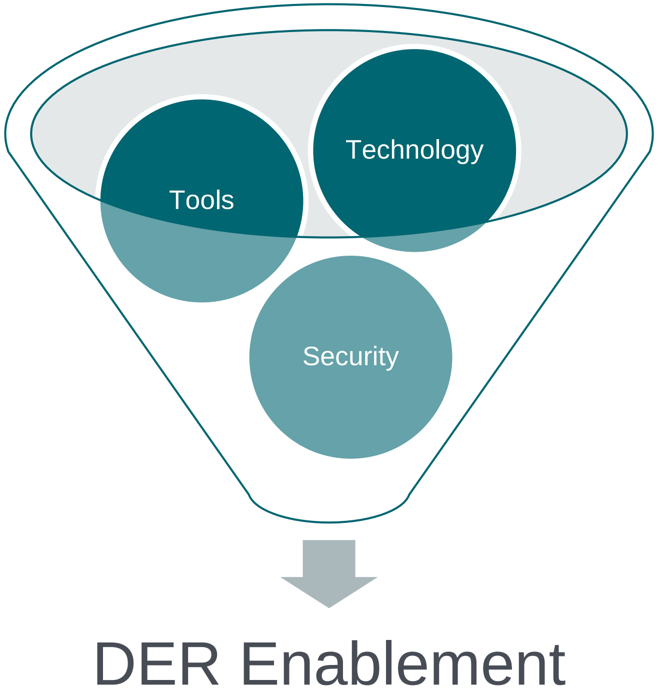
PSE's Grid modernization vision

To meet PSE customer expectations, PSE needs a grid that is

- **Safe** for the public and for those who work around it. Above all, safety continues to be the top priority.
- **Reliable**, with fewer and shorter power outages. When there is an outage, restoration and communication go hand-in-hand until the power is back.
- **Resilient** so that our region recovers quickly from weather extremes and other emergencies.
- **Smart**, utilizing automation and technology to save energy and improve customer satisfaction
- **Flexible**, enabling customers to control their energy on the basis of cost, carbon, or other preferences



PSE invests to support DER enablement



Technology provides enhanced visibility, insight and control – key attributes of a system with more DERs and bi-directional power flow.

Tools support optimal planning and operations, so DERs are sited and operated to minimize costs and maximize benefits.

Security means developing and utilizing standards for DER projects to support a safe, resilient, *and distributed* system.

Technology investments

Advanced Metering Infrastructure (AMI)

- Replaces aging meter technology and provides greater visibility and granularity of usage and operational data
- Enables Customer Programs and Service, Grid Management (ADMS), Planning Tools

Advanced Distribution Management System (ADMS)

- Software platform that coordinates programs impacting our distribution system, allowing us to monitor, manage, and optimize control of everything in real time.
- Enables Distributed Energy Resource Management System (DERMS)

Substation SCADA (Supervisory Control and Data Acquisition)

- Enhances telecommunications infrastructure to remotely monitor and control our substation equipment in real time and transmit key information
- Enables ADMS and DERMS, Predictive Analytics and Maintenance

Tools investments

Geospatial Load Forecasting

In addition to the system and county level forecasts, circuit-level load and DER forecasting will allow PSE to make more precise capital investments to support DER integration. This will result in higher confidence that system improvements are targeted to the highest need areas.

PSE plans to implement Geospatial Load Forecasting in 2021.

Hosting Capacity Analysis

HCA tells us how many DERs can be interconnected at a specific location on the grid without adversely impacting power quality or reliability under existing control and protection systems, and without infrastructure upgrades.

PSE is currently testing hosting capacity analysis tools to develop requirements in anticipation of circuit-level forecasting availability.

PSE PUGET SOUND ENERGY

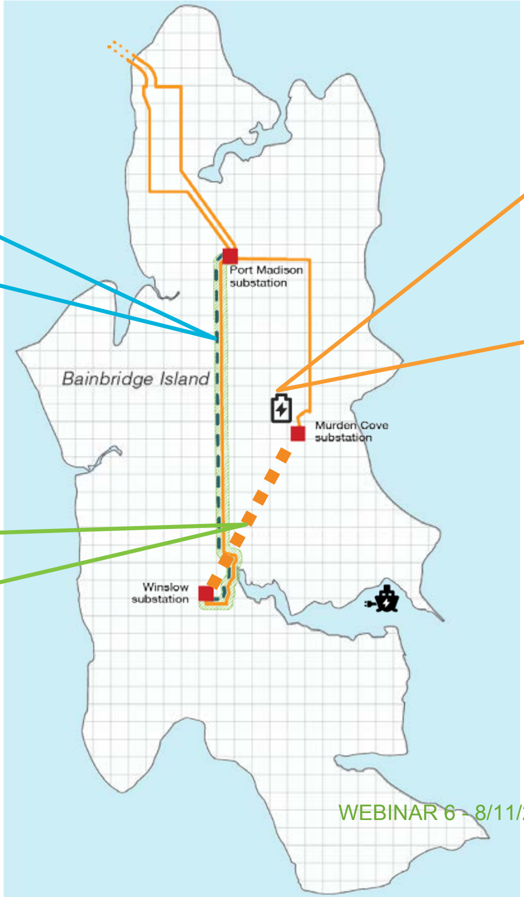
Non-wire Alternative Analysis – Bainbridge Island

Resiliency

Rebuild aging Winslow Tap line

Reliability

Build "missing link" transmission line



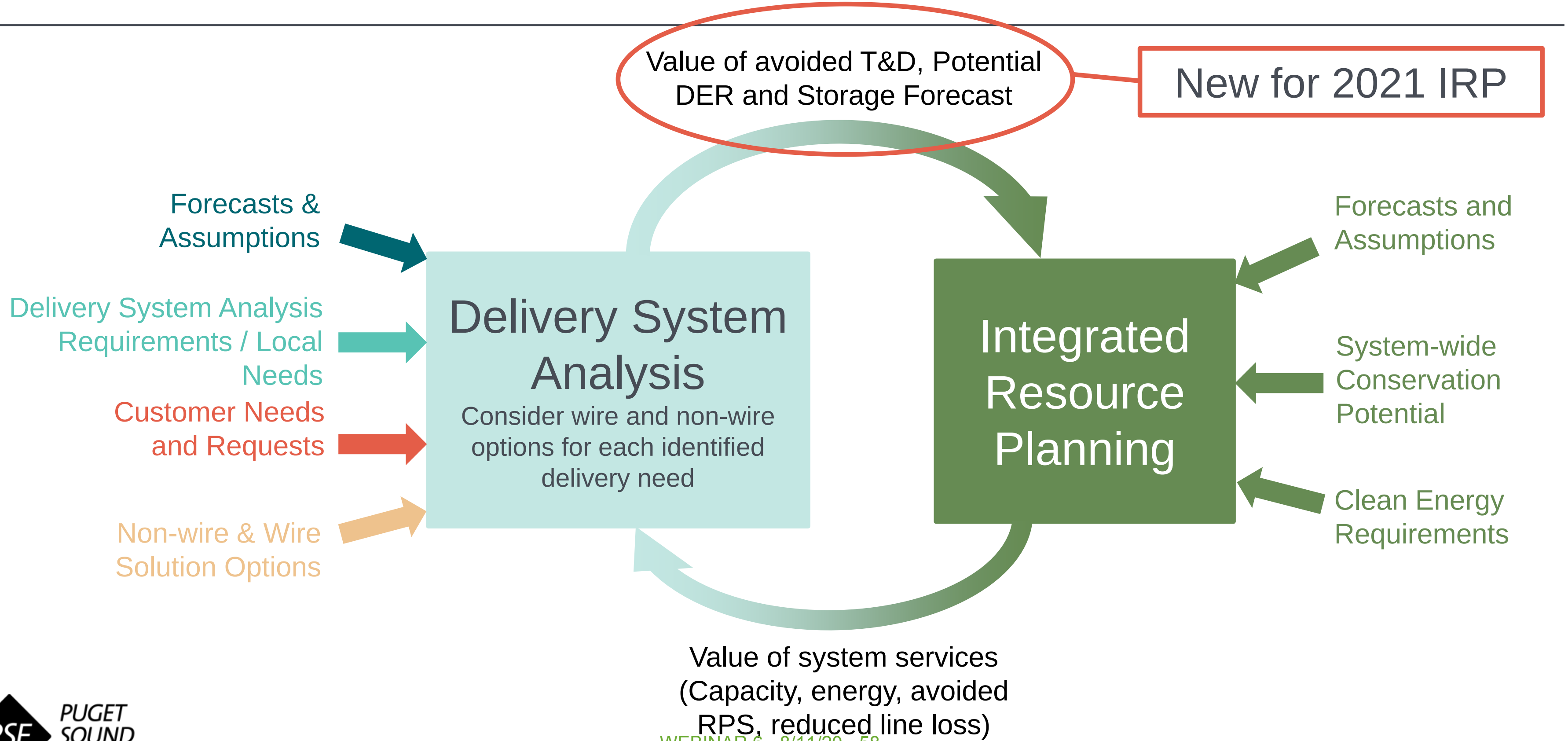
Needs addressed:

- Reliability
- Aging Infrastructure
- Capacity

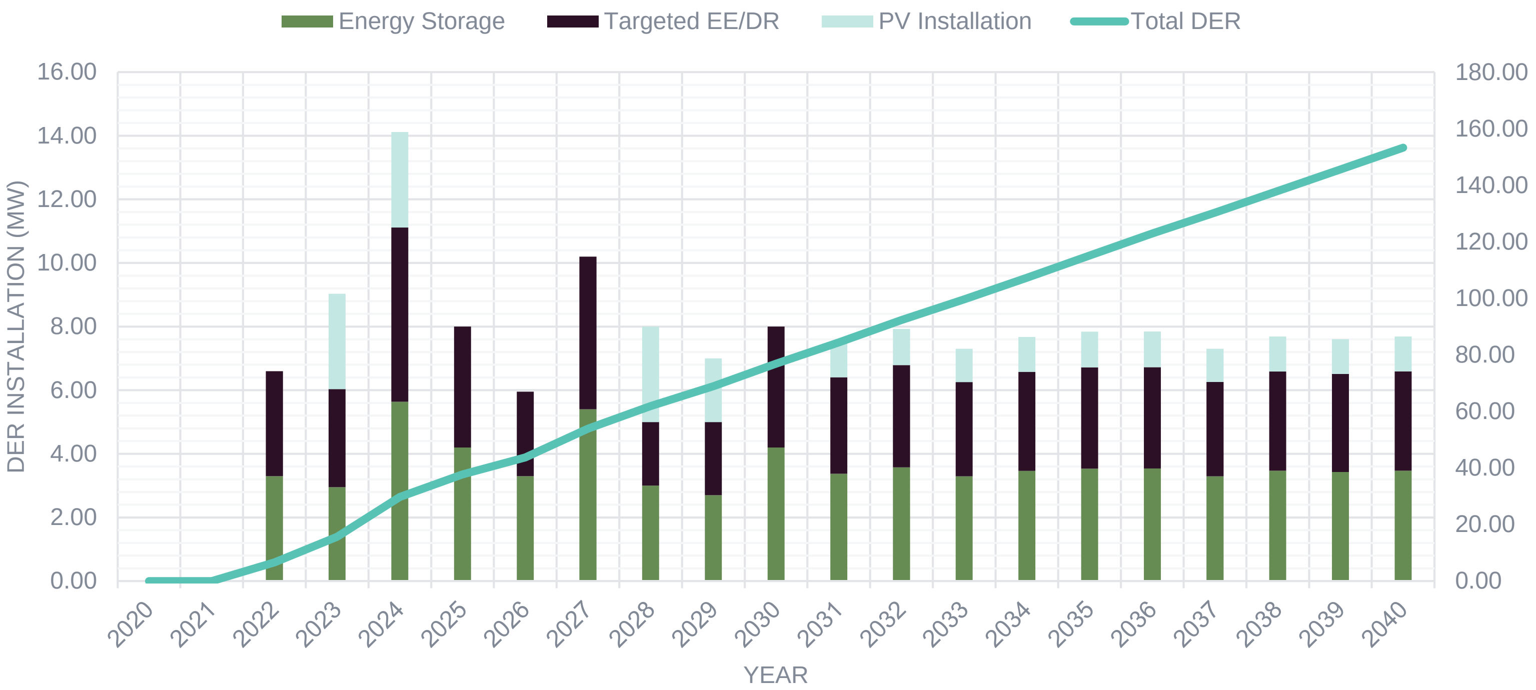
Smart, flexible Battery adds capacity and improves system flexibility

Smart, flexible conservation and demand response tools

DSP & IRP evolving integration to support DERs



DER forecast to address DSP T&D non-wire alternatives



DERs in the IRP

	Behind the Meter Load reduction and / or shaping	Front of the Meter Provide energy and / or capacity
Solar	• Accounted for in CPA • Include sensitivity to cost	• Modeled as a resource type • Some must-take due to summer-peak DSP NWA
Batteries	• Not currently forecasted • Accessibility to PSE depends on program design	• Modeled as a resource type (25 MW 4 hr storage) • Some must-take due to DSP NWA solutions
Demand Response	• Accounted for in CPA • Some must-take due to DSP NWA solutions	• N/A
Energy Efficiency	• Accounted for in CPA • Some must-take due to DSP NWA solutions	• Distribution efficiency accounted for in CPA
Combined Heat & Power (CHP)	• Accounted for in CPA	• N/A

CPA: Conservation Potential Assessment

Consultation update: electric price forecast

Stakeholder feedback included in 2021 IRP electric price forecast

On June 10, 2020 PSE presented the draft electric price forecast and incorporated stakeholder feedback regarding the electric price forecast

1. Regional demand forecast

   PSE received feedback from James Adcock, Kathi Scanlan, WUTC Staff, and Joni Bosh and Fred Heutte, NWEC, concerning PSE's use of the Northwest Power and Conservation Council's (the Council) 7th Power Plan regional demand forecast.

   - PSE contacted the Council and included the demand forecast from the 2019 Policy Update to the 2018 Wholesale Electricity Forecast

2. Washington renewable need

   PSE received feedback from Vlad Gutman-Britten, Climate Solutions, and James Adcock regarding the starting point for the ramp used for Washington state Clean Energy Transformation Act (CETA) requirements.

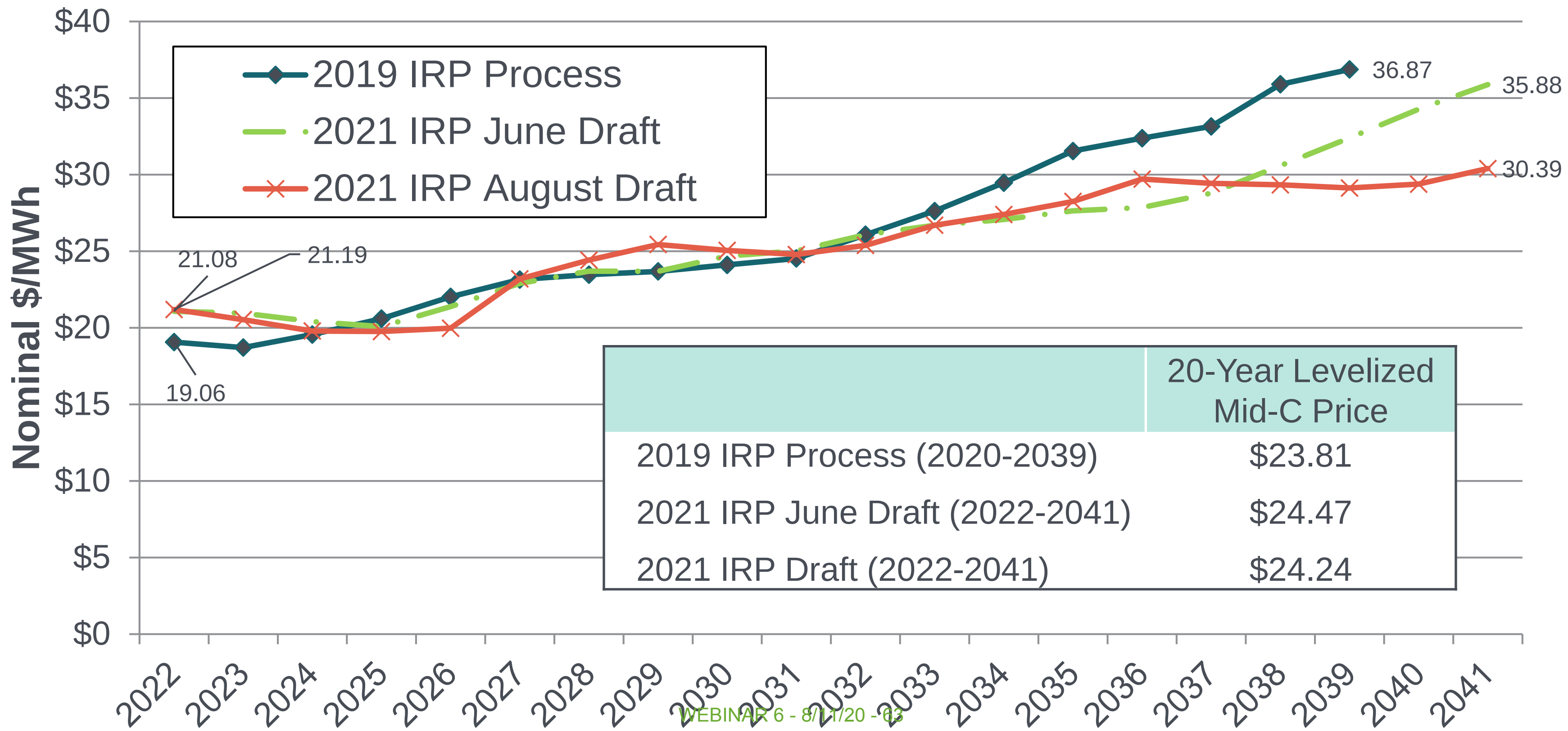
   - PSE updated the Washington renewable need for the updated demand forecast and started the ramp in 2022.

3. Natural gas price forecast

   PSE received feedback from Kathi Scanlan, Washington Utilities and Transportation Commission (WUTC) Staff, requesting the use of an updated gas price forecast to reflect the socioeconomic changes of the COVID-19 pandemic.

   - PSE updated to the most recent natural gas price forecast.

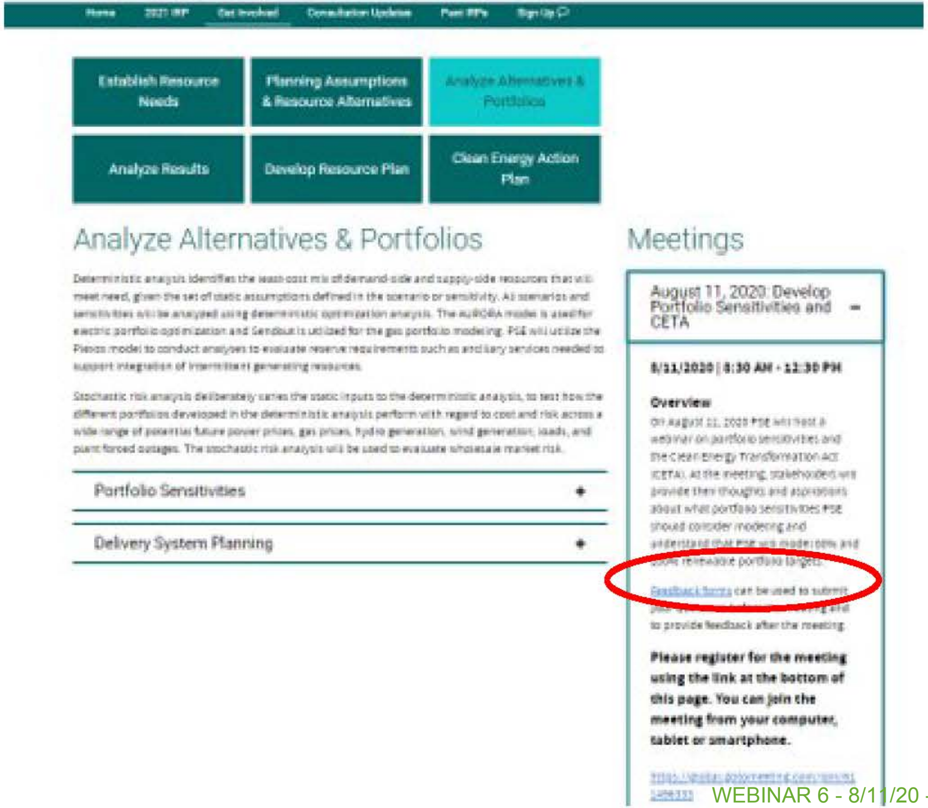
2021 IRP electric price August update

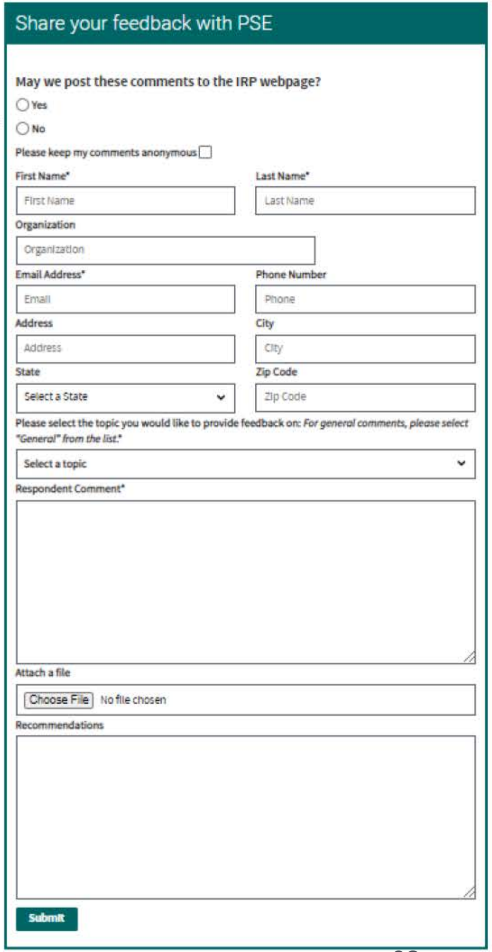


	20-Year Levelized Mid-C Price
2019 IRP Process (2020-2039)	$23.81
2021 IRP June Draft (2022-2041)	$24.47
2021 IRP Draft (2022-2041)	$24.24

Question and Answer

Feedback Form





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Feedback Form

- An important way to share your input
- Available on the website 24/7
- Comments, questions and data can be submitted throughout the year, but timely feedback supports the technical process
- Please submit your Feedback Form within a week of the meeting topic

Feedback Form → **Feedback Report** → **Consultation Update**

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Next steps

- Submit Feedback Form to PSE by **August 18, 2020**
- A recording and the chat from today's webinar will be posted to the website **tomorrow**
- PSE will compile all the feedback in the Feedback Report and post all the questions by **August 25, 2020**
- The Consultation Update will be shared on **September 1**

Details of upcoming meetings can be found at pse.com/irp

Date	Topic
September 1, 1:00 – 5:00 pm	Demand forecast (electric & gas) Resource adequacy Resource need: peak capacity, energy & renewable energy need
October 20, 1:30 – 4:30 pm	Portfolio sensitivities draft results Flexibility analysis
November 4, 1:00 – 4:30 pm	Clean Energy Action Plan 10-year Distribution & Transmission Plan
December 9, 1:00 – 4:30 pm	Portfolio draft results Stochastic analysis Wholesale market risk

Thank you for your attention and input.

Please complete your Feedback Form by August 18, 2020

We look forward to your attendance at PSE's next public participation webinar:
Demand Forecast (Gas and Electric)
Resource Adequacy Analysis
Resource need (Gas and Electric)
September 1, 2020

2021 IRP Webinar #6: Portfolio Sensitivities, CETA Assumptions, and Distributed Energy Resources

PUGET SOUND ENERGY

Analyze Alternatives and Portfolios
Electric & Gas Portfolio Model

August 11, 2020

Agenda

- Electric and gas portfolio sensitivities
- Clean Energy Transformation Act (CETA) assumptions
- Distributed energy resources (DER)
- Consultation update: electric price forecast

Safety Moment: Sun Safety

- Ultraviolet (UV) rays from the sun can damage your skin in as little as 15 minutes.
- When outdoors, use sunscreen with an **SPF of 15 or higher** on any exposed skin.
- Be sure to **reapply sunscreen after 2 hours**, after swimming, or after toweling off.
- Sunscreen usually only has a **shelf life of 3 years**.
- You can also reduce sun exposure by staying in the shade, wearing long pants, wearing long sleeves, and wearing a hat.
- **Sunglasses help protect your eyes** from UV rays, reducing the risk of cataracts and protecting the skin around your eyes.
- When hiking, you are exposed to more UV rays at **higher elevation**.
- You are still exposed to UV rays on cloudy or foggy days, so you should still wear sunscreen.

PSE PUGET SOUND ENERGY

Today’s Speakers

Elizabeth Hossner
Manager Resource Planning & Analysis, PSE

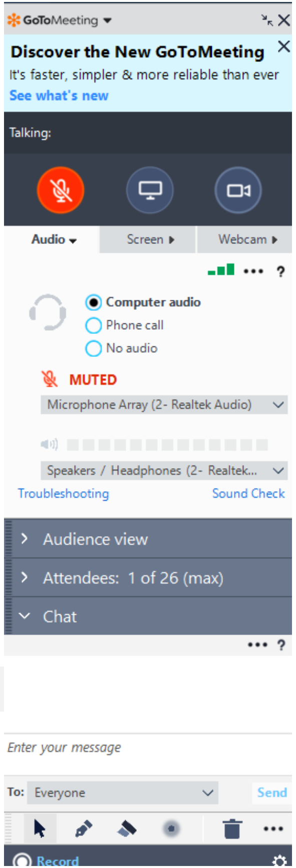
Jens Nedrud
Manager System Planning, PSE

Therese Miranda-Blackney
Manager Distributed Energy Resources, PSE

Elaine Markham
Manager Grid Modernization Strategy and Enablement, PSE

Penny Mabie & Alison Peters
Co-facilitators, EnviroIssues

Welcome to the webinar and thank you for participating!



Virtual webinar link: https://global.gotomeeting.com/join/611496333

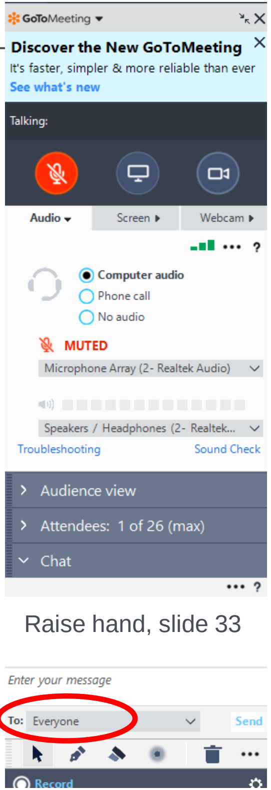
Access Code: 611-496-333

Call-in telephone number: +1 (669) 224-3412

How to participate using Go2Meeting

Presentation Do's

- Mute your mic during the presentation
- You can participate in writing or verbally using the chat window
  - **In writing:** your question will be read
  - **Verbally:** type "Raise hand" and slide #, share with "Everyone"; please wait to be called on to ask your question
- Be considerate of others waiting to participate
- We will try to get to all questions



PUGET SOUND ENERGY

Scenarios and Sensitivities

Participation Objectives

- PSE will involve stakeholders in planning scenarios and portfolio sensitivities for the 2021 Electric and Gas IRP.

  IAP2 level of participation: INVOLVE

Portfolio sensitivities overview

- The purpose of a scenario is to create a 20-year electric price forecast.
- The purpose of a portfolio sensitivity is to test how different generating resources, environmental regulations, market conditions, transmission assumptions and other variables change PSE's mix of generating resources to meet electric and gas load.
  - Sensitivities evaluate PSE's place in the market (defined by the 20-year electric price forecast).
- Portfolio sensitivity results are used to inform the forecast of resources to meet the peak capacity, energy and renewable need over the 24-year planning time horizon (2022-2045).
- All portfolio sensitivities will meet the Clean Energy Transformation Act:
  - By 2030: at least 80% of electric sales met by renewable/non-emitting resources
  - By 2045: 100% of electric sales met by renewable/non-emitting resources

Portfolio sensitivities

- PSE will run a set of portfolios using different economic conditions, varying gas prices and demand.

- PSE will then select a reference portfolio to use as the basis to make input changes for each portfolio comparison.

- These changes may include:

Social cost of carbon/CO_2 price	Renewable generation
Demand forecast	Natural gas generation
Gas prices	Energy Storage
Conservation	Transmission constraints/build limits
Demand Response	Market conditions

- Each sensitivity will create a unique set of results to examine how the portfolio changes, such as: generating resource mix, portfolio cost, portfolio emissions, and others.

Key Definitions

- **Scenario** – A consistent set of data assumptions that defines a specific picture of the future; it looks at different economic factors that can change the electric price forecast
- **Sensitivity -** A set of data assumptions based on a reference scenario in which only one input is changed. Used to isolate the effect of a single variable.
- **Power Price** – The wholesale price of power, provided by the Resource Planning team's Electric Price Forecast.
- **Demand** – The demand for electric power and natural gas from PSE's customers.
- **Gas Price** – The price of natural gas (NG), which is used as a fuel in NG generation plants, provided by Wood Mackenzie.
- **CO_2 Price/Regulation** – The price of CO_2 in the model (if applicable), or any other regulation regarding greenhouse gas emissions.
- **RPS/Clean Energy Regulation** – Regulation that dictates the type of generation that must be used to produce electricity.
- **Transmission Build Limits** – Model assumptions about transmission capacity and availability.
- **Market conditions** – This market conditions looks at PSE's connection into the electric power markets

Stakeholder involvement

- PSE would like involvement from stakeholders to create the list of portfolio sensitivities and asks for stakeholders to suggest sensitivities and help to prioritize the analysis.

  1. Are there sensitivities that should be added and/or removed?
  2. Do you have detailed assumptions or criteria that can inform the sensitivities?

- PSE will make best efforts to complete all the requested analysis, however some analysis may take longer than others to complete and it is possible that not everything can be finished to meet the IRP filing date.
  - PSE will start modeling with the highest priority items.

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Stakeholder involvement

- The list of sensitivities is the current thinking and includes sensitivities identified so far.
- The list of sensitivities will be finalized after stakeholder involvement is incorporated.
- Multiple sensitivities will be modelled for most themes.
- Details are included in the spreadsheet and on following slides.

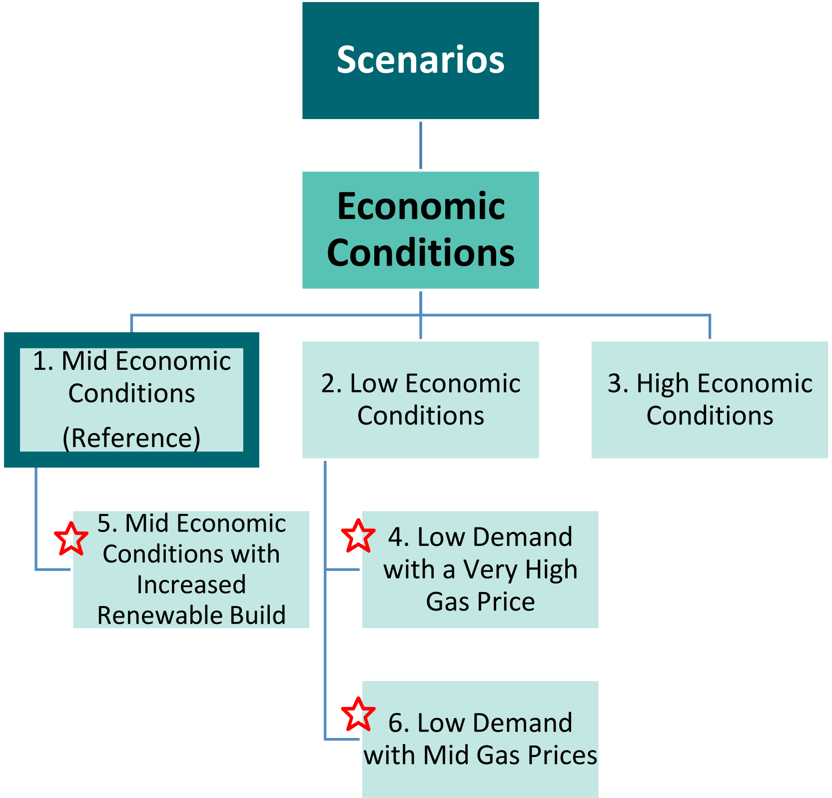
2021 IRP key issues

The following key issues are proposed for analysis:

- Portfolio resources to meet CETA
- Social cost of carbon impact on portfolio modeling
- Conservation impacts from CETA
- Electric vehicle, fuel conversion and temperature impacts on demand forecast
- Early retirement of natural gas generation and switching to alternative fuel sources
- Transmission availability for meeting CETA
- Future market availability

Other issues may be proposed by stakeholders.

Portfolio sensitivities



☆Stakeholder requested

Stakeholder requested

1. Mid Economic Conditions (reference)

Future Market Availability

- 7. Renewable Over-generation Test
- 8. Reduced Market Reliance at Peak

Market Conditions sensitivities help to quantify the effects of the PSE's reliance on power purchases and evaluate possible over generation from renewable resources.

Transmission Constraints and Build Limitations

- 9. Highly Distributed (Tier 1)
- 10. Distributed (Tier 2)
- 11. Highly Centralized (Tier 3)
- 12. Time Delayed
- 13. Firm Transmission as a Percent of Nameplate

Transmission Constrains and Build Limitations sensitivities allow PSE to evaluate the effects on different configurations of transmission capacity on the overall portfolio

Conservation

- 14. 6-yr Ramp Rate
- 15. 8-yr Ramp Rate
- 16. Non-Energy Impacts
- 17. Social Discount Rate for DSR

Conservation sensitivities help to evaluate the effect of different approaches to conservation, including the ramp rate of certain programs, different fiscal models, and what impacts are included in our assessments.

Social Cost of Carbon

- 18. High SCC
- 19. SCC as Dispatch Cost in Portfolio Model Only
- 20. SCC as Dispatch Cost in both Power Price and Portfolio Models
- 21. Modeling AR5 for upstream emissions
- 22. SCC as Fixed Cost, Plus a Federal Carbon Tax
- 23. High Load, SCC as Dispatch Cost in both Power Price and Portfolio Models
- 24. SCC as Tax in WA, OR and CA

Social Cost of Carbon sensitivities, including changing the price and application of the SCC, illustrate its effect on the portfolio.

Emissions Reduction

- 25. Biodiesel as a Fuel for Peakers
- 26. No New Gas Generation
- 27. Gas Generation Out by 2045
- 28. Carbon Reduction
- 29. Must-Take DR and Battery Storage

Emissions Reduction sensitivities vary PSE's options in building and operating NG peaker plants, including early retirements and certain emissions-related criteria.

Demand Adjustments

- 30. Fuel Switching for Gas to Electric
- 31. Temperature Sensitivity on Load

Demand Forecast sensitivities make minor adjustments to the demand forecast in order to assess the impact of certain variables, such as temperature and fuel switching rates.

Economic conditions sensitivities

Description	Power Price	Demand	Gas Price	CO_2 price/Regulation	RPS/Clean Energy Regulation
1. Mid economic conditions	Mid	Mid	Mid	2.5% SCC plus upstream natural gas GHG emissions	WA CETA – 80% renewable resources by 2030 and 100% by 2045
2. Low economic conditions	Low	Low	Low	2.5% SCC plus upstream natural gas GHG emissions	WA CETA – 80% renewable resources by 2030 and 100% by 2045
3. High economic conditions	High	High	High	2.5% SCC plus upstream natural gas GHG emissions	WA CETA – 80% renewable resources by 2030 and 100% by 2045

Note: all scenarios include unconstrained transmission (Tier 0), conservation and DR chosen economically, existing natural gas plants allowed to retired economically, and market purchases and sales available up to transmission limit.

Economic conditions sensitivities continued

Scenario	Power Prices	Demand	Gas Price	CO_2 price/Regulation	RPS/Clean Energy Regulation
4. Low demand with very high gas price	Low demand + very high gas	Low	Very High	2.5% SCC plus upstream natural gas GHG emissions	WA CETA – 80% renewable resources by 2030 and 100% by 2045
5. Increased Renewable Builds	Mid + increased renewable builds	Mid	Mid	2.5% SCC plus upstream natural gas GHG emissions	WA CETA – 80% renewable resources by 2030 and 100% by 2045, 100% by 2045 in OR plus utility goals
6. Modified low growth	Mid + low demand	Low	Mid	2.5% SCC plus upstream natural gas GHG emissions	WA CETA – 80% renewable resources by 2030 and 100% by 2045

Note: all scenarios include unconstrained transmission (Tier 0), conservation and DR chosen economically, existing natural gas plants allowed to retired economically, and market purchases and sales available up to transmission limit.

Future market availability sensitivities

- Market Conditions sensitivities help to quantify the effects of the PSE's reliance on power purchases and evaluate possible over generation from renewable resources.

- The Mid economic conditions is used as the baseline assumptions to make changes.

7. Renewable over generation

- This sensitivity tests for renewable over generation by modeling PSE in isolation

8. Declining market reliance

- This sensitivity reduces the availability of market purchases to meet peak capacity

Distributed generation/transmission constraint sensitivities

- Transmission Constrains and Build Limitations sensitivities allow PSE to evaluate the effects on different configurations of transmission capacity on the overall portfolio

- The Mid economic conditions is used as the baseline assumptions to make changes.

9. Highly Distributed Generation – results in more resources in Western WA
- Tier 1 with increased customer and PSE owned solar PV in Western Washington

10. Distributed Generation – results in more resources in Western WA
- Tier 2 with increased customer and PSE owned solar PV in Western Washington

11. Highly Centralized Generation
- Tier 3 transmission constraint that includes new builds

12. Time delayed transmission constraint
- Time delayed – Tier 1 (2022 – 2025), Tier 2 (2025 – 2030), Tier 3 (2030 – 2035), Tier 0 beyond 2035

13. Firm transmission as a percent of nameplate
- Firm transmission acquired for % of nameplate of renewable resources

4. Conservation sensitivities

- Conservation sensitivities help to evaluate the effect of different approaches to conservation, including the ramp rate of certain programs, different fiscal models, and what impacts are included in our assessments.

- The Mid economic conditions is used as the baseline assumptions to make changes.

14. 6 Year Ramp Rate

- This sensitivity models a 6 year ramp rate for DSR

15. 8 Year Ramp Rate

- This sensitivity models an 8 year ramp rate for DSR

16. Non-Energy Impacts

- This sensitivity includes non-energy impacts

17. Social Discount Rate for DSR

- This sensitivity models a 2.5% social discount rate

Social cost of carbon sensitivities

- Social Cost of Carbon sensitivities, including changing the price and application of the SCC, illustrate its effect on the portfolio.
- The Mid economic conditions is used as the baseline assumptions to make changes.

18. High Social Cost of Carbon

- A higher SCC value that includes upstream emissions

19. SCC as a Dispatch Cost – Portfolio Model Only

- SCC is applied as a dispatch cost to the portfolio model

20. SCC as a Dispatch Cost – Portfolio and Electric Price Models

- SCC is applied as a dispatch cost to the portfolio and electric price models. An updated electric price scenario will be run for this sensitivity

21. Modeling AR5 for upstream emissions

- This sensitivity would model the AR5 report fo upstream emissions instead of the AR4

Social cost of carbon sensitivities continued

- Social Cost of Carbon (SCC) sensitivities, including changing the price and application of the SCC, illustrate its effect on the portfolio.
- The Mid economic conditions is used as the baseline assumptions to make changes.

22. Federal CO_2 Tax

- A federal CO_2 tax of $15/short ton of CO_2 along with the social cost of carbon

23. High Growth and SCC Dispatch Cost

- SCC is applied as a dispatch cost to the portfolio and electric price models. An updated electric price scenario will be run for this sensitivity
- Note: This sensitivity uses the high economic growth and the reference.

24. SCC as a tax in WA, OR, CA

- This sensitivity uses SCC as a CO_2 tax in WA, OR, and CA. An updated electric price scenario will be run for this sensitivity
- Note: This sensitivity can also use the CA carbon price to model a west coast cap & trade. Given that the Mid-C is modeled as one pacific northwest zone, this sensitivity would need to include Idaho and Montana, otherwise there will be leakage into the other states.

6. Emissions reduction resource assumptions sensitivities

- Emissions Reduction sensitivities vary PSE’s options in building and operating NG peaker plants, including early retirements and certain emissions-related criteria.

- The Mid economic conditions is used as the baseline assumptions to make changes.

25. Biodiesel as a fuel for peaker plants

- This sensitivity models biodiesel as an option for peaker natural gas plants

26. No new natural gas generation

- This sensitivity models PSE becoming 100% renewable by 2030

27. Natural gas generation out by 2045

- This sensitivity models all natural gas plants retiring by 2045

28. Carbon Reduction

- This sensitivity models a time limitation on any new natural gas builds to limit CO_2 emissions

29. Demand Response and batteries prioritized

- This sensitivity forces the model to maximize demand response and batteries before new natural gas plants are built

7. Demand adjustment sensitivities

- Demand Forecast sensitivities make minor adjustments to the demand forecast in order to assess the impact of certain variables, such as temperature and fuel switching rates.

- The Mid economic conditions is used as the baseline assumptions to make changes.

30. Gas to Electric Conversion

- Demand forecast that includes the electrification of the gas sector

31. Temperature Sensitivity

- Temperature sensitivity demand forecast (increased summer peak)

Stakeholder involvement

- PSE would like involvement from stakeholders to create the list of portfolio sensitivities and asks for stakeholders to suggest sensitivities and help to prioritize the analysis.

    1. Are there sensitivities that should be added and/or removed?
    2. Do you have detailed assumptions or criteria that can inform the sensitivities?

- PSE will make best efforts to complete all the requested analysis, however some analysis may take longer than others to complete and it is possible that not everything can be finished to meet the IRP filing date.
    - PSE will start modeling with the highest priority items.

5-minute Break

CETA: 2030-2045

Participation Objectives

- PSE will consult stakeholders on assumptions to use for the alternative compliance as part of the Clean Energy Transformation (Act CETA) for the 2021 Electric IRP.

- PSE will consult with stakeholders about the best way to meet the 20% carbon-neutral method outlined by CETA.

IAP2 level of participation: CONSULT

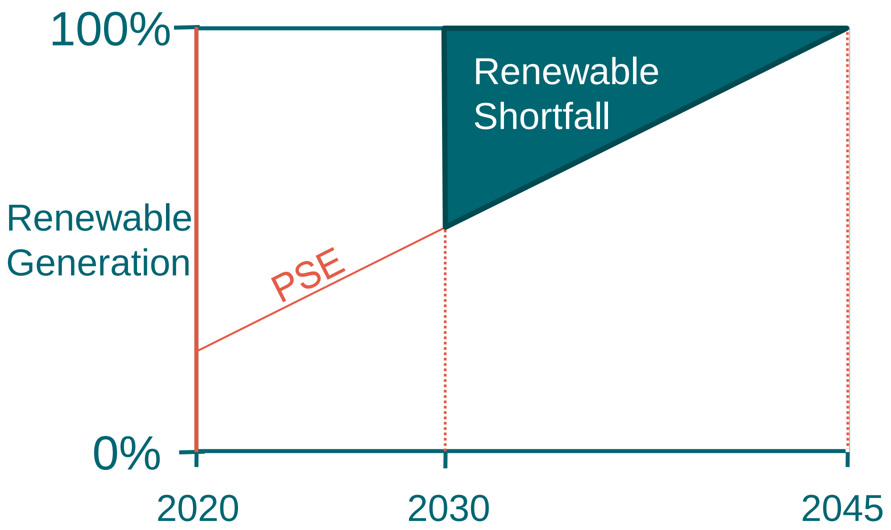
CETA Targets

"With our wealth of carbon-free hydropower, Washington has some of the cleanest electricity in the United States. But electricity remains a large source of emissions in our state. We are at a critical juncture for transforming our electricity system. **It is the policy of the state to eliminate coal-fired electricity, transition the state's electricity supply to one hundred percent carbon-neutral by 2030, and one hundred percent carbon-free by 2045.** In implementing this chapter, the state must prioritize the maximization of family wage job creation, seek to ensure that all customers are benefiting from the transition to a clean energy economy, and provide safeguards to ensure that the achievement of this policy does not impair the reliability of the electricity system or impose unreasonable costs on utility customers."

- CETA Section 1, Subsection 2

Carbon Neutral by 2030, with 80% Renewable Generation

- CETA states that all utilities must be carbon neutral by 2030, and that 80% generation must be renewable.
- CETA provides flexibility with the remaining 20% between the years 2030 and 2045.
- PSE must determine how to best meet the carbon neutral goal until the utility can achieve 100% renewable generation.



Meeting CETA between 2030 and 2045

(b) Through December 31, 2044, an **electric utility may satisfy up to twenty percent of its compliance obligation** under (a) of this subsection **with an alternative compliance** option consistent with this section. An alternative compliance option may include any combination of the following:

(i) **Making an alternative compliance payment** under section 9(2) of this act;

(ii) **Using unbundled renewable energy credits**, provided that there is no double counting of any nonpower attributes associated with renewable energy credits within Washington or programs in other jurisdictions, as follows:

(A) Unbundled renewable energy credits produced from eligible renewable resources, as defined under RCW 19.285.030, which may be used by the electric utility for compliance with RCW 19.285.040 and this section as provided under RCW 19.285.040(2)(e); and

(B) Unbundled renewable energy credits, other than those included in (b)(ii)(A) of this subsection, that represent electricity generated within the compliance period; p. 11 E2SSB 5116.PL

(iii) **Investing in energy transformation projects**, including additional conservation and efficiency resources beyond what is otherwise required under this section, provided the projects meet the requirements of subsection (2) of this section and are not credited as resources used to meet the standard under (a) of this subsection; or

(iv) **Using electricity from an energy recovery facility using municipal solid waste as the principal fuel source**, where the facility was constructed prior to 1992, and the facility is operated in compliance with federal laws and regulations and meets state air quality standards. An electric utility may only use electricity from such an energy recovery facility if the department and the department of ecology determine that electricity generation at the facility provides a net reduction in greenhouse gas emissions compared to any other available waste management best practice. The determination must be based on a life-cycle analysis comparing the energy recovery facility to other technologies available in the jurisdiction in which the facility is located for the waste management best practices of waste reduction, recycling, composting, and minimizing the use of a landfill.

Options for Meeting the Next 20%: Alternative Compliance Payments

- The alternative compliance payment is a base fine of $100 for each MWh of electricity that is not produced by a renewable or non-emitting resource.
  - Coal-fired resources receive a fine of $150/MWh
  - Gas-fired peakers receive a fine of $84/MWh
  - Gas-fired combined-cycle power plants receive a fine of $60/MWh

- These fines are adjusted to inflation every 2 years.

Options for Meeting the Next 20%: Unbundled RECs

- Unbundled Renewable Energy Credits (RECs) are tradeable certificates issued by the EPA that are attached to a single MWh of renewable generation.

- RECs are available nationally, but must correspond to an “eligible period” of generation.

    - For example, PSE could not purchase RECs from 2029 to meet the 2030 CETA requirements.

- “Unbundled” RECs mean that they are sold separately from the electricity that they are tied to.

- What is the price of unbundled RECs?

Options for Meeting the Next 20%: Energy Transformation Projects

- Utilities may also invest in “Energy Transformation Projects” to achieve the “Carbon Neutral” status outlined in CETA

- Energy transformation projects reduce emissions from sectors that are not specifically related to energy production. These reductions can be used to offset emissions from CO_2-generating resources.

- Potential projects include things like:
  - Electrification of the transportation sector (e.g. public transportation, electric vehicles)
  - Investments in hydrogen as a fuel for transportation
  - Distributed Energy resource programs
  - Efficiency and conservation efforts
  - Agricultural emission reduction

Stakeholder feedback on how PSE should be meeting the 20%

- PSE is seeking feedback from stakeholders if there is any prioritization of the options for the 20% alternative compliance to reach carbon neutral target by 2030 in the 2021 IRP.

- PSE will also analyze a sensitivity to reach 100% renewable resources by 2030 (see Sensitivity 26 No new gas generation)

PUGET SOUND ENERGY

DER Integration between Delivery System Planning (DSP) and Integrated Resource Planning (IRP)

PUGET SOUND ENERGY

Participation Objectives

- PSE will inform stakeholders on how distributed energy resources are incorporated into the 2021 IRP

IAP2 level of participation: INFORM

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This session is being recorded by Puget Sound Energy. Third-party recording is not permitted.

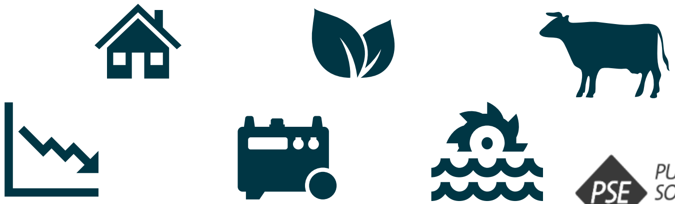
Agenda

- Distributed Energy Resource (DER) evolution
- Delivery System Planning (DSP) and IRP integration
- DER pilots
- Grid modernization – DER enablement
- DSP Non-wire alternative evaluations
  - Bainbridge example
- DER forecast

Distributed Energy Resources play an important role in PSE’s customer future

- Experiencing tremendous change across industry
- Distributed Energy Resources (DERs) solve a resource need
- Non-Wired Alternatives (NWAs) solve a system deficiency and potentially a resource need
- Both are important and can be distribution and/or transmission connected depending upon size / location; either in front or behind the meter
- Non-emitting / renewable
- Sets of technologies used together (such as microgrid) or alone (such as PV)

“Distributed Energy Resources (DERs) and Non-Wire Alternatives (NWAs) are a set of technologies including PV cells, battery storage, fuel cell, wind, thermal, hydro, biogas, cogeneration, compressed air, flywheel, combustion generators, demand response (DR), and energy efficiency”
NY Reform the Energy Vision (REV)



PUGET SOUND ENERGY

How does it all fit together?

Load Forecasting

- Electricity demand
- System-wide
- Locational
  - End use

Integrated Resource Planning

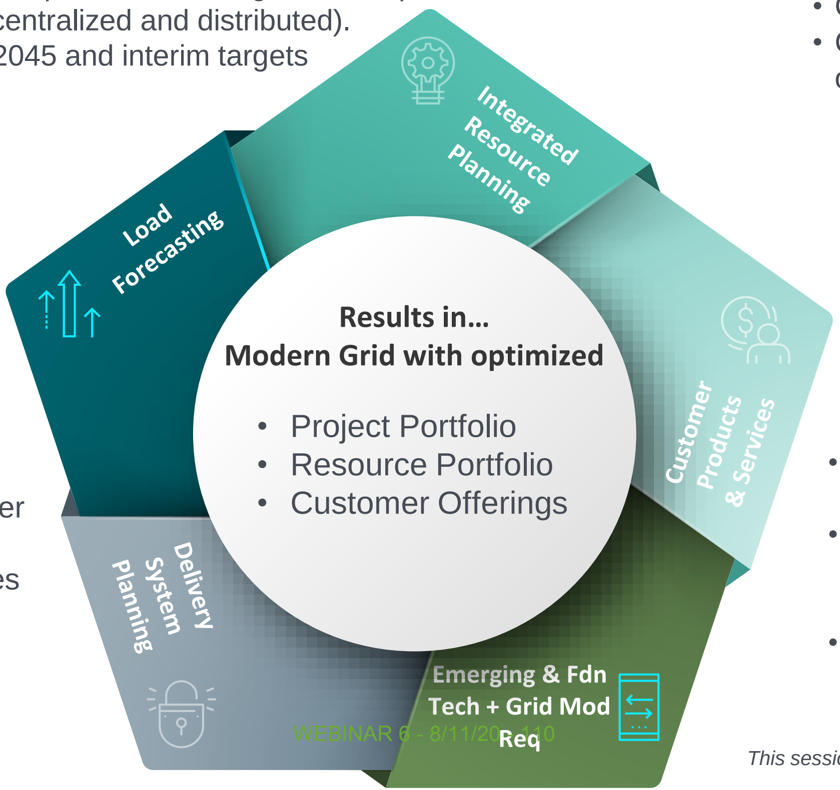
- Resource portfolio enabling CETA requirements (DER centralized and distributed).
- 2030, 2045 and interim targets

Customer Products & Services

- Customer desires for clean energy
- Customer product and service offerings to:
  - Mitigate upward rate pressure from grid/resource investments
  - Support customer engagement in CETA goals

Delivery System Planning

- Infrastructure solutions that:
  - Enable resource portfolio (distributed and centralized)
  - Maintain reliability, resiliency, capacity and power quality
  - Promote customer / stakeholder engagement
  - Consider Non-Wire Alternatives (NWAs)



Emerging & Foundational Technologies + Grid Modernization Requirements

- Smart / flexible capabilities to delivery system
- Systems such as:
  - AMI
  - ADMS
- Pilot technologies such as:
  - Microgrids
  - Storage

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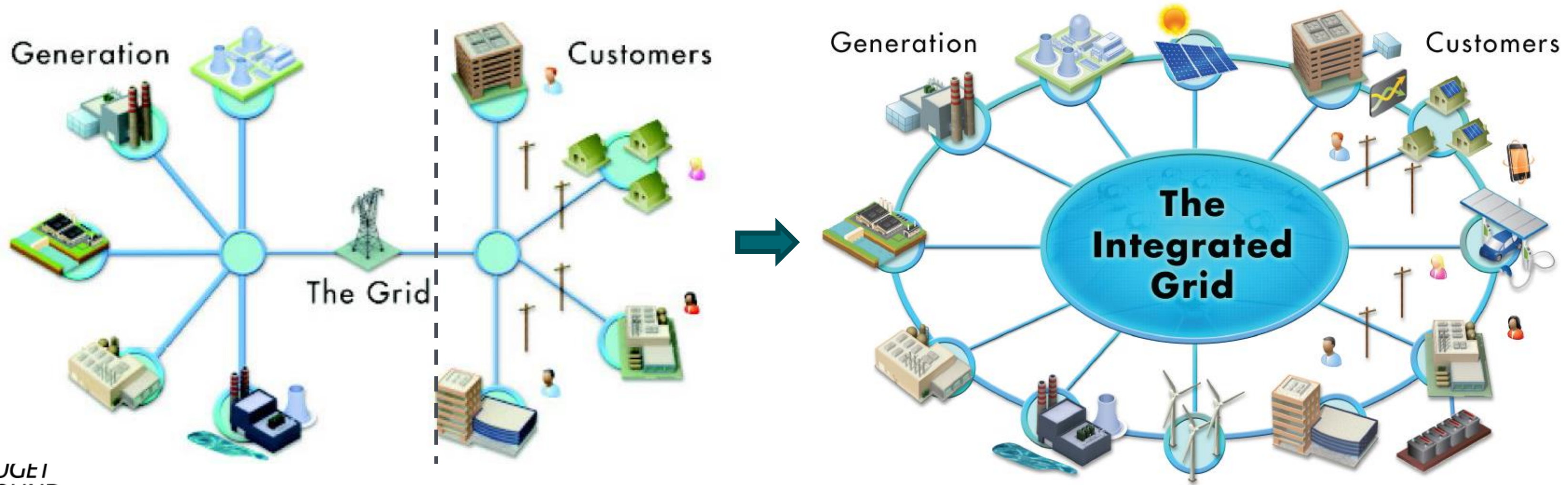
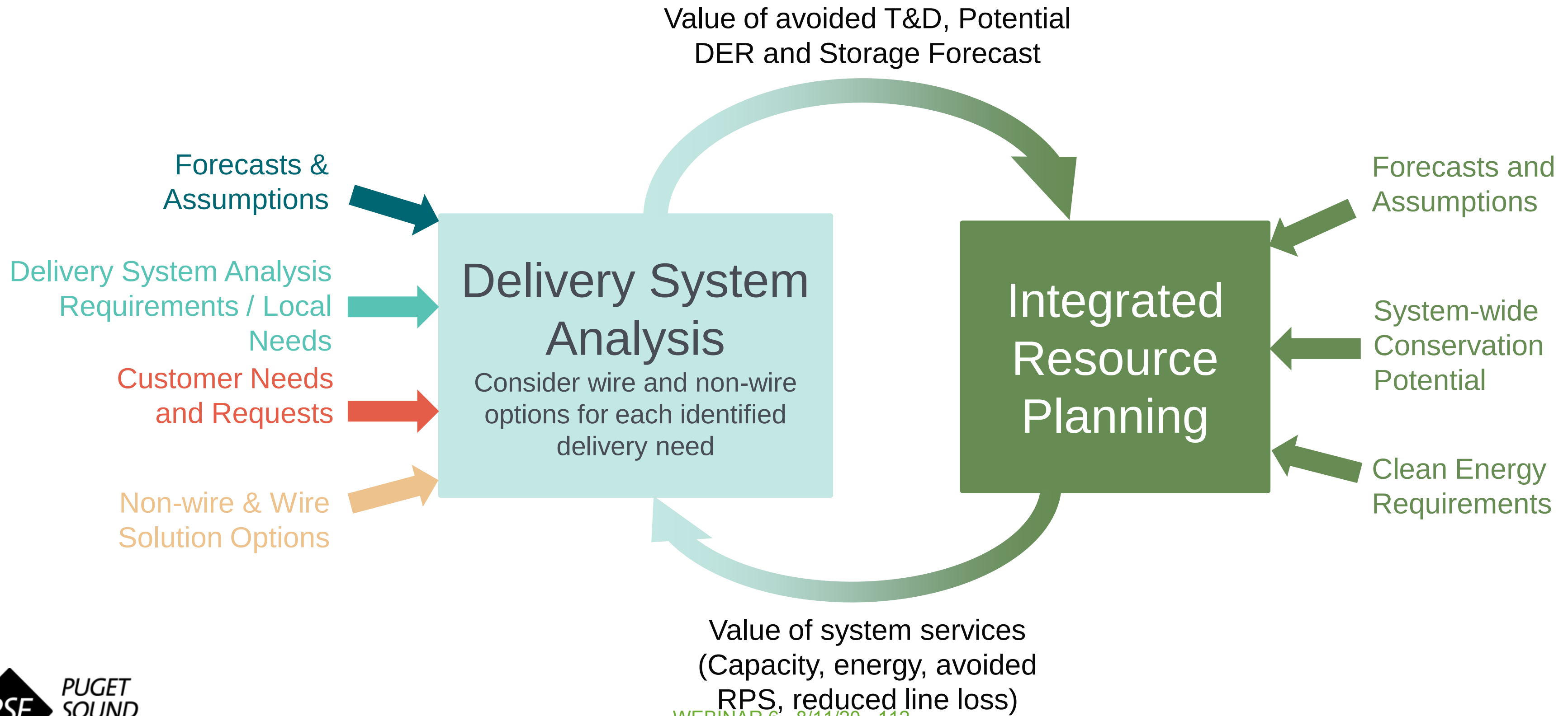
PSE's IRP and DSP linked closely

- Integrated Resource Planning (IRP) optimizes resources which deliver power to grid.
- Delivery System Planning (DSP) ensures that electricity gets to our customers



Existing grid design – push power to customers
EPRI - 2014

DSP & IRP evolving integration to support DERs



Active DERs at PSE today

- Customer connected solar
- Community solar (under development)
- Energy storage

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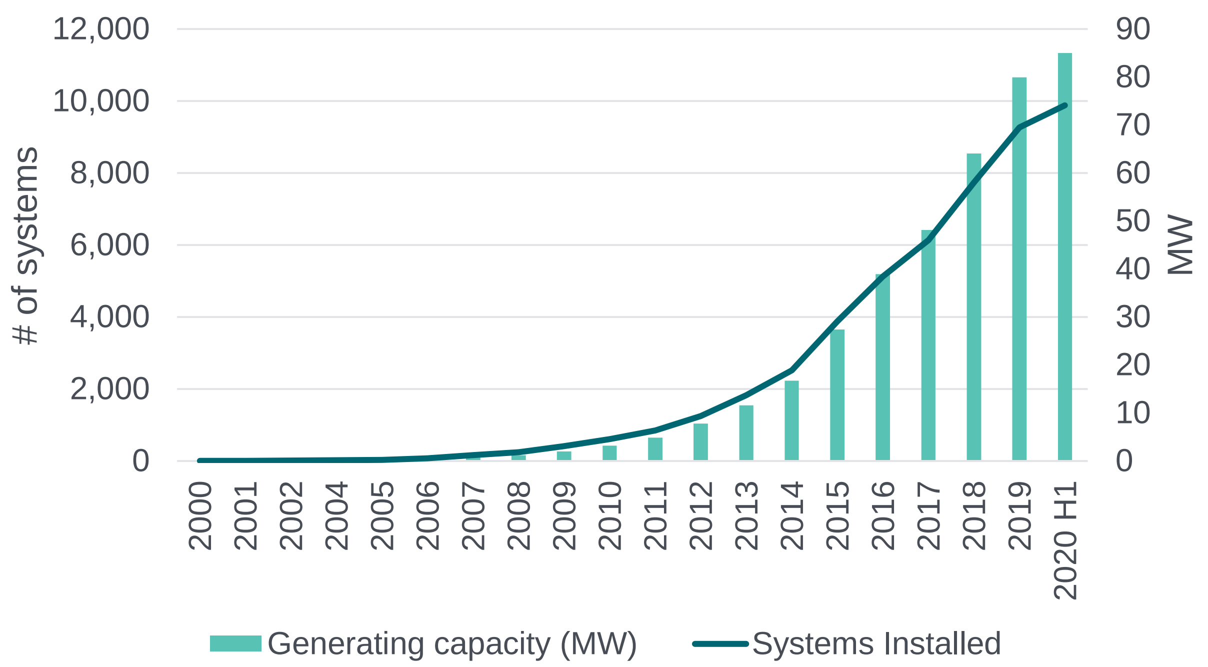
PSE’s solar net metering program continues to grow



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Community solar overview

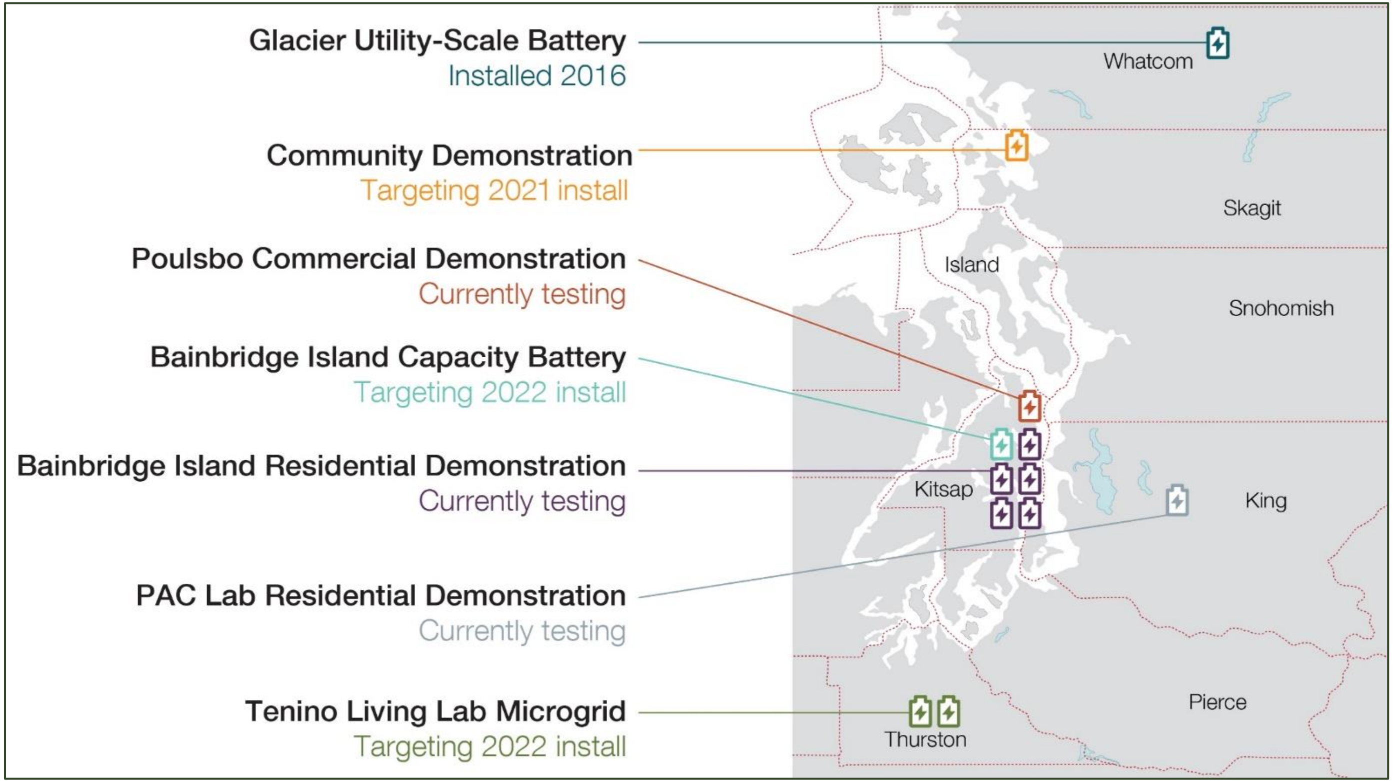
Community solar refers to local solar projects wherein multiple subscribers voluntarily pay a small amount each month and receive credit on their electric bills energy for produced by their share of the project.

Community solar programs can **expand access** to renewable energy to a broader set of customers such as renters, those with shaded roofs, and those who choose not to install a residential system on their home for financial or other reasons.

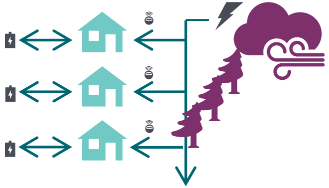
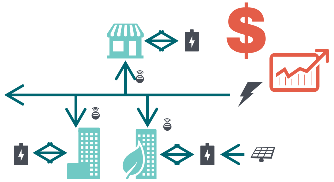
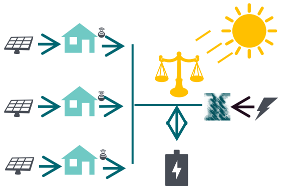
PRELIMINARY PRODUCT DESIGN

- New, local solar capacity in PSE's electric service territory
- Participants select specific projects to participate in
- Monthly subscription model
- Customers can purchase multiple shares
- Customers sign year-long commitment
- 8-year program length
- Portion of discounted subscriptions dedicated for low-income customers
- Available to residential and commercial customers

PSE's portfolio of energy storage



Customer-sited energy storage demos

Project	Primary Use Case	Battery Deployment and Project Scale	On the Grid
1 **Residential Project: Bainbridge Island**	Backup power during grid outage	• Behind-the-Meter (6-units) • Consumer-scale (6kW/15.5kWh) • Proprietary software platform for operation	
2 **Commercial Project: Poulsbo**	Demand (kW) management	• Behind-the-Meter (1-unit) • C&I Building-scale (30kW/183kWh) • Integrated communication and controls	
3 **Community Project: Samish Island**	Balance solar PV backfeed to the grid	• Front-of-Meter (1-unit) • Distribution-scale (~75kW/160kWh) • Controls and grid integration for microgrid	

PUGET SOUND ENERGY

Current PSE battery storage projects


Bainbridge Island Residential Demonstration


Bainbridge Island Residential Demonstration

Mobile Battery Trailer


Glacier utility-scale battery

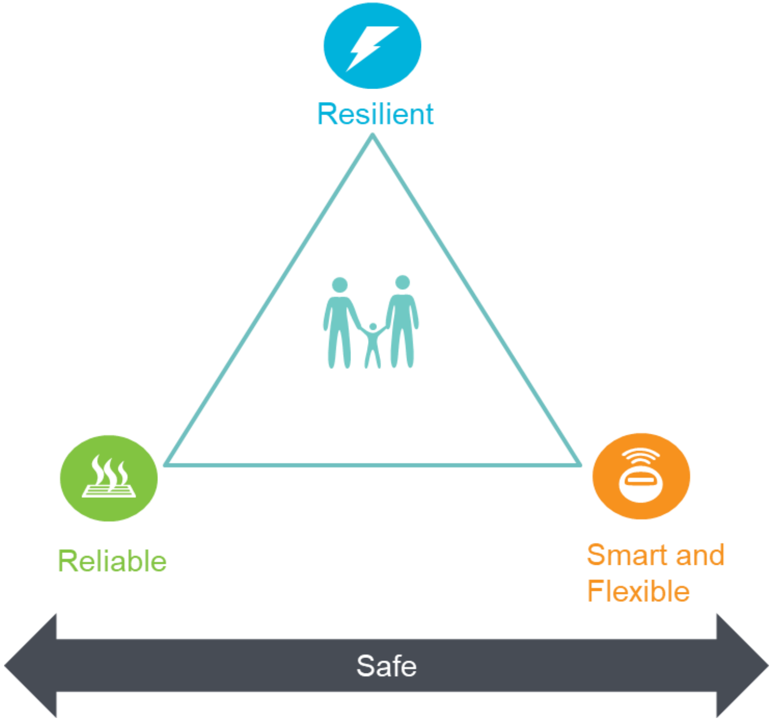

Poulsbo Commercial Demonstration

5-minute Break

PSE’s Grid modernization vision

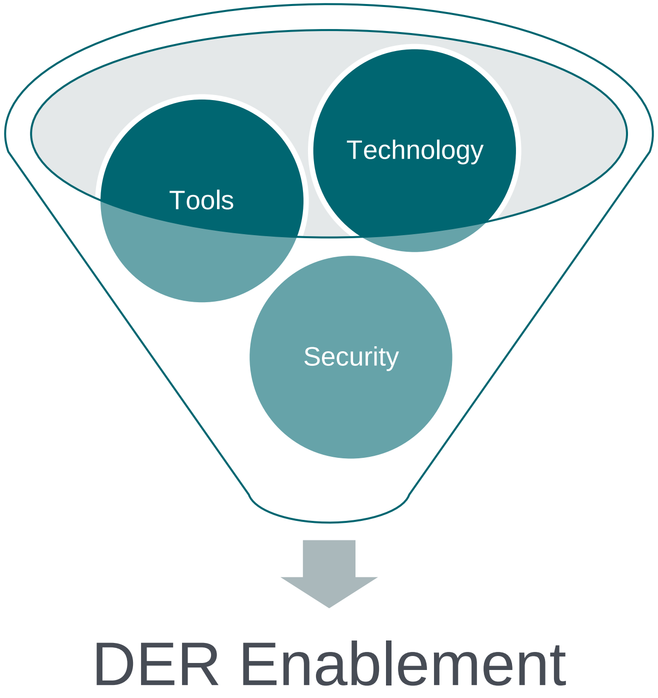
To meet PSE customer expectations, PSE needs a grid that is

- **Safe** for the public and for those who work around it. Above all, safety continues to be the top priority.
- **Reliable**, with fewer and shorter power outages. When there is an outage, restoration and communication go hand-in-hand until the power is back.
- **Resilient** so that our region recovers quickly from weather extremes and other emergencies.
- **Smart**, utilizing automation and technology to save energy and improve customer satisfaction
- **Flexible**, enabling customers to control their energy on the basis of cost, carbon, or other preferences



PUGET SOUND ENERGY

PSE invests to support DER enablement



Technology provides enhanced visibility, insight and control – key attributes of a system with more DERs and bi-directional power flow.

Tools support optimal planning and operations, so DERs are sited and operated to minimize costs and maximize benefits.

Security means developing and utilizing standards for DER projects to support a safe, resilient, *and distributed* system.

Technology investments

Advanced Metering Infrastructure (AMI)

- Replaces aging meter technology and provides greater visibility and granularity of usage and operational data
- Enables Customer Programs and Service, Grid Management (ADMS), Planning Tools

Advanced Distribution Management System (ADMS)

- Software platform that coordinates programs impacting our distribution system, allowing us to monitor, manage, and optimize control of everything in real time.
- Enables Distributed Energy Resource Management System (DERMS)

Substation SCADA (Supervisory Control and Data Acquisition)

- Enhances telecommunications infrastructure to remotely monitor and control our substation equipment in real time and transmit key information
- Enables ADMS and DERMS, Predictive Analytics and Maintenance

Tools investments

Geospatial Load Forecasting

In addition to the system and county level forecasts, circuit-level load and DER forecasting will allow PSE to make more precise capital investments to support DER integration. This will result in higher confidence that system improvements are targeted to the highest need areas.

PSE plans to implement Geospatial Load Forecasting in 2021.

Hosting Capacity Analysis

HCA tells us how many DERs can be interconnected at a specific location on the grid without adversely impacting power quality or reliability under existing control and protection systems, and without infrastructure upgrades.

PSE is currently testing hosting capacity analysis tools to develop requirements in anticipation of circuit-level forecasting availability.

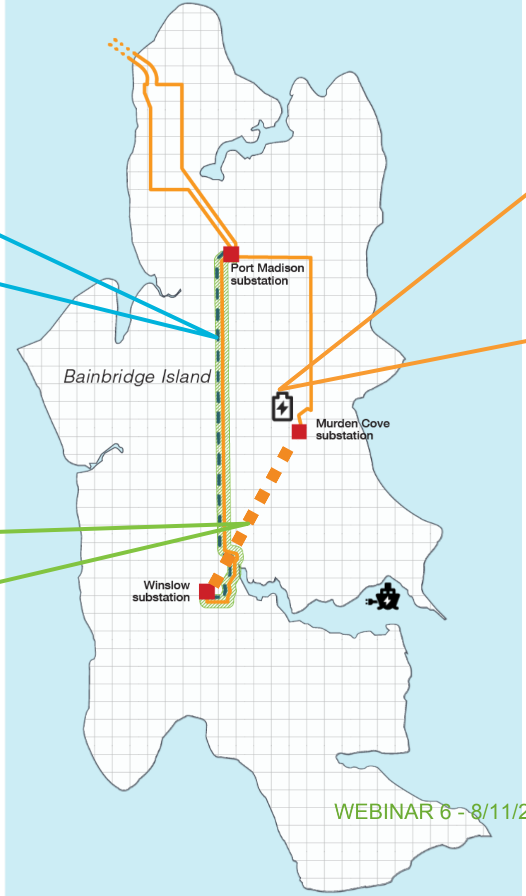
Non-wire Alternative Analysis – Bainbridge Island

Resiliency

Rebuild aging Winslow Tap line

Reliability

Build "missing link" transmission line



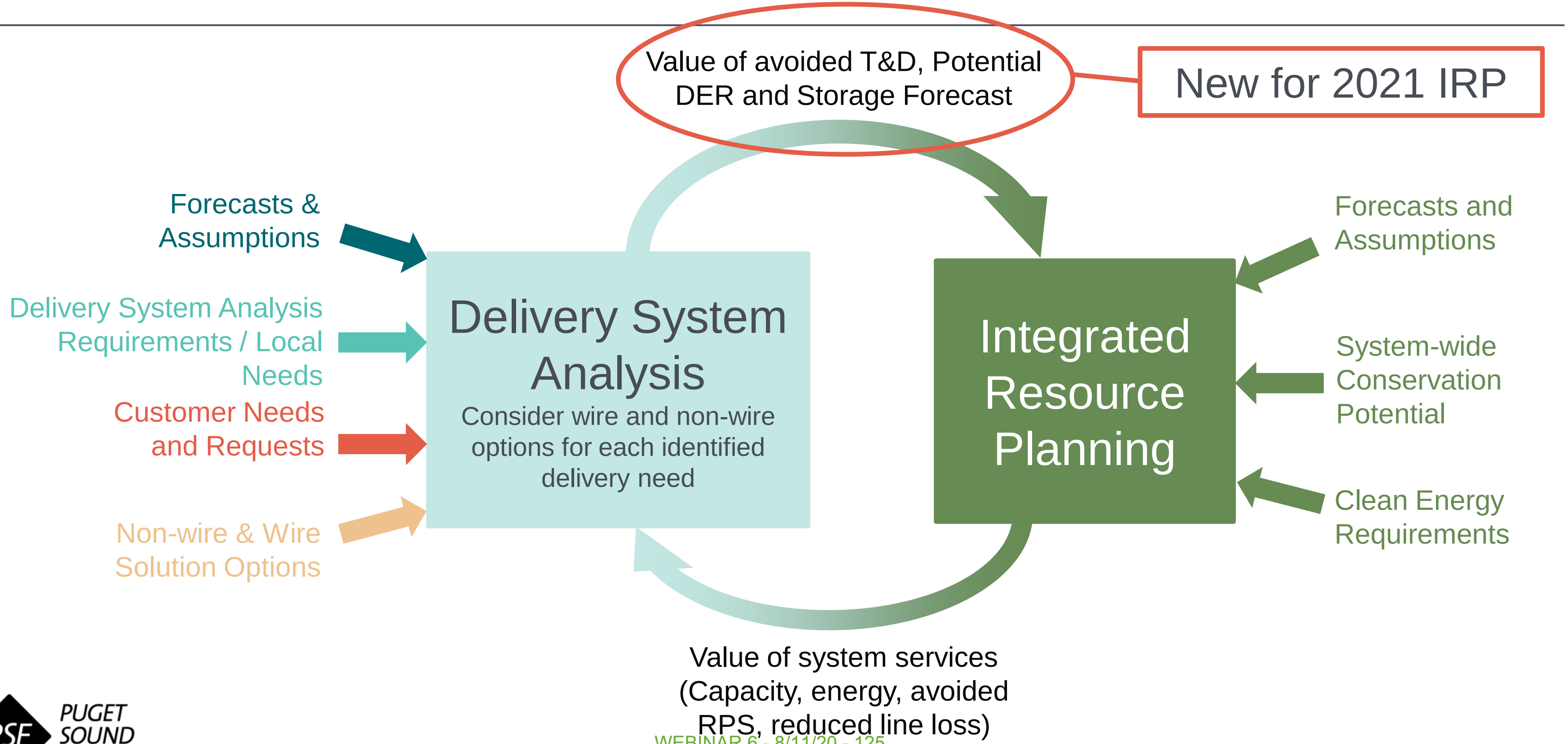
Smart, flexible Battery adds capacity and improves system flexibility

Smart, flexible conservation and demand response tools

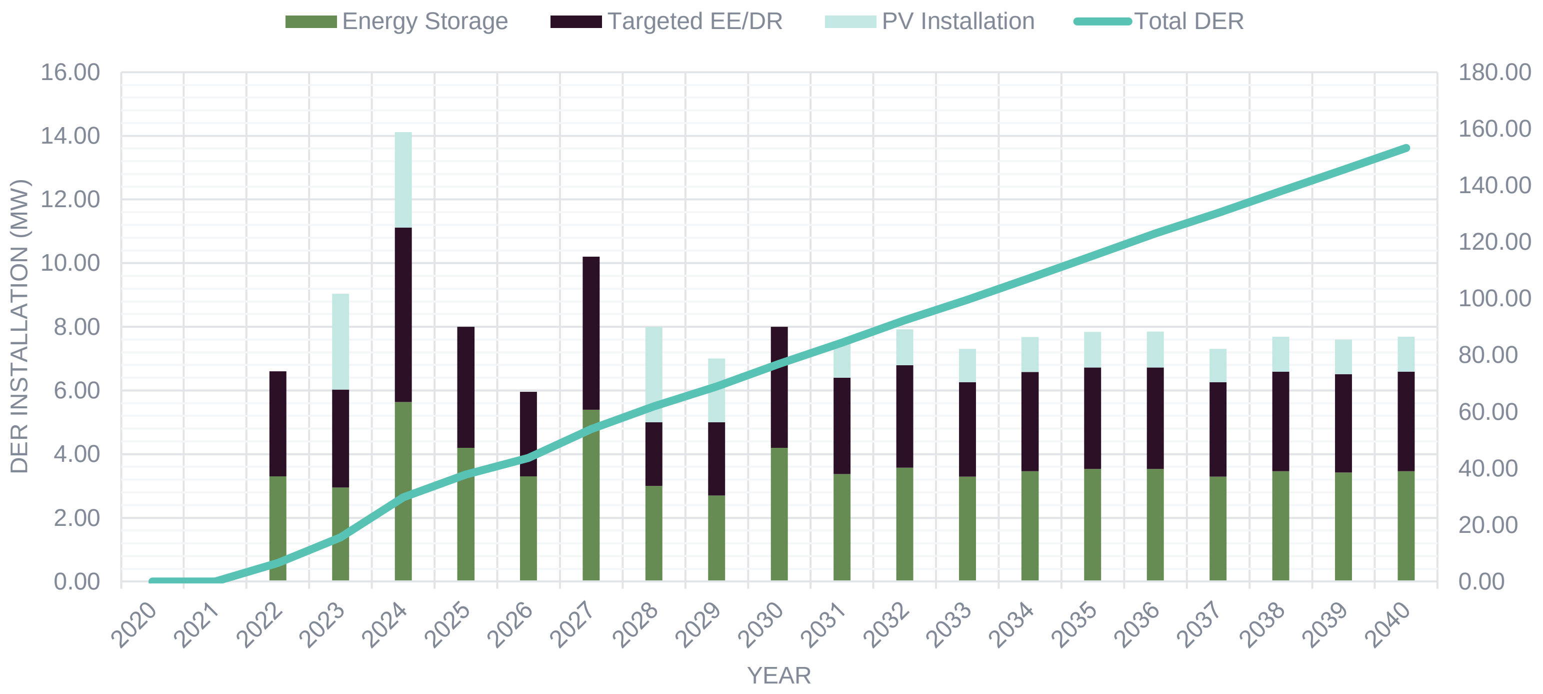
Needs addressed:

- Reliability
- Aging Infrastructure
- Capacity

DSP & IRP evolving integration to support DERs



DER forecast to address DSP T&D non-wire alternatives



DERs in the IRP

	Behind the Meter Load reduction and / or shaping	Front of the Meter Provide energy and / or capacity
Solar	• Accounted for in CPA • Include sensitivity to cost	• Modeled as a resource type • Some must-take due to summer-peak DSP NWA
Batteries	• Not currently forecasted • Accessibility to PSE depends on program design	• Modeled as a resource type (25 MW 4 hr storage) • Some must-take due to DSP NWA solutions
Demand Response	• Accounted for in CPA • Some must-take due to DSP NWA solutions	• N/A
Energy Efficiency	• Accounted for in CPA • Some must-take due to DSP NWA solutions	• Distribution efficiency accounted for in CPA
Combined Heat & Power (CHP)	• Accounted for in CPA	• N/A

CPA: Conservation Potential Assessment

Consultation update: electric price forecast

PUGET SOUND ENERGY

Stakeholder feedback included in 2021 IRP electric price forecast

On June 10, 2020 PSE presented the draft electric price forecast and incorporated stakeholder feedback regarding the electric price forecast

1. Regional demand forecast

   PSE received feedback from James Adcock, Kathi Scanlan, WUTC Staff, and Joni Bosh and Fred Heutte, NWEC, concerning PSE's use of the Northwest Power and Conservation Council's (the Council) 7th Power Plan regional demand forecast.

   - PSE contacted the Council and included the demand forecast from the 2019 Policy Update to the 2018 Wholesale Electricity Forecast

2. Washington renewable need

   PSE received feedback from Vlad Gutman-Britten, Climate Solutions, and James Adcock regarding the starting point for the ramp used for Washington state Clean Energy Transformation Act (CETA) requirements.

   - PSE updated the Washington renewable need for the updated demand forecast and started the ramp in 2022.

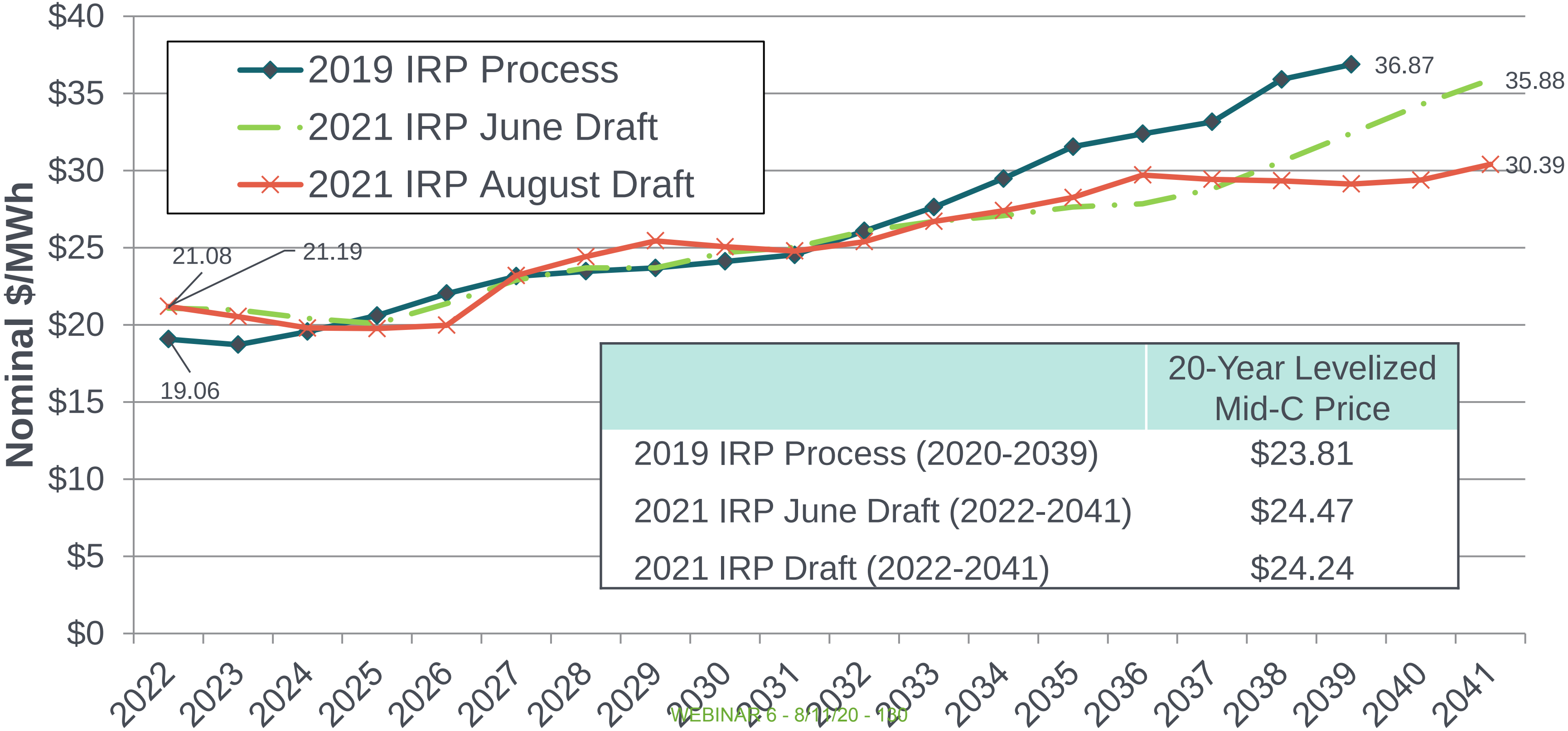
3. Natural gas price forecast

   PSE received feedback from Kathi Scanlan, Washington Utilities and Transportation Commission (WUTC) Staff, requesting the use of an updated gas price forecast to reflect the socioeconomic changes of the COVID-19 pandemic.

   - PSE updated to the most recent natural gas price forecast.

PUGET SOUND ENERGY

2021 IRP electric price August update

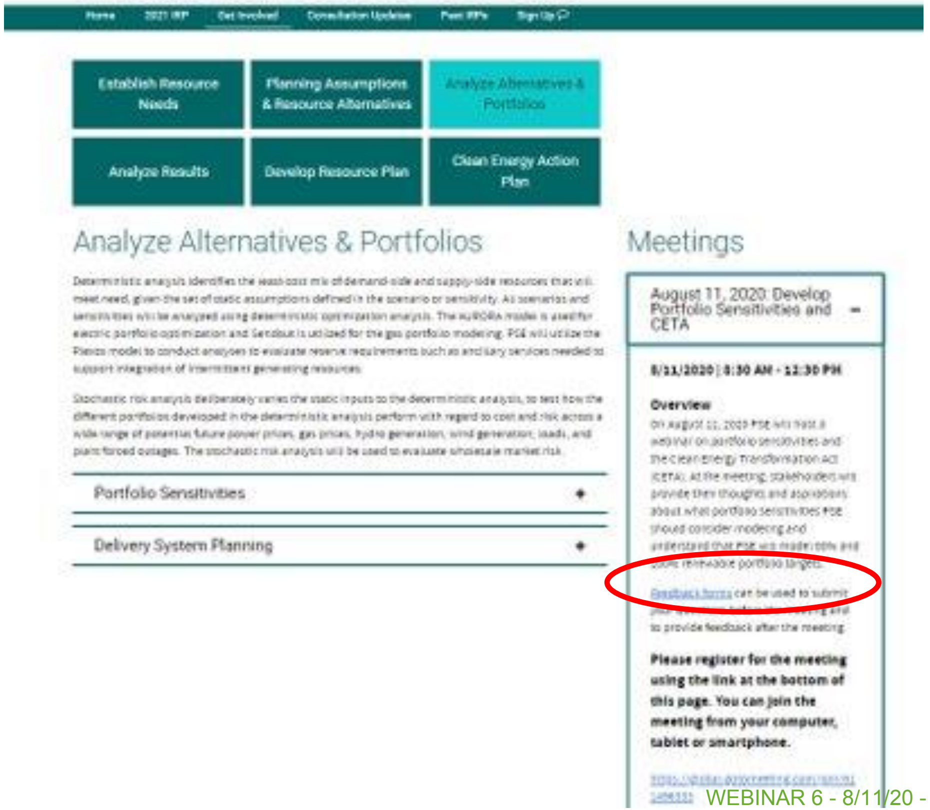


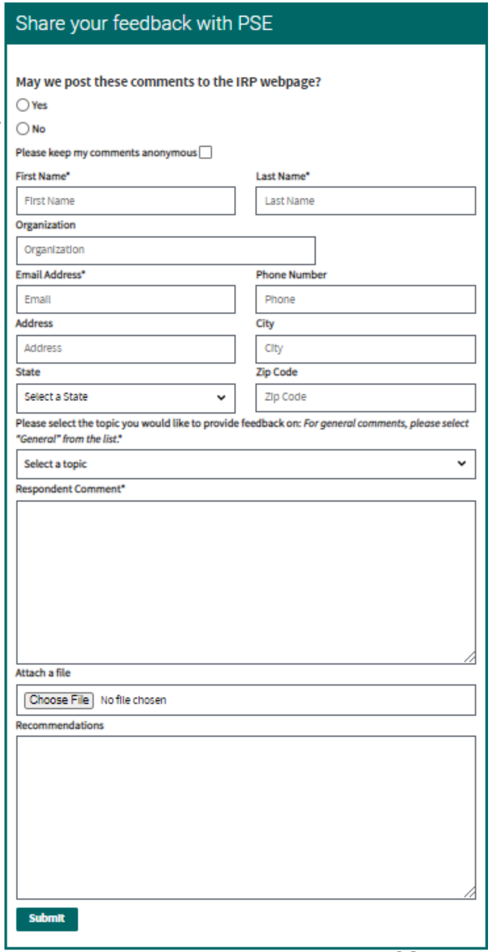
	20-Year Levelized Mid-C Price
2019 IRP Process (2020-2039)	$23.81
2021 IRP June Draft (2022-2041)	$24.47
2021 IRP Draft (2022-2041)	$24.24

Question and Answer

This session is being recorded by Puget Sound Energy. Third-party recording is not permitted.

Feedback Form





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Feedback Form

- An important way to share your input
- Available on the website 24/7
- Comments, questions and data can be submitted throughout the year, but timely feedback supports the technical process
- Please submit your Feedback Form within a week of the meeting topic

Feedback Form → Feedback Report → Consultation Update

Next steps

- Submit Feedback Form to PSE by **August 18, 2020**
- A recording and the chat from today's webinar will be posted to the website **tomorrow**
- PSE will compile all the feedback in the Feedback Report and post all the questions by **August 25, 2020**
- The Consultation Update will be shared on **September 1**

Details of upcoming meetings can be found at pse.com/irp

Date	Topic
September 1, 1:00 – 5:00 pm	Demand forecast (electric & gas) Resource adequacy Resource need: peak capacity, energy & renewable energy need
October 20, 1:30 – 4:30 pm	Portfolio sensitivities draft results Flexibility analysis
November 4, 1:00 – 4:30 pm	Clean Energy Action Plan 10-year Distribution & Transmission Plan
December 9, 1:00 – 4:30 pm	Portfolio draft results Stochastic analysis Wholesale market risk

Thank you for your attention and input.

Please complete your Feedback Form by August 18, 2020

We look forward to your attendance at PSE's next public participation webinar:
Demand Forecast (Gas and Electric)
Resource Adequacy Analysis
Resource need (Gas and Electric)
September 1, 2020

PSE PUGET SOUND ENERGY

Webinar #6: Portfolio Sensitivities Q&A

8/12/2020

Overview

On August 11, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss portfolio sensitivities, CETA assumptions and Distributed Energy Resources (DERs). Additionally, participants were able to ask questions and make comments using a chat box provided by the Go2Meeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 58 stakeholders and PSE staff attended the webinar, plus another 11 attendees who called into the meeting and did not identify themselves (69 people total).

Attendees included: Anne Newcomb, Ashton Davis, Bill Pascoe, Bob Stolarski, Brad Tuffley, Brandon Houskeeper, Brett Rendina, Brian Grunkemeyer, Brian Robertson, Brian Tyson, Charlie Black, Cody Duncan, Colin O'Brien, Corina Pfeil, Michael Corrigan, Dan Kirschner, David Perk, Don Marsh, Fred Heutte, Glenn Blackmon, Harrison Matherne, James Adcock, Jenny Lybeck, Joni Bosh, Kassie Markos, Kate Maracas, Katie Ware, Kevin Jones, Cathy Koch, Kyle Frankiewich, Lorin Molander, Leslie Almond, Marcus Sellers-Vaughn, Margaret Miller, Devin McGreal, Michael Laurie, Mike Elenbaas, Mike Hopkins, Nancy Esteb, Peter Sawicki, Peter Tassani, Rachel Brombaugh, Rahul Venkatesh, Sarah Vorpahl, Sheri Maynard, Stephanie Chase, Stephanie Imamovic, Steve Greenleaf, Susan Christensen Wimer, Ted Drennan, Thomas Cameron, Tom Flynn, Virginia Lohr, Vlad Gutman-Britten, Willard Westre, Elyette Weinstein and Zac Yanez.

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 8:30 AM PDT and ended at 12:48 PM PDT.

Name	Time Sent	Comment
Alison Peters	**8:22 AM**	Good morning, all. Nice to see you this morning.
Virginia Lohr	**8:35 AM**	How do we know the level of public participation before the meeting starts?
Alison Peters	**8:38 AM**	Hi Virginia, the levels are labeled in the PowerPoint deck that was posted a week prior to this webinar. Thanks for asking.
Kevin Jones	**8:43 AM**	Slide 10: What criteria does PSE use to select the “reference portfolio”?
Kevin Jones	**8:44 AM**	Slide 10: Not sure I understand this slide. PSE selects a “reference portfolio”, then makes changes to that portfolio “for each portfolio comparison”. Is PSE saying that changes made to the “reference portfolio” will allow PSE to evaluate the impacts of these changes on all the other portfolios (each portfolio comparison)?
Kevin Jones	**8:45 AM**	Slide 10: Are the “changes” listed on this slide actually a list of the parameters that are varied to create different sensitivities?
Joni Bosh	**8:47 AM**	Slide 10 – what criteria do you use to select the refernce portfolio?
James Adcock	**8:47 AM**	Hand Raise Slide 9
Kevin Jones	**8:48 AM**	Participants - Go To Meeting default is set so your chat messages go only to EnviroIssues. You can change that setting to "everyone" to receive your chat messages in the pulldown menu next to the chat "To" line. Please do that.
Kevin Jones	**8:48 AM**	Slide 10: Not sure I understand this slide. PSE selects a “reference portfolio”, then makes changes to that portfolio “for each portfolio comparison”. Is PSE saying that changes made to the “reference portfolio” will allow PSE to evaluate the impacts of these changes on all the other portfolios (each portfolio comparison)?
Kevin Jones	**8:48 AM**	Slide 10: Are the “changes” listed on this slide actually a list of the parameters that are varied to create different sensitivities?
Alison Peters	**8:49 AM**	Thanks Kevin. I see you’ve shared your question with everyone now.
Fred Heutte	**8:49 AM**	slide 9: "The purpose of a scenario is to create a 20-year electric price forecast" -- isn't the purpose of a scenario to create a resource portfolio that includes a price forecast and other factors?
Fred Heutte	**8:51 AM**	Slide 13: what is meant by “themes”
Kyle Frankiewich	**8:57 AM**	Slide 9/10: I am also confused by the distinction between scenarios and forecasts. Are "scenarios" model runs where something outside of PSE changes, and "sensitivites" runs where PSE's resource choices are altered?
Joni Bosh	**8:59 AM**	Slide 14 – just to clarify, are you saying the items on this slide are themes?
Don Marsh	**9:00 AM**	On slide 14, I think a key issue is the increasing capacity and decreasing costs of technologies like solar panels, batteries, smart grid, etc. Given the considerable impact on the industry, these developments qualify as a "key issue."
James Adcock	**9:00 AM**	Slide 14 -- where does availability / CETA applicability of RECs fit in here?
Corina Pfeil	**9:00 AM**	When would that happen

Michael Laurie	**9:03 AM**	On slide 10 you have chosen conservation as one of the changes that you may include. I strongly suggest that you include it because if significant conservation is achieved it will reduce the need for additional power plants including peaker plants. And most conservation is cheaper than new power plants and does not face a risk that natural gas plants face of being outlawed by future legislation at the state and federal level. So it will help PSE to stay consistent with providing energy at lowest cost to their customers. And with some many laws having been passed at the state level that will increase conservation and uncertainty of how much conservation they will achieve PSE should include different scenarios of high, medium, and low conservation being achieved by these laws. And absoluteluy support increase the ramp rate to 6 years.
Willard Westre	**9:04 AM**	Raise Hand S-16
Alison Peters	**9:05 AM**	Hi Corina. Could you send your question to "Everyone" and clarify what you meant? THank you.
Kyle Frankiewich	**9:05 AM**	Slide 16: really like this slide. Have a bunch of Qs but will save them for later when we get into the details.
Michael Laurie	**9:06 AM**	Is PSE looking at a sensitivity related to a much more wholistic approach to conservation including approaches that make wholistic conservation easier to achieve?
James Adcock	**9:06 AM**	Slide 16 -- what do you mean by "renewable overgeneration?" If you have too much reneable capacity just don't run all of it. How is this different than having too much NG Peaker capacity at a given point in time? If you don't need that NG Peaker capacity just don't run it. So I don't understand what you are saying here?
Virginia Lohr	**9:07 AM**	What is the range of the number of sensitivities you anticipate being able to run? I'm wondering about how many might need to be dropped. For example, do you anticipate only 1 or 2 being left under a "theme" or "issue"?
Vlad Gutman-Britten	**9:08 AM**	80% clean delivered to load?
Charlie Black	**9:08 AM**	I strongly encourage PSE to place a high priority on analyzing the SCC as an environmental externality. The SCC should be included as a variable cost of dispatch. This approach is the most consistent implmentation of the CETA requirements to include the SCC in IRP.
Joni Bosh	**9:10 AM**	Back on RECs – why can't the model sell the over generation with its RECs?
Anne Newcomb	**9:14 AM**	On slide 16 under Emissions Reductions: What do you think about adding Hydrogen as well as biodiesel?
James Adcock	**9:17 AM**	+1 Charlie
David Perk	**9:17 AM**	Agree with Charlie Black's comment re SCC.
Joni Bosh	**9:19 AM**	+1 Charlie
Don Marsh	**9:19 AM**	Did Elizabeth have a response to Charlie's suggestion?
Corina Pfeil	**9:21 AM**	agreed
David Perk	**9:22 AM**	Absolutely agree with Charlie
Don Marsh	**9:22 AM**	Also agree.
David Perk	**9:22 AM**	PSE needs to get SCC right, from the start

Elyette Weinstein	**9:22 AM**	Penny's method causes confusion and inhibits transparency.
Kate Maracas	**9:23 AM**	Stakeholders: I suggest that you frame your comments as questions so that they can be addressed.
Virginia Lohr	**9:24 AM**	Does over generation consider using it to make renewable hydrogen?
Kyle Frankiewich	**9:24 AM**	Slide 18: I'd like to better understand what is going into the low-growth scenario, as this economic downturn could last longer than we'd hope, and the changes in energy use (substantial work from home, lower office energy use, etc) could well become permanent.
Willard Westre	**9:24 AM**	S18- Agree with Charlie
James Adcock	**9:24 AM**	Agree with Charlie that I not including SCC in all aspects of IRP and REC modeling of dispatch [as opposed to PSE's approach of modeling it [incorrect] as a "fixed cost] is a "fatal error" which destroys any value to PSE's entire IRP and RFP efforts, including analysis of DR and Conservation.
Willard Westre	**9:24 AM**	Agree with Charlie
Elyette Weinstein	**9:25 AM**	Where do questions end and statements begin? Observations logically include statements which cause the questions? Is Penny serving as a PSE advocate or partial judge? She should be a neutral party that is impartial.
Charlie Black	**9:24 AM**	Thanks, Kate. I was just thinking the same thing.
Elyette Weinstein	**9:26 AM**	I agree with Charlie.
Don Marsh	**9:27 AM**	When meeting efficiency is valued more than honest inquiry and conversation, the process needs to be rethought. I encourage meeting organizers to do some soul searching regarding the fairness of this process.
James Adcock	**9:27 AM**	Slide 18 Raise Hand.
Michael Laurie	**9:27 AM**	Is it true that PSE is considering selling some of their transmission lines from Montana? If so why sell transmission when that could allow transmission of wind resources with a high capacity factor?
Elyette Weinstein	**9:27 AM**	Thank you Don!
Kyle Frankiewich	**9:28 AM**	slide 19: Market reliance presumes a) availability of sellers at Mid-C, and b) functioning Tx that can move that power to load. I understand that this will be modeling a). Are these sensitivities and scenarios stochastic in nature? Do they get an idea of what PSE's risks are in relying on key infrastructure, ie, the 1500 MW Tx backbone into MidC? I'm generally puzzled about when stochastic modeling and the mixing and matching of load shapes vs renewable generation shapes gets analyzed.
Vlad Gutman-Britten	**9:30 AM**	Support the use of hydrogen as long term storage, but hydrogen also is a commodity with independent market value. It would be good to model both potential dispositions of hydrogen--as a marketable product to financially benefit customers and as a system resource, including how it may support compliance with CETA.
Anne Newcomb	**9:30 AM**	If you have an excess of Renewable energy before 2045, can it be used rather than any fossil fuels that may be in the mix at the moment?
Corina Pfeil	**9:31 AM**	Yes

Willard Westre	**9:34 AM**	Hand Raised S-20
Fred Heutte	**9:35 AM**	responding to comment by Elizabeth: renewables can be held as reserves, there is nothing preventing that and as costs continue to fall it will become reasonable to do so
Fred Heutte	**9:35 AM**	That allows renewables to be used for both incs and decs
James Adcock	**9:36 AM**	Slide 20 raise hand.
Fred Heutte	**9:36 AM**	in addition renewables and other inverter based resources with power electronics respond to dispatch signals much faster and with more fidelity than thermal
Kate Maracas	**9:37 AM**	+1 to Fred
Don Marsh	**9:37 AM**	Fred, lots of good comments. Maybe you need to ask a question?
Fred Heutte	**9:38 AM**	that was a comment not a question
Don Marsh	**9:39 AM**	Not necessary for PSE to address in this meeting? I think an answer might clarify a few things, but it's up to you.
Virgina Lohr	**9:41 AM**	I agree with Bill Westre
Michael Laurie	**9:41 AM**	I also agree with Bill Westre. I think it is a key element because of the options for renewables and storage in Montana.
Bill Pascoe	**9:43 AM**	Raise Hand Slide #20
Don Marsh	**9:44 AM**	PSE says it needs to build new transmission capacity to handle renewables. I don't understand how selling the Montana lines is a benefit to PSE's ratepayers. I'd really like to understand the econmic benefits of that sale.
James Adcock	**9:44 AM**	In terms of "comments" vs. "questions" PSE's lawyer in the cover letter to PSE's current RFP draft claims that PSE's IRPs include "discussion" which PSE seems to be clearly actively *preventing* by not responding to comments -- only to questions.
Vlad Gutman-Britten	**9:45 AM**	With conservation and other DERs, are you evaluating any equity metrics consistent with CETA? Distributional impacts/benefits, etc?
Michael Laurie	**9:45 AM**	Slide 21 could you also include here the idea of a more wholistic approach to conservation as I mentioned earlier?
Corina Pfeil	**9:45 AM**	Ramp Rate - nomaly also indicates systemic rate increses to customers - are you intending to make rate increase over the next year ?
James Adcock	**9:46 AM**	Slide 21 Raise Hand.
Corina Pfeil	**9:46 AM**	Considering the COVID Pandimic - most agencies are freezing customer increases over the year -
Willard Westre	**9:48 AM**	S-21 Will the 2.5% cost of financing be applied to generation assets as well?
Don Marsh	**9:48 AM**	Elizabeth says if you increase the conservation ramp rate, PSE will do less conservation later. However, the 10-year ramp rate has been used in several IRPs, and I see no reduction of conservation on the horizon. Does this really work the way Elizabeth is describing?
Corina Pfeil	**9:48 AM**	Low income, Seniors, and Disabled, along with Race
Corina Pfeil	**9:48 AM**	Thank you Vlad
David Perk	**9:48 AM**	+1 Vlad's comment re deeper work on equity
David Perk	**9:48 AM**	Particularly in the current economic environment

Michael Laurie	**9:51 AM**	The answer of thank you to my suggestion about looking at a wholistic approach does not tell me whether you will look at it or not. Do you plan to look at it? or not? Or are you unsure?
Kyle Frankiewich	**9:53 AM**	slide 21: I'm still trying to make sense of the value stream of DR. I think one of the bigger values of DR might be its ability to hedge against the risk of super-peak events, which might not be immediately visible in a determinative model run. Can PSE identify other scenarios and sensitivities that are more likely to miss some hard-to-see risks or benefits?
Fred Heutte	**9:54 AM**	slide 22 hand raise: NWEC supports the use of AR5 for sensitivity 21. Will PSE also run a separate sensitivity for an updated emissions rate for upstream emissions, for example the EDF Low rate as we have suggested?
Don Marsh	**9:55 AM**	Kyle's question is good. DR provides reliability and resiliency benefits that might not be fully captured in the economic model. I worry about that. Reliability is very valuable to residents and businesses.
Vlad Gutman-Britten	**9:56 AM**	It would be very helpful to model SCC in absense of 2030 and 2045 portfolio requirements to better understand the impact of modeling SCC on dispatch and post dispatch. I'm reading these SCC sensitivities as being in context of the portfolio requirements which your previous models have shown to yield little impact for SCC.
James Adcock	**9:57 AM**	Slide 22 Raise Hand.
Michael Laurie	**9:58 AM**	What is the economic reasoning for using a fixed cost of carbon at dispatch when the amount of carbon based energy that is used at dispatch will be a variable demand that is not possible to predict ahead of time. A fixed cost for a variable activity is hard to understand.
Virginia Lohr	**9:58 AM**	Raise Hand: Slide 23, Sensitivity 22
Joni Bosh	**10:00 AM**	+1 kyle
Michael Laurie	**10:01 AM**	What is the reasoning for using the very low federal tax of $15/ton. If it were to come to pass it would likely come to pass if the federal government is controlled by Democrats and in that scenario there will be strong pressure to have a much higher tax.
Vlad Gutman-Britten	**10:02 AM**	Support Fred's recommendation for a sensitivity estimating high leakage rates for NG.
Virginia Lohr	**10:03 AM**	I also strongly support what Fred Heutte is saying.
Joni Bosh	**10:04 AM**	Clarification on #23 - is this one modeled like 19 or 20?
Kyle Frankiewich	**10:05 AM**	Q for Jim Adcock: Are you looking for a layered scenario that includes both SCC at dispatch and with various tweaks to conservation ramp rates?
Vlad Gutman-Britten	**10:05 AM**	Hand raised on SCC.
Charlie Black	**10:06 AM**	Raise hand on SCC
Michale Laurie	**10:10 AM**	Agree with Virginia Lohr on using a higher federal tax in the analysis.

James Adcock	**10:10 AM**	Answer to Kyles question posed to me: I read CETA as *requiring* Puget to always include social cost of carbon in *all* aspects of IRP and RFP *all of the time* up to and including actual purchase of resources including DR and Conservation, as such I believe Puget is *required* to include SCC as a variable dispatch cost in *all* of their modeling efforts re IRP and RFP, not just the "base case." So from my point of view its not a question of which "portfolios" or "schenarios" should include SCC in dispatch, because I believe Puget is *required* by CETA to include SCC in dispatch in *all* of them.
David Perk	**10:12 AM**	Agree with Charlie Black's SCC comments.
James Adcock	**10:13 AM**	...in comparison if Puget for a private business analysis reason *not* part of the IRP or the RFP wants to *not* include SCC in that private business modeling that would be Puget's business, not ours.
David Perk	**10:13 AM**	Important to get SCC right, from the beginning
Charlie Black	**10:14 AM**	Raise hand
Joni Bosh	**10:14 AM**	Agree with Charlie Black's request.
Virginia Lohr	**10:17 AM**	SCC is a variable cost and should NOT be run as a fixed cost.
Kyle Frankiewich	**10:18 AM**	+1 on Vlad's suggestion - will provide a an interesting perspective on the impact of SCC compared to other CETA reqs
Virginia Lohr	**10:19 AM**	Raise Hand: Slide 24, Sensitivity 25.
Don Marsh	**10:19 AM**	Slide 24, sensitivity 24: Stakeholders are concerned that PSE is using prices for batteries that are too high. During the transmission constraints webinar, PSE showed exorbitant costs for connecting batteries which made no sense to us. Have these issues been corrected?
Elyette Weinstein	**10:20 AM**	I agree that SCC is a variable cost and should NOT be run as a fixed cost.
Don Marsh	**10:22 AM**	Thanks for the correction on battery interconnection costs. But are you still modeling 5 miles of transmission to connect batteries? That also made no sense. Batteries are typically sited close to existing transmission. Was that corrected?
Don Marsh	**10:23 AM**	Also, what is the basis of PSE's cost for the batteries themselves? We have seen significantly lower prices used by Portland General Electric. Maybe PacifiCorp too.
Michael Laurie	**10:23 AM**	Agree with Virginia Lohr's point that since there are limitations on what can be limited it is better to model hydrogen instead of biodiesel.
Kevin Jones	**10:23 AM**	raise hand slide 24

James Adcock	**10:24 AM**	Re batteries, in RFP Puget dismissed my concerns that transmission costs which are 1600% too high, in part because it appears PSE assumes a 5 mile interconnect cost, but in my aerial photographic review of recent actual "state of the art" battery storage systems, the actual connection length is only about 0.1 miles -- because battery systems can be sited "anywhere" -- and so real peer utlities of Puget are siting them "as close as possible" to existing infrastructure -- no additional stub line required -- next to either an existing solar or wind facility, or next to an existing substation -- so that transmission interconnect costs are minimized. In addition Puget was estimating Battery Storage cost for the base facility 53% higher than NREL estimates. These estimates seem to be so extremely high as to prohibit any fair modeling of Battery Storage [as competition to NG Peakers] at at all.
James Adcock	**10:25 AM**	Raise Hand “Transmission Interconnect Costs.”
Don Marsh	**10:26 AM**	Thanks for actual data on battery costs, James Adcock. Very useful. I encourage PSE to correct the exaggerated assumptions that seem to be skewing the models against batteries.
Don Marsh	**10:27 AM**	Many utilities are finding batteries are much more practical than PSE is. For example, PacifiCorp and Portland. PSE must fix the skewed analysis.
Don Marsh	**10:28 AM**	We look forward to clarity on those battery costs. Thanks for looking into it!
Dan Kirschner	**10:28 AM**	Raise Hand Slide 25
Vlad Gutman-Britten	**10:28 AM**	Hand raised on sensitivity 30
Charlie Black	**10:29 AM**	Raise hand on process for responding to requests by stakeholders.
Don Marsh	**10:29 AM**	Sensitivity 31: Does the sensitivity also include higher temperatures reducing winter peak?
Michael Laurie	**10:29 AM**	Is PSE looking at other Demand adjustments like control of hot water tanks, conservation, using batteries to reduce peak demand and more?
Virginia Lohr	**10:30 AM**	Please give us more detail on how you will be doing your temperature sensitivity. What you have is too vague to mean anything.
Don Marsh	**10:31 AM**	In sensitivity 31, is the temperature trend based on the last 10-15 years of rising temperatures? PSE has been using much longer trends that reduce the impact of recent climate trends.
James Adcock	**10:32 AM**	Slide 25 Raise Hand.
Fred Heutte	**10:34 AM**	On #31, the NW Council is finalizing an important assessment of climate change effects on regional temperature, precipitation, demand and hydro runoff.
Fred Heutte	**10:36 AM**	See for example the presentation at the Council's Power Committee yesterday: https://www.nwcouncil.org/sites/default/files/2020_08_p3.pdf
Virginia Lohr	**10:37 AM**	I’m glad to see consideration of a summer peak.
Fred Heutte	**10:37 AM**	The Council staff assessment now shows that climate effects are already observed in the historical record and will continue through the 2020s and beyond.

Don Marsh	**10:37 AM**	Is PSE anticipating any V2G development in the near future? That could dramatically change the amount of battery resource available during the next decade.
Fred Heutte	**10:38 AM**	A significant result is the upward shift in late summer demand peak and somewhat reduced hydro runoff.
Don Marsh	**10:39 AM**	+1 on specificity on temperature trends
Kyle Frankiewich	**10:41 AM**	Slide 25: What might help is for PSE to provide PSE's current weather baseline so that folks can provide substantive input on #31. Would that be feasible?
Michael Laurie	**10:42 AM**	Agree with Don about looking at vehicle batteries as a major demand management resource.
Anne Newcomb	**10:44 AM**	Great job Everyone!!! :-) Thank You!
Vlad Gutman-Britten	**10:45 AM**	Thanks everyone.
Charlie Black	**10:48 AM**	Re-raising my hand on process for PSE following up on requests by stakeholders.
Fred Heutte	**10:56 AM**	raise hand for upstream emissions factor
Don Marsh	**10:57 AM**	We could do some research to see what other utilities are doing regarding V2G. I don't know now whether it's a sensitivity, but by ignoring the possibility, PSE might be creating a significant blind spot for future planning.
Joni Bosh	**10:57 AM**	Question on Excel sheet - can we submit suggestions later, as we have time to look at the corrected version.
James Adcock	**10:58 AM**	For the record: I would "want" to have SCC modeled as a variable cost of dispatch, not a fixed cost, in every one of these Portfolio Analysis conditions, because that is what I understand as being required by the CETA law.
Virginia Lohr	**10:58 AM**	Are you entering what we have already requested today?
Don Marsh	**10:58 AM**	Does PSE's demand response portfolio include time-of-day pricing? Until energy costs are better reflected in retail prices, we are ignoring the significant effects of market forces. With history as our guide, it's not smart to do that.
Michael Laurie	**10:59 AM**	Raising my hand to include a sensitivity to include a Wholistic approach to conservation. Basically assuming most conservation efforts carry out the majority of possible and cost effective conservation in each building instead of the piecemeal limited measures approach which has been the case for most PSE and other utility efforts.
Don Marsh	**11:02 AM**	During PSE time-of-day trial 20 years ago, PSE discovered an unexpected conservation effect in addition to peak shifting. That would be beneficial for the environment as well as ratepayer wallets.
Vlad Gutman-Britten	**11:02 AM**	Two sensitives--SCC as adder and in dispatch in absence of portfolio requirements.
Alison Peters	**11:03 AM**	Replying to all re: Joni's question: Yes, please submit suggestions via the Feedback Form online by August 18.
Joni Bosh	**11:03 AM**	Thanks
James Adcock	**11:04 AM**	Raise Hand.
Michael Laurie	**11:04 AM**	I agree that time of day pricing should be looked at. Without it demnd responses options will be underutilitized.
Michael Laurie	**11:06 AM**	Agree with using higher and rising cost for federal carbon tax.

Don Marsh	**11:07 AM**	I like this spreadsheet exercise. It feels like our suggestions are considered. Thank you.
Joni Bosh	**11:11 AM**	I believe Charlie's clarification is correct.
Don Marsh	**11:14 AM**	Raised hand
Kyle Frankiewich	**11:14 AM**	raised hand
Vlad Gutman-Britten	**11:15 AM**	Thanks Elizabeth for including EIA in the SCC-only sensitivities. That is correct.
Vlad Gutman-Britten	**11:15 AM**	(or whoever is typing)
Charlie Black	**11:16 AM**	Raise hand
Michael Laurie	**11:17 AM**	I agree with Don to start out looking early on at using a variable social cost of carbon. And use that result to guide further modeling of a variable social cost of carbon especially at Dispatch.
Willard Westre	**11:20 AM**	Agree with Charlie
Elyette Weinstein	**11:20 AM**	I agree with Charlie
James Adcock	**11:21 AM**	Raise Hand.
Charlie Black	**11:21 AM**	Raisew hand
Don Marsh	**11:22 AM**	PSE's diligence, fairness, and transparency on the analysis of these sensitivities is SO important for all of us. I am hoping that we will all agree in the end that PSE earned an A+ grade on this. If the results seem opaque or skewed in some way, it is going to damage relationships that need healing at this point. Please do a great job!
Charlie Black	**11:23 AM**	Agree with Joni – 2019 analysis treat SCC as a tax, not as an externality.
Vlad Gutman-Britten	**11:23 AM**	They did it both ways.
Charlie Black	**11:24 AM**	Raise hand
Michael Laurie	**11:24 AM**	How could raising the price of a resource at dispatch, using a variable social cost of carbon at dispatch, not reduce the demand for that resource and increase the demand for competitive resources which are now cheaper in comparison because they don't have that social cost of carbon?
Vlad Gutman-Britten	**11:25 AM**	Because the implicit carbon price of CETA is higher than SCC.
Don Marsh	**11:25 AM**	Raise hand
James Adcock	**11:26 AM**	+1 Charlie's Comments
Kyle Frankiewich	**11:29 AM**	raised hand
Virginia Lohr	**11:29 AM**	Pleaseask Maichael Laurie's question
Kyle Frankiewich	**11:31 AM**	oh, never mind - I see that a copy of the spreadsheet Elizabeth is sharing with us is also posted online. I'll populate a copy of that spreadsheet and add to it, then include it with staff's comments
Michael Laurie	**11:32 AM**	Don is making a major point about the importance of including time of day rates to properly analyze demand management options. Without time of day rates many demand management options will be undervalued and underutilitzed.

James Adcock	**11:35 AM**	When you decrease the dispatch of an *emitting* plant then you are increasing the use of *non-emitting* plants, conservation, and dispatch -- which is the whole point of the CETA law and the detailed *requirements* of that law, including its requirements about how PSE performs their IRP and RFP analysis.
James Adcock	**11:43 AM**	For the record: It appears PSE is skipping presentation of slides 30 to 36 due to "time constaints."
Fred Heutte	**11:45 AM**	hand raise for a question on slide 43
Penny Mabie	**11:46 AM**	Yes, James, PSE is skipping slides 30 to 36 today. Those slides will be included in the September 1 webinar.
James Adcock	**11:47 AM**	Thank you!
Brian Grunkemeyer	**11:48 AM**	To integrate DER's, are you considering a technique like dynamic price forecasts to tell DER's when to operate and/or shift load?
James Adcock	**11:52 AM**	Raise Hand.
Michael Laurie	**11:56 AM**	Thanks for working on and planning to propose a community solar program. This gives those who don't have good solar access to invest in solar and it gives communities more options.
Charlie Black	**11:58 AM**	Specific requests regarding PSE's side-by-side modeling of SCC as a variable cost of dispatch and as an annual fixed cost:
Don Marsh	**11:58 AM**	Slide 48: Is PSE doing any experiments with "Virtual Power Plants" (coordinated small batteries to provide reliability and resilience)?
Michael Laurie	**11:59 AM**	How are installed costs looking when comparing utility batteries versus batteries in customer buildings? And what costs are included in that analysis?
Kevin Jones	**12:00 PM**	To what extent are the solar projects you mentioned PSE owned versus "publicly" owned by the community members? To what extent does PSE promote and encourage public ownership of these types of resources?
Charlie Black	**12:01 PM**	1. In the SCC as a variable cost of dispatch sensitivity, dispatch a GHG-emitting resource when the Mid-C spot market price exceeds the sum of the resource's variable cost plus the SCC
Michael Laurie	**12:01 PM**	Thanks for saying that you are looking at how can the grid respond these battery storage options.
Charlie Black	**12:02 PM**	2. In the SCC as fixed cost, dispatch a GHG-emitting resources when the Mid-C spot market price exceeds the resource's variable operating cost.
Don Marsh	**12:03 PM**	Jens said DERs and NWAs are now becoming lower cost than transmission lines. Totally agree. When was that analysis last updated for PSE's "Energize Eastside" project, which will cost ratepayers hundreds of millions of dollars?
Charlie Black	**12:05 PM**	3. In the modeling results for each sensitivity, track and report the quantity of power generated by each type of GHG-emitting resource. Provide a comparison of the quantities of generation for each type of GHG-emitting resource in the two sensitivities.
Charlie Black	**12:12 PM**	4. In the results from the side-by-side senstivities, also provide the amounts and timing of additions of any new GHG-emitting generating resources to PSE's resource portfolio.
Don Marsh	**12:16 PM**	Would ADMS be able to coordinate many small residential batteries? Or do you need additional software to implement a VPP?

Michael Laurie	**12:17 PM**	Are you considering customer based software.thermostat systems that allow the customer to input which of their resources can be temporarily or permanently shifted to off-peak hours and compares that to PSE's peak demand times and then makes choices to shift customer loads to off-peak times?
Anne Newcomb	**12:18 PM**	What ADMS software platform will you be using?
Fred Heutte	**12:19 PM**	raise hand on slide 54 concerning hosting capacity analysis
Michael Laurie	**12:20 PM**	To add to my question about customer based software/thermostat systems to guide customer based peak demand reduction; I understand that there may not be any such systems out there now but with work by some of the techies around here such systems could likely be developed.
Willard Westre	**12:21 PM**	S-53 does AMI allow for Dr control features
James Adcock	**12:23 PM**	Comment: To state it again, PSE needs to figure out how to appropriately apportion the costs of these modernization efforts as being "directly related" to CETA or not, in particular in regards to the CETA 2% offramp. There are modernization efforts, including for example the ability to "remotely disconnect" a customer, which might be things that a utility might want to have, and might even claim is cost-effective -- but which would not be "directly related" to CETA requirements.
Fred Heutte	**12:27 PM**	here's the 2017 IREC reference on hosting capacity analysis: https://irecusa.org/publications/optimizing-the-grid-regulators-guide-to-hosting-capacity-analyses-for-distributed-energy-resources/ plus a more recent article and research paper: https://pv-magazine-usa.com/2020/06/16/solar-hosting-capacity-maps-must-be-accurate-to-be-useful/
Kyle Frankiewich	**12:28 PM**	i'm able to stay on for a bit longer
Don Marsh	**12:28 PM**	I can stay.
Michael Laurie	**12:28 PM**	I am happy to stay longer.
David Perk	**12:29 PM**	there's no where I'd rather be ;-)
Fred Heutte	**12:34 PM**	Hand raise for question about slide 57
Joni Bosh	**12:34 PM**	Slide 55 – do you consider the BI batteries part of a microgrid?
Don Marsh	**12:35 PM**	We love your solution on Bainbridge. So sad that you didn't use the same solution in Bellevue, where PSE decided to cut down 300 beloved community trees to connect two substations, the opposite of what the company did in Bainbridge. We hope not to see that again.
Kyle Frankiewich	**12:35 PM**	would like to hear more about that 20 MW heuristic for NWAs
Kyle Frankiewich	**12:37 PM**	slide 58: to clarify, PSE knows that some projects will select NWAs, and that those NWAs will involve DERs. So, some resources are included in the portfolio as must-take to reflect that cost-effective NWAs will be taken, and are likely to contribute to the company's resource stack. Is that right?
Michael Laurie	**12:39 PM**	Agree with Fred's point. Since the new law requires all hot water tanks to have a communication port to allow controlling them.
James Adcock	**12:42 PM**	Slide 60 Raise Hand.

SCENERIOS AND SENSITIVITIES

EXCEL SPREADSHEET

REVISION DATE: AUGUST 25, 2020

Click this link to download the spreadsheet:

https://oohpseirp.blob.core.windows.net/media/Default/documents/2021_PSE_IRP_Emission-Price-Calculations.xls

PSE IRP Feedback Report
Webinar 6: Portfolio Sensitivities
August 11, 2020

8/25/2020

The following stakeholder input was gathered through the online Feedback Form, from August 4 through August 18, 2020. PSE's response to the feedback can be found in the far-right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on September 1, 2020.

Feedback Form Date	Stakeholder	Comment	PSE Response
8/11/2020	Don Marsh, CENSE	I am attaching a recommendation that PSE seriously consider Vehicle-to-Grid technology in the next 5-10 years to take advantage of idle car batteries to store increasing amounts of renewable energy from variable sources like wind and solar.	Thank you for your suggestion concerning a demand response Vehicle-to-Grid technology scenario. PSE will be asking stakeholders to prioritize the sensitivities during the October 20 IRP meeting. To address Vehicle-to-Grid specifically, this is a distributed energy storage resource and it is captured as part of the distributed batteries that we are modeling in the 2021 IRP. We acknowledge that your suggestion could be a lower cost than installing a new battery system. As a response to your input, we have included a sensitivity with a lower cost for batteries in the updated "Scenarios and Sensitivities" excel file located here located in the meeting materials for Webinar 6. This suggestion is also relevant to stakeholders who are concerned about the (high) interconnection cost for batteries. Thank you again for the contribution.
8/11/2020	Don Marsh, CENSE	Please take this seriously for the sake of your customers, the environment, and the long-term health of your company.	Thank you for your comment, thoughts, and suggestions.
8/12/2020	Don Marsh, CENSE	Attached is a request for PSE to include a time-of-use sensitivity in its studies of Distributed Energy Resources. Such programs can save money, increase reliability, and reduce greenhouse gas emissions. These are goals that are mandated by Washington's Clean Energy Transformation Act.	Thank you for your suggestion concerning a demand response time of use scenario and the attachment, as well as the four supporting documents. All of the documents you provided have been uploaded as part of the Webinar 6 Feedback Form package on pse.com/irp. PSE will be asking stakeholders to prioritize the sensitivities during the October 20 IRP meeting. Concerning PSE's current work regarding time of use, PSE is modeling a critical peak price demand response program as part of the resource alternatives.
8/12/2020	Don Marsh, CENSE	If a time-of-use sensitivity is not included, please explain to stakeholders why not.	Thank you for your suggestion concerning a demand response time of use scenario. PSE will be asking stakeholders prioritize the sensitivities during the October 20 IRP meeting.
8/13/2020	Michael Laurie, Watershed LLC	I strongly support the submissions you received from Don Marsh on Time of Use Sensitivity and Vehicle to Grid potential. I think these will be 2 key needed pieces in adapting the grid and PSE's energy supply to our changing world and to the need to rapidly transition to a climate friendly energy system. Thanks	Thank you for expressing your support of Don Marsh's suggestions for sensitivities. PSE will be asking stakeholders prioritize the sensitivities during the October 20 IRP meeting. PSE has included your support in the updated "Scenarios and Sensitivities" excel file.
8/13/2020	Don Marsh, CENSE	I attached a request to study Virtual Power Plants to save customers money, to provide better reliability and resiliency for our energy grid, to reduce greenhouse gas emissions, and to provide local jobs at a time when the economy could use some assistance without taxpayer funds.	Thank you for your request to study Virtual Power Plants (VPPs) and the attachment you provided. VPPs are a platform to find the best use of distributed energy resources (DER) on the grid and are included on PSE's grid modernization road map. PSE is evaluating distributed resources in the 2021 IRP.
8/13/2020	Don Marsh, CENSE	The 2021 should have a sensitivity assessing the potential of VPPs to help achieve CETA goals.	Thank you for your suggestion of a 2021 IRP sensitivity assessing the potential of VPPs to help achieve CETA goals. PSE is modeling 80% renewable resources by 2030 and 100% by 2045 to meet the Washington Clean Energy Transformation Act (CETA). VPPs are a platform to find the best use of distributed energy resources (DER) on the grid and are included on PSE's grid modernization road map. PSE is evaluating distributed resources in the 2021 IRP.

Feedback Form Date	Stakeholder	Comment	PSE Response
8/15/2020	Jane Lindley, Act 4 Climate	Here is an example of a utility that is wise enough to plan for large increase of EV ownership: https://www.utilitydive.com/news/xcel-energy-unveils-plan-to-serve-15m-evs-by-2030/583428/ “Electric vehicles are the next frontier in the clean energy transition," Xcel Chairman and CEO Ben Fowke said in a statement. "We have substantial plans in place in the states we serve, and we can expand on this with partnership and support from policymakers, regulators, customers, automakers and our communities.” The plan will result in $1 billion in annual customer fuel savings, through a mix of residential charging, increased access to public electric transportation and charging, and faster fleet electrification, according to the utility.	Thank you for providing information concerning EVs and Xcel Energy’s promotion and support of EVs.
8/15/2020	Jane Lindley, Act 4 Climate	Along with helping to build EV infrastructure, I recommend that PSE seriously consider Vehicle-to-Grid technology, which will almost certainly become a large and inexpensive resource to store renewable energy as PSE strives to meet CETA goals by 2030 and 2045.	Thank you for your comment considering Vehicle-to-Grid technology.
8/17/2020	Anne Newcomb	I would like to compliment you on the great presentations you have put together and your clear and kind communications with us as Stakeholders. It is very exciting to see PSE moving to the clean energy future! It feels right to be working together on this very important project for the entire planet!	Thank you for sharing your positive impression of PSE’s 2021 IRP process.
8/17/2020	Anne Newcomb	I like many others involved would like to see the variable social cost of carbon included. By this I mean having the cost reflected at the time of burned fossil fuels for electricity produced. I think this will help customers and regulators see a truer cost of burning fossil fuels than if the cost is included in the entire mix. If you could also add in the cost of clean up of ground water from Colstrip and any oil or gas spills or explosion clean up this would be helpful. I have heard PSE can get community pushback for Solar and Wind projects. Possibly by showing the true costs of fossil fuels to customers they will become more and more supportive of renewable energy in their communities. This could make PSE's renewable energy projects flow more easily. Thank you for including the ramp up of Solar projects on the Westside. By creating solar energy projects in public parks, homes and business roofs and grounds the energy can be produced near the end user reducing energy loss on transmission lines and hopefully reducing the amount of transmission lines needed. Incentives are very helpful! I bet County and State Parks would be interested in collaboration on solar and wind projects. I appreciated seeing your integrated grid model on page 42! It looks like with the help of many talented PSE employees, PSE is going to be on track to meet CETA's important CO'2 reduction goals!!! Thank You for your dedicated work on the most important PSE IRP yet! Keep up the great work!	Thank you for sharing your support for PSE examining the social cost of carbon as a variable cost and thoughts concerning capturing costs differently in the IRP concerning specific resource types. PSE includes costs associated with electric generating plants including capital costs, taxes, insurance, transmission, fixed operations & maintenance, variable operations & maintenance, fuel, and decommissioning costs. Thank you for sharing your appreciation for the presentation on DER Integration in the August 11 webinar. Thank you for sharing your positive impression of PSE’s 2021 IRP process.
8/18/2020	Orijit Ghoshal, Invenergy	Attached are Invenergy's comments on the social cost of carbon as presented on August 11. [PSE inserted Overall Comment on Use of the Social Cost of Carbon] During Webinar 6 on August 11, 2020, Puget Sound Energy (PSE) did not adequately respond to or resolve the concerns expressed by Invenergy and other stakeholders about its preferred approach to including the Social Cost of Carbon (SCC) in its 2021 Integrated Resource Plan (IRP). Invenergy strongly encourages PSE to reconsider including the SCC as a fixed annual cost in the resource portfolio modeling for its 2021 IRP. Instead, PSE should treat the SCC as an incremental cost of hourly dispatch for Greenhouse Gas (GHG)-emitting resources. This approach will be more consistent with: a) the purpose and intent of the Clean Energy Transformation Act (CETA); b) accepted practices for internalizing the environmental externality costs of GHG emissions into decision making; and c) how the SCC was developed as an estimate of the economic value of environmental damages caused by GHG emissions and the intended use of the SCC. Before proceeding with the resource portfolio modeling sensitivity analyses, Invenergy strongly encourages PSE to address the issues surrounding properly including the SCC in its resource portfolio modeling analyses for the 2021 IRP.	Thank you for the attachment, your comments and questions. PSE has inserted the content of your letter directly in the form to facilitate our responses. The attachment you provided has also been uploaded as part of the Webinar 6 Feedback Form package on pse.com.

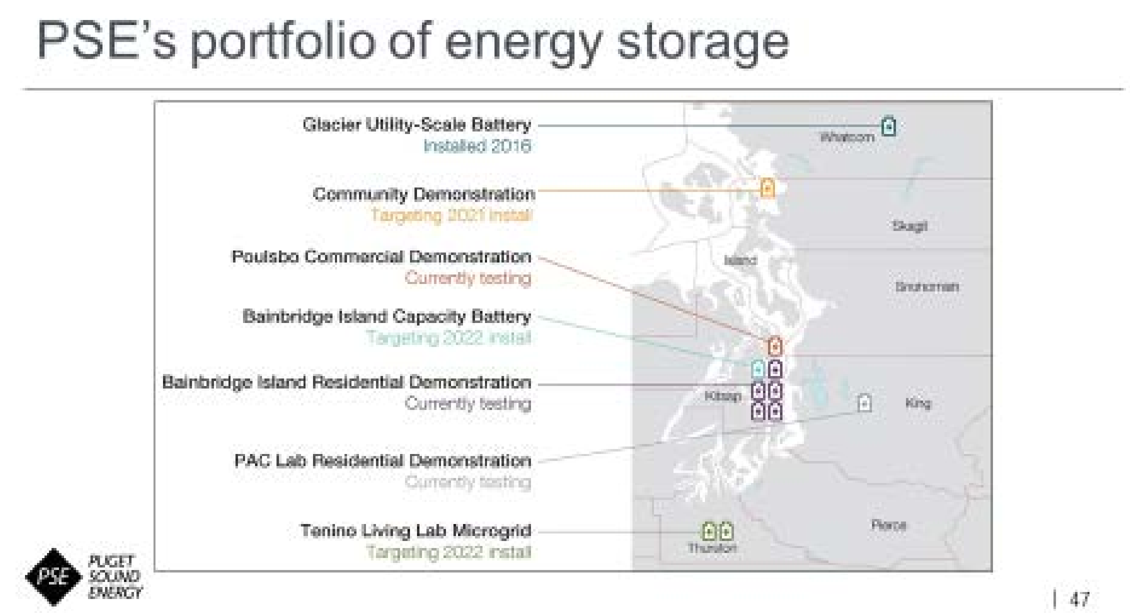
Feedback Form Date	Stakeholder	Comment	PSE Response
8/18/2020	Orijit Ghoshal, Invenergy	Incorporate the social cost of carbon into the incremental dispatch cost of all generators used to serve loads subject to CETA.	Thank you for your comment. As requested by Invenergy and other stakeholders, and discussed during the August 11 IRP meeting and in a prior meeting with Invenergy and other stakeholders, PSE has included a portfolio sensitivity that incorporates the social cost of carbon as a variable dispatch cost.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 1] CETA imposes two distinct requirements for PSE to limit its GHG emissions. The first requirement is to limit its annual GHG emissions (i.e., 80 percent GHG-free by 2030 and 100 GHG-free by 2045). The second requirement is for PSE to incorporate the SCC into its resource planning and acquisition decisions.	PSE understand CETA requirements and agrees with Invenergy's statement. PSE is including the SCC in its resource planning and acquisition decisions. A portfolio sensitivity where SCC is included as a dispatch cost has been added to the list and a sensitivity where annual GHG emissions is limited has also been added to the list of portfolios to analyze.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 2] Satisfying just one of these requirements does not relieve PSE of its obligation to satisfy the other requirement. Therefore, PSE needs to properly incorporate the SCC in its 2021 IRP.	Thank you for your concern about making sure PSE includes the SCC as part of the 2021 IRP. PSE is including the SCC in the decision to add new supply-side or demand side resources or to retire existing resources in the 2021 IRP. PSE plans to address both requirements through the 2021 IRP portfolio modeling.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 3] GHG emissions are an environmental externality. They are a real cost to society that is caused by but not borne by PSE or its retail electric customers. As a result, GHG emissions and the environmental damages they cause represent a clear market failure. Until and unless a mechanism to solve this market failure (e.g., carbon tax or GHG cap and trade program) is implemented in Washington State, the best available means for dealing with this market failure is to treat GHG emissions as an environmental externality.	Thank you for your suggestion concerning a scenario where social cost of carbon is incorporated in the incremental dispatch cost of all generators used to serve loads. This has been added to the portfolio sensitivity list to be analyzed.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 4] Instead of imposing a carbon tax or creating a GHG cap and trade program, it is quite clear that the intent of CETA is to treat GHG emissions as an environmental externality. While CETA does not explicitly use the terms "environmental externality" or "market failure", it recognizes and requires utilities to deal with GHG emissions as such. For example, Subsection 14(3)(a) of CETA states the following: An electric utility shall consider the social cost of greenhouse gas emissions, as determined by the commission for investor-owned utilities pursuant to section 15 of this act and the department for consumer-owned utilities, when developing integrated resource plans and clean energy action plans. An electric utility must incorporate the social cost of greenhouse gas emissions as a cost adder when: (i) Evaluating and selecting conservation policies, programs, and targets; (ii) Developing integrated resource plans and clean energy action plans; and (iii) Evaluating and selecting intermediate term and long-term resource options.	Thank you for your comment.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 5] Further, Section 15 of CETA identifies the SCC as the required metric for treating GHG emissions as an environmental externality: *For the purposes of this act, the cost of greenhouse gas emissions resulting from the generation of electricity, including the effect of emissions, is equal to the cost per metric ton of carbon dioxide equivalent emissions, using the two and one-half percent 21 discount rate, listed in table 2, technical support document: Technical update of the social cost of carbon for regulatory impact analysis under Executive Order No. 12866, published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016. The commission must adjust the costs established in this section to reflect the effect of inflation.*	Thank you for your comment.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 6] The SCC was developed by the federal Interagency Working Group (IWG) as an economic estimate of the real, incremental environmental damage costs caused by the emission of one metric ton of CO2equivalent GHG emissions. The IWG specifically designed and developed the SCC to quantify the externality effects of GHG emissions and incorporate them into economic decisions.	Thank you for your comment.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 7] Applying the SCC as an incremental cost is also consistent with well-established economic principles for incorporating environmental externalities into decision-making, including for integrated resource planning.	Thank you for your comment.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 8] Environmental damages caused by GHG emissions are incremental costs; they are not fixed costs. Correspondingly, the SCC is an estimate of the incremental economic costs – not the fixed economic costs – of the environmental damages caused by GHG emissions.	Thank you for your comment.

Feedback Form Date	Stakeholder	Comment	PSE Response
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 9] While CETA requires PSE to use the SCC to represent the environmental damage costs caused by GHG emissions, it does not authorize PSE to include the damage costs in its revenue requirements or in its retail electric rates.	Thank you for your comment.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 10] Therefore, PSE's analysis for its 2021 IRP needs to recognize the distinction between the two types of costs and account for them properly. Specifically, resource decisions should be made on the basis of the sum of revenue requirements costs plus environmental damage costs (as represented by the SCC). However, rate impacts of resource decisions should only include revenue requirements costs.	Thank you for your comment.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 11] There is nothing in CETA that requires or justifies treating the SCC as a fixed annual cost.	Thank you for your comment.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 12] Treating the SCC as a fixed annual cost biases resource decisions in favor of more GHG-intensive resources. A key reason for this is that excluding the SCC from simulation of hourly dispatching decisions in the portfolio modeling leads to increased generation by more GHG-intensive resources. In turn, this allows the fixed costs of the more GHG-intensive resources to be spread over a larger quantity of generation, thereby causing the total (revenue requirements and externality) costs of those resources to artificially appear lower than if the SCC were included in hourly dispatching decisions.	Thank you for your comment.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 13] PSE has said its past analyses showed that including the SCC as a variable cost of dispatch did not materially change the mix of resources in its modeling results. Invenergy remains skeptical about the validity of this conclusion, including due to flaws in PSE's prior assumptions and methodology for incorporating the SCC. Further, if including the SCC as a variable cost of dispatch truly does not change PSE's resource decisions, then PSE should have no objection to using that method.	Thank you for your comments. As discussed during the August 11 webinar, PSE will conduct new analysis for the 2021 IRP to model the SCC as both the cost adder and a variable cost of dispatch.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 14] If PSE does not agree that the SCC should be properly modeled as an incremental cost of hourly dispatch, PSE should perform a fair and rigorous side-by-side analysis of PSE's preferred approach of treating the SCC as a fixed annual cost with the more sound approach of including the SCC as a variable hourly dispatch cost for existing and new GHG-emitting resources it would use to serve its retail customers' needs. PSE should complete the side-by-side analysis and obtain feedback on the results from stakeholders before proceeding with the numerous portfolio sensitivity analyses it is planning to perform.	Thank you for your comment.
8/18/2020	Katie Ware, Renewable Northwest	Please see attachment.	Thank you for your comments. As discussed during the August 11 webinar, PSE will conduct new analysis for the 2021 IRP to model the SCC as both the cost adder and a variable cost of dispatch. The side-by-side results will be shared during upcoming webinars and stakeholders will be able to review the results.
8/18/2020	Katie Ware, Renewable Northwest	1. Renewable Northwest appreciates PSE's request for stakeholder suggestions regarding the appropriate portfolio sensitivities PSE should model. Below are our recommendations: a. Regarding the renewable over-generation test, we recommend that PSE incorporate the effects of this sensitivity on the 2% cost threshold relevant to compliance with CETA standards. Specifically, should PSE choose to or be required to over-generate renewables to meet load, how early in a compliance period would PSE meet the 2% cost threshold, and thus be considered in compliance with the clean energy standards? b. Regarding the must-take DR and battery storage sensitivity, we again recommend that PSE incorporate the effects on the 2% cost threshold. We recommend that PSE consider this detail in modeling other sensitivities which may lead PSE to the cost cap early in each compliance period. c. Regarding the highly-centralized sensitivity within the Transmission Constraints and Build Limitations category, we recommend that PSE consider including additional constraints specific to renewable proxy locations, whereby a strict delivery requirement mandated by CETA may create geographic limitations to new-build renewables. d. Regarding the SCC as a tax in WA, OR and CA sensitivity, we agree with PSE that this tax should be modeled WECC-wide for consistency.	Thank you for your comments and questions. PSE responses referenced as "a – d": a. PSE plans to include renewables to meet CETA requirement and does not elect to over-generate renewables during planning. However, over-generation may occur during certain times of the year. It is important to understand the impact of over-generation without additional constraints. Including the 2% cost threshold may limit the addition of new resources and thus not meet CETA requirements. PSE plans to model the over-generation sensitivity without the 2% cost threshold. b. The description you provided is consistent with PSE's approach regarding the must-take DR and battery storage. c. PSE will be reaching out to you to clarify this suggestion. d. Thank you for expressing your support that SCC PSE that this tax should be modeled WECC. This will be noted in the updated spreadsheet file.

Feedback Form Date	Stakeholder	Comment	PSE Response
8/18/2020	Katie Ware, Renewable Northwest	2. Renewable Northwest supports PSE's approach to modeling the social cost of carbon (SCC) as a post-economic dispatch fixed cost adder. Our understanding aligns with what PSE has vocalized in multiple webinars, that an alternative methodology applying the SCC as a dispatch adder would artificially deflate the capacity factors of emitting resources, thus skewing the model's output.	Thank you for your feedback.
8/18/2020	Katie Ware, Renewable Northwest	3. Renewable Northwest appreciates PSE's consideration of stakeholder feedback in considering how to meet the 20% alternative compliance permitted by CETA's greenhouse-gas neutrality standard. While our preference is always going to be that PSE does not rely on alternative compliance, we recognize the utility in planning a gradual transition to 100% clean. That said, we would advise against relying on resource-based compliance payments, given the more climate-beneficial options granted by CETA. Unbundled RECs support renewable energy development, and Energy Transformation Projects (ETPs) aim to reduce the state's non-energy sector GHG emissions. Both of these options support system transformation and GHG-emission reductions, while penalties do not.	Thank you for your feedback. CETA alternative compliance will be further discussed in the September 1, 2020 webinar.
8/18/2020	Katie Ware, Renewable Northwest	Renewable Northwest thanks PSE for its consideration of this feedback. We look forward to continued engagement as a stakeholder in this 2021 IRP process.	PSE appreciates the involvement of Renewable Northwest! Thank you for your participation!
8/18/2020	Joni Bosh, NW Energy Coalition	See attached comments	Thank you for the attached letter directed to Elizabeth Hossner, Manager Resource Planning & Analysis, and your comments and questions. PSE has inserted the content of your letter directly in the form to facilitate our responses. The attachment you provided has also been uploaded as part of the Webinar 6 Feedback Form package on pse.com/irp.
8/18/2020	Joni Bosh, NW Energy Coalition	NW Energy Coalition (NWEC) appreciates the opportunity to ask questions about and make suggestions regarding Puget Sound Energy's (PSE's) proposed portfolio scenarios and sensitivities to address in analysis in the Integrated Resource Planning effort. Our comments focus on the excel slide presented in the webinar of July 11th that lists all the various scenarios that PSE might model, respond to PSE's question of how it should meet the 20% alternative compliance option offered in the Clean Energy Transformation Act (CETA), and on demand response.	PSE appreciates the involvement by NWEC and thank you for your input.
8/18/2020	Joni Bosh, NW Energy Coalition	The Social Cost of Carbon (SCC) represents the costs of environmental damages that society at large, not PSE customers, bears from GHG emissions. The SCC is an environmental externality which CETA requires be applied when making resource decisions to account for the effects of GHG emissions. As an externality, the SCC should be applied to dispatch of all resources both owned and acquired, and all market purchases (since the source cannot generally be known for market purchases), rather than applied as part of the fixed costs of capital assets. In neither case should the SCC be treated as part of the revenue requirement.	Thank you for your description concerning defining environmental externality in terms of relevant to the SCC.
8/18/2020	Joni Bosh, NW Energy Coalition	We would further clarify that the comment under "Notes" on scenario 19 on the excel sheet does not exactly capture what we are asking for – the SCC should be added at dispatch to all resources; adding the SCC as a separate cost to market purchases would be appropriate, as long as those added costs are not included in the revenue requirement. Therefore, we would change the Note on line 19 to: dispatch cost in LTCE only, SCC not included in electric price, BUT AS so a separate EXTERNAL COST adder included for TO ALL market purchases.	Thank you for the clarification.
8/18/2020	Joni Bosh, NW Energy Coalition	We would consider the options described on lines 35 and 36 as "bookends" for the initial analysis purposes.	Thank you for your comment.
8/18/2020	Joni Bosh, NW Energy Coalition	Slide 17 – NWEC would appreciate if the actual values that will be used in modeling are presented in the slide, rather than the descriptors "low", "mid" and "high".	Thank you for the suggestion PSE add more detail to the slides, specifically value ranges on Slide 17 of the August 11 presentation.
8/18/2020	Joni Bosh, NW Energy Coalition	Slide 26 - PSE will need to be very clear as to how the choices will be ranked or prioritized, so there are no unanticipated disappointments if some analyses are not completed.	The actual prioritization of the sensitivities by stakeholders will occur at the October 20, 2020 webinar. We are still thinking through the best way to do that and appreciate this comment.
8/18/2020	Joni Bosh, NW Energy Coalition	Slide 36 – requests feedback from stakeholders on prioritizing the four options that can be considered for alternative compliance. To be very clear, 19.405.040(1)(a)(ii) actually requires a utility to " use electricity from renewable resources and non-emitting electric generation in an amount equal to one hundred percent of the utility's retail electric loads over each multiyear compliance period", which would be the preferred compliance. But we recognize that 19.405.040(1)(b), which immediately follows, allows a utility to meet up to 20 percent of that obligation between 2030 and 2045 with alternative compliance options. Of the options available, the one that should not be evaluated is energy from MSW generators ("garbage burners"), which have yet to be proven to provide a net reduction in GHG emissions.	To clarify, PSE is modeling 100% of the utility's retail electric loads over each multiyear compliance period as a sensitivity. There will be opportunity to additional stakeholder feedback at the October 20, 2020 webinar. PSE agrees with NWEC; PSE will not be evaluating the MSW generators ("garbage burners") in the 2021 IRP.

Feedback Form Date	Stakeholder	Comment	PSE Response
8/18/2020	Joni Bosh, NW Energy Coalition	NWEC proposes the following additional sensitivities: • Advanced Demand Response, based on the Northwest Power and Conservation Council draft inputs, including resource potential and cost by DR type, for the 2021 Northwest Power Plan, adjusted as appropriate for the mix of customer classes and uses in PSE's service territory. This will help provide an estimate of the potential to address PSE's capacity needs as the resource mix changes in the coming decade and beyond. • Updated Upstream Methane Factor, using the EDF Low upstream emissions factor of 2.47% as documented in the NW Council's workshop that we forwarded as part of the IRP comment process. NWEC requested this sensitivity during the August 11 workshop but it is not reflected in the updated version of the summary spreadsheet. We recommend running this sensitivity using scenario #1, mid economic conditions, and substituting the 2.47% upstream methane emissions factor. This will provide a bookend sensitivity on upstream emissions and the social cost of carbon for PSE's resource portfolio and market purchases. • High Electric Vehicle Saturation, using an appropriate scale-up factor such as 50% higher than the forecast estimate for 2025, adjusted appropriately thereafter. We recommend two versions of this sensitivity, one assuming no load shaping and the other assuming some combination of rate design and incentives to shape demand away from system peak. The purpose of this sensitivity is to assess the impact of faster EV saturation on overall resource needs and specifically on daily and seasonal peak impact.	Thank you for providing your additional sensitivities requests. They have been added to the list. PSE is still considering the modeling options related to the upstream emissions and will provide additional information in the consultation update on September 1, 2020. PSE will be asking stakeholders prioritize the sensitivities during the October 20 IRP meeting. At this part of the process, stakeholders will have access to the draft portfolio results to better inform their selections. Stakeholders will provide valuable feedback as to how PSE can best prioritize sensitivity analyses.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 11: I'm still struggling some with the difference between a scenario and a sensitivity. It seems to me that some single-input changes, which could be called a sensitivity, could change the company's electric price forecast. It would be nice if it was possible to freeze the electric price forecast, and then compare various tweaks to the models and see how PSE might respond to that forecast, but if a sensitivity is likely to impact the forecast, then the comparison becomes difficult.	Scenarios are different sets of assumptions that create future power market conditions. These assumptions include: - Gas prices, carbon regulation, and regional loads that create different wholesale market power prices, which affect the relative value of different resources. - Wholesale price forecasts developed using the AURORA model. - Other major generators in the Western U.S., as well as loads from those areas. Portfolio sensitivities are minor changes to a scenarios set of assumptions that create alternate portfolios of supply and demand side generation for PSE. - A scenario must be selected to change in order to perform a sensitivity analysis. - Typically, a single variable or single set of assumptions is changed in order to isolate the effect of that change on the scenario. - The results of a sensitivity can be compared to the base scenario, or other sensitivities that are based on the same scenario. The electric price forecast is an input to the IRP model. PSE runs different scenarios to create different electric price forecasts to test with PSE's portfolio. PSE will reach out to you to discuss this further.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 15: Economic conditions are perhaps the biggest assumptions in the portfolio, and have become very difficult to vet given the pandemic and apparent recession. How will PSE's scenarios and sensitivities give the company a good view of the relative value of different resource decisions in a volatile environment? Is there a tipping point for economic indicators that would prompt PSE to either use the inputs representing low economic conditions for various sensitivities? o In general, how, if at all, does the IRP modeling process inform which indicators the utility monitors to inform adaptive management practices?	Concerning how the IRP modeling process informs which indicators the utility monitors to inform adaptive management practices, PSE applies adaptive management practices through our corporate governance processes. For example, the demand forecast is approved by an executive oversight group prior to sharing with stakeholders. For the IRP, PSE runs a stochastic analysis that varies different economic conditions such as demand forecast, gas prices and electric price forecasts.

Feedback Form Date	Stakeholder	Comment	PSE Response
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 19: What does the over-generation sensitivity represent? Is this the removal of a modeling constraint that prevents overgeneration?	During the 2019 IRP process, PSE evaluated modeling results and found that there were hours where renewable generation was being sold into the market but the energy was still being counted towards meeting the renewable requirement. This test is isolates PSE as a system to prevent the renewable energy from being sold, forcing it to be curtailed or stored instead.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 20: What decision point does sensitivity 13 analyze? It seems that the trapped energy issue explored here might be better understood through a stochastic analysis using PSE's granular historical data for wind and solar resources in WA. There also may be some Tx paths or renewable generation profiles that are complement each other such that 'overbuilding' relative to available Tx is more reasonable in some regions than it is in others. Is this nuance explored within sensitivity 13? Relatedly, do the transmission constraint sensitivities effectively model minimum in-state builds?	Concerning the first question, yes, PSE will be getting to the trapped energy issue in sensitivity 13. This sensitivity evaluates buying less than nameplate firm transmission and evaluating the risk if non-firm transmission can be purchased for the energy over transmission limit or if the energy will get curtailed. Concerning 'overbuilding' or complimentary renewable generation, this is addressed in the baseline assumptions with dual purpose transmission.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 21: What NEIs are included in sensitivity 16? I understand that the CPA provided some NEIs on a measure-by-measure basis. I'd like to better understand this and verify that there's no double-counting here, and that NEIs are appropriately included in the baseline model run. Relatedly, the company has previously mentioned that early runs show the cost-effective conservation selection are pretty far up the conservation curve. Where specifically? In the company's current runs, what is the $/MWh delta between where the marginally cost-effective bundle and the next available conservation bundle that was marginally not cost-effective?	PSE will provide additional information in the consultation update available on September 1, 2020.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 24: It seems that sensitivity 26 includes two different constraints – no new gas, and 100% renewable by 2030. I have no problem with these constraints as a modeling exercise, but would appreciate some clarification. Are these separate constraints? Or does no new gas lead to 100% renewable by 2030 for some reason?	Sensitivity #26 models 100% renewable generation by 2030. We understand your confusion and will change the description to say "100% renewable resources by 2030, no gas generation" in the updated excel file.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slides 29-36 were skipped. I hope we get a chance to discuss these, as I think stakeholder feedback on how to contemplate Energy Transformation Projects in the IRP would be useful.	Thank you for your comment. Slides 29-36 will be presented at the September 1 webinar. Concerning how PSE will contemplate Energy Transformation Projects, this is an IRP result, and will be presented later in the process and be included in the final 2021 IRP.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slides 47-48: These projects are exciting. Other utilities, such as Green Mountain Power, PGE and a number of California IOUs, are even further down this road. Is PSE going to extrapolate from current demonstrations and projects from other utilities to develop cost and resource size estimates appropriate to PSE's service territory? Will these resources be selectable within PSE's modeling tools?	For the 2021 IRP modeling process, PSE plans to use the generic resource cost discussed during the 2021 IRP webinar 1 held on May 28, 2020. Stakeholders reviewed those costs and provided feedback, which was summarized in the feedback report and consultation update available on our website. The IRP process will select generic storage resources, which could be delivered through many different program designs. PSE's own demonstration work, and our regular discussions with other utilities, form a basis for what will actually be implemented in future programs and the associated values from that implementation.

Feedback Form Date	Stakeholder	Comment	PSE Response
			
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 54: How soon will these forecasting and hosting capacity capabilities be available? Will this granularity prompt a revisit of the system-wide T&D deferral estimates?	PSE will be addressing these questions in the consultation update on September 1, 2020.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 54: How does PSE anticipate the geospatial analysis will inform the utility's compliance with CETA's requirement to equitably distribute energy- and non-energy benefits?	PSE will be addressing these questions in the consultation update on September 1, 2020.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slides 57-58: I understood the company's explanation of the must-take solar and batteries as an inclusion of PSE's acquisition of these resources not for whole-system need, but as cost-competitive alternatives to other distribution-level system projects. Is this correct? This seems reasonable, but more information would be useful – info on historical acquisition rates for these types of NWAs, and on the company's forecasted future acquisitions. Are the ~160 MW of cumulative resources shown in slide 57 *all* included as must-take?	PSE will be addressing these questions in the consultation update on September 1, 2020.
8/18/2020	Kyle Frankiewich, WUTC Staff	[Recommendation 1:] Clarity on baseline to sensitivities: The IRP participants discussed many requests that would alter the assumptions that are nailed down in the baseline. I'm using the word 'baseline' to mean the best approximation at a business-as-usual forecast with middle-of-the-road inputs across the board. I encourage the company to spend some time going over what inputs are included in this baseline run, as, if I understand correctly, all sensitivities and some scenarios will be compared to this.	Thank you for your feedback. PSE will include a full description in the IRP book and discuss the baseline assumptions in more detail at the October 20 webinar.
8/18/2020	Kyle Frankiewich, WUTC Staff	[Recommendation 2:] Sensitivity and scenario requests: I've tried to pull together staff requests made thus far in the process. I've compiled these in the attached Excel spreadsheet. Staff appreciates that many of our requests have been included in the 31 sensitivities listed by PSE.	Thank you for the attached Excel spreadsheet and the additional sensitivity requests. The file you provided have been uploaded as part of the Webinar 6 Feedback Form package on pse.com.
8/18/2020	Kyle Frankiewich, WUTC Staff	[Recommendation 3:] SCC as fixed-cost adder vs in dispatch: Staff is still at the learning stages in vetting this modeling decision. I understand that previous analysis has shown that the RPS component of CETA carries the most weight in determining PSE's future resource needs. I hope the company does a similar comparison in this cycle. Accepting the	Thank you for your feedback. PSE will include an SCC only sensitivity on the list and will run the analysis to test how the portfolio builds change with SCC as a fixed-cost adder vs a dispatch cost. This can be found as sensitivity 38 in the updated sensitivity spreadsheet.

Feedback Form Date	Stakeholder	Comment	PSE Response
		premise that, over the long term, the RPS is the main constraint guiding PSE's resource acquisitions, I still think this may be relevant with regard to gauge near-term cost-effectiveness for conservation, demand response, and distributed energy resources. I am also interested in Participant Gutman-Britten's proposal to run this side-by-side without the RPS constraint, which will give us a view into whether the optimized portfolio changes dramatically based on this modeling decision.	
8/18/2020	Kyle Frankiewich, WUTC Staff	[Recommendation 4:] Federal CO2 tax: I echo other stakeholders in recommending that the federal carbon tax modeled in sensitivity 22 be structured to align with bills being proposed in Congress.	Thank you for your feedback. This support is noted in the updated sensitivity spreadsheet.
8/18/2020	Kyle Frankiewich, WUTC Staff	[Recommendation 5:] Upstream emissions and NWPCC: I haven't verified this, but I understand that the Northwest Power and Conservation Council intends to model upstream emissions on natural gas in their next power plan. I have heard that their estimate is about 1.37% leakage. How does this compare to the estimates PSE intends to use? How does this compare with other published studies exploring this issue, such as the 2018 EDF assessment? Do the NWPCC's approach and assumptions align with PSE's (EPA and Canadian province govt estimates, if I recall)? To the extent PSE's modeling of this issue diverges from the Council's, I'd like to fully understand why.	PSE will be addressing these questions in the consultation update on September 1, 2020.
8/18/2020	Kyle Frankiewich, WUTC Staff	[Recommendation 6:] Climate change and weather data inputs: This issue may be more appropriate in the stochastic modeling and resource adequacy portion of the IRP process, but I wanted to flag this as an area of interest for staff. My core concern is whether PSE's preferred resource portfolio performs great under historical weather and water inputs, but poorly under weather inputs adjusted to account for climate change. PSE's planning efforts should contemplate this risk. Perhaps this could be part of a scenario tree as in slide 15, or perhaps we can see what we learn from scenario 31; we're open to discussion on how best to address this. Relatedly, is PSE's Itron Study re: Climate Change complete? If so, please provide a copy of the study and findings; please provide a rough timeframe if not.	Thank you for your feedback. PSE shares your concerns and plans to use the temperature sensitivity as well as the high and low demand forecasts and the stochastic analysis to inform the resource plan. PSE's load forecast is based on a normal weather assumption of heating degree days (HDD) and cooling degree days (CDD) calculated using hourly temperatures measured at the NOAA SeaTac weather station. This normal assumption is constant throughout the forecast period. Itron will construct trended HDDs and CDDs that reflect historical temperature trends at the SeaTac weather station. Steps include: 1. Itron will evaluate average and peak-producing temperature trends. Itron will evaluate the following concepts: • Average annual temperature • Maximum annual temperature • Minimum annual temperature 2. From the analysis in step 1, Itron will construct a trended normal daily temperature series, and trended normal daily and monthly HDD and CDD that may be used by PSE's current set of load forecast models. Results will be delivered to PSE in an Excel spreadsheet. 3. Itron will produce a report documenting the methodology and the results of the temperature trend analysis. The draft report is expected by early October.

PSE IRP Feedback Report Addendum
Webinar 6: Portfolio Sensitivities
August 11, 2020

9/01/2020

The following stakeholder input was gathered through the online Feedback Form, from August 4 through August 18, 2020. PSE was unable to gather the responses in time for the August 25, 2020 Feedback Form. This report addendum is a response to the items not included in the August 25, 2020. The responses were published on September 1, 2020 and referenced in the Consultation Update.

Feedback Form Date	Stakeholder	Comment	PSE Response
8/18/2020	Katie Ware, Renewable Northwest	1. Renewable Northwest appreciates PSE's request for stakeholder suggestions regarding the appropriate portfolio sensitivities PSE should model. Below are our recommendations: a. Regarding the renewable over-generation test, we recommend that PSE incorporate the effects of this sensitivity on the 2% cost threshold relevant to compliance with CETA standards. Specifically, should PSE choose to or be required to over-generate renewables to meet load, how early in a compliance period would PSE meet the 2% cost threshold, and thus be considered in compliance with the clean energy standards? b. Regarding the must-take DR and battery storage sensitivity, we again recommend that PSE incorporate the effects on the 2% cost threshold. We recommend that PSE consider this detail in modeling other sensitivities which may lead PSE to the cost cap early in each compliance period. c. Regarding the highly-centralized sensitivity within the Transmission Constraints and Build Limitations category, we recommend that PSE consider including additional constraints specific to renewable proxy locations, whereby a strict delivery requirement mandated by CETA may create geographic limitations to new-build renewables. d. Regarding the SCC as a tax in WA, OR and CA sensitivity, we agree with PSE that this tax should be modeled WECC-wide for consistency.	Thank you for your comments and questions. PSE responses referenced as "a – d": a. PSE plans to include renewable resources to meet CETA requirement and does not elect to over-generate renewable resources during planning. However, over-generation may occur during certain times of the year. It is important to understand the impact of over-generation without additional constraints. Including the 2% cost threshold may limit the addition of new resources and thus not meet CETA requirements. PSE plans to model the over-generation sensitivity without the 2% cost threshold. b. The description you provided is consistent with PSE's approach regarding the must-take DR and battery storage. c. <u>Update for September 1</u>: PSE reached out to Katie Ware on 08/27 and the clarification will be made well before the October 20 IRP meeting. d. Thank you for expressing your support for implementing the SCC as a WECC-wide tax. This will be noted in the updated spreadsheet file.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 11: I'm still struggling some with the difference between a scenario and a sensitivity. It seems to me that some single-input changes, which could be called a sensitivity, could change the company's electric price forecast. It would be nice if it was possible to freeze the electric price forecast, and then compare various tweaks to the models and see how PSE might respond to that forecast, but if a sensitivity is likely to impact the forecast, then the comparison becomes difficult.	Scenarios are different sets of assumptions that create future power market conditions. These assumptions include: - Gas prices, carbon regulation, and regional loads that create different wholesale market power prices, which affect the relative value of different resources. - Wholesale price forecasts developed using the AURORA model. - Other major generators in the Western U.S., as well as loads from those areas. Portfolio sensitivities are minor changes to a scenario that creates alternate portfolios of supply and demand side resources for PSE. - A scenario must be selected to change in order to perform a sensitivity analysis. - Typically, a single variable or single set of assumptions is changed in order to isolate the effect of that change on the scenario. - The results of a sensitivity can be compared to the chosen scenario, or other sensitivities that are based on the same scenario. The electric price forecast is an input to the IRP model. PSE runs different scenarios to create different electric price forecasts to test with PSE's portfolio. PSE will reach out to you to discuss this further. <u>Update for September 1</u>: PSE discussed this with Kyle on 08/27/2020.

Feedback Form Date	Stakeholder	Comment	PSE Response
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 21: What NEIs are included in sensitivity 16? I understand that the CPA provided some NEIs on a measure-by-measure basis. I'd like to better understand this and verify that there's no double-counting here, and that NEIs are appropriately included in the baseline model run. Relatedly, the company has previously mentioned that early runs show the cost-effective conservation selection are pretty far up the conservation curve. Where specifically? In the company's current runs, what is the $/MWh delta between where the marginally cost-effective bundle and the next available conservation bundle that was marginally not cost-effective?	PSE will use the EPA study suggested by NWEC for the sensitivity that accounts for the health benefits of conservation. There will be no overlap with the NEIs that are currently in the CPA as they not related to the health benefits addressed by the study. More data will be available regarding the supply curve once the portfolio analyses are complete.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 54: How soon will these forecasting and hosting capacity capabilities be available? Will this granularity prompt a revisit of the system-wide T&D deferral estimates?	PSE expects to implement geospatial load forecasting in 2021. Hosting capacity analysis methods are currently being researched and requirements for those tools are in development. The requirements of the selected tool will drive the implementation schedule, but implementation of HCA is expected by 2022. Full capability will not be realized until the completion of AMI implementation in 2023. Geospatial load forecasting and HCA would not trigger a revisit of the system-wide T&D deferral estimate. Additional analysis would be required to determine if adjusting the T&D deferral value was warranted.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 54: How does PSE anticipate the geospatial analysis will inform the utility's compliance with CETA's requirement to equitably distribute energy- and non-energy benefits?	PSE anticipates that demand side management and customer DER program participation will be modeled in the geospatial load forecast. Equity and accessibility in program design will be reflected in the forecast, and will drive electric system investments accordingly.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slides 57-58: I understood the company's explanation of the must-take solar and batteries as an inclusion of PSE's acquisition of these resources not for whole-system need, but as cost-competitive alternatives to other distribution-level system projects. Is this correct? This seems reasonable, but more information would be useful – info on historical acquisition rates for these types of NWAs, and on the company's forecasted future acquisitions. Are the ~160 MW of cumulative resources shown in slide 57 *all* included as must-take?	Yes, that is correct. As presented in the table on Slide 58, must-take solar and batteries as an inclusion of PSE's acquisition of these resources not for whole-system need, but as cost-competitive alternatives to other distribution-level system projects. As presented in the table on Slide 58, must-take solar and batteries are included as cost-competitive alternatives to other distribution-level system projects. Concerning your suggestion for additional information: PSE's work regarding NWAs began in 2018/2019 and is growing. To date, one area's concerns are economically solved by NWA (Bainbridge Island). More area studies on this process are underway to determine solution viability. The NWA forecast as shown on slide 57 was developed from comparing the known concerns against characteristics that were proven by the Bainbridge Island solution. More detailed studies will be performed to sharpen this forecast over time. The forecast basis for storage and targeted EE/DR are based on both the Bainbridge Island and Lynden NWA study results, while the PV projection is based on current industry knowledge. The forecast will become more accurate as we complete more studies. This forecast includes Non-wire alternatives to solve localized capacity needs. Correct, the ~160 MW of cumulative resources shown in slide 57 *all* are included as must-take.
8/18/2020	Kyle Frankiewich, WUTC Staff	[Recommendation 5:] Upstream emissions and NWPCC: I haven't verified this, but I understand that the Northwest Power and Conservation Council intends to model upstream emissions on natural gas in their next power plan. I have heard that their estimate is about 1.37% leakage. How does this compare to the estimates PSE intends to use? How does this compare with other published studies exploring this issue, such as the 2018 EDF assessment? Do the NWPCC's approach and assumptions align with PSE's (EPA and Canadian province govt estimates, if I recall)? To the extent PSE's modeling of this issue diverges from the Council's, I'd like to fully understand why.	PSE reached out to Kyle on 08/27 to discuss this and there will be additional follow-up.

Vehicle to Grid Potential

On August 11, PSE held a webinar on Distributed Energy Resources. Among the topics I expected to be mentioned was Vehicle-To-Grid (V2G) or Vehicle/Grid Integration (VGI). This is a technology that allows unused battery capacity in electric vehicles to provide electricity to the grid, especially during periods of peak demand or outage scenarios. Many utilities are now starting to include pilot programs in their IRPs. Although broad penetration of V2G may be some years away, it is likely to provide huge opportunities in the 20-year timeframe, especially as storage is needed to stabilize the contribution of variable renewable resources.

PSE's analysis of DERs is even longer than 20 years to plan for the CETA mandate of 100% clean electricity by 2045. For this reason, I was surprised when I asked about V2G technology, and PSE planners did not seem familiar with the term. Perhaps they know it as VGI instead, but neither term appeared in their long-range plans or sensitivities.

A quick Google of the terms V2G and IRP gives an overview of what is occurring in other states. For example, Austin Energy announced a partnership with Pecan Street 18 months ago to start a pilot project. The partners said, "**V2G/V2H/V2B should not be left out of utility integrated resource planning** (IRP), distribution resource planning (DRP) and/or energy procurement plans. Given the long planning horizon, it makes sense to start thinking about V2G soon."[1]

Energy and Environmental Economics (E3), a consultant PSE has used for analysis of DERs and NWAs on several occasions, says, "The base case benefits of $338 per vehicle per year are achieved with limited cycling to preserve battery heath and without the expense and complication of providing ancillary services. Including ancillary services increases the value to $407 per EV."[2] Also, the value of outage relief might be of significant value to residential customers.

Rocky Mountain Institute has a detailed paper titled "Electric Vehicles as Distributed Energy Resources," now more than three years old.[3]

Given the challenges of achieving CETA goals, it is almost inconceivable that PSE is not seriously contemplating V2G as a significant part of the puzzle. As the resource of idle car batteries continues to grow, it is likely to become the largest battery resource in PSE's service territory, if it hasn't already earned that crown. To integrate larger percentages of solar and wind resource without batteries of this capacity will be difficult, if not impossible, to achieve in a cost-effective manner. These batteries have already been purchased, and most are idle for 90% or more of their existence. PSE should become a leader in V2G adoption and show the rest of the country how clean, green, and technologically advanced the Puget Sound region is.

[1] https://utilityanalytics.com/2019/05/austin-energy-and-others-moving-closer-to-v2g/
[2] https://www.linkedin.com/pulse/capacity-benefits-v2g-eric-cutter
[3] https://rmi.org/wp-content/uploads/2017/04/RMI_Electric_Vehicles_as_DERs_Final_V2.pdf

Time-of-use sensitivity

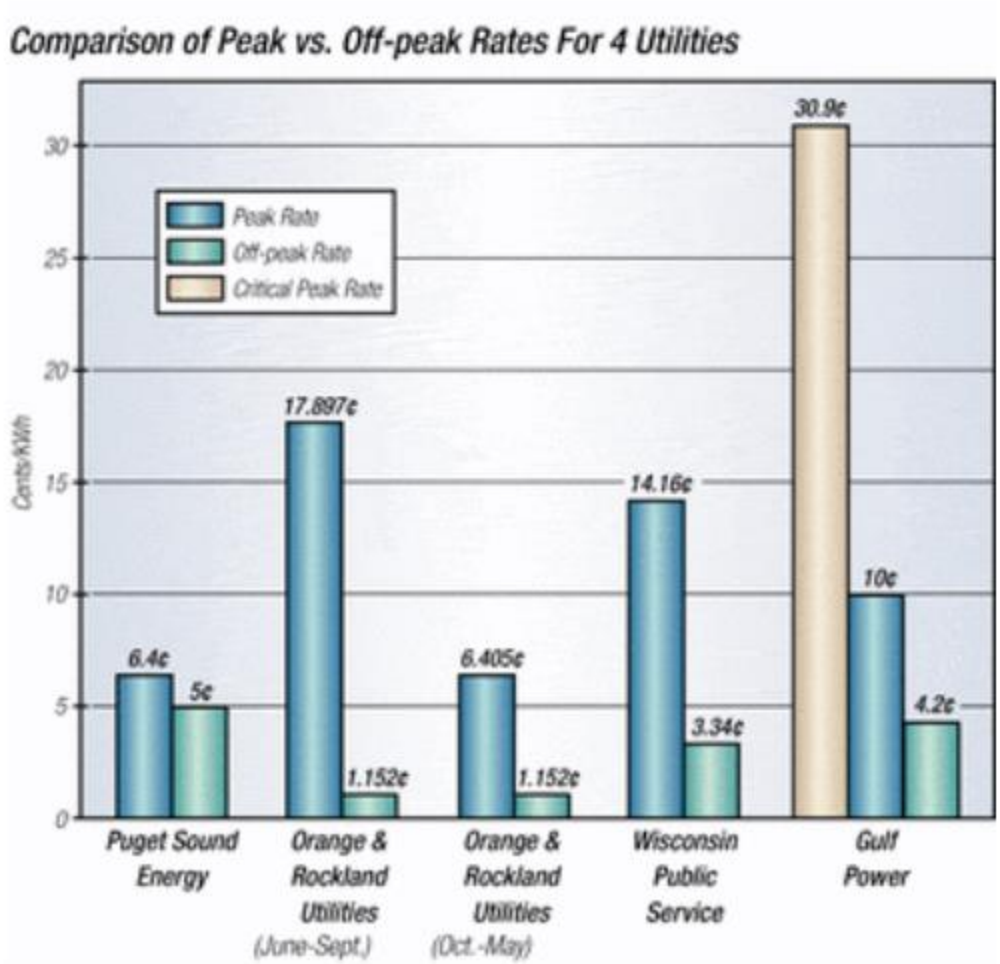
I encourage PSE to include a robust "time-of-use" (TOU) analysis in its sensitivities related to Distributed Energy Resources. The company's recent investments in smart meters enable broad deployment of this important economic signal throughout its service territory.

Why is TOU so important at this time?

1. TOU shifts and smooths the daily demand curve, better matching supply from renewable resources, and helping to reduce greenhouse gas emissions.
2. TOU makes investments in batteries more attractive for customers. Customers can charge their batteries during off-peak hours when TOU rates are low. Then they can withdraw that electricity when TOU rates are high. The difference in the rates allows customers to gradually recoup the cost of their investment. Customers or installers can simply set a few configuration parameters for the battery system. It's truly "set it and forget it." We want to incentivize battery purchases because they make our electric grid more reliable and resilient, keeping the lights on after a big storm or earthquake damages the grid.
3. By avoiding wild swings in electricity consumption throughout the day, stress on equipment is reduced. Less frequent failures save customers money and reduce unplanned outages. Also, reduction of demand peaks reduces the need to overbuild infrastructure to handle excessive peaks. This also saves money.
4. TOU rates give customers another tool to reduce their monthly electric bill. By voluntarily shifting high-demand activities to off-peak times (especially charging EVs or doing laundry), customers can reduce bills significantly.
5. When PSE pioneered TOU rates 20 years ago, the program not only shifted peak consumption, it actually led to overall conservation of about 1%. This should not be a surprise. Customers who are aware of their energy use and make conscious choices about consumption are more likely to avoid wasting electricity, even during less expensive hours.

Although PSE was a leader in TOU technology, the company's large-scale pilot program ended with a whimper. Many customers found the program *increased* their monthly bills, and the UTC pulled the plug on the program. However, this failure can easily be avoided today, for the following reasons:

1. As noted in several post-mortem analyses (like https://www.power-grid.com/2003/01/01/why-time-ran-out-on-pses-time-of-use-program/), the difference between PSE's highest and lowest TOU rates was not great enough to motivate customers to make significant changes. In the graph below, PSE's rate differential was only 1.4 cents per kilowatt-hour. The average differential among the other utilities was almost 10 cents per kilowatt-hour, an amount that could really get customers' attention! A proportional differential would be 15-20 cents today.



2. PSE hired a very expensive subcontractor to manage the large amounts of consumption data generated by the program. PSE passed the costs onto customers, resulting in higher bills than the customers were expecting. Today, PSE can probably handle the data in house at much lower costs.
3. Customers have more options to shift demand now than they did 20 years ago. Many appliances come with timers. All the EVs that I'm aware of have configuration options to delay charging until off-peak hours. Currently, customers have no incentive to configure these options. This will become a challenge for the grid as more customers buy EVs. With TOU rates, a customer who spends a few minutes configuring the charging program can significantly reduce the cost of operating the vehicle.
4. If customers are aware that electricity consumed during peak hours creates higher greenhouse gas emissions, they will have an extra incentive to "do the right thing" and reduce peak consumption, even if they aren't worried about peak prices. PSE can help educate the public as Sacramento Municipal Utility District does so well in this video: https://ipx.bcove.me?url=https%3A%2F%2Fwww.smud.org%2Fen%2FIn-Our-Community%2FWorkshops-and-education-resources%2FResidential%2FEducational-Video-Library%3FvideoId%3D6034376728001&accountId=769719904&experienceId=5bbfbfcbb5a78f000f3eaa37&videoId=6034376728001

If PSE implements a TOU program with a large differential between low and high rates, if data handling charges are handled responsibly, and if the public is well aware of the economic and environmental benefits of this program, we expect to see a significant shift in peak demand that would decrease the need for, and the value of, new peaker plants. If paired with incentives for batteries and Vehicle-to-Grid programs, TOU could become instrumental in achieving CETA goals in a cost-effective, highly reliable manner.

PSE led the industry with a forward-looking TOU program 20 years ago. According to the Power Grid article referenced earlier, “The ballyhooed pilot program garnered industry awards and headliner status at power industry trade shows. It was a bright and shining star in an otherwise gloomy Western power scene, and it had industry participants excited about the prospects of demand response in general.”

The time has come for PSE to lead again toward a cleaner, more sustainable future for Puget Sound and the world!

Don Marsh
August 12, 2020

Virtual Power Plant Sensitivity

I request that PSE's 2021 IRP sensitivity studies include analysis of PSE-orchestrated Virtual Power Plants (VPP). A VPP is the epitome of Distributed Energy Resources, using monitoring and control software to optimize the contributions of many small resources (like residential batteries and solar panels). Such a system can provide significant amounts of electricity to the grid during peak demand periods.

At the PSE's August 11 IRP webinar, PSE said the company did not have the right software to implement a VPP at present, but this will likely change in the 24-year period covered by this IRP.

To appreciate the benefits of VPPs, imagine that tens of thousands of PSE's residential customers have installed batteries paired with solar panels. (As prices fall, this is a likely scenario in the next decade or two, whether PSE participates or not.) Without technology to coordinate the operation of this large collective resource, individual systems operate independently for the benefit of their owners, but not necessarily addressing grid needs. The resource is wasted.

Now imagine a scenario where PSE can coordinate those systems via its VPP software. As demand peaks on a typical morning, PSE taps thousands of batteries to help meet demand rather than firing up carbon-spewing peaker plants. As demand starts to subside in the late morning hours, PSE reverses the flow. Now the batteries soak up extra electricity coming from solar and wind plants, as well as solar panels on customer rooftops. When the next demand peak comes late in the afternoon, the batteries are full and ready to assist once again. During the night, the batteries are gradually recharged to prepare for the next morning.

That scenario could be handled with large grid batteries, but there are a few advantages to a VPP created with thousands of small batteries.

1. A VPP delivers higher reliability and resilience when a big storm or earthquake damages the grid for days or weeks. It is advantageous for at least some customers to have power in that dire scenario. They can help their neighbors, charge cell phones, or even provide temporary refuge for vulnerable members of society.

2. Many customers are willing to pay a portion of the cost of an energy system that provides greater security and increases the value of their homes. Some customers are motivated to make investments that reduce the environmental impact of their energy consumption.

3. Small batteries don't require a dedicated plot of land and high interconnection costs. A VPP can't be destroyed by an accident in a single location.

4. Local jobs will be created to install these systems. It would be a post-COVID shot in the arm for our economy, supporting local businesses without tapping taxpayer funds.

To provide equitable access, we think PSE should incentivize purchase of solar and battery systems. Perhaps families in the bottom quartile of the income scale could buy the system with attractive financing and a 75% discount. Even with financing payments, they would enjoy lower energy bills than without the system. Families with higher incomes should also get a discount, but perhaps only 25%.

Portland General Electric and PacifiCorp are both considering VPP for their next IRPs. PSE should likewise study a sensitivity with a growing VPP resource over time. Although the prevalence of VPPs will grow over time, Tesla is currently running a VPP with 1,000 low-income participants, growing to 50,000 in the years ahead (video here: https://youtu.be/k8WHS2n4Iq0). The U.K. and China also have large programs.

The "transformation" aspiration of the Clean Energy Transformation Act requires bold planning and timely action to achieve our emission targets by 2030 and 2045. VPPs, Vehicle-to-Grid, and Time-of-Use electric rates are powerful tools to achieve this transformation. All should be included in sensitivities studied for the 2021 IRP.

Don Marsh
August 13, 2020

Overall Comment on Use of the Social Cost of Carbon

During Webinar 6 on August 11, 2020, Puget Sound Energy (PSE) did not adequately respond to or resolve the concerns expressed by Invenergy and other stakeholders about its preferred approach to including the Social Cost of Carbon (SCC) in its 2021 Integrated Resource Plan (IRP).

Invenergy strongly encourages PSE to reconsider including the SCC as a fixed annual cost in the resource portfolio modeling for its 2021 IRP. Instead, PSE should treat the SCC as an incremental cost of hourly dispatch for Greenhouse Gas (GHG)-emitting resources. This approach will be more consistent with:

a) the purpose and intent of the Clean Energy Transformation Act (CETA);
b) accepted practices for internalizing the environmental externality costs of GHG emissions into decision-making; and
c) how the SCC was developed as an estimate of the economic value of environmental damages caused by GHG emissions and the intended use of the SCC.

Before proceeding with the resource portfolio modeling sensitivity analyses, Invenergy strongly encourages PSE to address the issues surrounding properly including the SCC in its resource portfolio modeling analyses for the 2021 IRP.

Specific Comments

1. CETA imposes two distinct requirements for PSE to limit its GHG emissions. The first requirement is to limit its annual GHG emissions (i.e., 80 percent GHG-free by 2030 and 100 GHG-free by 2045). The second requirement is for PSE to incorporate the SCC into its resource planning and acquisition decisions.

2. Satisfying just one of these requirements does not relieve PSE of its obligation to satisfy the other requirement. Therefore, PSE needs to properly incorporate the SCC in its 2021 IRP.

3. GHG emissions are an environmental externality. They are a real cost to society that is caused by but not borne by PSE or its retail electric customers. As a result, GHG emissions and the environmental damages they cause represent a clear <u>market failure</u>. Until and unless a mechanism to solve this market failure (e.g., carbon tax or GHG cap and trade program) is implemented in Washington State, the best available means for dealing with this market failure is to treat GHG emissions as an environmental externality.

4. Instead of imposing a carbon tax or creating a GHG cap and trade program, it is quite clear that the intent of CETA is to treat GHG emissions as an environmental externality. While CETA does not explicitly use the terms “environmental externality” or “market failure”, it recognizes and requires utilities to deal with GHG emissions as such. For example, Subsection 14(3)(a) of CETA states the following:

    > *An electric utility shall consider the social cost of greenhouse gas emissions, as determined by the commission for investor-owned utilities pursuant to section 15 of this act and the department for consumer-owned utilities, when developing integrated resource plans and clean energy action plans. An electric utility must incorporate the social cost of greenhouse gas emissions as a cost adder when:*

(i) Evaluating and selecting conservation policies, programs, and targets;
(ii) Developing integrated resource plans and clean energy action plans; and
(iii) Evaluating and selecting intermediate term and long-term resource options.

5. Further, Section 15 of CETA identifies the SCC as the required metric for treating GHG emissions as an environmental externality:

> *For the purposes of this act, the cost of greenhouse gas emissions resulting from the generation of electricity, including the effect of emissions, is equal to the cost per metric ton of carbon dioxide equivalent emissions, using the two and one-half percent 21 discount rate, listed in table 2, technical support document: Technical update of the social cost of carbon for regulatory impact analysis under Executive Order No. 12866, published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016. The commission must adjust the costs established in this section to reflect the effect of inflation.*

6. The SCC was developed by the federal Interagency Working Group (IWG) as an economic estimate of the *real, incremental* environmental damage costs caused by the emission of one metric ton of CO2-equivalent GHG emissions. The IWG specifically designed and developed the SCC to quantify the externality effects of GHG emissions and incorporate them into economic decisions.

7. Applying the SCC as an incremental cost is also consistent with well-established economic principles for incorporating environmental externalities into decision-making, including for integrated resource planning.

8. Environmental damages caused by GHG emissions are *incremental* costs; they are not *fixed* costs. Correspondingly, the SCC is an estimate of the *incremental* economic costs – not the fixed economic costs – of the environmental damages caused by GHG emissions.

9. While CETA requires PSE to use the SCC to represent the environmental damage costs caused by GHG emissions, it does not authorize PSE to include the damage costs in its revenue requirements or in its retail electric rates.

10. Therefore, PSE's analysis for its 2021 IRP needs to recognize the distinction between the two types of costs and account for them properly. Specifically, resource decisions should be made on the basis of the sum of revenue requirements costs plus environmental damage costs (as represented by the SCC). However, rate impacts of resource decisions should only include revenue requirements costs.

11. There is nothing in CETA that requires or justifies treating the SCC as a fixed annual cost.

12. Treating the SCC as a fixed annual cost biases resource decisions in favor of more GHG-intensive resources. A key reason for this is that excluding the SCC from simulation of hourly dispatching decisions in the portfolio modeling leads to increased generation by more GHG-intensive resources. In turn, this allows the fixed costs of the more GHG-intensive resources to be spread over a larger quantity of

generation, thereby causing the total (revenue requirements and externality) costs of those resources to artificially appear lower than if the SCC were included in hourly dispatching decisions.

13. PSE has said its past analyses showed that including the SCC as a variable cost of dispatch did not materially change the mix of resources in its modeling results. Invenergy remains skeptical about the validity of this conclusion, including due to flaws in PSE's prior assumptions and methodology for incorporating the SCC. Further, if including the SCC as a variable cost of dispatch truly does not change PSE's resource decisions, then PSE should have no objection to using that method.

14. If PSE does not agree that the SCC should be properly modeled as an incremental cost of hourly dispatch, PSE should perform a fair and rigorous side-by-side analysis of PSE's preferred approach of treating the SCC as a fixed annual cost with the more sound approach of including the SCC as a variable hourly dispatch cost for existing and new GHG-emitting resources it would use to serve its retail customers' needs. PSE should complete the side-by-side analysis and obtain feedback on the results from stakeholders *before* proceeding with the numerous portfolio sensitivity analyses it is planning to perform.

NW Energy Coalition
Comments on and Requests
regarding the PSE 2021 IRP Webinar #6:
Scenarios Feedback Session, August 11th, 2020

Elizabeth Hossner
Manager Resource Planning & Analysis
Puget Sound Energy

Dear Elizabeth:

NW Energy Coalition (NWEC) appreciates the opportunity to ask questions about and make suggestions regarding Puget Sound Energy's (PSE's) proposed portfolio scenarios and sensitivities to address in analysis in the Integrated Resource Planning effort. Our comments focus on the excel slide presented in the webinar of July 11th that lists all the various scenarios that PSE might model, respond to PSE's question of how it should meet the 20% alternative compliance option offered in the Clean Energy Transformation Act (CETA), and on demand response.

The Social Cost of Carbon (SCC) represents the costs of environmental damages that society at large, not PSE customers, bears from GHG emissions. The SCC is an environmental externality which CETA requires be applied when making resource decisions to account for the effects of GHG emissions. As an externality, the SCC should be applied to dispatch of *all* resources both owned and acquired, and *all* market purchases (since the source cannot generally be known for market purchases), rather than applied as part of the fixed costs of capital assets. In neither case should the SCC be treated as part of the revenue requirement.

We would further clarify that the comment under "Notes" on scenario 19 on the excel sheet does not exactly capture what we are asking for – the SCC should be added at dispatch to *all* resources; adding the SCC as a separate cost to market purchases would be appropriate, as long as those added costs are not included in the revenue requirement. Therefore, we would change the Note on line 19 to: *dispatch cost in LTCE only, SCC not included in electric price, BUT AS ~~so~~ a separate EXTERNAL COST adder ~~included for~~ TO ALL market purchases*.

We would consider the options described on lines 35 and 36 as "bookends" for the initial analysis purposes.

Slide 17 – NWEC would appreciate if the actual values that will be used in modeling are presented in the slide, rather than the descriptors "low", "mid" and "high".

Slide 26 - PSE will need to be very clear as to how the choices will be ranked or prioritized, so there are no unanticipated disappointments if some analyses are not completed.

Slide 36 – requests feedback from stakeholders on prioritizing the four options that can be considered for alternative compliance. To be very clear, 19.405.040(1)(a)(ii) actually requires a utility to " *use electricity from renewable resources and non-emitting electric generation in an amount equal to one hundred percent of the utility's retail electric loads over each multiyear compliance period*", which would be the preferred compliance. But we recognize that 19.405.040(1)(b), which immediately follows, allows a utility to meet up to 20 percent of that obligation between 2030 and 2045 with alternative compliance options. Of the options available, the one that should not be evaluated is energy from MSW generators ("garbage burners"), which have yet to be proven to provide a net reduction in GHG emissions.

NWEC proposes the following additional sensitivities:

- Advanced Demand Response, based on the Northwest Power and Conservation Council draft inputs, including resource potential and cost by DR type, for the 2021 Northwest Power Plan, adjusted as appropriate for the mix of customer classes and uses in PSE's service territory. This will help provide an estimate of the potential to address PSE's capacity needs as the resource mix changes in the coming decade and beyond.
- Updated Upstream Methane Factor, using the EDF Low upstream emissions factor of 2.47% as documented in the NW Council's workshop that we forwarded as part of the IRP comment process. NWEC requested this sensitivity during the August 11 workshop but it is not reflected in the updated version of the summary spreadsheet. We recommend running this sensitivity using scenario #1, mid economic conditions, and substituting the 2.47% upstream methane emissions factor. This will provide a bookend sensitivity on upstream emissions and the social cost of carbon for PSE's resource portfolio and market purchases.
- High Electric Vehicle Saturation, using an appropriate scale-up factor such as 50% higher than the forecast estimate for 2025, adjusted appropriately thereafter. We recommend two versions of this sensitivity, one assuming no load shaping and the other assuming some combination of rate design and incentives to shape demand away from system peak. The purpose of this sensitivity is to assess the impact of faster EV saturation on overall resource needs and specifically on daily and seasonal peak impact.

Cordially,

Joni Bosh	Fred Huette
Senior Policy Associate	Senior Policy Associate
NW Energy Coalition	NW Energy Coalition
joni@nwenergy.org	fred@nwenergy.org

August 18, 2020

Puget Sound Energy
IRP Team

RE: Feedback of Renewable Northwest, Portfolio Sensitivities
Puget Sound Energy's August 11, 2020, Feedback Webinar Relating to Portfolio Sensitivities and CETA for PSE's 2021 Integrated Resource Plan.

I. INTRODUCTION

Renewable Northwest thanks Puget Sound Energy ("PSE") for this opportunity to provide feedback as a stakeholder in PSE's 2021 Integrated Resource Plan ("IRP"). This feedback is a response to PSE's August 11, 2020, Feedback Webinar regarding Portfolio Sensitivities and the Clean Energy Transformation Act (CETA) for the 2021 IRP.

Renewable Northwest participated in the Feedback Webinar on August 11, 2020. Below, we provide feedback based on PSE's slide deck regarding portfolio sensitivities for PSE's 2021 IRP.

II. FEEDBACK

1. Renewable Northwest appreciates PSE's request for stakeholder suggestions regarding the appropriate portfolio sensitivities PSE should model. Below are our recommendations.

   a. Regarding the renewable over-generation test, we recommend that PSE incorporate the effects of this sensitivity on the 2% cost threshold relevant to compliance with CETA standards. Specifically, should PSE choose to or be required to over-generate renewables to meet load, how early in a compliance period would PSE meet the 2% cost threshold, and thus be considered in compliance with the clean energy standards?
   b. Regarding the must-take DR and battery storage sensitivity, we again recommend that PSE incorporate the effects on the 2% cost threshold. We recommend that PSE consider this detail in modeling other sensitivities which may lead PSE to the cost cap early in each compliance period.
   c. Regarding the highly-centralized sensitivity within the Transmission Constraints and Build Limitations category, we recommend that PSE consider including additional

constraints specific to renewable proxy locations, whereby a strict delivery requirement mandated by CETA may create geographic limitations to new-build renewables.

d. Regarding the SCC as a tax in WA, OR and CA sensitivity, we agree with PSE that this tax should be modeled WECC-wide for consistency.

2. Renewable Northwest supports PSE's approach to modeling the social cost of carbon (SCC) as a post-economic dispatch fixed cost adder. Our understanding aligns with what PSE has vocalized in multiple webinars, that an alternative methodology applying the SCC as a dispatch adder would artificially deflate the capacity factors of emitting resources, thus skewing the model's output.

3. Renewable Northwest appreciates PSE's consideration of stakeholder feedback in considering how to meet the 20% alternative compliance permitted by CETA's greenhouse-gas neutrality standard. While our preference is always going to be that PSE does not rely on alternative compliance, we recognize the utility in planning a gradual transition to 100% clean. That said, we would advise against relying on resource-based compliance payments, given the more climate-beneficial options granted by CETA. Unbundled RECs support renewable energy development, and Energy Transformation Projects (ETPs) aim to reduce the state's non-energy sector GHG emissions. Both of these options support system transformation and GHG-emission reductions, while penalties do not.

III. CONCLUSION

Renewable Northwest thanks PSE for its consideration of this feedback. We look forward to continued engagement as a stakeholder in this 2021 IRP process.

Sincerely,

/s/ Katie Ware

Katie Ware
Washington Policy Manager
Renewable Northwest
katie@renewablenw.org

PSE IRP Consultation Update
Webinar 6: Portfolio Sensitivities
August 11, 2020

09/01/2020

The following consultation update is the result of stakeholder suggestions gathered through the IRP online Feedback Form, collected between August 4 through August 18 and summarized in the August 25, 2020 Feedback Report. The report themes have been summarized along with responses to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

PSE thanks Kyle Frankiewich (WUTC Staff) for follow-up discussions concerning his questions on August 27, 2020.

PSE thanks Katie Ware (Renewable Northwest) for being available for a clarification call concerning her suggestion for a sensitivity; a call will be arranged well before the October 20 IRP Meeting.

Certain responses were not included in the August 25, 2020 Feedback Report. Those questions have been addressed in the Webinar 6 Feedback Form Addendum, also dated and uploaded to pse.com on September 1, 2020.

Feedback Report Addendum

The feedback received from Kyle Frankiewich (WUTC Staff) regarding non-energy benfits on slide 21, questions regarding slide 54, and questions on slides 57-58 on distributed solar and batteries was not answered in the Feedback Report posted on August 25, so an addendum to answer the questions has been posted.

Summary of Stakeholder Feedback on Portfolio Sensitivities

PSE appreciates the feedback provided by stakeholders. In summary, the following list of sensitivities has been added to the list:

Portfolio sensitivities added during the August 11 webinar:

1. Social cost of carbon only (as a planning adder), no CETA renewable requirement
2. Social cost of carbon only (as a dispatch cost), no CETA renewable requirement
3. Add 185 MW to MT transmission from Colstrip transmission line
4. Fuel switching from electric to gas
5. High economic conditions with SCC as a dispatch cost in the portfolio model only
6. Electric vehicle battery to grid available as a distributed energy resource
7. Time of use pricing for conservation and demand response
8. Wholistic conservation approach

Portfolio sensitivities added from the feedback report for the August 11 webinar:

9. Municipal bans on new natural gas
10. Refinements to resource cost assumptions
11. Private solar input testing
12. Equity focused portfolio
13. 2% Cost threshold
14. 2% Cost threshold - Must take DR and Battery storage first, then optimize other builds
15. 2% Cost threshold - Renewable Overgeneration Test
16. Virtual Power Plants (VPP)
17. Hydrogen as an alternative fuel for NG plants

Notes received from stakeholders regarding sensitivities already on the list:

Sensitivity #22 - Mid economic conditions with SCC as a fixed cost plus a federal CO_2 tax
Virginia Lohr suggested to use a higher cost than $15, more consistent with proposed federal legislation

Sensitivity #31 - Temperature sensitivity on load
Don Marsh suggested to use most recent 10-15 years of temperature data to capture recent trends

PSE will make best efforts to complete as many portfolio sensitivities as possible for the 2021 IRP. However, given that the list has over 50 different portfolio sensitivities, PSE will ask stakeholders to prioritize the list. PSE will begin with the analysis with portfolios 1-3 (Mid, Low, and High economic conditions). The draft portfolios will be presented at the October 14 meeting for natural gas and the October 20 meeting for electricity. Once the stakeholders have an opportunity to view the draft results, PSE will will re-evaluate the list of sensitivities with the stakehodlers, then prioritize list of portfolio sensitivities.

PSE is committed to keeping our stakeholders informed of our progress toward incorportating feedback into the 2021 IRP process.

Update on the Electric Price Forecast - follow-up from June 10 Webinar as referenced in the August 11 Webinar 6 and related updates

On June 10, 2020, PSE presented the draft electric price forecast and incorporated stakeholder feedback regarding the electric price forecast.

1. Regional Demand Forecast

PSE received feedback from James Adcock, Kathi Scanlan (WUTC Staff), and Joni Bosh and Fred Heutte (NWEC), concerning PSE's use of the Northwest Power and Conservation Council's (the Council) 7th Power Plan regional demand forecast.

> **PSE response**: PSE contacted the Council and included the demand forecast from the 2019 Policy Update to the 2018 Wholesale Electricity Forecast, which is the latest available demand forecast.

2. Washington Renewable Need

PSE received feedback from Vlad Gutman-Britten (Climate Solutions) and James Adcock regarding the starting point for the renewable ramp used for meeting the Washington state CETA requirements.

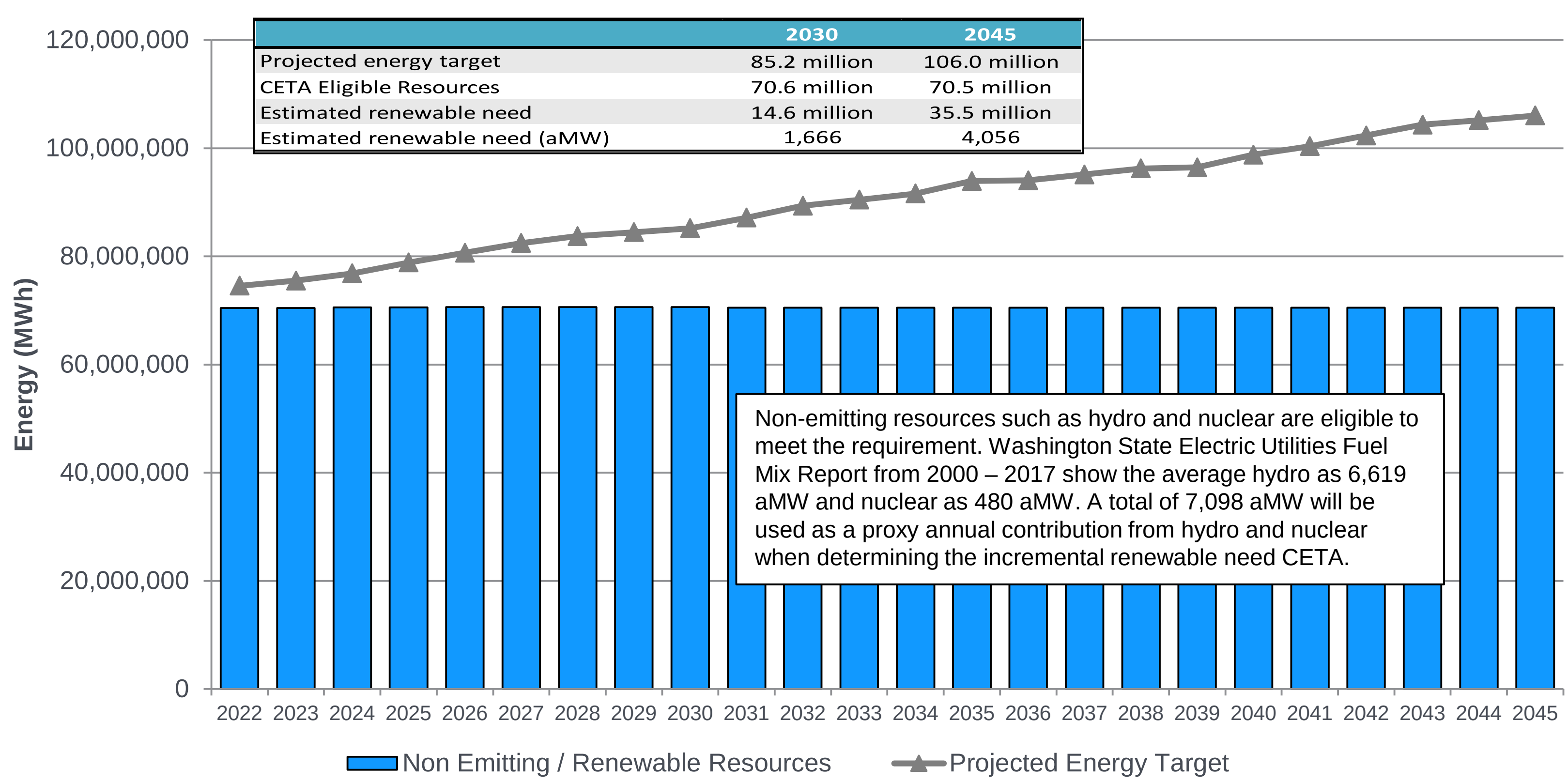
> **PSE response**: PSE updated the Washington renewable need for the updated demand forecast and started the ramp in 2022.

3. Natural Gas Price Forecast

PSE received feedback from Kathi Scanlan (WUTC Staff), requesting the use of an updated gas price forecast to reflect the socioeconomic changes of the COVID-19 pandemic.

> **PSE response**: PSE updated to the most recent natural gas price forecast from Wood Mackenzie.

The final electric price forecast was presented at the August 21 webinar as an update for stakeholders. James Adcock requested to see the updated Washington renewable need chart used for the electric price forecast during the webinar. PSE replied that it will be included in the constulation update for the webinar. The chart below is the renewable need for Washington state (MWh).



	2030	2045
Projected energy target	85.2 million	106.0 million
CETA Eligible Resources	70.6 million	70.5 million
Estimated renewable need	14.6 million	35.5 million
Estimated renewable need (aMW)	1,666	4,056

Webinar 7, September 1, 2020

CETA Assumptions, Load Forecast, Resource Adequacy, Electric and Resource Need

Webinar #7: CETA Assumptions, Demand Forecast, Resource Adequacy, Resource Need
September 1, 2020 from 1:00 p.m. to 5:00 p.m. PST

Virtual webinar link: https://global.gotomeeting.com/join/178101165
Access code: 178-101-165

Topic	Lead
Welcome • Agenda review • Safety moment • How to participate • Speaker introductions	EnviroIssues
CETA Assumptions	Elizabeth Hossner, Manager Resource Planning & Analysis, PSE
Demand Forecast [There is a 10-minute break in this part of the presentation]	Lorin Molander Manager Load Forecasting & Analysis, PSE Allison Jacobs Senior Economic Forecasting Analyst, PSE Michael Noreika Senior Economic Forecasting Analyst, PSE Meghan Weinman Product Development Manager, Transportation Electrification, PSE Stephanie Price Senior Economic Forecasting Analyst, PSE
Resource Adequacy	Elizabeth Hossner, Manager Resource Planning & Analysis, PSE Zhi Chen Senior Resource Planning Analyst, PSE
Resource Need	Elizabeth Hossner, Manager Resource Planning & Analysis, PSE
Wrap up and next steps • Next steps • Upcoming meeting schedule • Thank you's	EnviroIssues

Call-in telephone number (audio only): +1 (646) 749-3112

2021 IRP Webinar #7: CETA Assumptions, Demand Forecast, Resource Adequacy, Resource Need

PUGET SOUND ENERGY

Establish Resource Need
Electric & Gas Portfolio Model

September 1, 2020

Agenda

- Clean Energy Transformation Act (CETA) alternative compliance assumptions
- Electric and natural gas demand forecast
- Electric resource adequacy analysis
- Electric resource need

Safety Moment: Water Safety

- Know the water – Water that is warm on the surface, may be much colder below. Use caution when swimming and always supervise young children playing in or near the water.

- Know your limits – stay in lifeguarded areas and be cautious of sudden drop-offs in lakes and rivers

- Where a life jacket that fits you

- Be prepared - Check river or steam conditions, or beach advisories before you go swimming

More information:
https://www.doh.wa.gov/CommunityandEnvironment/WaterRecreation/LakeRiverandBeachSafety

Today's Speakers

Elizabeth Hossner
Manager Resource Planning & Analysis, PSE

Zhi Chen
Senior Resource Planning Analyst, PSE

Meghan Weinman
Product Development Manager Transportation Electrification, PSE

Elise Johnson & Alexandra Streamer
Co-facilitators, EnviroIssues

Lorin Molander
Manager Load Forecasting & Analysis, PSE

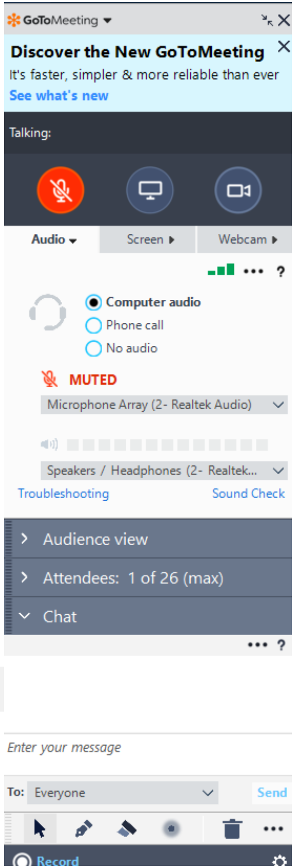
Allison Jacobs
Senior Economic Forecasting Analyst, PSE

Stephanie Price
Senior Economic Forecasting Analyst, PSE

Michael Noreika
Senior Economic Forecasting Analyst, PSE

Welcome to the webinar and thank you for participating!

GoToMeeting



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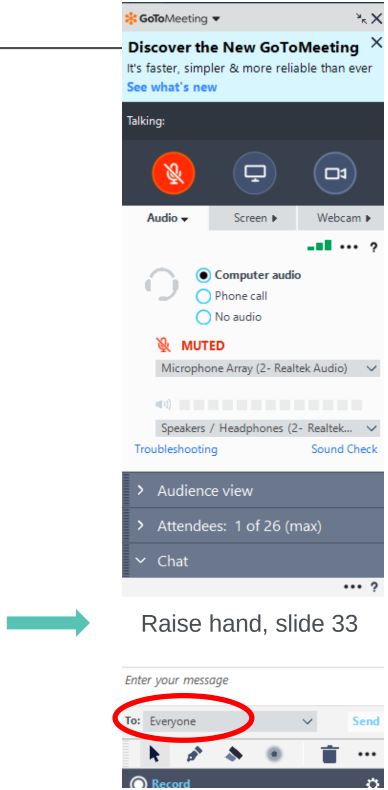
- Mute your mic during the presentation
- You can participate in writing or verbally using the chat window
  - **In writing:** your question will be read
  - **Verbally:** type "Raise hand" and slide #, share with "Everyone"; please wait to be called on to ask your question
- Be considerate of others waiting to participate
- We will try to get to all questions



CETA alternative compliance assumptions: 2030-2045

Participation Objectives

- PSE will consult stakeholders on assumptions to use for the alternative compliance as part of the Clean Energy Transformation Act (CETA) for the 2021 Electric IRP.
- PSE will consult with stakeholders about the best way to meet the 20% carbon-neutral method outlined by CETA.

IAP2 level of participation: CONSULT

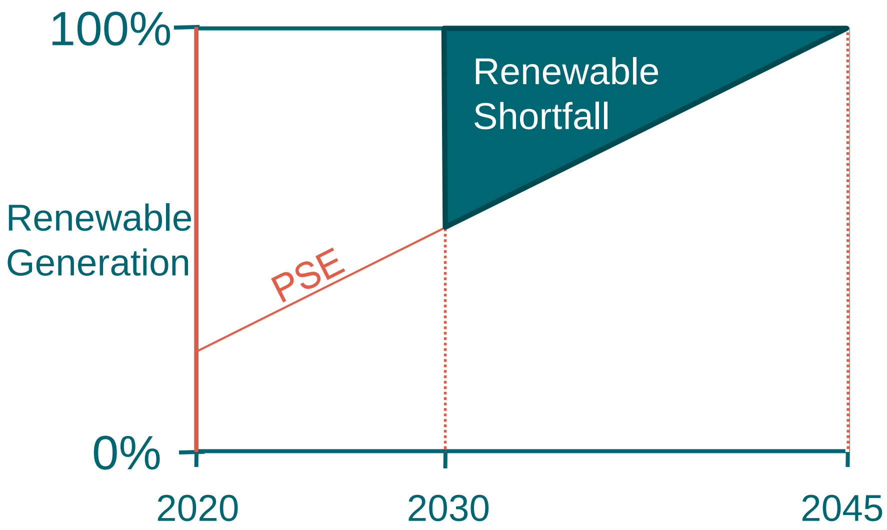
CETA Targets

"With our wealth of carbon-free hydropower, Washington has some of the cleanest electricity in the United States. But electricity remains a large source of emissions in our state. We are at a critical juncture for transforming our electricity system. **It is the policy of the state to eliminate coal-fired electricity, transition the state's electricity supply to one hundred percent carbon-neutral by 2030, and one hundred percent carbon-free by 2045.** In implementing this chapter, the state must prioritize the maximization of family wage job creation, seek to ensure that all customers are benefiting from the transition to a clean energy economy, and provide safeguards to ensure that the achievement of this policy does not impair the reliability of the electricity system or impose unreasonable costs on utility customers."

- CETA Section 1, Subsection 2

Carbon Neutral by 2030, with 80% renewable/non-emitting generation

- CETA states that all utilities must be carbon neutral by 2030, and that 80% generation must be renewable/non-emitting.
- CETA provides flexibility with the remaining 20% between the years 2030 and 2045.
- PSE must determine how to best meet the carbon neutral goal until the utility can achieve 100% renewable/non-emitting generation.



Meeting CETA between 2030 and 2045

(b) Through December 31, 2044, an **electric utility may satisfy up to twenty percent of its compliance obligation** under (a) of this subsection **with an alternative compliance** option consistent with this section. An alternative compliance option may include any combination of the following:

(i) **Making an alternative compliance payment** under section 9(2) of this act;

(ii) **Using unbundled renewable energy credits**, provided that there is no double counting of any nonpower attributes associated with renewable energy credits within Washington or programs in other jurisdictions, as follows:

(A) Unbundled renewable energy credits produced from eligible renewable resources, as defined under RCW 19.285.030, which may be used by the electric utility for compliance with RCW 19.285.040 and this section as provided under RCW 19.285.040(2)(e); and

(B) Unbundled renewable energy credits, other than those included in (b)(ii)(A) of this subsection, that represent electricity generated within the compliance period; p. 11 E2SSB 5116.PL

(iii) **Investing in energy transformation projects**, including additional conservation and efficiency resources beyond what is otherwise required under this section, provided the projects meet the requirements of subsection (2) of this section and are not credited as resources used to meet the standard under (a) of this subsection; or

(iv) **Using electricity from an energy recovery facility using municipal solid waste as the principal fuel source**, where the facility was constructed prior to 1992, and the facility is operated in compliance with federal laws and regulations and meets state air quality standards. An electric utility may only use electricity from such an energy recovery facility if the department and the department of ecology determine that electricity generation at the facility provides a net reduction in greenhouse gas emissions compared to any other available waste management best practice. The determination must be based on a life-cycle analysis comparing the energy recovery facility to other technologies available in the jurisdiction in which the facility is located for the waste management best practices of waste reduction, recycling, composting, and minimizing the use of a landfill.

Options for meeting the next 20%: Alternative compliance payments

- The alternative compliance payment is a base fine of $100 for each MWh of electricity that is not produced by a renewable or non-emitting resource.
  - Coal-fired resources receive a fine of $150/MWh
  - Gas-fired peakers receive a fine of $84/MWh
  - Gas-fired combined-cycle power plants receive a fine of $60/MWh

- These fines are adjusted to inflation every 2 years.

Options for meeting the next 20%: Unbundled RECs

- Unbundled Renewable Energy Credits (RECs) are tradeable certificates issued by the EPA that are attached to a single MWh of renewable generation.
- RECs are available nationally, but must correspond to an "eligible period" of generation.
  - For example, PSE could not purchase RECs from 2029 to meet the 2030 CETA requirements.
- "Unbundled" RECs mean that they are sold separately from the electricity that they are tied to.
- What is the price of unbundled RECs?

Options for Meeting the Next 20%: Energy Transformation Projects

- Utilities may also invest in “Energy Transformation Projects” to achieve the “Carbon Neutral” status outlined in CETA.

- Energy transformation projects reduce emissions from sectors that are not specifically related to energy production. These reductions can be used to offset emissions from CO_2-generating resources.

- Potential projects may include:
  - Electrification of the transportation sector (e.g. public transportation, electric vehicles)
  - Investments in hydrogen as a fuel for transportation
  - Distributed energy resource programs
  - Efficiency and conservation efforts
  - Agricultural emission reduction

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Stakeholder feedback on 20% alternative compliance

- PSE is seeking feedback from stakeholders on prioritization of the options for the 20% alternative compliance to reach carbon neutral target by 2030 in the 2021 IRP.

- PSE will also analyze a sensitivity to reach 100% renewable resources by 2030. (see Sensitivity 26 No new gas generation)

Service Area Electric and Natural Gas Demand Forecast

Participation Objectives

- PSE will inform stakeholders about the electric and natural gas demand forecast.

IAP2 level of participation: INFORM

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Presentation outline

- Introduction and role of demand forecast in IRP
- Methodology
- Forecast drivers/assumptions
  - Economics and demographics
  - COVID-19
  - Electric vehicles
  - Normal weather
- 2021 IRP Demand forecast results
  - Gas
  - Electric

Introduction

- The demand forecasts developed for the IRP estimate the amount of electricity and natural gas that will be required to meet the needs of customers through 2045.

- The demand forecast that PSE develops for the IRP is an estimate of energy sales, customer counts, and peak demand.

- The forecasts presented herein are for PSE's service area.
  - Trends for pockets within PSE's service area may differ from overall trends forecasted for PSE's service area.

- Forecast results presented herein are for the Base Demand Forecast case.
  - To model a range of potential economic and weather conditions PSE also prepares Low and High Forecasts in addition to the Base Forecast, to be presented at a later date.

Role of demand forecasts in the Integrated Resource Plan

- The 20+ year demand forecasts are used as an input into the IRP, and do not include long-term projections of demand-side resources (DSR).
    - Note: DSR measures through December 2021 (i.e., committed targets) are included in the forecast.
- The IRP analysis determines the most cost-effective amount of future DSR to include in the resource plan.
- Demand is reduced significantly when forward projections of DSR savings are applied.
    - DSR includes utility-sponsored conservation programs, codes and standards, distribution efficiency, and demand response.
- This presentation reviews the demand forecasts used as an input into the IRP analysis, therefore is the demand forecast ***before forward projections of DSR*** are applied.
- Distributed generation, including customer-level generation via solar panels, is not included in the demand forecast; this energy production is captured in the IRP scenario modeling process.
- The Clean Energy Transformation Act (CETA) affects the amount of demand-side resources. Demand-side resources are included as an option in the IRP portfolio model and not included in the base demand forecast.

Terminology

- The terms “demand” and “load” are often used interchangeably, but in the IRP they actually refer to different concepts.
  - **Demand** refers to the amount of energy needed to meet the needs of customers, including energy to account for losses.
  - **Load** refers to demand plus the planning margin and operating reserves needed to ensure reliable and safe operation of the electric and gas systems.
  - The forecast results presented herein are demand forecasts and do not include planning margin and operating reserves.
- **Energy demand** refers to the total amount of electricity or natural gas needed to meet customer needs in a given year.
- **Peak demand** refers to the maximum energy needed to serve customer demand in a given hour (electric) or day (natural gas), typically occurring on the coldest hour/day of the year, since PSE is a winter-peaking utility.
- **Conservation** and **Demand-Side Resources (DSR)**. Used interchangeably in this presentation to represent optimal bundles of conservation programs, codes and standards, distribution efficiency, and demand response as developed by the Conservation Potential Assessment (CPA) and the Portfolio Model activities.
- **System-level** demand forecasts (both electric and gas) include residential, commercial, industrial, and interruptible customer classes; does not include transport or network loads.
- **Average annual rate of growth (aarg)** for the forecast period is provided in the results graphics.

Demand forecast development

The demand forecasts presented herein are the forecasts before additional DSR.

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Demand forecast models

Total Energy	=	Customer Counts	×	Energy Use Per Customer

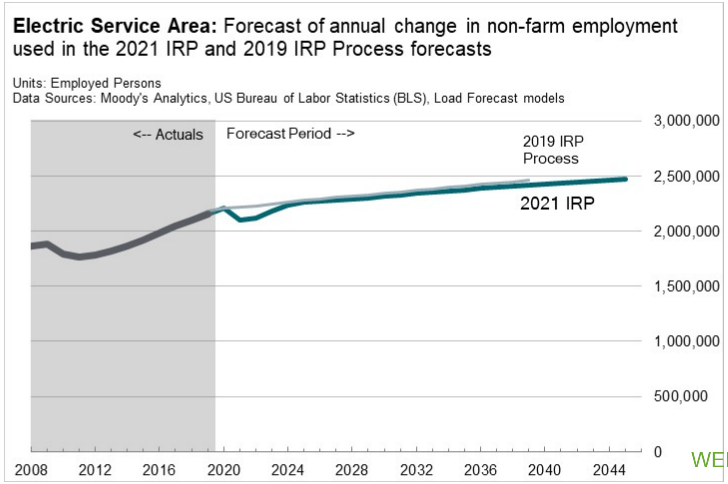
Typical Drivers (Customer Counts):
- Population
- Housing Permits
- Employment

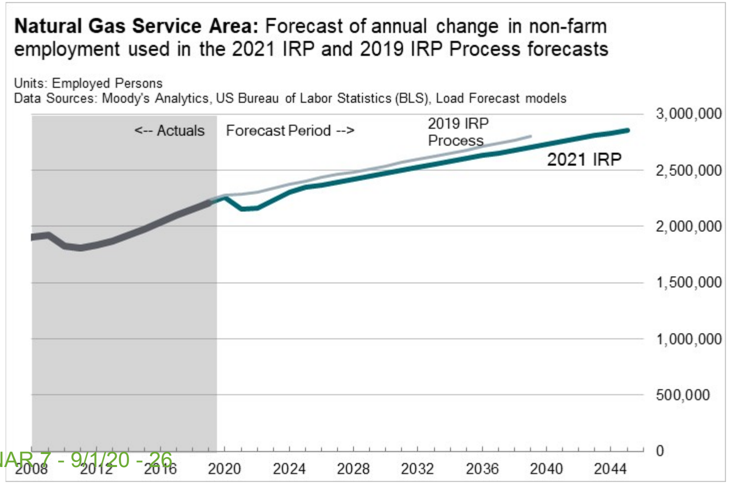
Typical Drivers (Energy Use Per Customer):
- Employment
- Energy retail rates
- Personal Income
- Weather

- STEP 1: Compile actual history
  - Compile actual PSE sales data and drivers
  - Determine the *relationship* of drivers to customer growth and sales
- STEP 2: Forecast the future
  - Compile forecasts of economic and demographic drivers, normal weather
  - Apply historical *relationships* to forecasts of drivers and normal weather

Economic & demographic model: employment forecast

- Pandemic assumptions (Moody's May 2020 forecast):
  - New infections begin to abate in July.
  - Does not include a second wave of infections.
- Economic assumptions (Moody's May 2020 forecast):
  - Partial bounce back in Q3 2020, then slow, steady recovery.
  - Housing/construction and manufacturing quicker bounce back.
  - Unemployment rate above 6% until Q1 2022 and above 5% until Q1 2023.
  - Long term total employment down 1.8% from 2019 IRP process projections.





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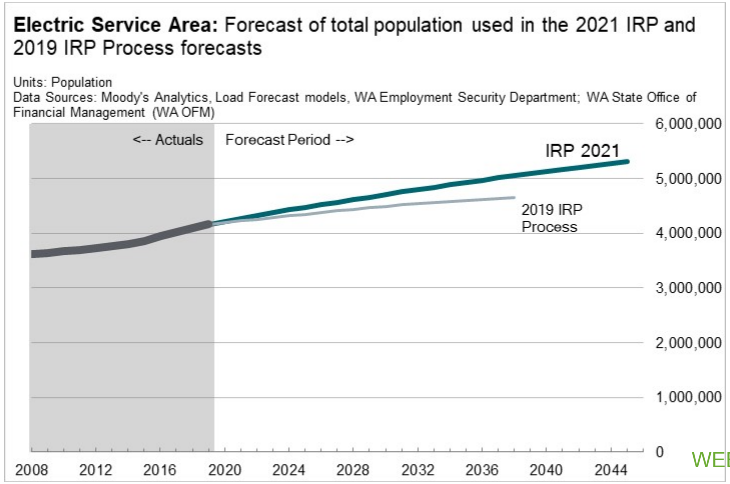
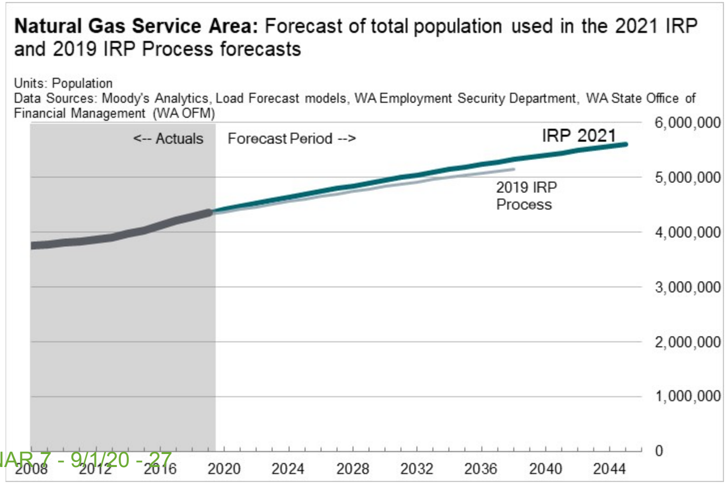
Economic & demographic model: population forecast

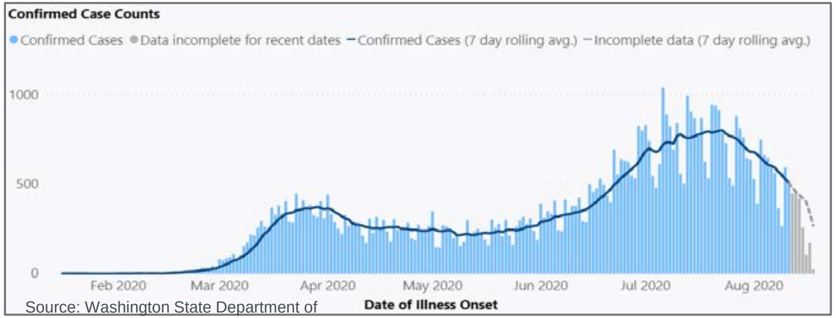
- Population drives residential customer growth
- Switched to WA Employment Security Department (ESD) population forecast instead of Moody’s US level forecast.
- COVID-19 impacts not included in ESD population forecast.
- Aligned residential growth with slowing population growth





COVID-19 Impacts

- COVID-19 reached the Puget Sound region in earnest early March 2020
- Immediate impacts to local economy
  - “Stay Home, Stay Healthy” order officially issued March 23rd
- Typical historical economic assumptions used in the forecast were not going to capture all of the immediate impacts
- Additional assumptions and adjustments were made to the forecast to reflect the quantitative and qualitative impacts



Source: Washington State Department of Health

In our last economic crisis the economy shrank around 6 percent relative to its long-run trend, and the unemployment rate rose around five percentage points. At a guess, we’re now looking at a slump three to five times that deep.

This plunge isn’t just quantitatively off the charts; it’s qualitatively different from anything we’ve seen before. **Normal recessions happen when people choose to cut spending**, with the unintended consequence of destroying jobs. **So this slump mainly reflects the deliberate, necessary shutdown of activities** that increase the rate of infection.

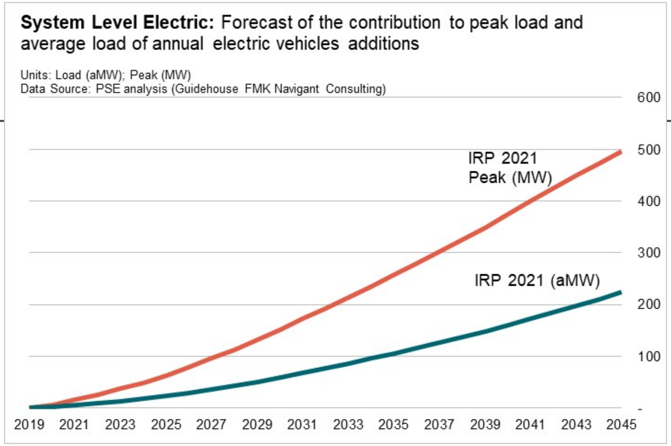
-Paul Krugman in the NY Times 4/7/2020

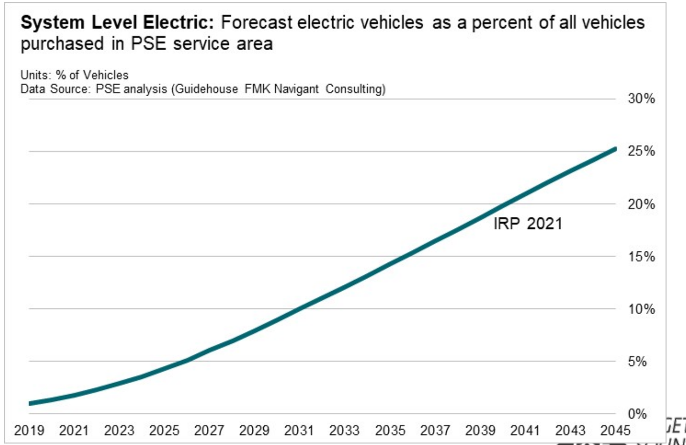
COVID-19 Impacts (cont.)

- **Immediate impacts, 2020**
  - Forecast used the most current Moody's economic forecasts (May 2020),
    - Includes epidemiological assumptions about the pandemic and its effects on economy
    - No model history to pick up severity of immediate downturn
  - Additional analyses that were incorporated into the demand forecast for the remainder of 2020:
    - Tracked daily loads of residential, commercial, and industrial classes
    - Assessed the potential impacts of the "Stay Home, Stay Healthy" order on commercial building energy consumption
    - Aligned expected energy consumption patterns to the "Safe Start" order
- **Medium-term impacts, 2021 – 2024**
  - Macroeconomic variables drive COVID impacts to forecast beyond 2020
  - Persistence of the pandemic and slow recovery affect demand for the next few years
- **Long term impacts, 2024+**
  - While the economic forecasts assume a recovery by ~2024, lingering effects of the recession persist throughout the remainder of the forecast

Electric Vehicles (EVs)

- The electric vehicle market remains nascent and heavily influenced by state/federal policy along with automaker's model availability.
- Forecast of electric light duty vehicles provided by consultant Guidehouse (formerly Navigant).
    - EV adoption
    - Charger counts
    - Annual Energy
    - Load Profiles
- Forecasted EV demand increases to 2-3% of total load and peak forecasts by 2030, and 7-8% by the end of forecast period.
- Future EV forecasts will include medium and heavy duty vehicles.





Normal heating and cooling degree days

- Energy demand is forecasted on a normal weather basis.
- PSE assumption of normal weather is based on average of most recent 30 years.
- Alternative definitions of normal will be analyzed as sensitivities.

Normal Degree Days (Base65), Annual			
Period	Description	Heating	Cooling
1990-2019	**2021 IRP Forecast (30 years)**	**4,765**	**200**
1988-2017	2019 IRP Process Forecast (30 years)	4,800	192
1981-2010	NOAA Normal Period	4,903	167
2000-2019	20 years	4,761	218
2005-2019	15 years	4,689	241
2010-2019	10 years	4,538	266
2015-2019	5 years	4,323	336

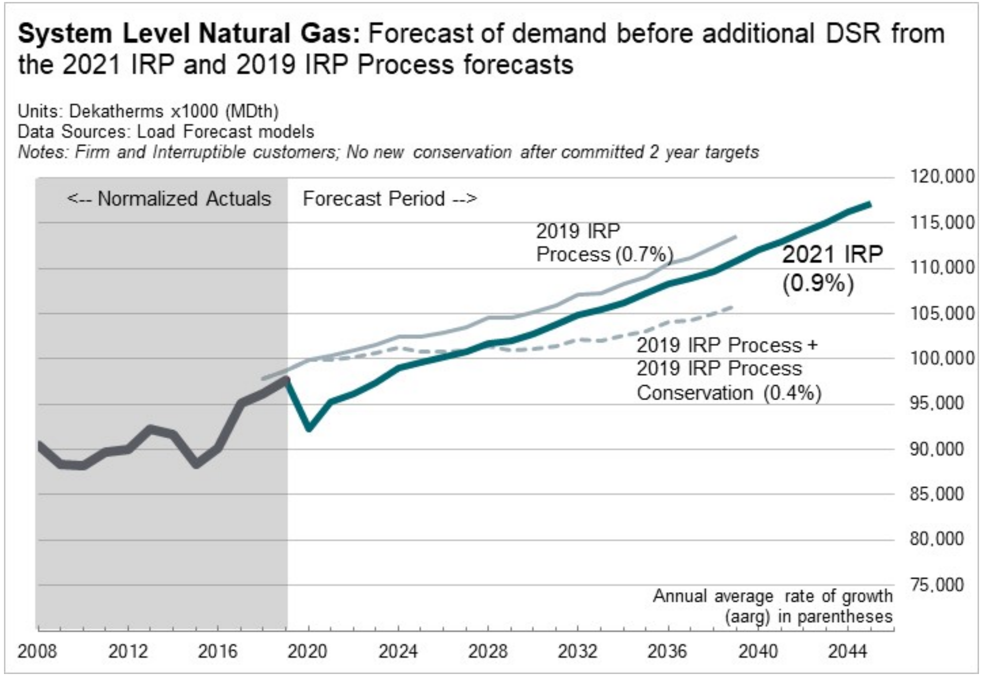
10 minute break

Results outline

- Natural Gas Demand Forecasts
  - Energy Demand
  - Peak Demand
- Electric Demand Forecasts
  - Energy Demand
  - Peak Demand

Natural Gas: Energy demand forecast [System Level]

- Demand lower by 5-8% in short term due to COVID-19 impacts.
- Demand down 2% in long term:
  - Slower residential customer growth.
  - Lower residential Use Per Customer (UPC).
  - Commercial usage is up.
  - 2020/21 conservation targets.
- The 2021 IRP demand forecast after DSR will be available once final DSR determined by the 2021 IRP process.



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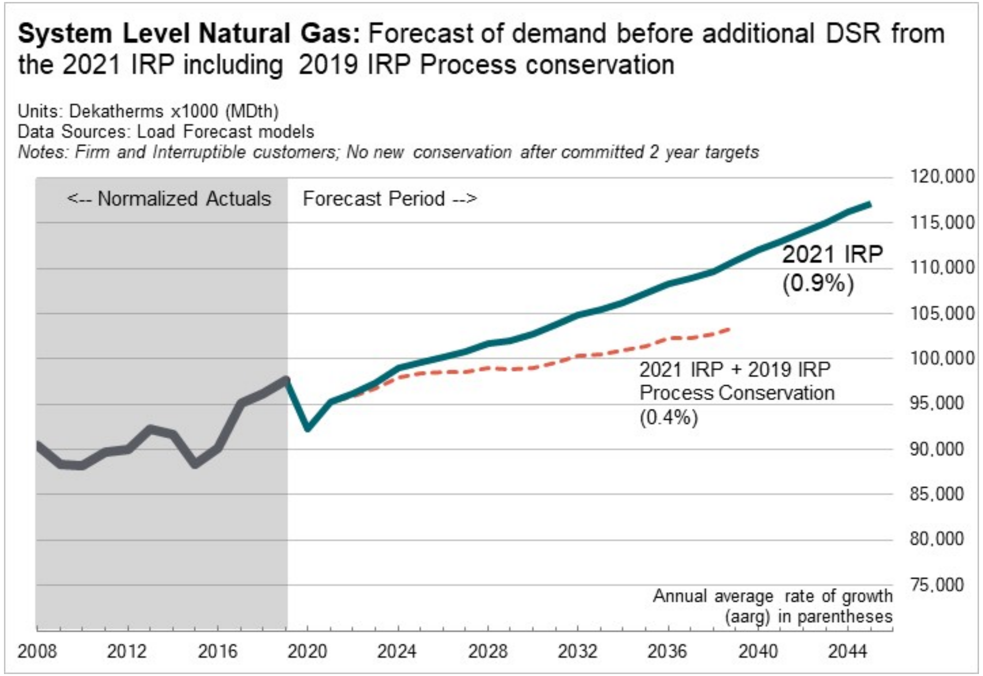
Natural Gas: Energy demand forecast after DSR [System Level]

- *This graph is for illustrative purposes only.*

- Using the amount of DSR determined by the 2019 IRP process, this graph illustrates an example of the 2021 IRP demand forecast after DSR.

- The final DSR amount for 2021 IRP is still to be determined by the portfolio model.



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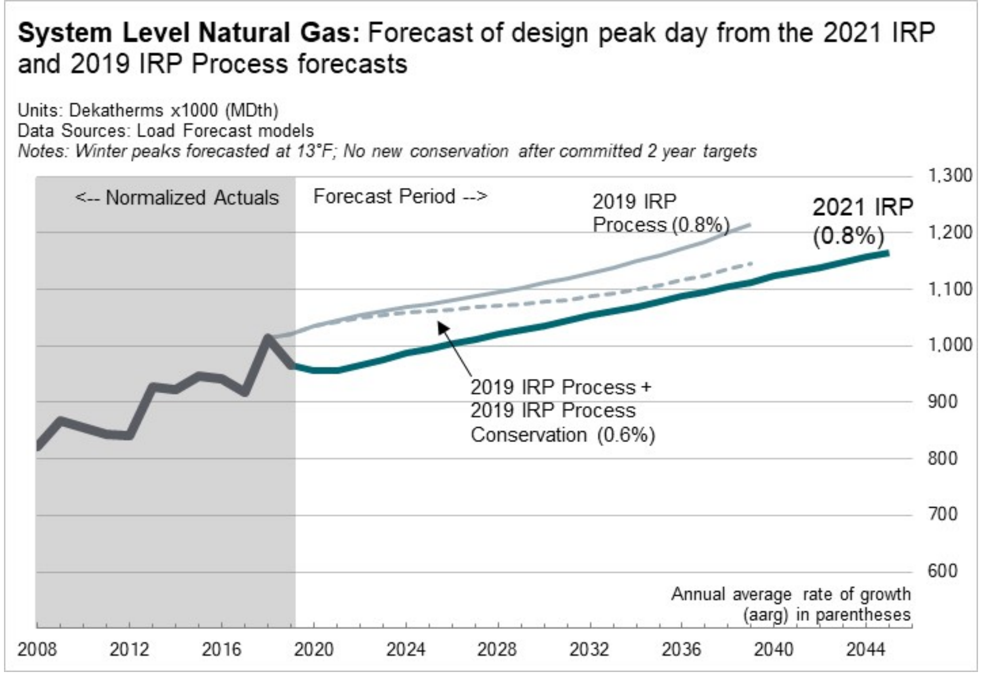
Natural Gas: Peak demand forecast [System Level]

- 2021 IRP peak down 7% compared to 2019 IRP process forecast.
- Lower peak demand:
  - Lower residential customer and UPC growth.
  - Incorporating recent cold winters.
  - COVID-19 slows initial growth.
  - 2020/2021 conservation targets.
- Long term growth drivers:
  - New customer growth.
- The 2021 IRP peak forecast after DSR will be available once final DSR determined by the 2021 IRP process.



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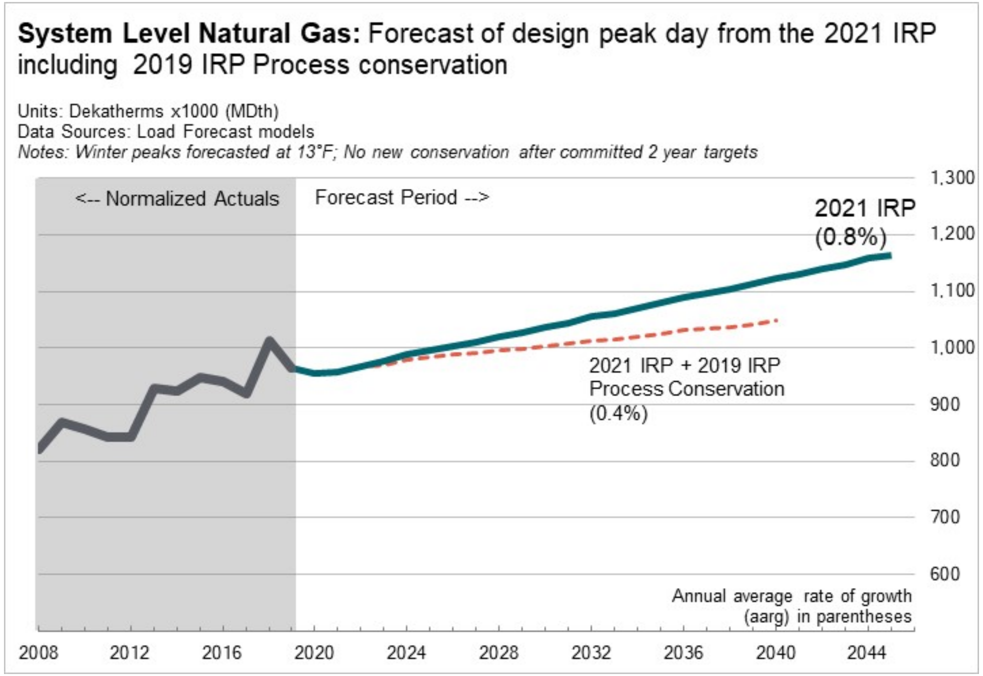
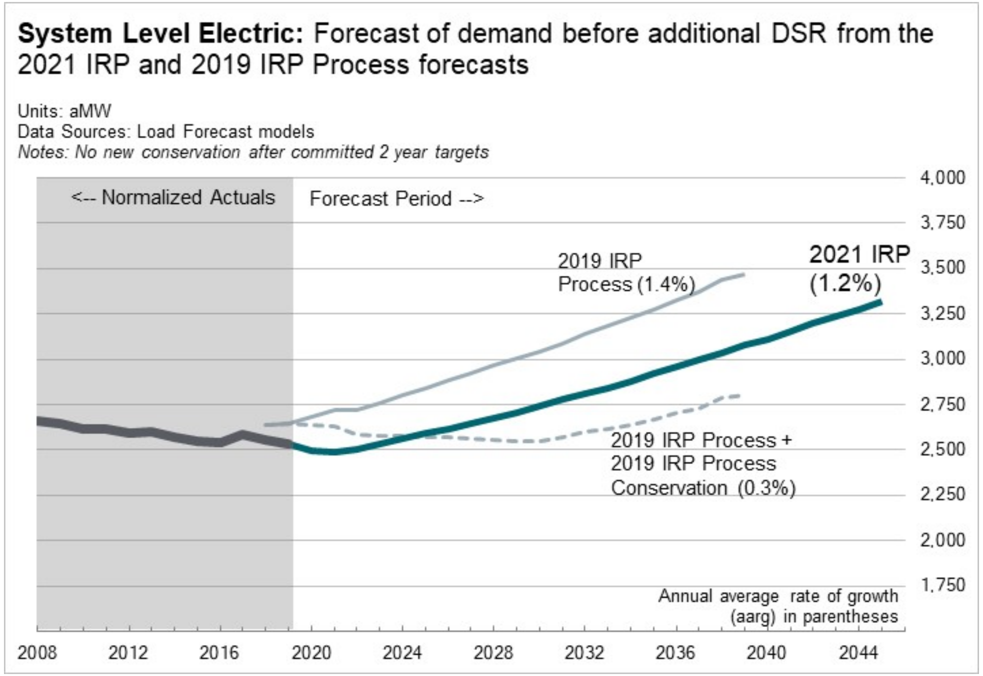


Electric: Energy demand forecast [System Level]

- Positive customer growth, steady UPC, and EVs yield demand growth, before DSR.
  - Applying DSR will result in an "after DSR" forecast with lower growth than "before DSR."
- Conservation targets for 2020/21 decreases load materially (standard IRP methodology, ~50% of initial 2022 forecast change).
- Lower growth than 2019 IRP process forecast due to:
  - Lower customer growth (commercial significantly).
  - Lower UPC forecast (all non-residential).
- The 2021 IRP demand forecast after DSR will be available once final DSR determined by the 2021 IRP process.



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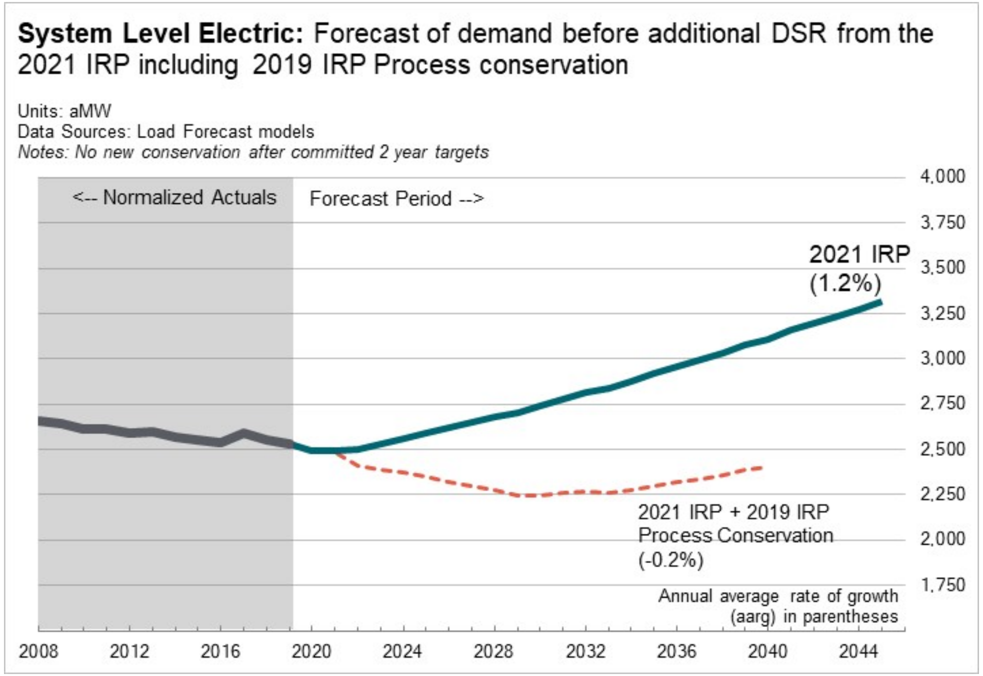
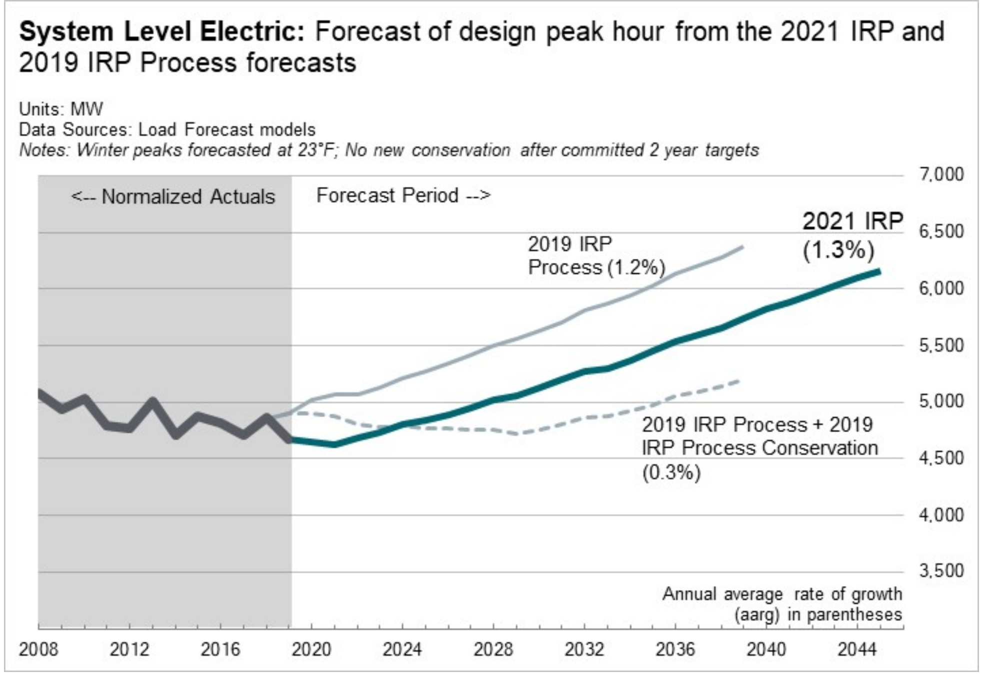


Electric: Peak demand forecast [System Level]

- Hourly forecast for winter weekday non-holiday evening at 23°F.
- Short-term downward driving forces:
  - Recent observed actuals (peak events, especially Feb. 2019 cold snap).
  - 2020/2021 conservation targets.
  - Economic slowdown due to COVID-19 will likely mitigate growth until ~2024.
- Long-term growth drivers:
  - New customer growth.
  - Electric Vehicles.
- The 2021 IRP peak demand forecast after DSR will be available once final DSR determined by the 2021 IRP process.



Electric: Peak demand forecast after DSR [System Level]

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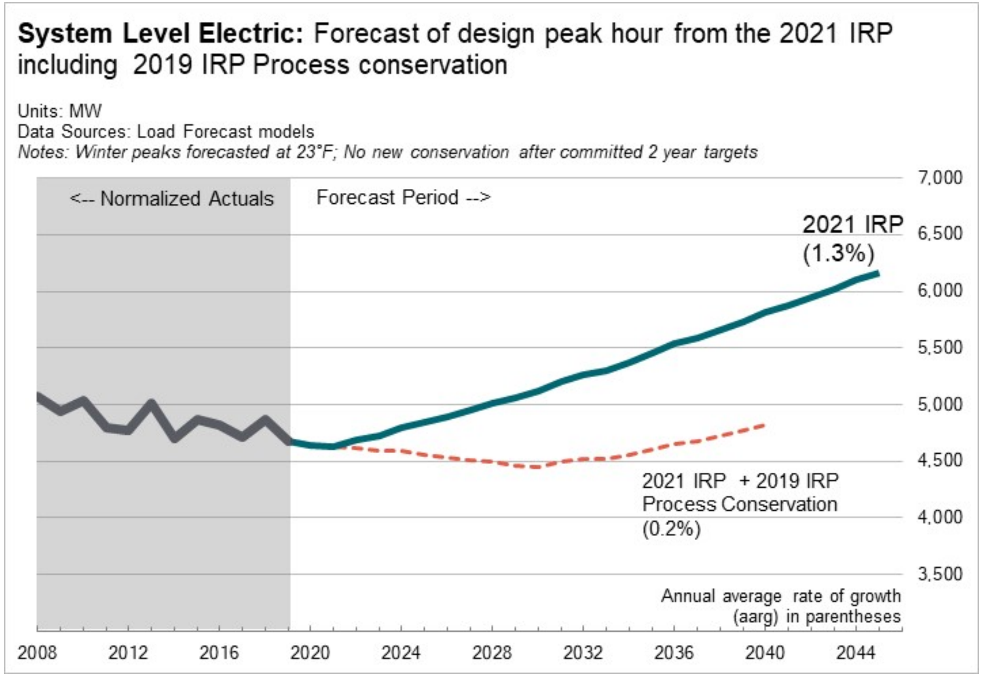

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Appendix – Demand Forecast

Economic & demographic model: Data sources

- PSE's economic and demographic model uses both national and regional data to produce a forecast of:
  - total employment,
  - types of employment,
  - unemployment,
  - personal income,
  - population,
  - households,
  - consumer price index (CPI) and
  - building permits.

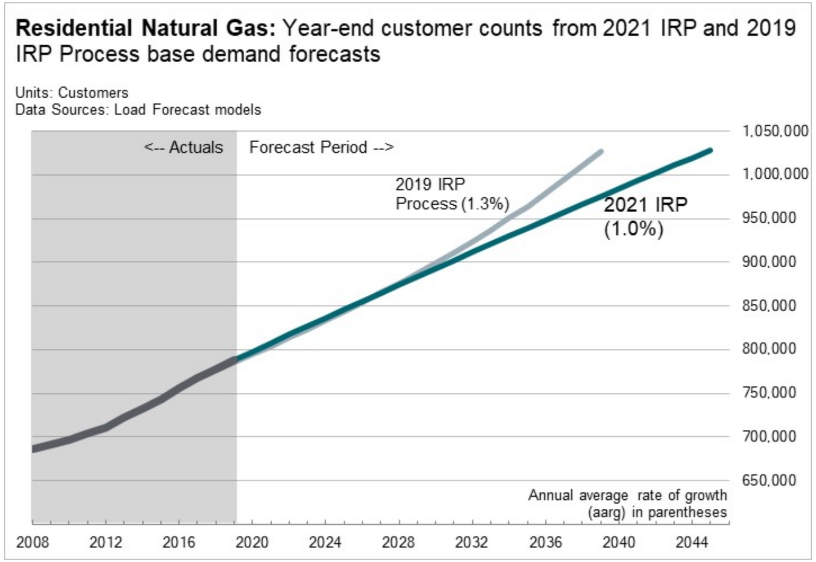
- Historical data are sourced from a number of external data sources, including local and federal agencies

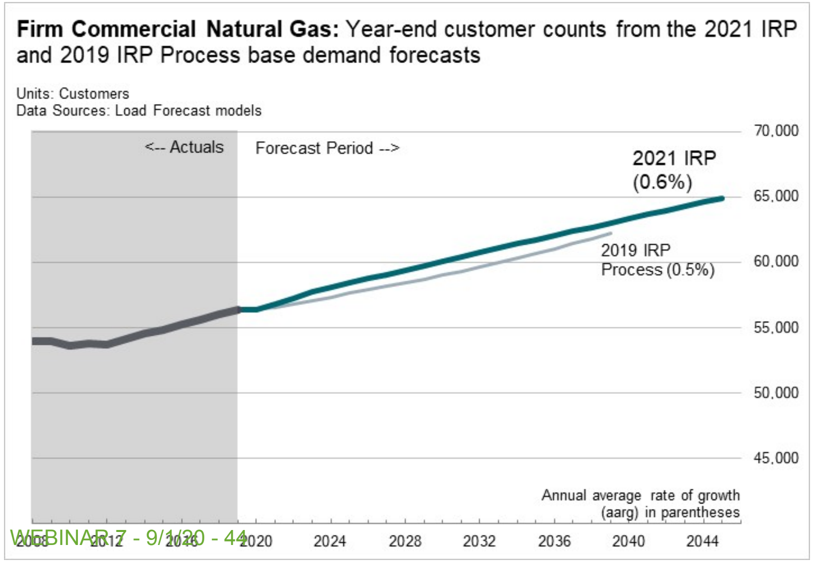
- US-level forecasts come from Moody's Analytics

DATA USED IN ECONOMIC AND DEMOGRAPHIC MODEL	
County-level Data	**Source**
Labor force, employment, unemployment rate	U.S. Bureau of Labor Statistics (BLS) www.bls.gov Puget Sound Regional Council (PSRC) www.psrc.org
Total non-farm employment, and breakdowns by type of employment	WA State Employment Security Department, using data from Quarterly Census of Employment and Wages https://fortress.wa.gov/
Personal income	U.S. Bureau of Economic Analysis (BEA) www.bea.gov
Wages and salaries	
Population	U.S. Bureau of Economic Analysis (BEA) WA State Office of Financial Management (OFM) www.ofm.wa.gov Washington State Employment Security Department (ESD) https://www.esd.wa.gov/
Households, single- and multi-family	U.S. Census www.censtats.census.gov
Household size, single- and multi-family	
Housing permits, single- and multi-family	U.S. Census / Puget Sound Regional Council (PSRC) / City Websites / Building Industry Association of Washington (BIAW) www.biaw.com
Aerospace employment	Puget Sound Economic Forecaster www.economicforecaster.com
US-level Data	**Source**
GDP	Moody's Analytics www.economy.com
Industrial Production Index	
Employment	
Unemployment rate	
Personal income	
Wages and salary disbursements	
Consumer Price Index (CPI)	
Housing starts	
Conventional mortgage rate	
T-bill rate, 3 months	

Natural Gas: Customer counts forecast [Class Level]

- System demand includes residential, commercial, industrial, and interruptible demand.
- Residential and Firm Commercial make up 93% of natural gas system consumption.
- Residential growth aligned with population growth.





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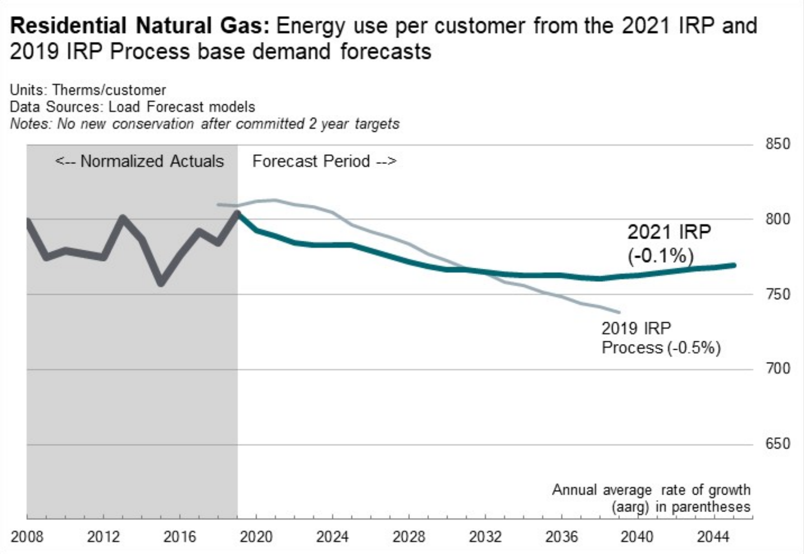
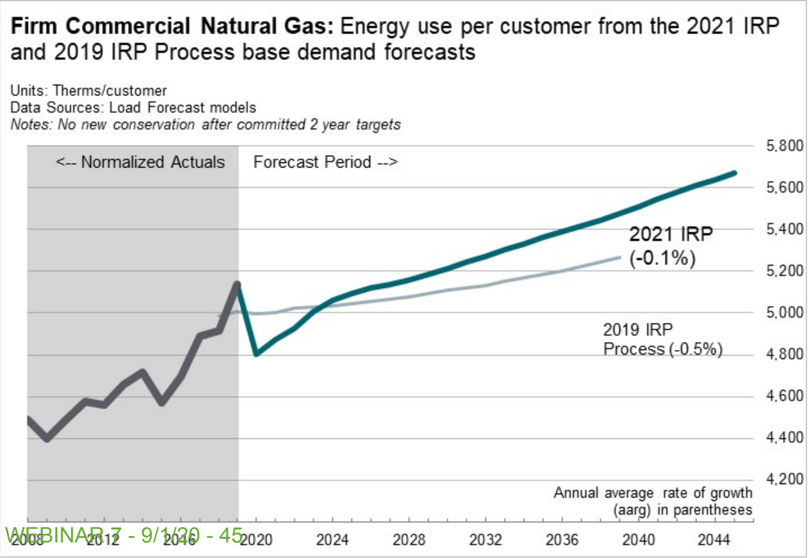
Natural Gas: Energy Use Per Customer (UPC) Forecast [Class Level]

- Residential
  - Lower recent actuals, Conservation commitments applied in 2020/2021, lower retail rate.
  - No explicit COVID-19 impacts in addition to economic forecast.
- Commercial
  - Drop in 2020 due to COVID-19 impacts, higher recent actuals.





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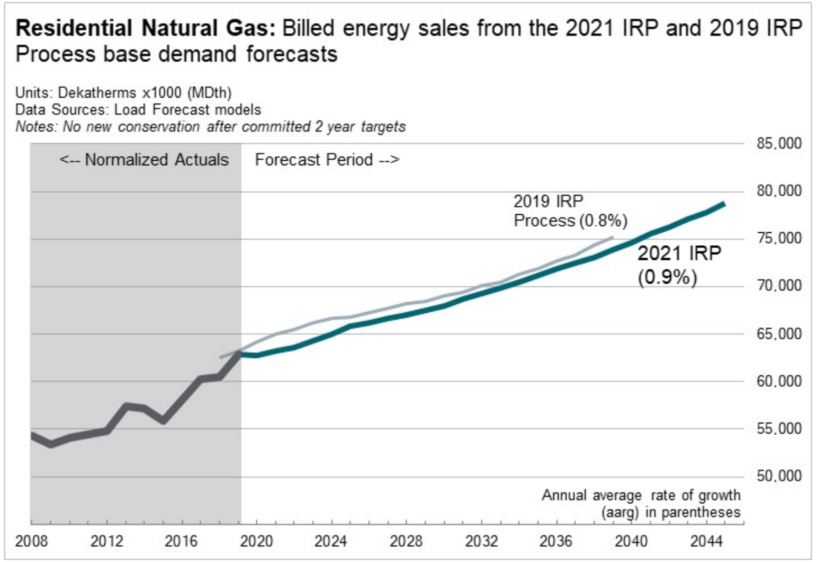
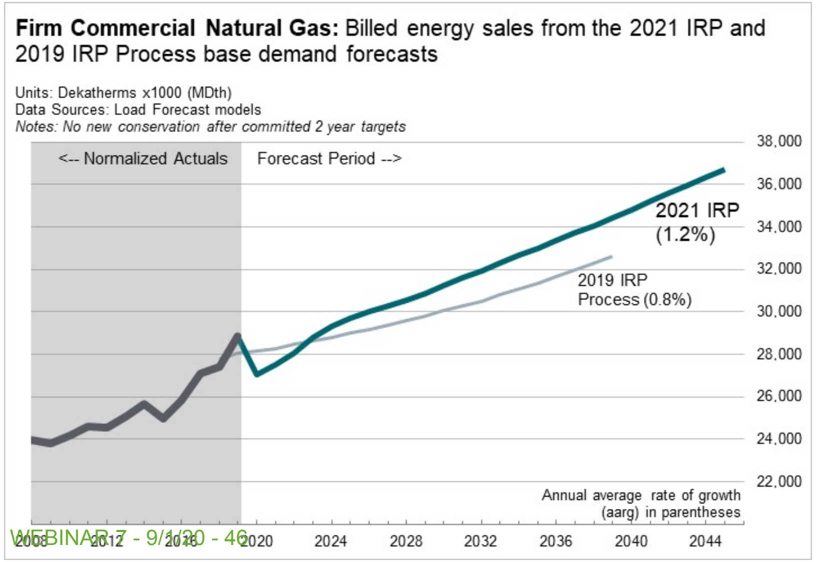
Natural Gas: Billed energy sales Forecast [Class Level]

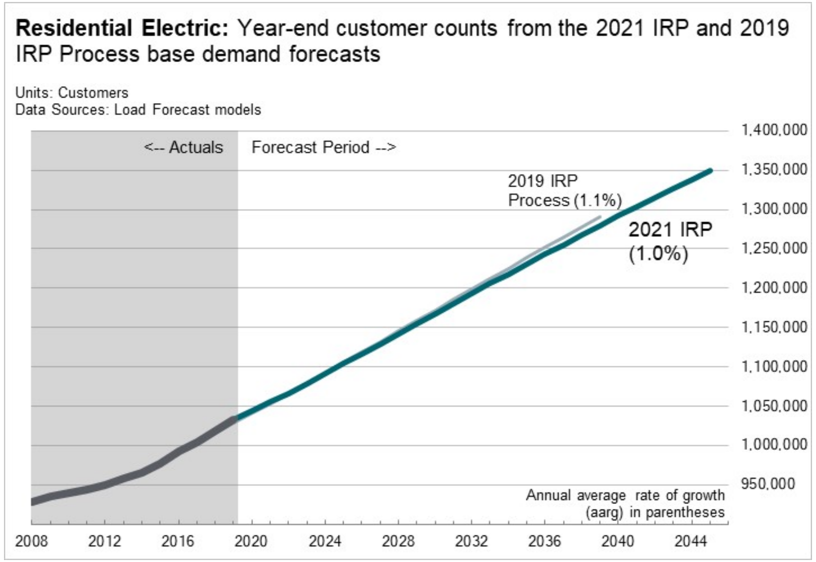
- Lower residential sales from slower customer growth.
- Higher commercial customers and UPC post COVID-19 results in higher sales in the long term.

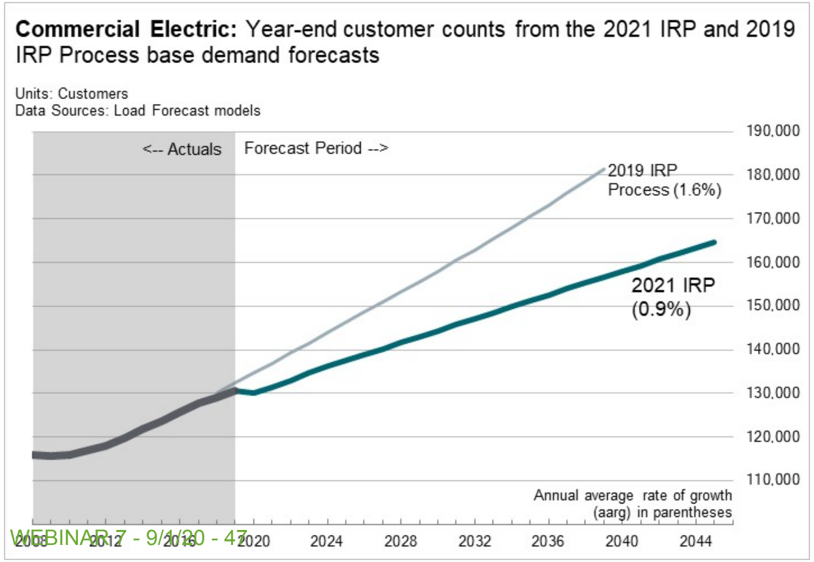




Electric: Customer counts forecast [Class Level]

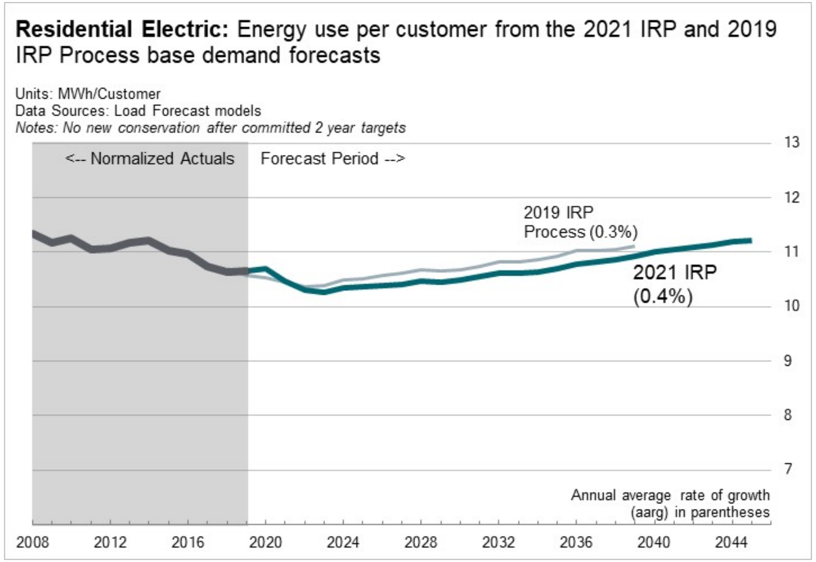
- Starting point adjustment: more residential and fewer commercial additions in 2018/2019.
- Lower growth than 2019 IRP process forecast due to:
  - COVID-19 shut down.
  - Updated economic outlook and relationships.
  - Updated trends/drivers (commercial growth more aligned with residential).

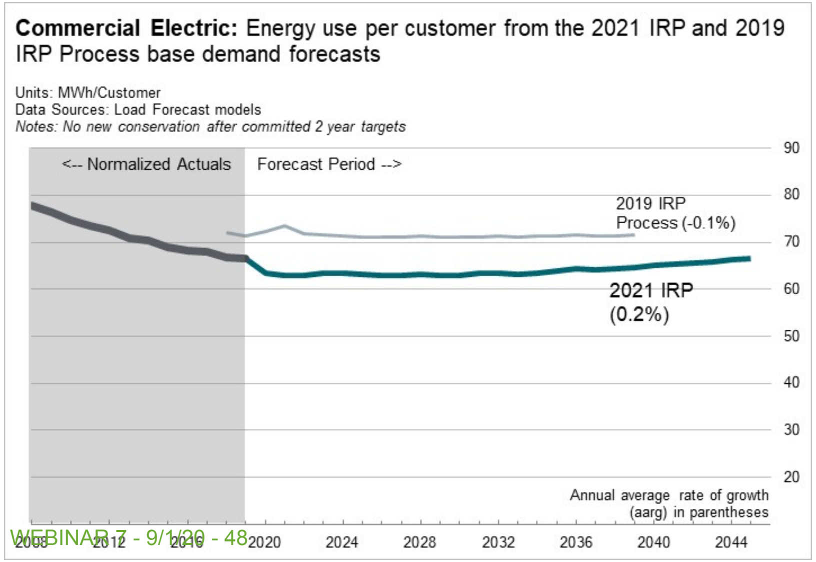




Electric: Energy Use Per Customer (UPC) forecast [Class Level]

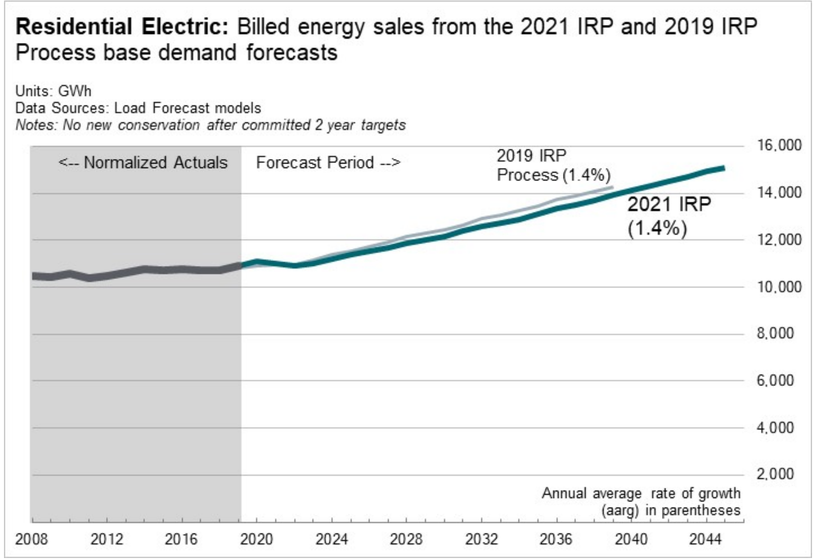
- 2020/2021 conservation targets shift forecast levels downward, all else equal.
- Increased residential and decreased commercial usage due to pandemic effects pre-2023.
- EV growth solely drives UPC growth.
- Updated methodology to better estimate non-residential temperature sensitivity and growth.

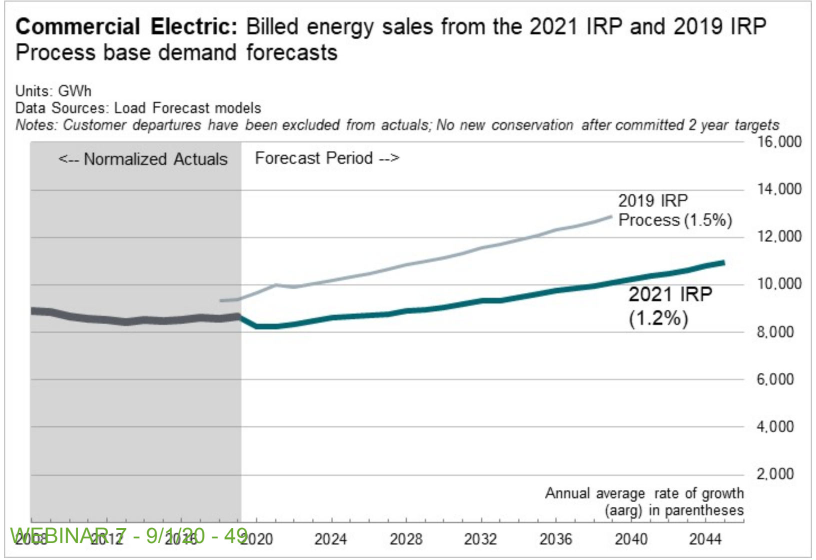




Electric: Billed energy sales forecast [Class Level]

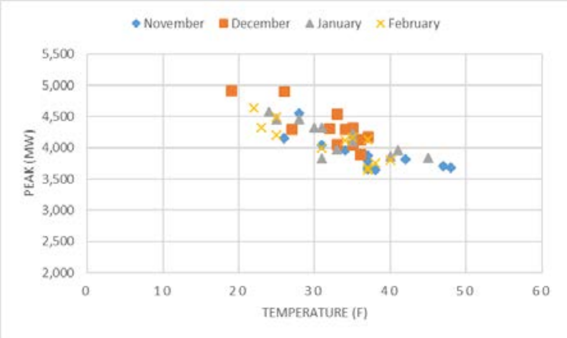
- Positive customer growth, steady UPC, and EVs yield sales growth, all else equal
- Inclusion of conservation targets for 2020/2021 decreases total usage levels materially (~50% of initial 2022 forecast change, standard practice)
- Lower growth than 2019 IRP process forecast due to
  - Lower customer growth (commercial significantly)
  - Lower UPC forecast (all non-residential)

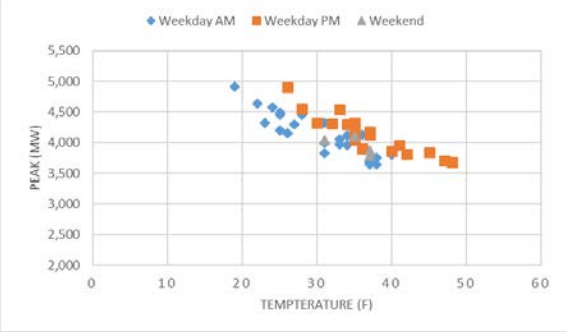




Electric: Observed system winter peaks 2008 - 2019

- Source: Puget Sound Energy FERC Form 1 Years 2008 – 2019 (https://elibrary.ferc.gov page 401b)
- System peak forecast is for winter weekday non-holiday evening at 23°F.
- The system peak forecast varies between 4,350-4,650 through 2022 for Nov/Dec/Jan/Feb.
- Historical observed values includes Jefferson County through March 2013 and Microsoft through April 2019.





Winter Peak MW**, Seatac Hourly Temperature, Day of Week, and Hour				
Winter Season	November	December	January	February
2008/2009	3,696MW (37°F,M,HE8)	4,906MW (26°F,M,HE19)	4,451MW (25°F,M,HE8)	4,171MW (35°F,T,HE19)
2009/2010	3,683MW (48°F,W,HE18)	4,911MW (19°F,Th,HE8)	3,837MW (45°F,Th,HE18)	3,760MW (38°F,M,HE8)
2010/2011	4,547MW (28°F,W,HE18)	4,305MW* (32°F,F,HE18)	4,326MW (31°F,M,HE8)	4,317MW (23°F,F,HE8)
2011/2012	3,874MW (37°F,Sun,HE18)	4,297MW (34°F,M,HE19)	4,328MW (30°F,W,HE18)	3,997MW (31°F,M,HE8)
2012/2013	3,812MW (42°F,M,HE19)	4,172MW (37°F,T,HE18)	4,226MW (35°F,M,HE18)	3,799MW (40°F,F,HE8)
2013/2014	3,955MW (34°F,F,HE8)	4,543MW (33°F,M,HE18)	3,973MW (33°F,M,HE8)	4,637MW (22°F,Th,HE8)
2014/2015	4,048MW (31°F,Sun,HE19)	4,298MW (27°F,M,HE8)	3,866MW (40°F,F,HE18)	3,680MW (37°F,M,HE8)
2015/2016	4,155MW (26°F,M,HE8)	4,047MW* (35°F,W,HE19)	4,101MW (35°F,Sun,HE18)	3,649MW (37°F,T,HE8)
2016/2017	3,709MW (47°F,M,HE18)	4,317MW (35°F,Th,HE18)	4,572MW (24°F,Th,HE8)	4,114MW (34°F,Th,HE8)
2017/2018	3,652MW (37°F,M,HE8)	4,058MW (33°F,M,HE8)	3,954MW (41°F,T,HE18)	4,206MW (25°F,F,HE8)
2018/2019	3,644MW (38°F,M,HE8)	4,132MW (36°F,Th,HE8)	3,833MW* (31°F,T,HE8)	4,498MW (25°F,W,HE9)
2019	3,786MW (37°F,Sa,HE10)	3,902MW* (36°F,Th,HE18)		
*On or adjacent to Federally observed holiday				
** Not adjusted for Jefferson County and other large customer exits				
Source: Puget Sound Energy FERC Form 1 Years 2008-2019, Accessed via https://elibrary.ferc.gov/, Reference Page 401b				

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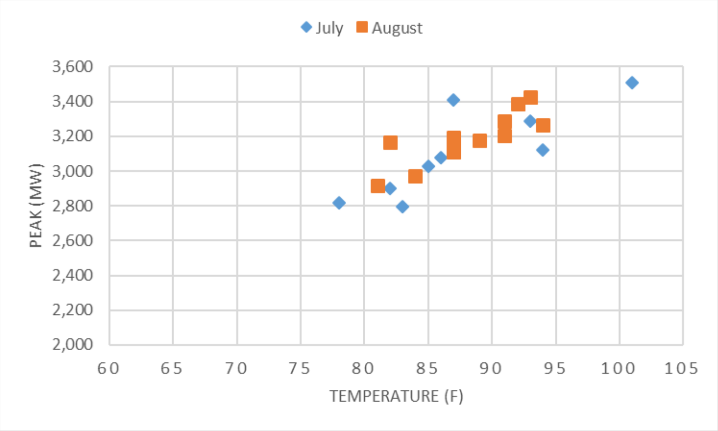
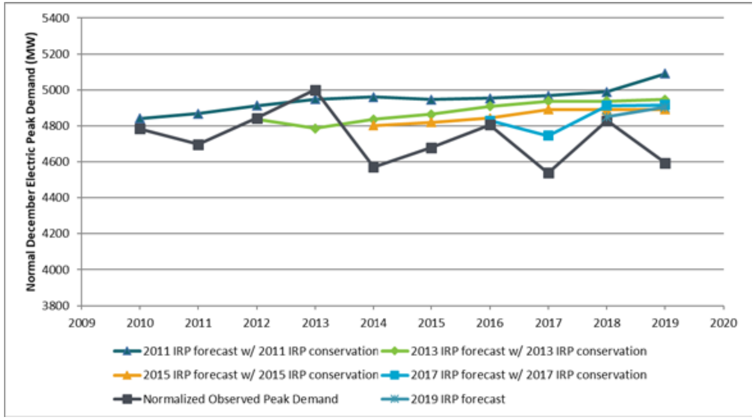
Electric: Observed system summer peaks 2008 - 2019

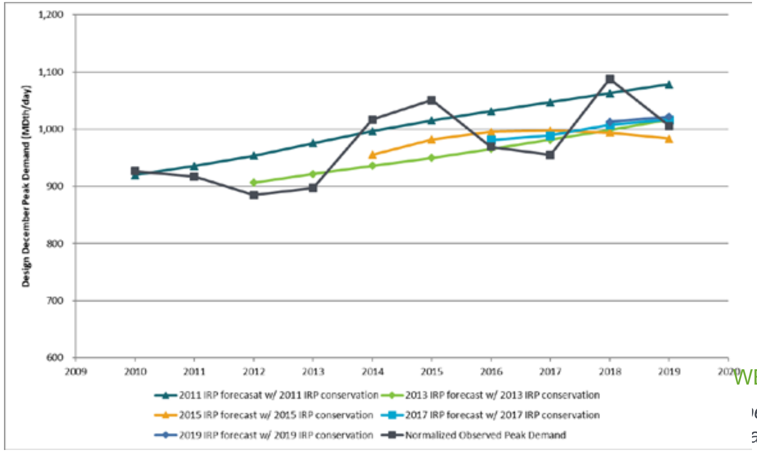
- Source: Puget Sound Energy FERC Form 1 Years 2008 – 2019 (https://elibrary.ferc.gov page 401b)
- Observed system summer peaks from 2008 – 2019 occur in the evening.
- System peak forecast is for summer weekday at 93°F.
- The system peak forecast varies between 3,380-3,500 through 2022 for July/August.
- Historical observed values includes Jefferson County through March 2013 and Microsoft through April 2019.



Summer Peak MW**, Seatac Hourly Temperature, Day of Week, and Hour		
Year	July	August
2008	2,900MW (82°F,T,HE18)	3,113MW (87°F,F,HE16)
2009	3,508MW (101°F,W,HE15)	3,164MW (82°F,W,HE13)
2010	3,123MW (94°F,Th,HE18)	3,176MW (89°F,M,HE17)
2011	2,795MW (83°F,W,HE18)	2,917MW (81°F,Th,HE17)
2012	2,820MW (78°F,Th,HE18)	3,204MW (91°F,Th,HE17)
2013	3,147MW (87°F,M,HE17)	2,973MW (84°F,M,HE18)
2014	3,123MW (87°F,W,HE18)	3,288MW (91°F,M,HE18)
2015	3,286MW (93°F,Th,HE18)	3,179MW (87°F,W,HE18)
2016	3,163MW (87°F,Th,HE18)	3,266MW (94°F,F,HE17)
2017	3,079MW (86°F,T,HE18)	3,386MW (92°F,Th,HE18)
2018	3,407MW (87°F,M,HE18)	3,423MW (93°F,W,HE18)
2019	3,026MW (85°F,F,HE18)	3,196MW (87°F,M,HE18)

Previous IRP electric and gas peak demand Forecasts





- PSE updates and adopts a new long-term forecast each year.
- Forecasts are projections of peak demand with normal/design temperatures and for peak conditions (i.e., time of day, day of week, etc.).
- For comparison purposes, actual observed December loads are "normalized."
  - The normalized actual observations account for peak hourly temperature, monthly HDDs, and the day of week and time of day the actual peak was observed.
- These are "after DSR is applied."

Forecast performance discussion

- **Economic and Demographic Forecasts**
  - Economic and demographic factors are key drivers for the IRP peak demand forecast. After the 2008 recession hit the US economy, many economists assumed that the economy would recover sooner than it did. A full recovery was pushed out with each successive forecast as the U.S. economy failed to bounce back to its previous state year after year.

- **Conservation and Customer Usage**
  - Consumers have adopted energy efficient technologies that are above and beyond what is incentivized by utility-sponsored conservation programs and building codes and standards. This leads to more actual conservation taking place than forecasted.
  - Conservation programs can change over time. Programs that were not cost effective in the past, and therefore not included in the optimal bundle, can be chosen in a later IRP as cost effective. This can make an older forecast out of date, making the forecast of conservation too low and therefore the load forecast after conservation too high.
  - The Global Settlement from the 2013 General Rate Case (GRC) PSE accelerates electric conservation by 5 percent each year. This was taken into account in the 2015 IRP forecast and subsequent forecasts, but it was not included in conservation estimates for the 2011 or 2013 IRP forecasts after conservation. Similarly, gas conservation was increased 5 percent each year from the 2017 GRC and was taken into account in the 2019 IRP process forecast, but not included in prior forecasts.

- **Weather Sensitivity**
  - Over time PSE's customers' weather sensitivity has been changing. As energy efficiency measures have been implemented, customers use less energy at a given temperature, including at peak temperatures. More recent forecasts reflect this change in weather sensitivity better than older forecasts.

- **Non-design Conditions during Observed Peaks**
  - Peak values are normalized using the peak forecasting model. This model uses peak values from each month to create a relationship between peak demand, monthly demand and peak temperature. However, some of the observed December peaks shown above occurred on atypical days rather than typical days.
    - Gas peaks in 2010, 2013, 2016, and 2017 occurred on weekends, and gas peaks in 2010, 2012, and 2015 occurred on New Year's Eve
    - In 2014, the electric peak occurred on the Monday morning after Thanksgiving weekend, and in 2015 it occurred on New Year's Eve
- **Service Area Changes**
  - In March 2013, Jefferson County left the PSE service area. Jefferson County usage was included in the electric peak demand forecast in the 2011 IRP, therefore, when comparing that forecast to today's actuals, we would expect those forecasts to be higher than the actual peak demand.

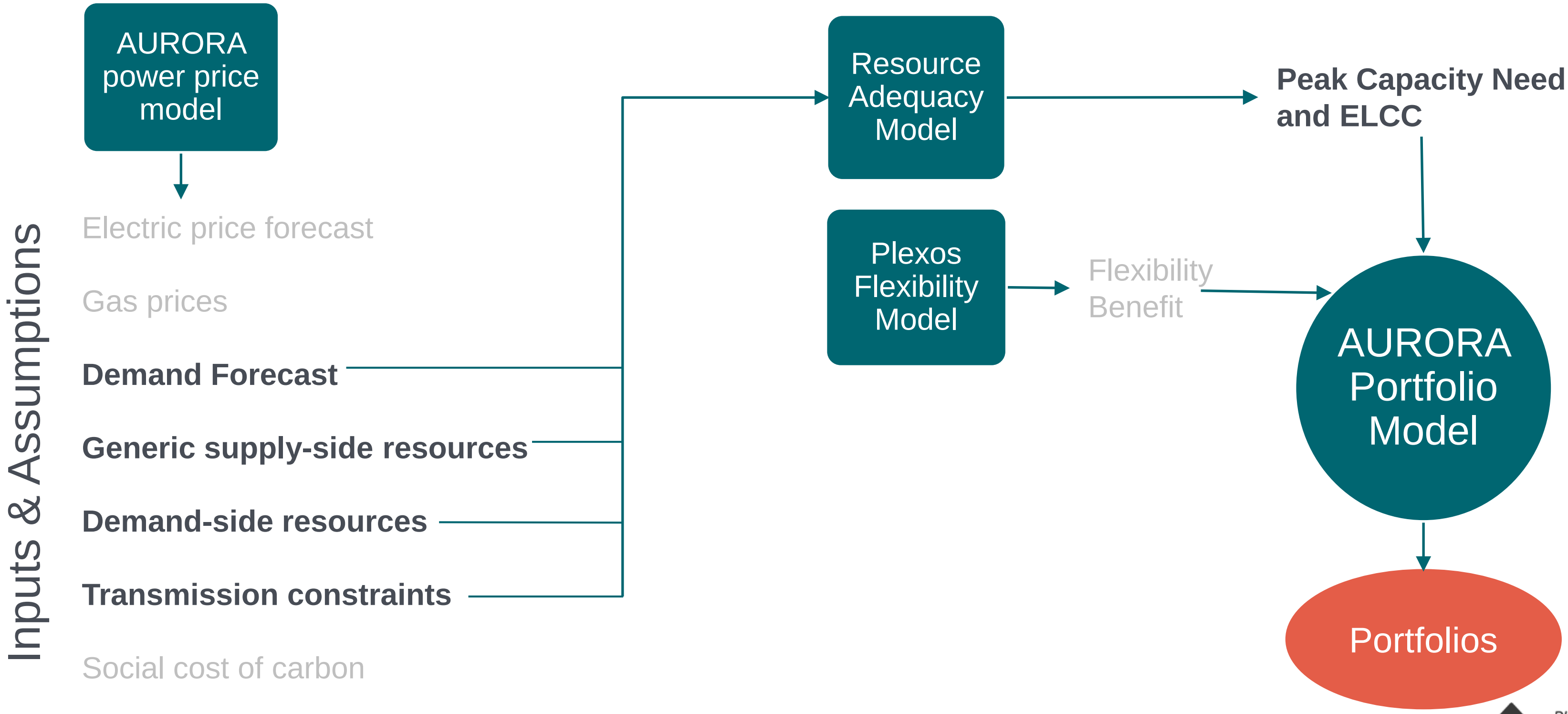
Electric resource adequacy

Participation Objectives

- PSE will inform stakeholders about the resource adequacy analysis and electric peak capacity need.

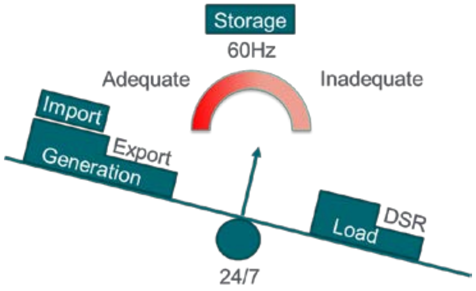
IAP2 level of participation: INFORM

Electric IRP Models



Resource Adequacy overview

- A system is “**Resource Adequate**” if it has sufficient capacity to serve load across a broad range of weather conditions, subject to a long-run standard for frequency of reliability events.
- Resource adequacy analysis determines the amount of peak capacity needed to meet a reliability standard.
- There is no mandatory or voluntary standard for Resource Adequacy in the PNW.
  - Each Balancing Authority establishes its own standard subject to oversight by state commissions or locally-elected boards.
  - North American Electric Reliability Council (NERC) and Western Electric Coordinating Council (WECC) publish information about Resource Adequacy but have no formal governing role.



Resource Adequacy Model (RAM)

Storage **Hydro** **DR**

RAM calculates reliability metrics for high renewable systems:

- **<u>LOLP:</u> Loss of Load Probability**
- **<u>LOLH:</u> Loss of Load Hours**
- **<u>LOLE:</u> Loss of Load Expectation**
- **<u>EUE:</u> Expected Unserved Energy**
- **<u>ELCC:</u> Effective Load-Carrying Capability for hydro, wind, solar, storage and DR**
- **<u>PM:</u> Planning Margin needed to meet specified LOLP**

The resource adequacy model (RAM) evaluates adequacy through stochastic simulations over varying years of temperature/load, renewable, hydro, and stochastic forced outage conditions

- Captures thermal resource forced outages
- Captures variable availability of renewable & hydro generation
- Captures market through regional resource adequacy
- Aligns with most recent NWPCC Adequacy Assessment reliability standard

RAM calculates a number of metrics that are useful for resource planning

- Loss of Load Probability (LOLP) (%): is the probability of a shortfall (load plus reserves exceed generation) in a given year
    - ➢ Northwest Power & Conservation Council adequacy metric targets 5%
- Loss of Load Hours (LOLH) (hrs/yr): is total number of hours in a year wherein load plus reserves exceeds generation
- Loss of Load Expectation (LOLE) (days/yr): is total number of days in a year wherein load plus reserves exceeds generation
    - ➢ CAISO targets 1-in-10
- Expected Unserved Energy (EUE) (MWh/yr): is the expected unserved load plus reserves in MWh per year
- Effective Load Carrying Capability (ELCC) (%): is the additional load met by an incremental generator while maintaining the same level of system reliability (used for dispatch-limited resources such as wind, solar, storage and demand response)
- Planning Margin (PM) (%): is the resource margin above 1-in-2-year peak load, in %, that is required in order to maintain acceptable resource adequacy

Years modeled for resource adequacy analysis

(2) For an investor-owned utility, **the clean energy action plan must**:

> (d) identify renewable resources, non-emitting electric generation, and distributed energy resources that may be acquired and **evaluate how each identified resource may be expected to contribute to meeting the utility's resource adequacy requirement**;

CETA – Section 14

PSE IRP start year: 2022
5-years from start: 2027 → modeled October 2027 – September 2028
10-years from start: 2031 → modeled October 2031 – September 2032

Note: The modeled year follows the hydro year (October – September) and allows the full winter and summer seasons to stay intact for the analysis. This is consistent with the Northwest and Conservation Council's GENESYS model. If PSE modeled the calendar year, it would break up the winter season (November – February).

Planning for resource adequacy

Regional planning standard: 5% LOLP

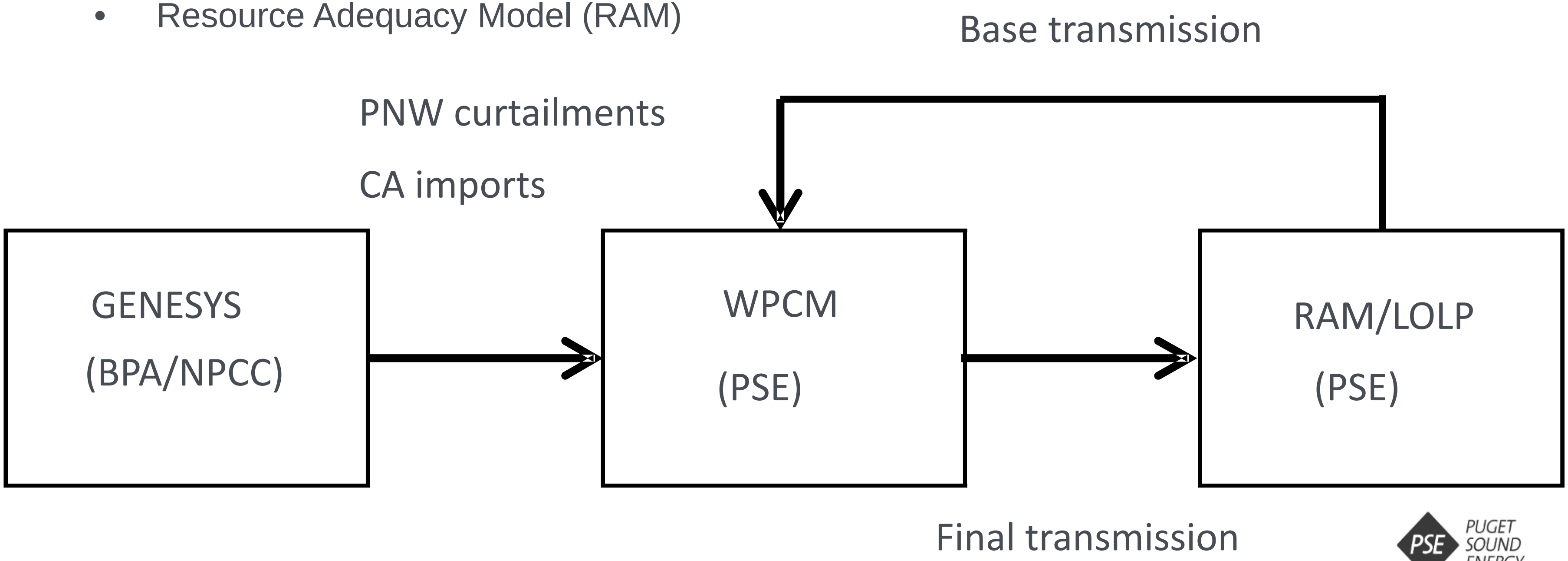
- Used by Northwest Power and Conservation Council (NWPCC)
- Consistent with WUTC guidance in 2015 IRP

What does this mean?

- Loss of load probability of any firm shortage in a given year, e.g., net demand exceeds firm supply in at least one hour
- 5% is a one-in-twenty chance in a given year
- Does not reflect magnitude or duration of shortages

Model interactions

- GENeration Evaluation SYStem Model (GENESYS)
- Wholesale Purchase Curtailment Model (WPCM)
- Resource Adequacy Model (RAM)



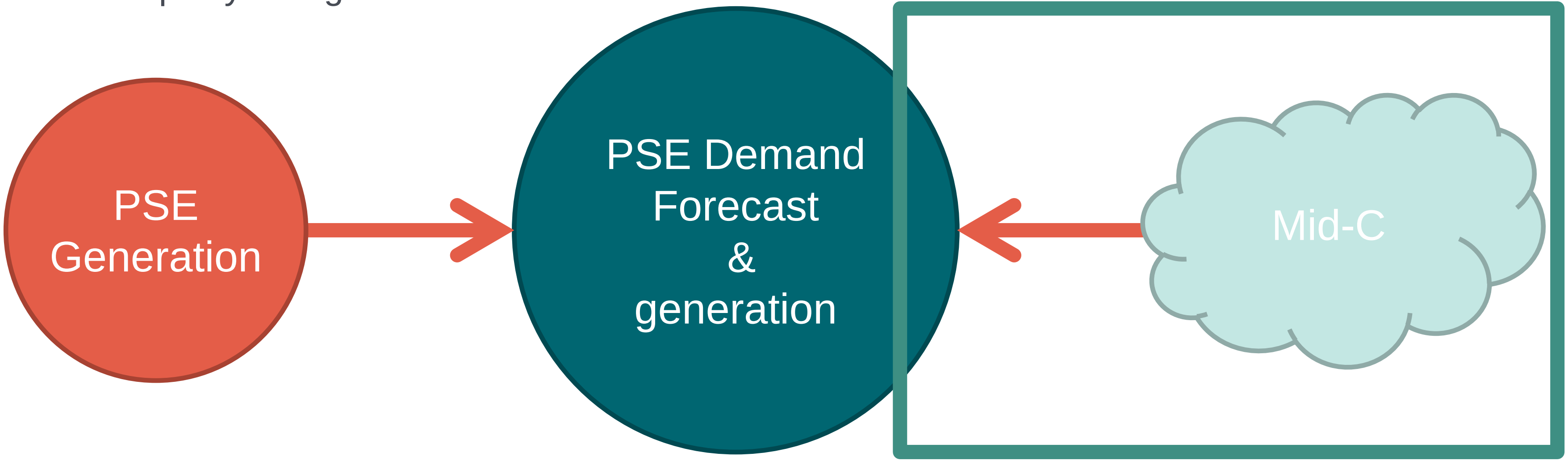
Regional view from GENESYS

- NWPCC Adequacy Assessment for 2023 GENESYS base case is used for the 2021 IRP
  - Updated for load growth and unit retirements expected in 2027 and 2031
  - Includes new PSE resource additions

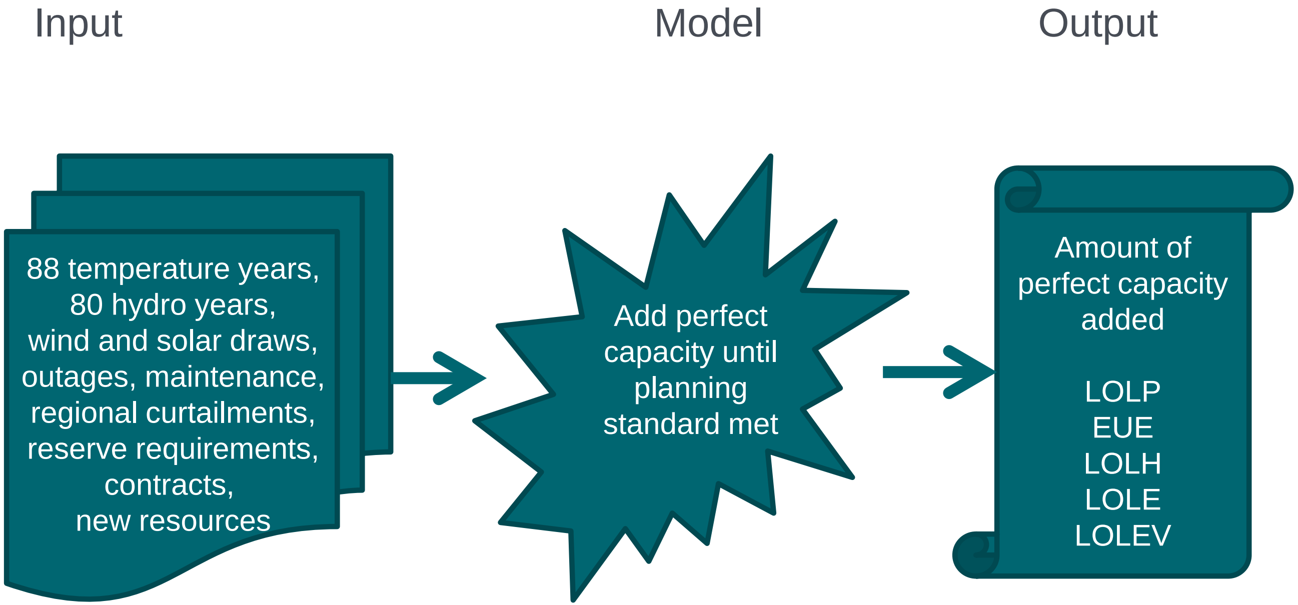
- Key assumption in regional model:
  - Economics drive joint coordination of resources in the Pacific Northwest
  - No consideration of firm transmission rights
  - All PNW transmission resources can be fully utilized up to modeled limits by any entity
  - Assumes 3400 MW California import limit

PSE's system diagram for RAM

- Firm transmission to Mid-C power trading hub for short-term capacity market purchases is treated as a resource.
- PSE currently relies on 1500 MW of firm transmission to Mid-C for peak planning, so adequacy of region is critical.

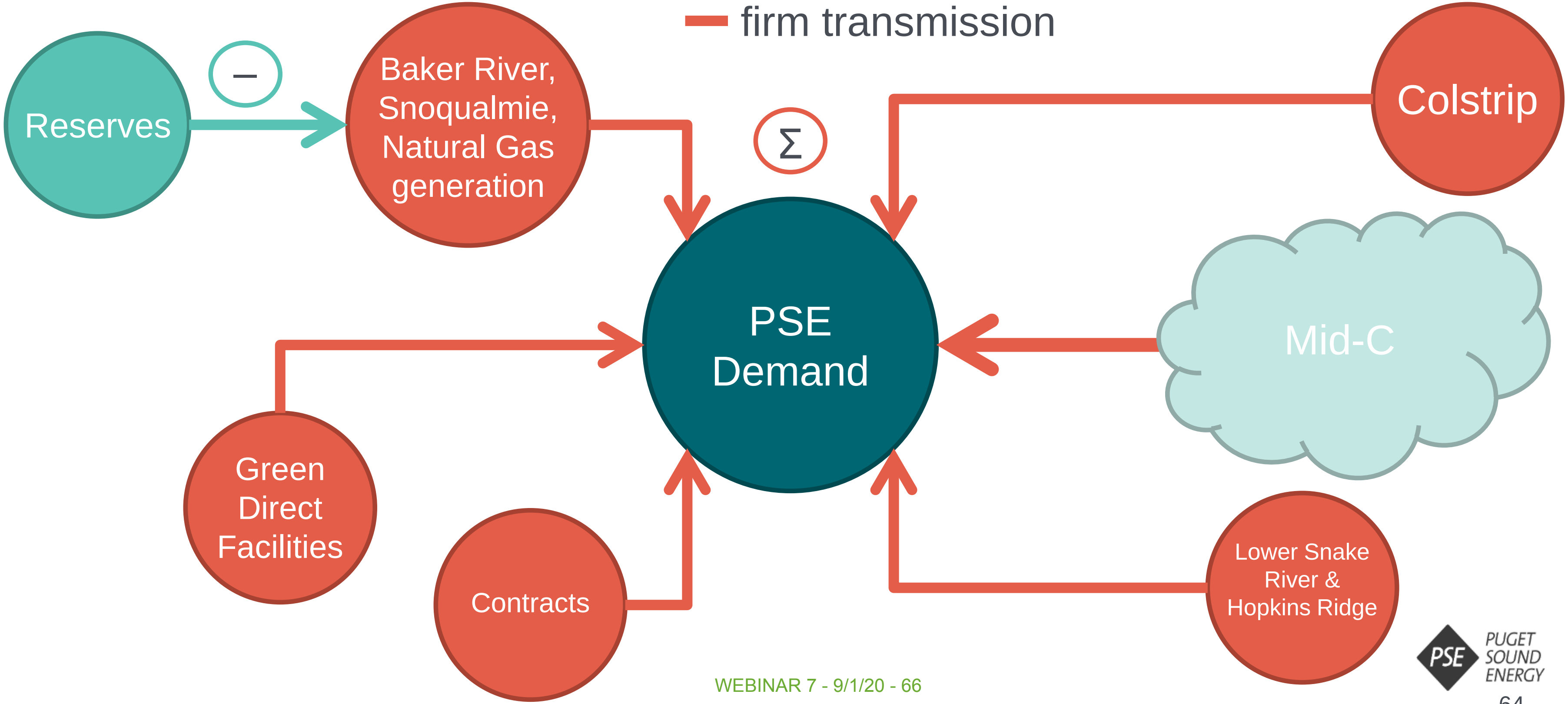


RAM inputs and outputs

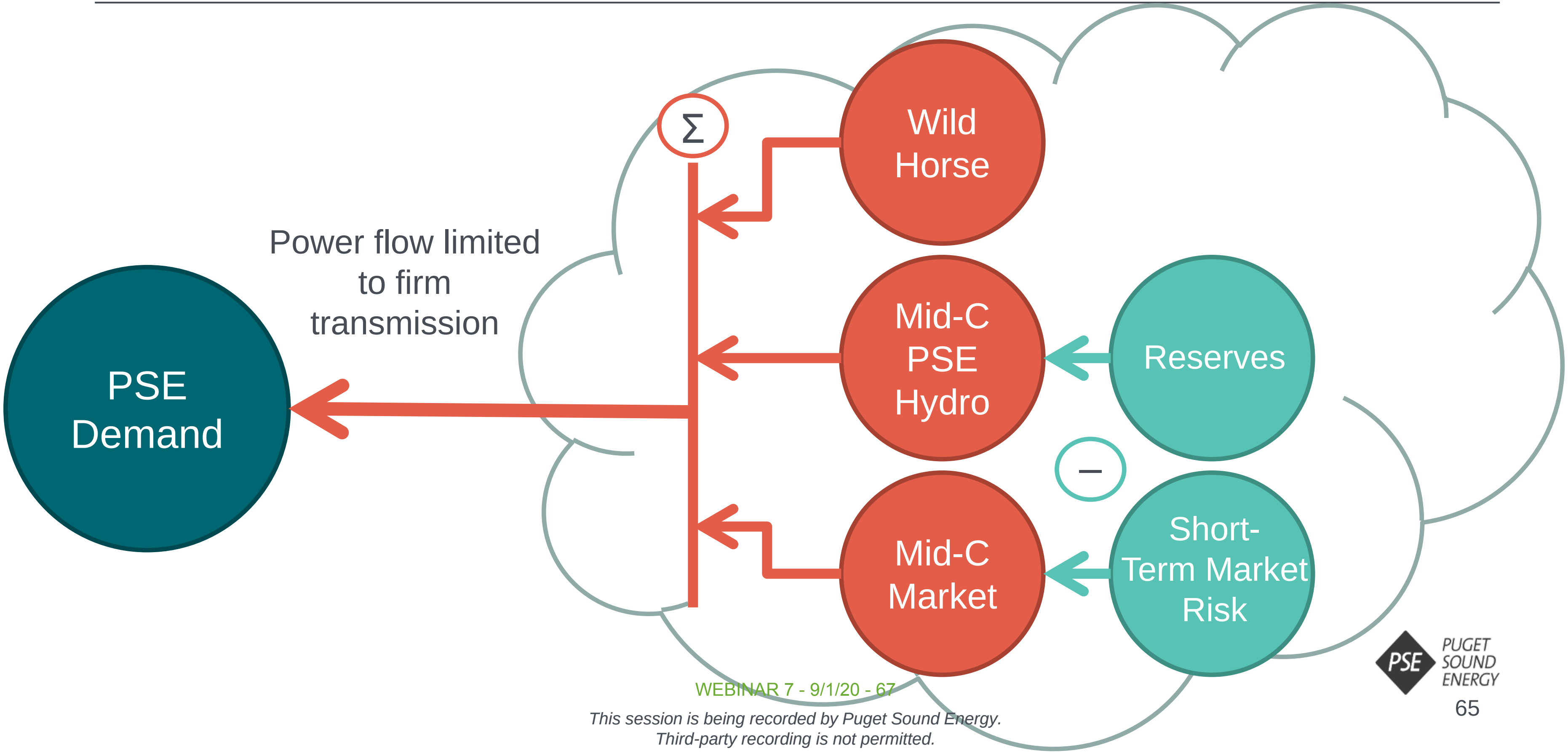


7040 simulations

RAM framework



RAM Mid-C framework



Draft PSE Resource need at 5% LOLP for 2027-2028

- Study year October 2027 – September 2028
- **1273 MW resource need** for 5% LOLP
- Reliability metrics at 5% LOLP:

Metric Name	Base System, No Added Resources	System at 5% LOLP, 1273 MW Added
LOLP	74.97%	4.99%
EUE	6667 MWh	88 MWh
LOLH	18.70 hours/year	0.16 hours/year
LOLE	4.06 days/year	0.06 days/year
LOLEV	5.46 events/year	0.06 events/year

Draft PSE Resource need at 5% LOLP for 2031-2032

- Study year October 2031 – September 2032
- **1581 MW resource need** for 5% LOLP
- Reliability metrics at 5% LOLP:

Metric Name	Base System, No Added Resources	System at 5% LOLP, 1581 MW Added
LOLP	98.61%	4.99%
EUE	28551 MWh	188 MWh
LOLH	85.81 hours/year	0.34 hours/year
LOLE	18.96 days/year	0.07 days/year
LOLEV	24.51 events/year	0.09 events/year

Draft Planning Margin

The planning margin (expressed as percent) is determined as:

Planning Margin = (Peak Need – Normal Peak Load) / Normal Peak Load

Where Peak Need (in MW) is the resource capacity that meets the reliability standard established in a probabilistic resource adequacy model (Peak Capacity Need from LOLP) in addition to the peak capacity contribution from existing resources (Total Resources) and short-term Mid-C bilateral market purchases.

	Winter Peak 2027	**Winter Peak 2031**
Peak Capacity Need to meet 5% LOLP	1,273 MW	1,581 MW
Total Resources Peak Capacity Contribution	3,326 MW	3,316 MW
Short-term Market Purchases	1,492 MW	1,497 MW
Peak Need	6,091 MW	6,394 MW
Normal Peak Load	4,949 MW	5,199 MW
Planning Margin	**23.1%**	**23.0%**

Note: planning margin includes contingency and balancing reserves

Electric resource need

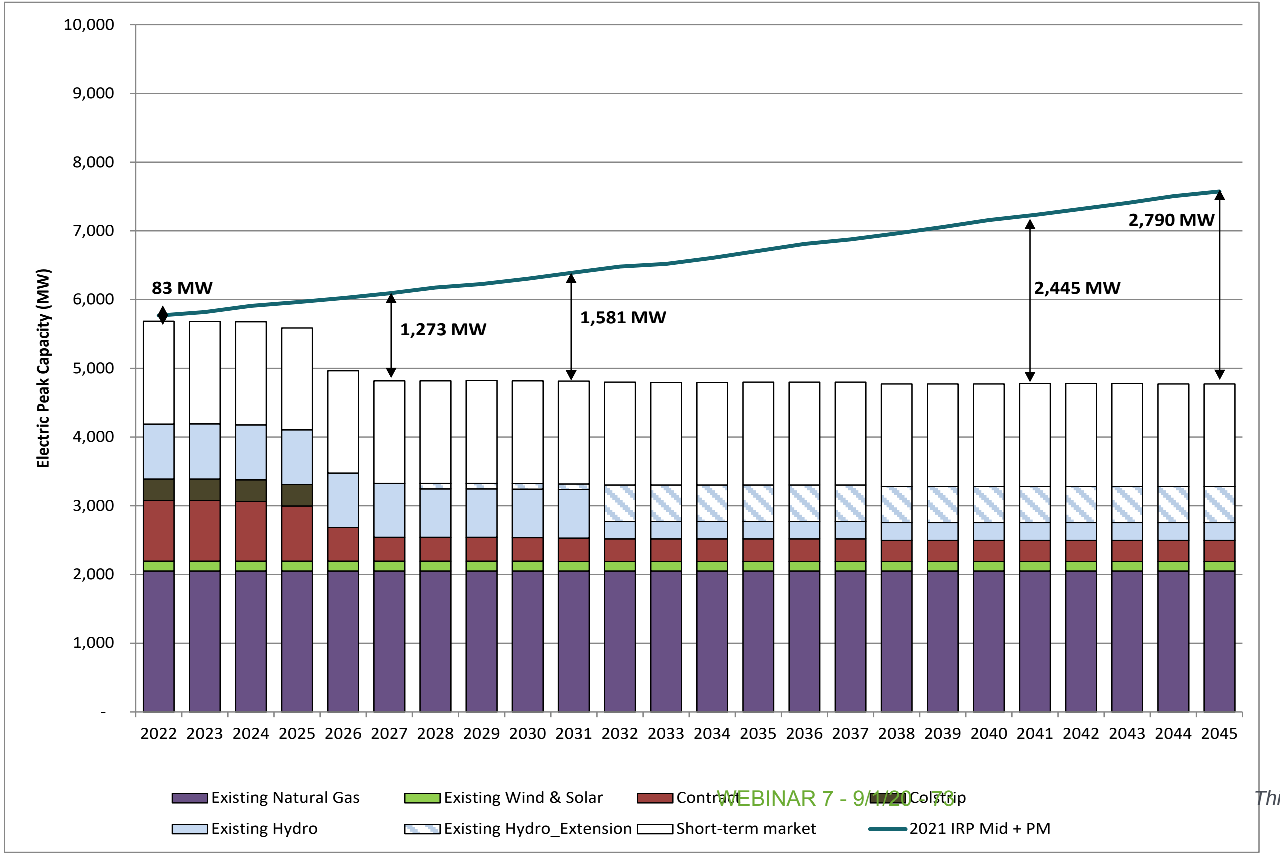
PUGET SOUND ENERGY

Participation Objectives

- PSE will inform stakeholders about the electric resource need.

IAP2 level of participation: INFORM

Draft electric peak capacity resource need

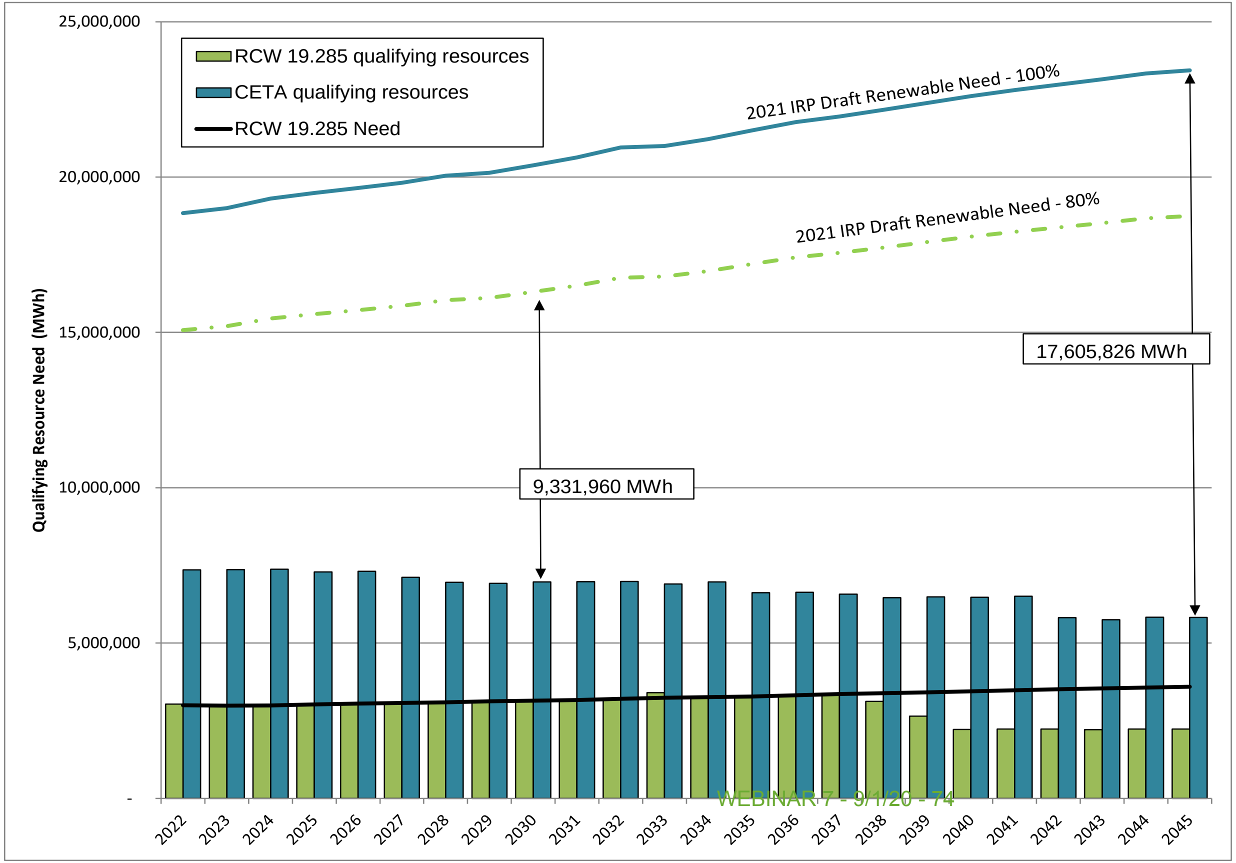


Notes:

1. 2021 IRP peak capacity need does not include any demand side resources. Demand side resources will be determined as part of the 2021 IRP and include conservation (energy efficiency), codes and standards, distribution efficiency, or demand response.

2. 2021 IRP peak capacity need does not include 2018 RFP resources under negotiations. Peak need will be updated for new resources.

Draft electric renewable need



Notes:

1. 2021 IRP renewable need does not include any demand side resources. Demand side resources will be determined as part of the 2021 IRP and include conservation (energy efficiency), codes and standards, distribution efficiency, or demand response.

2. 2021 IRP peak capacity need does not include 2018 RFP resources under negotiations. Peak need will be updated for new resources.

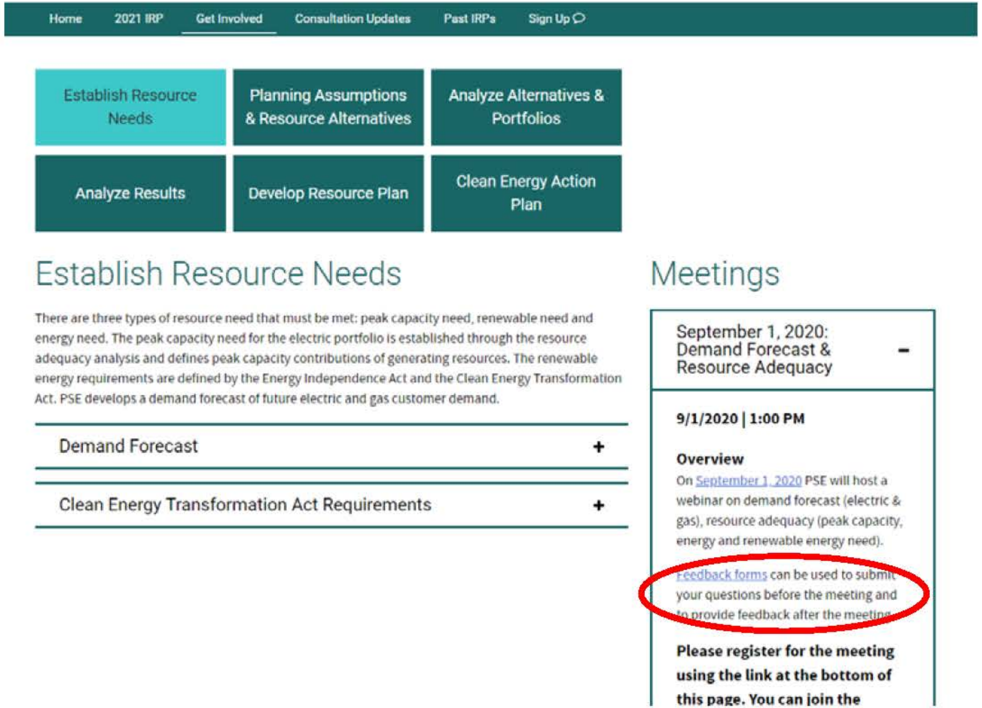
PSE PUGET SOUND ENERGY

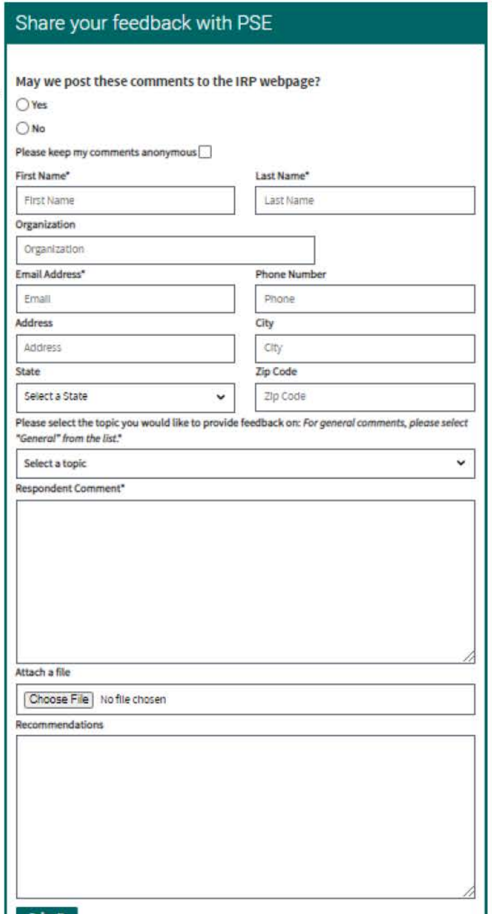
Wrap-up

WEBINAR 7 - 9/1/20 - 75

This session is being recorded by Puget Sound Energy. Third-party recording is not permitted.

Feedback Form





Feedback Form

- An important way to share your input
- Available on the website 24/7
- Comments, questions and data can be submitted throughout the year, but timely feedback supports the technical process
- Please submit your Feedback Form within a week of the meeting topic

Feedback Form → **Feedback Report** → **Consultation Update**

Next steps

- Submit Feedback Form to PSE by **September 8, 2020**
- A recording and the chat from today's webinar will be posted to the website **tomorrow**
- PSE will compile all the feedback in the Feedback Report and post all the questions by **September 15, 2020**
- The Consultation Update will be shared on **September 22, 2020**

PUGET SOUND ENERGY

Details of upcoming meetings can be found at pse.com/irp

Date	Topic
October 14, 1:00 – 5:00 pm	Natural gas IRP: design peak day, portfolio modeling and draft results, resource alternatives, scenarios and portfolio sensitivities review
October 20, 1:30 – 4:30 pm	Portfolio sensitivities draft results Flexibility analysis
November 4, 1:00 – 4:30 pm	Clean Energy Action Plan 10-year Distribution & Transmission Plan
December 9, 1:00 – 4:30 pm	Portfolio draft results Stochastic analysis Wholesale market risk

Thank you for your attention and input.

Please complete your Feedback Form by September 8, 2020

We look forward to your attendance at PSE's next public participation webinar:

Natural gas IRP

October 14, 2020

IRP DEMAND FORECAST SPREADSHEET

Click this link to download the spreadsheet:

https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/September_1_meeting/PSE_2021_IRP_Demand_Forecast_2022-2045_09012020.xlsx

Webinar #7: CETA Assumptions, Demand Forecast, Resource Adequacy, Resource Need Q&A

9/2/2020

Overview

On September 1, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss CETA assumptions, demand forecast, resource adequacy and resource need. Additionally, participants were able to ask questions and make comments using a chat box provided by the Go2Meeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 70 stakeholders and PSE staff attended the webinar, plus another 11 attendees who called into the meeting and did not identify themselves (81 people total).

Attendees included: Allison Jacobs, Anne Newcomb, Anthony O'Rourke, Benjamin Zwirek, Bill Pascoe, Brian Grunkemeyer, Charlie Inman, Cody Duncan, Court Olson, Dan Kirschner, Don Marsh, Elyette Weinstein, Fred Heutte, Graham Horn, James Adcock, Jenny Lybeck, Jim Heidell, Jon Howell, Joni Bosh, Julie Zuckerman, Katie Ware, Kevin Jones, Kevin Yates, Kyle Frankiewich, Lana Gonoratsky, Larry Becker, Lori Elworth, Mike Hopkins, Natalie Mims, Nick Abrams, Nick Bengtson, Norm Hansen, Orijit Ghoshal, Patrick Leslie, Rachel Brombaugh, Rahul Venkatesh, Robert Briggs, Sarah Laycock, Stephanie Chase, Steve Johnson, Ted Drennan, Virginia Lohr, Vlad Gutman-Britten, Warren Halverson, Weimin Dang, Willard Westre

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 1:00 PM PDT and ended at 4:11 PM PDT.

Name	Time Sent	Comment
James Adcock	**1:07 PM**	Hand Raise Slide 10
James Adcock	**1:09 PM**	Hand Raise Slide 13
Kyle Frankiewich	**1:14 PM**	Hello all! Apologies for joining late; had some internet troubles at home.
Joni Bosh	**1:15 PM**	Since Ecology has not finished the rule making around what kinds of projects qualify as ETPs,
Alexandra Streamer	**1:15 PM**	@Kyle, no problem – thanks for joining us!
Don Marsh	**1:20 PM**	We would like to see more forecasts for those "pockets" of demand, since PSE develops responses for those pockets. This seems like a blind spot in the IRP process.
Alexandra Streamer	**1:23 PM**	Thanks for the comment, Don
Don Marsh	**1:26 PM**	Raise hand slide 23
Anne Newcomb	**1:37 PM**	Thank you for including Covid impacts. How is PSE effected by the current and in many cases the future work from home ethic and less building occupation?
Warren Halverson	**1:41 PM**	PSE has actual demand data from Mar-Se', 6 months, please share with us the quantitative change and that actual percent impact for the next few years.
Warren Halverson	**1:41 PM**	Thank you.
Anne Newcomb	**1:44 PM**	Thanks for the great answer!
Warren Halverson	**1:47 PM**	Thank you
Don Marsh	**1:48 PM**	Raise hand slide 28
Vlad Gutman-Britten	**1:52 PM**	Do you consider the impact of ETPs on this EV deployment?
Kyle Frankiewich	**1:53 PM**	agree that it’s reasonable to expect some interactive effects between EVSE-based ETPs and EV adoption
Anne Newcomb	**1:54 PM**	Well said Don! :-)
Natalie Mims	**1:54 PM**	1:54 PM: Could you (repeat) the assumptions about on-peak and off-peak charging (e.g., 100% of charging is on-peak, 50% is on-peak)?
Fred Heutte	**1:54 PM**	I'm curious about the eventual saturation of EVs at about 25% by 2050. PGE also had analysis from Navigant and estimated a mid-range of 35% by 2050, with a low estimate about half that, and a high estimate more than double. Is PSE also including a low and high estimate in the IRP modeling?
Brian Grunkemeyer	**1:54 PM**	I'd like to suggest a CETA Energy Transformation Project. I think EV charging can be used to help further your carbon reduction goals. Looks like we can reduce emissions by about 10% using Don's suggestion of a fixed TOU, but we have some preliminary data suggesting a 20% reduction in emissions using a marginal CO2 emissions forecast. Would PSE consider something like this?
Bill Pascoe	**1:55 PM**	Raise Hand #28
Kyle Frankiewich	**1:56 PM**	ETP = Energy Transformation Projects
Anne Newcomb	**1:58 PM**	Has peak demand changed during the pandemic?

Don Marsh	**2:02 PM**	Raise hand slide 29
Fred Heutte	**2:03 PM**	Comment on slide 29.
Virginia Lohr	**2:04 PM**	Looking at new forecasts related to Covid and making immediate changes to your demand forecasts for the future is impressive. Projecting accurately what will happen in the future is essential for an IRP to be valid, so your making such rapid adjustment for Covid is noteworthy For temperature data, I see only backward looking data. The proposed scenarios look at using different segments of historic data, but none of the proposals are future looking. Clearly, you found projections on the impact of covid, and projections of changes of future temperatures could be found. We know that getting good projections for future temperatures is essential to getting useful projections for the environment in which PSE will be operating. Your President has said "I have been a very vocal advocate of the need to combat climate change however we can." Please help me understand the rationale for treating temperature data so differently from all the other forecasts, such as electric vehicle use, and how this will help your
Alexandra Streamer	**2:05 PM**	@Virginia thanks for your question – looks like it may have been cut off at the end.
Don Marsh	**2:07 PM**	Thanks, Elisabeth!
Fred Heutte	**2:08 PM**	Here's the NW Council staff's most recent summary of the climate-adjusted load forecast inputs for the 2021 Northwest Plan. Extensive presentations on how climate modeling has been incorporated into their estimates can also be found on their site: **https://www.nwcouncil.org/sites/default/files/2020_08_p3.pdf**
James Adcock	**2:08 PM**	I suggest that everyone should be less worried about average Heating Degree Days, or Cooling Degree Days, and instead worry more about how Puget is modeling Peak Capacity needs aka "Coldest Winter Day" assumptions for "Resource Adequacy" purposes -- because I think Puget may be high by about 700 Megawatts.
Virginia Lohr	**2:17 PM**	Looking at forecasts related to Covid & making changes to your demand forecasts is impressive. Projecting the future accurately is essential for an IRP to be valid, so your making such rapid adjustment for Covid is noteworthy. For temperature data, I see only backward looking data. The proposed scenarios use different segments of historic data, but none of the proposals are future looking. You found projections on the impact of covid, and projections of changes of future temperatures could be found. Getting good projections for future temperatures is essential to getting useful projections for the environment in which PSE will be operating. Your President said "I have been a very vocal advocate of the need to combat climate change however we can." Please help me understand the rationale for treating temperature so differently from all the other IRP forecasts, and how this will help your President show us that she intends for PSE to combat climate change if temperature forecasts are not used in this IRP.
Anne Newcomb	**2:17 PM**	Does PSE have any new NG fired turbines under construction or any NG Gas plants in the pipeline currently or are there any future plans to add NG facilities?

Don Marsh	**2:22 PM**	Raise hand slide 32
Kyle Frankiewich	**2:26 PM**	Agree that 2019 post-DSR lines provide really useful context
Court Olson	**2:33 PM**	I second the comments that Don Marsh is making on the gas demand projection chart.
Don Marsh	**2:40 PM**	Raise hand
Anne Newcomb	**2:42 PM**	Good answer. Thanks!
Court Olson	**2:42 PM**	Good to see no peak load growth over the next 12 to 15 years with the anticipated conservation. I think that trend is likely to continue beyond that time frame.
Court Olson	**2:44 PM**	FYI, recent modeling by the State of Washington predicts that Summer Peak will be bigger than winter peak by 2050. PSE should be predicting such a change.
Fred Heutte	**2:46 PM**	Comment on summer peak: the issue is not so much that it is lower than winter, but that the market is limited and will be moreso in the future with coal retirements.
Kyle Frankiewich	**2:48 PM**	+1 for Fred's comment. Even if PSE's load isn't as big in July as it is in December, it may still be a bigger challenge to meet that load, or may have to pay exorbitant prices in competition with OR and CA to do so.
Kevin Jones	**2:49 PM**	Please don't overlook Anne Newcomb's question at 2:17
Steve Johnson	**2:50 PM**	From 2017 IRP page E-6 showing regression variables states $\chi 1$= dummy variables used to put special emphasis on summer months to reflect growing summer peaks.
Brian Grunkemeyer	**2:50 PM**	To augment Kyle's comment - An easy way to proivde more context would be to see what the BPA and other utilities are doing with power sales during the summer vs. winter. If all available power is being sold to California in the summer, the power available in the NW may be quite limited. (No need to discuss, but please consider offline.)
Fred Heutte	**2:53 PM**	Slide 55 – a comment.
James Adcock	**2:53 PM**	To augment Brian's comments about BPA -- BPA has a legal requirement to meet the needs of the PNW before sales to other regions -- such as California. I don't believe BPA would want to be in the position of selling to California during a power shortage in the PNW -- I think that action would prove to be very troublesome for BPA to defend.
Kevin Jones	**3:05 PM**	raise hand
Brian Grunkemeyer	**3:06 PM**	Elizabeth, can you please confirm that your RA work looks at market availability of power during the summer, in addition to winter?
Fred Heutte	**3:07 PM**	Just to point out BPA must first meet the needs of its preference customers (public power), then offer any remaining resource within the Northwest ("regional preference") and only then sell outside the region.
Brian Grunkemeyer	**3:08 PM**	.. So essentially, if we have a Northwest-wide spike in demand, PSE may still not be able to get power during a summer. PSE's summer peak may of course be lower, but if they are still short in the summer during a peak demand period, PSE could need to curtail load. Correct?
James Adcock	**3:10 PM**	Raise Hand Slide 63

Don Marsh	**3:11 PM**	+ 1 on Brian's comment. I just looked up Avista's 2021 IRP. That utility is showing historical peaks and forecasts for both summer and winter. PSE shouldn't hide the summer peak forecast.
Don Marsh	**3:11 PM**	Raise hand slide 63
Willard Westre	**3:13 PM**	Raise Hand s-66 & 67
Kyle Frankiewich	**3:18 PM**	**Raised hand**
Fred Heutte	**3:21 PM**	question on slide 65
James Adcock	**3:27 PM**	Re Slide 63 it would also be good to know that the "Hydro Data" has actually been "corrected" to reflect BPA change in operational conditions back in th 1980s -- a question which Puget hasn't clearly answered yet (and these issues have been unresolved for more than a decade now.)
Brian Grunkemeyer	**3:27 PM**	Kyle, great question. Would probably have a higher LOLP in summer, and lower in winter. But these numbers are computed on an annual basis. It's tricky. But this is important to avoid a California-style power shortage.
James Adcock	**3:39 PM**	It is also important to not build emitting resources in excess of what is in-practice needed on a 20-year basis.
James Adcock	**3:30 PM**	There has been about one day of largish Mid-C price spikes per year the last couple of years.
Brian Grunkemeyer	**3:31 PM**	You've just put your finger on the tension here. We want a lower LOLP to ensure PSE doesn't over-build based on the winter peak. We want a carefully-computed LOLP that might be higher in the summer to ensure we don't have a California-style blackout. This is a tricky tension, and the UTC has to make sure they can understand and defend this process to a future governor if something goes wrong.
James Adcock	**3:33 PM**	It is not UTC's job to defend Puget's choices right or wrong. It is Puget's job to defend Puget's choices right or wrong. And they can be wrong in two different directions -- they can "model" their peak capacity needs too high, or too low.
Brian Grunkemeyer	**3:34 PM**	What should PSE do? Two versions of the RA model, take the max of two LOLP's?
James Adcock	**3:35 PM**	In practice I suggest Puget should limit themselves to the most recent 30 years of temperature data. And they need to make sure that their hydro data has actually been "corrected" to account for BPA changes in operational practices as-of in 1980s.
Don Marsh	**3:37 PM**	Agreed. 30 years for RAM, 20 years for normal temperature calculation for peaks.
Court Olson	**3:37 PM**	These charts don't have significant value without DSR included.
Fred Heutte	**3:38 PM**	responding to Brian: as Tom Eckman from the NW Council liked to say, "you always want to be a little 'long' but not too long!"
Anne Newcomb	**3:39 PM**	It looks like my question will be better on slide 72. I see you are having a fresh look at your 2018 RFP which had a peaker plant Does PSE have any new NG fired turbines under construction or any NG Gas plants in the pipeline currently or are there any future plans to add NG facilities?
Virginia Lohr	**3:40 PM**	That question was from Anne. That was not my question.
James Adcock	**3:40 PM**	Renewables fuels are only allowed to the extent that they are fed directly to the NG power plant.

Virginia Lohr	**3:41 PM**	Please askmy question.
Anne Newcomb	**3:41 PM**	No problem at all! Thanks!
Don Marsh	**3:41 PM**	Raise hand
James Adcock	**3:42 PM**	Raise hand
Court Olson	**3:42 PM**	I didn't hear an answer to Anne's question on future PSE plans to build gas facilities. It was sidestepped.
Fred Heutte	**3:42 PM**	comment in response to Don Marsh

PSE IRP Feedback Report
Webinar 7: CETA Assumptions, Demand Forecast, Resource Adequacy, Resource Need
September 1, 2020

9/15/2020

The following stakeholder input was gathered through the online Feedback Form, from August 25 through September 8, 2020. PSE's response to the feedback can be found in the far-right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on September 22, 2020.

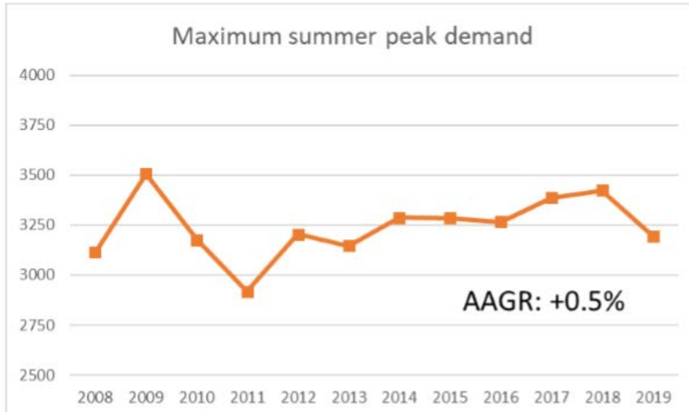
<table>
<tr><th>Feedback Form Date</th><th>Stakeholder</th><th>Comment</th><th>PSE Response</th></tr>
<tr><td>8/27/20</td><td>Mike Hopkins, Fortis BC</td><td>I was wondering if the peak electric load forecast on slide 28 includes any programs/initiatives/rates, such as time-of-use or EV charging rates, that would reduce the impacts of EV home charging on peak loads by shifting charging to off-peak times? If yes, how much is the peak load reduced vs. without these things? if no, are you planning to include them or include a qualitative discussion of what they might be able to do in terms of shifting peak charging?</td><td>The peak loads associated with EVs do not include assumptions for specific future programs, initiatives, or rates. In this IRP, PSE is modeling several demand response programs including commercial and industrial (C&I) critical peak pricing (CPP) and EV charging:
<table>
<tr><th>Product</th><th>Group</th><th>Number of Events</th><th>Notification Type</th></tr>
<tr><td>C&I CPP-No Enablement</td><td>Commercial Critical Peak Pricing</td><td>Up to ten 4-hour events</td><td>Day-ahead (non-dispatchable)</td></tr>
<tr><td>C&I CPP-With Enablement</td><td>Commercial Critical Peak Pricing</td><td>Up to ten 4-hour events</td><td>Day-ahead</td></tr>
<tr><td>Res Electric Vehicle DLC</td><td>Residential Electric Vehicles</td><td>Up to ten 4-hour events</td><td>Day-ahead</td></tr>
</table>

The IRP modeling process will determine how much peak load may be reduced by these types of demand response programs.

Additionally, going forward in future IRPs, assumptions about EV demand response program design and peak load reduction will be based on experience gained through the Up & Go Pilot Program, which PSE is currently running.</td></tr>
<tr><td>[sent by email 08/22/20]</td><td>Don Marsh, CENSE</td><td>Don provided a two-page letter directed to Irena Netik and IRP staff with questions for the September 1 webinar.</td><td>Thank you for providing questions prior to the meeting. Your questions informed the meeting content. Questions 1 through 10 were addressed during the webinar. Question 11 is addressed below. The letter, dated July 22, 2020, is uploaded as part of the Feedback Report.</td></tr>
<tr><td>[sent by email 08/22/20]</td><td>Don Marsh, CENSE</td><td>Explain any significant differences between PSE's demand forecast and those of nearby utilities such as Seattle City Light, Snohomish PUD, Tacoma Power, PacifiCorp, Avista, and Portland General Electric. What regional factors may cause PSE's forecast to diverge from other utilities?</td><td>PSE expects load forecasts to differ among regional utilities due to various reasons, including:
1. Differences in type of service area. Utilities with primarily urban service areas have different opportunities for growth than do utilities with service areas that include suburban and/or rural areas. Additionally, whether customers have access to natural gas service affects trends in electric consumption.
2. Difference in composition of customer class mix. Trends in growth and usage differ among the residential, commercial, and industrial classes.
3. Climate. A utility that is primarily peaking due to heating load will have different consumption trends than a utility that serves both heating and cooling load equally.</td></tr>
<tr><td>8/28/20</td><td>Don Marsh, CENSE</td><td>Attached is a two-page letter with feedback on the electric demand forecast. This will also be sent to UTC staff by email. This letter contains several requests for corrections and more transparent data.</td><td>The letter, dated July 22, 2020 and received on August 28, 2020, is uploaded as part of the Feedback Report and the material content provided below.</td></tr>
<tr><td>8/28/20</td><td>Don Marsh, CENSE</td><td>After reviewing the presentation for the upcoming (Sept. 1) IRP webinar to review PSE's latest load forecast, I would like to thank the team for some positive steps in this forecast:

1. The declining post-DSR electric forecast is more inline with forecasts for other nearby utilities (Seattle City Light, Tacoma</td><td>Thank you for this positive comment concerning improvements to PSE's IRP process.</td></tr>
</table>

Feedback Form Date	Stakeholder	Comment	PSE Response
		Power, Snohomish PUD). For example, PSE's forecast shows a -0.4% AAGR for 2021-2031. For comparison, Seattle City Light's 2018 IRP shows an AAGR of -0.6% for the same period. We are pleased to see the post-DSR estimate on the same graph as forecast growth pre-DSR. 2. PSE includes summer and winter peak demand data for 2008-2019 (slides 48 and 49), and a reference to the data source from the FERC library. This data clarifies historical trends. 3. In response to our queries about weather records and the basis of weather normalization, PSE published a table on slide 29 showing different durations for calculating normal weather. It is obvious that heating declines with shorter history periods (probably due to local climate change), and cooling increases. PSE's chosen standard is for a 30-year period, which appears to overstate heating and understate cooling.	
8/28/20	Don Marsh, CENSE	[Opportunity for improvement 1] The AAGR shown in the post-DSR electric forecast appears misleading without further context. The expected demand declines until 2031, and then starts to increase, leading to an overall AAGR of 0.2%. But the increases and the AAGR may be illusory because PSE is not accounting for any new conservation programs after 2031. The graph says, "No new conservation after committed 2-year targets," but this does not clarify that the increasing demand after 2031 is an accounting artifact, not a realistic possibility. If anything, more aggressive conservation will be necessary after 2031 to reach 100% clean energy by 2045 in accordance with CETA goals. This graph is specifically extended to 2046 to account for CETA, but the load forecast itself doesn't appear to account for the effects of CETA.	Positive customer growth, steady use per customer, and electric vehicles yield demand growth before demand side resources (DSR) are included. Applying DSR will result in an "after DSR" forecast with lower growth than "before DSR." The final amount of DSR will be determined by the portfolio model. The portfolio model results are forthcoming in the current IRP process and are yet to be determined. The "after DSR" results presented during the webinar are for illustrative purposes only and is based on DSR amounts determined by the 2019 IRP process. The final "after DSR" demand forecast will be available once the economic DSR amount is determined. The Clean Energy Transformation Act (CETA) affects the amount of demand-side resources. Demand-side resources are included as a resource option in the IRP portfolio model and are not included in the "before DSR" base demand forecast. The demand forecast from 2022 through 2045 is used as an input into the portfolio modeling, which is the purpose of showing the forecast through 2045 even though the forecast "before DSR" does not account for CETA.
8/28/20	Don Marsh, CENSE	[Opportunity for improvement 2] Although PSE included a table showing historical summer peak demand, the presentation includes no forecast for summer peaks. It doesn't even include a graph of historical summer peak demand, so I created the graph from PSE's data [see Don's letter OR Michele to insert picture]:	The IRP analysis optimizes generation resources to meet the maximum capacity need. For PSE the customer load has historically peaked in the winter. However, PSE will consider providing stakeholders the historical and forecasted electric summer peak information.

Feedback Form Date	Stakeholder	Comment	PSE Response
		 The graph shows a very gradual rise in summer peak demand, averaging about 0.5% per year. The peak in 2018 was almost as high as the highest peak in 2009, although the peak temperature in 2018 was eight degrees cooler, so it appears that peaks are gradually increasing.	
8/28/20	Don Marsh, CENSE	[Opportunity for improvement 3] We are puzzled why PSE is issuing RFPs for winter demand response, but no corresponding RFP for summer demand response. Summer peaks are increasing, and winter peaks are not. Obviously, the summer peaks are about 25% lower than winter peaks, but we understand that PSE is concerned about summer reliability. Does PSE believe that summer demand response is not needed or not as feasible as winter demand response?	The RFP is targeting specific areas that have a winter morning peak capacity need. Future RFPs will have different objectives.
8/28/20	Don Marsh, CENSE	[Opportunity for improvement 4] Using 30 years of weather records to normalize weather calculations is at the upper limit of what we consider reasonable, given recent changes in climate. As we observed in earlier letters, New York's utility commission is using 15 years of weather records for normalization.	The effects of warming temperature trends on the demand forecast will be analyzed as a sensitivity and has been added to list of portfolio sensitivities.
8/28/20	Don Marsh, CENSE	[Opportunity for improvement 5] On slide 63, PSE appears to be using "88 temperature years" as an input to the Resource Adequacy Model. This may distort the results and introduce "cold bias" in the model that could be potentially costly for ratepayers. We ask that no record before 1990 be used to better account for recent climate changes.	The effects of warming temperature trends on the demand forecast will be analyzed as a sensitivity and has been added to list of portfolio sensitivities.
8/28/20	Don Marsh, CENSE	[Closing suggestion] Declining winter peaks and gradually increasing summer peaks provide PSE and ratepayers some room to concentrate on CETA goals and smart energy management. However, clear data is needed to understand the challenges and opportunities before us. We encourage PSE to provide this data and strong leadership to achieve successful outcomes.	Thank you for your comment.

Feedback Form Date	Stakeholder	Comment	PSE Response
9/2/20	James Adcock	I am concerned that Elizabeth Hossner keeps saying that the EPA somehow is responsible for "RECs" -- vetting them, defining them, etc. I have diligently searched the EPA website and find nowhere any indication that these statements are true. On the contrary, RECs seem to be defined, tracked, and retired by various regional authorities, and the process of "vetting" RECs appears to be done by independent third parties. I ask that Puget and Elizabeth Hossner please double-check and update their understanding of RECs and how they work -- and why they are not "available" on a nationwide-basis, but only within a region. And please communicate this corrected understanding to IRP participants once you have done so, because I am afraid your comments are confusing participants. See for example, the REC registration organization for the Western region: https://www.wecc.org/WREGIS/Pages/Default.aspx	RECs are a nation-wide program and can be sold nation-wide. There is a national REC market for voluntary REC purchases (for corporations/entities wanting to voluntarily buy RECs). For compliance purposes, there are many regional markets across the nation and PSE participates in the WECC region. Eligible RECs for the WA Renewable Portfolio Standard (RPS) have to meet certain requirements outlined in RCW 19.285 and 194-37 WAC, one of which states that the generation source be located in the Pacific Northwest. Therefore there is a WA RPS Compliant regional market. The Washington Clean Energy Transformation Act (CETA) does not have a geographic restriction. WREGIS is the tracking system for purposes of verification of RECs under RCW 19.285. WREGIS certifies RECs for the WECC region for the Energy Independence Act (EIA), RCW 19.285. This information is available to all stakeholders. All feedback forms and consultation updates are available on pse.com/irp.
9/2/20	James Adcock	I ask that Puget and Elizabeth Hossner please double-check and update their understanding of RECs and how they work -- and why they are not available on a nationwide-basis, but only within a region. And please communicate this corrected understanding to IRP participants once you have done so, because I am afraid your comments are confusing participants.	The response is provided above.
9/2/20	Don Marsh, CENSE	After participating in yesterday's Demand Forecast webinar for PSE's 2021 IRP, a number of stakeholders were dismayed that PSE refused our requests to include a forecast of peak summer demand. The attached letter shows that Avista is supplying this information in its 2021 IRP. The convergence of winter and summer forecasts in Avista's service area may justify concern by PSE's customers as well. If summer demand is actually growing in PSE's service area, perhaps greater investment in solar panels and energy storage would be a cost-effective solution. Without good data about these trends, it is difficult to tell.	The letter, dated September 2, 2020, is uploaded as part of the Feedback Report. Your questions and PSE's responses are provided below. The IRP analysis optimizes generation resources to meet the maximum capacity need. For PSE the customer load has historically peaked in the winter. However, PSE is evaluating your request and will respond in the Consultation Update.
9/2/20	Don Marsh, CENSE	Please share PSE's summer peak demand forecast with normal weather based on 15-20 years of historic data.	The IRP analysis optimizes generation resources to meet the maximum capacity need. For PSE the customer load has historically peaked in the winter. However, PSE is evaluating your request and will respond in the Consultation Update. The normal weather assumption for PSE's demand forecast is based on the most recent 30 years of weather data. PSE has added a temperature sensitivity to the list of portfolio sensitivities.
9/8/20	Joni Bosh, NW Energy Coalition	See attached comments	The comments have been uploaded as part of the Feedback Report and the material content provided below for PSE's response.

Feedback Form Date	Stakeholder	Comment	PSE Response
9/8/20	Joni Bosh, NW Energy Coalition	In response to the question posed on prioritizing options for the 20% alternative compliance actions that might be addressed in the 2021 IRP, NWEC would urge PSE to model an aggressive amount of conservation and demand response. Beyond the required conservation and demand response required in sections .040 and .050 of CETA, additional innovative conservation, efficiency, storage and demand response should be considered for Energy Transformation Projects. Exploring those has the double impact of further reducing/managing load and achieving additional GHG reductions.	Thank you for your feedback, PSE will add a sensitivity to increase conservation and demand response as part of the alternative compliance options to the list of portfolio sensitivities.
9/8/20	Joni Bosh, NW Energy Coalition	Regarding the two charts on pages 24 and 38 of the presentation, it would be helpful to have more discussion on the impact of a couple of assumptions: 1. How would demand look in both the short and long run if there is a second or even third wave of coronavirus infections? 2. How does the current economic demographic model on slide 24 link with the demand forecast by the mid-2020s on slide 38? Is most of the lower peak attributable to lower per customer usage? –	Thank you for your two questions on pages 24 and 38 of the September 1, 2020 webinar. PSE's responses are provided below: 1. The base demand forecast includes assumptions about the pandemic, based on Moody's May 2020 economic outlook assumptions. The base demand forecast assumes that new infections begin to abate in July 2020 and there is no second wave of infections. PSE has not developed a demand forecast specifically for alternative pandemic scenarios. As part of regular IRP practice, in addition to the base demand forecast, a low and high demand forecast will be developed. The low demand forecast could be used as a proxy for a more severe pandemic scenario. 2. The employment forecast presented on slide 24 is an element of the customer growth and usage forecast, with employment levels appearing mostly in non-residential modelling. The 2020 slowdown impacts the demand forecast through lower usage in the short term and lasting "lost" customer additions in the medium and long term. However, separate from downstream impacts resulting from the economic contraction, other modelling updates yielded lower projections of non-residential customer growth and usage as well. The lower IRP peak demand after 2025 is a mix of several things: inclusion of 2020/2021 conservation targets not included in the 2019 IRP process, lower customer usage projections (particularly non-residential), and lower customer growth (which includes the lagged economic effects presented on slide 24).
9/8/20	Joni Bosh, NW Energy Coalition	We would strongly encourage using a 15-year historical base for heating and cooling day analysis instead of the 30-year base, as the data on slide 29 certainly supports that approach. Assuming "average weather" is probably acceptable for the energy forecast, if PSE uses the shorter time period of 15 years, as the shorter time period incorporates actual, real climate change impacts. Using the 15 year historical base could well modify the forecast peak trends.	PSE has added a temperature sensitivity to the list of portfolio sensitivities.
9/8/20	Robert Briggs, Vashon Climate Action Group	Given the strong correlation between PSE's electric load and outdoor temperature, I'm surprised PSE has not tapped into regional expertise in climate modeling to inform the IRP process. During the webinar, much discussion centered around what length of historic weather data should be used in load forecasting. PSE uses economic and other types of forecasting in projecting future loads. Why not do the same for climate, which impacts temperature-driven space-conditioning loads and water availability for hydro? World-class capabilities in regional climate modeling can be found at the University of Washington's Climate Impacts Group [https://cig.uw.edu/] and at Pacific Northwest National Laboratory's Atmospheric Sciences and Global Change Division [https://www.pnnl.gov/atmospheric/]. During the webinar, one of the presenters suggested that PSE's winter electric peak was typically about one gigawatt	Thank you for your comments and suggestions. PSE has added a temperature sensitivity to the list of portfolio sensitivities.

Feedback Form Date	Stakeholder	Comment	PSE Response
		higher than its summer peak. This could change very rapidly given the rate at which heat records are being broken in many parts of the world. The Pacific Northwest is particularly at risk of rapid, unprecedented growth in summer electric peaks, because residential buildings have not traditionally needed air-conditioning. For example, if 250,000 residences in the Pacific Northwest added central air-conditioning drawing 4 kW each, an additional GW of summer demand could appear very quickly. Heat and smoke from wild fires are making natural ventilation untenable. PSE needs to be planning for both summer and winter peaks and to be employing best available science to project how weather conditions will be changing in the future.	

July 22, 2020

To: Irena Netik – PSE Director of Energy Supply Planning and Analytics

Cc: Brad Cebulko – UTC Staff
Steve Johnson – UTC Staff
Deborah Reynolds – UTC Staff
Kyle Frankiewich – UTC Staff
Kathi Scanlan – UTC Staff

Subject: 2021 IRP Electric Demand Forecast

Dear Ms. Netik and IRP Team,

Members of the IRP stakeholders are looking forward to PSE's 2021 load forecast, to be covered in an IRP webinar scheduled for September 1.

As you know, PSE's gas and electric demand forecasts are important elements of its Integrated Resource Plan. In addition to justifying resource acquisitions, the demand forecasts also become the basis of other consequential calculations. For example, the expected rate of demand growth is a primary input to calculate the cost-effectiveness of Demand Side Resources.

For the past ten years, PSE's forecast of electric demand has been consistently higher than observed demand. According to a 2016 study by Lawrence Livermore National Laboratories,[1] the discrepancy between observed load growth and PSE's base forecast was the highest among utilities serving Washington and Idaho in the study (Avista, Seattle City Light, PacifiCorp, Idaho Power).[2] We are heartened that PSE's base forecast of peak demand, although high, was more accurate than most of the utilities in the study, except PacifiCorp.[3]

PSE has not adequately explained why previous forecasts were too aggressive. Correcting these problems is critical to improve accuracy of future forecasts. We surmise that the company failed to properly account for warmer winters in the Puget Sound area, conservation and efficiency pursued by customers beyond PSE's conservation measures, and perhaps some lingering cost-consciousness among consumers after the Great Recession. Members of PSE's 2019 Technical Advisory Group also mentioned potential bias of PSE's weather normalization methodology using data from 30 years ago, before technology and climate change made significant impacts on demand.

Although the 2019 IRP was never completed, there were some encouraging developments. For the first time, PSE showed historical demand trends using actual data points in addition to the weather normalized data. The timeframe of the historical trend, about ten years, was reasonable. However, weather normalization continued to use at least three decades of past data. Seven years ago, the Journal of Applied Meteorology and Climate recommended using 15 years of temperature data for normalization, a standard that was adopted by New York's utility commission:[4]

[1] https://emp.lbl.gov/sites/default/files/lbnl-1006395.pdf
[2] *Ibid,* Table 19
[3] *Ibid,* Table 20
[4] https://www.scottmadden.com/insight/traditional-weather-normalization-practices-used-utilities-ratemaking-process-appropriate-given-increased-climate-variability/

According to a 2013 paper published in the Journal of Applied Meteorology and Climate, the use of 30-year surface temperature averages as estimates of future temperatures will, in many instances, result in a 'cold bias'—predicting temperatures will be colder than those actually experienced; using the most recent 15-year average is the best method for developing weather normalization curves.

Another concern is PSE's use of demand peaks in December as an approximation for maximum annual peak. During the past 15 years, two-thirds of the maximum yearly peaks occurred in months other than December. It is normal practice for Washington utilities to report the maximum annual peak rather than restricting the analysis to the month of December.

To provide an accurate and transparent load forecast, we ask PSE to address the following issues in the September meeting:

1. Please explain the source of inaccuracies in past forecasts, and how those errors have been corrected for the 2021 load forecast.
2. Explain any significant differences between the 2021 forecast and past growth trends.
3. Show approximately ten years of actual winter and summer peak demand data to illustrate past trends.
4. In collaboration with University of Washington and/or Pacific Northwest National Laboratory, use the best recent climate models to anticipate regional climate trends during coming decades.
5. If weather normalization remains relevant with updated climate models, use 10 to 15 years of past data to avoid "cold bias." Show all the data used for normalization.
6. Show past winter peak trends using the maximum peak values observed during all cold months (November-March) rather than just December.
7. Show past summer peak trends using the maximum peak values observed during all warm months (June-September).
8. Explain how the effects of CETA may significantly impact demand growth during the coming decade.
9. Explain how COVID might alter demand in coming years. Although the long-term economic impacts may be difficult to foresee, it would be helpful for PSE to share low, medium, and high forecasts with an explanation of the assumptions used in each.
10. Explain how rapid technological advances in solar panels, batteries, demand response, electrical efficiency, electric vehicles, and the desire to switch from fossil fuels to electricity are likely to alter demand growth in the coming decade.
11. Explain any significant differences between PSE's demand forecast and those of nearby utilities such as Seattle City Light, Snohomish PUD, Tacoma Power, PacifiCorp, Avista, and Portland General Electric. What regional factors may cause PSE's forecast to diverge from other utilities?

Transparent and thorough coverage of these points will help stakeholders understand the forecast and feel comfortable with PSE's analysis.

Sincerely,

Don Marsh, principal stakeholder
Fran Korten, Climate Action, Bainbridge
Warren Halverson, CENSE
Rob Briggs, Vashon Climate Action Group
Kevin Jones, Vashon Climate Action Group
David Perk, 350 Seattle
Norm Hansen, Bridle Trails Neighborhood
Michael Laurie, Sustainability Consultant, Watershed LLC
Kate Maracas, Managing Director, Sound Energy Group
Willard Westre, Union of Concerned Scientists

July 22, 2020

To: Irena Netik – PSE Director of Energy Supply Planning and Analytics

Cc: Brad Cebulko – UTC Staff
Steve Johnson – UTC Staff
Deborah Reynolds – UTC Staff
Kyle Frankiewich – UTC Staff
Kathi Scanlan – UTC Staff
Kendra White – UTC Staff

Subject: 2021 IRP Electric Demand Forecast

Dear Ms. Netik and IRP Team,

After reviewing the presentation for the upcoming (Sept. 1) IRP webinar to review PSE's latest load forecast, I would like to thank the team for some positive steps in this forecast:

1. The declining post-DSR electric forecast is more inline with forecasts for other nearby utilities (Seattle City Light, Tacoma Power, Snohomish PUD). For example, PSE's forecast shows a -0.4% AAGR for 2021-2031. For comparison, Seattle City Light's 2018 IRP shows an AAGR of -0.6% for the same period. We are pleased to see the post-DSR estimate on the same graph as forecast growth pre-DSR.

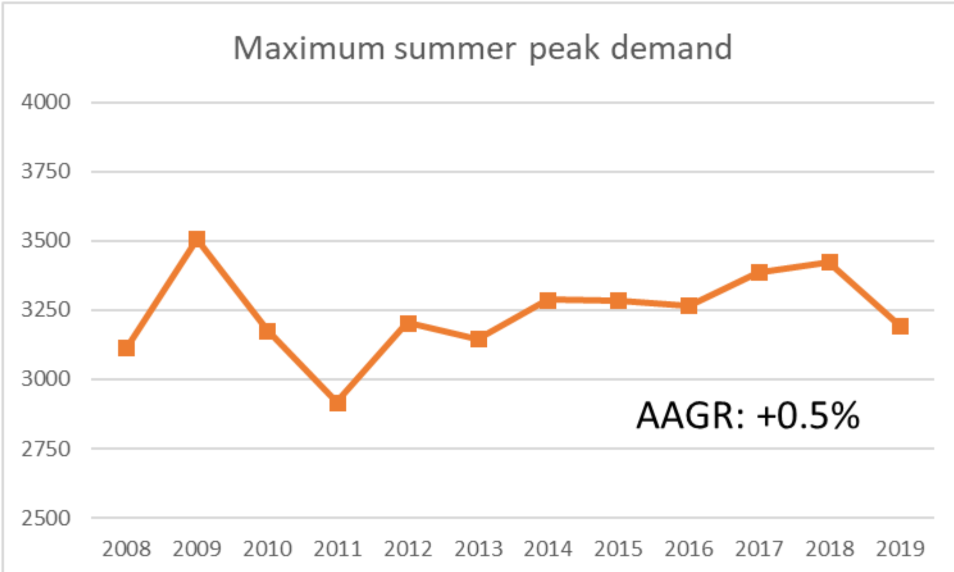
2. PSE includes summer and winter peak demand data for 2008-2019 (slides 48 and 49), and a reference to the data source from the FERC library. This data clarifies historical trends.

3. In response to our queries about weather records and the basis of weather normalization, PSE published a table on slide 29 showing different durations for calculating normal weather. It is obvious that heating declines with shorter history periods (probably due to local climate change), and cooling increases. PSE's chosen standard is for a 30-year period, which appears to overstate heating and understate cooling.

Among these positive developments, we see opportunities for improvement. Here are some of the issues we would like to see addressed in the webinar and going forward:

1. The AAGR shown in the post-DSR electric forecast appears misleading without further context. The expected demand declines until 2031, and then starts to increase, leading to an overall AAGR of 0.2%. But the increases and the AAGR may be illusory because PSE is not accounting for any new conservation programs after 2031. The graph says, "No new conservation after committed 2-year targets," but this does not clarify that the increasing demand after 2031 is an accounting artifact, not a realistic possibility. If anything, more aggressive conservation will be necessary after 2031 to reach 100% clean energy by 2045 in accordance with CETA goals. This graph is specifically extended to 2046 to account for CETA, but the load forecast itself doesn't appear to account for the effects of CETA.

2. Although PSE included a table showing historical summer peak demand, the presentation includes no forecast for summer peaks. It doesn't even include a graph of historical summer peak demand, so I created the graph from PSE's data:



   The graph shows a very gradual rise in summer peak demand, averaging about 0.5% per year. The peak in 2018 was almost as high as the highest peak in 2009, although the peak temperature in 2018 was eight degrees cooler, so it appears that peaks are gradually increasing.

3. We are puzzled why PSE is issuing RFPs for winter demand response, but no corresponding RFP for summer demand response. Summer peaks are increasing, and winter peaks are not. Obviously, the summer peaks are about 25% lower than winter peaks, but we understand that PSE is concerned about summer reliability. Does PSE believe that summer demand response is not needed or not as feasible as winter demand response?

4. Using 30 years of weather records to normalize weather calculations is at the upper limit of what we consider reasonable, given recent changes in climate. As we observed in earlier letters, New York's utility commission is using 15 years of weather records for normalization.

5. On slide 63, PSE appears to be using "88 temperature years" as an input to the Resource Adequacy Model. This may distort the results and introduce "cold bias" in the model that could be potentially costly for ratepayers. We ask that no record before 1990 be used to better account for recent climate changes.

Declining winter peaks and gradually increasing summer peaks provide PSE and ratepayers some room to concentrate on CETA goals and smart energy management. However, clear data is needed to understand the challenges and opportunities before us. We encourage PSE to provide this data and strong leadership to achieve successful outcomes.

Sincerely,

Don Marsh

September 2, 2020

To: Irena Netik – PSE Director of Energy Supply Planning and Analytics

Cc: Brad Cebulko – UTC Staff
Steve Johnson – UTC Staff
Deborah Reynolds – UTC Staff
Kyle Frankiewich – UTC Staff
Kathi Scanlan – UTC Staff
Kendra White – UTC Staff

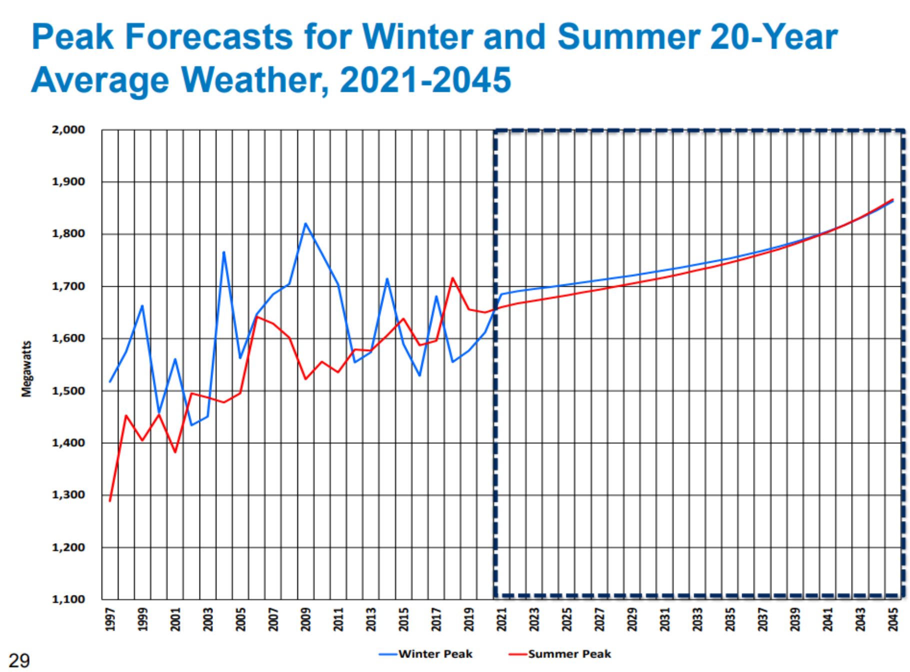
Subject: 2021 IRP Electric Demand Forecast

Dear Ms. Netik and IRP Team,

During PSE's Demand Forecast webinar on September 1, I asked PSE to show us trends and forecasts for summer peak demand. Irena Netik said summer peak demand was about 1,000 MW lower than winter peak demand, and therefore is not a major driver for peak or resource adequacy.

This assertion was challenged by at least three or four stakeholders participating in the webinar. Although summer peaks are lower than winter peaks, winter peaks are declining, and summer peaks may be growing. As a result, the peaks may achieve rough parity during the period considered by this IRP.

For example, Avista, another Washington investor-owned utility, is showing both summer and winter peak forecasts in its 2021 IRP materials:[1]



[1] https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/2021-irp-tac-2-economic-and-load-forecast.pdf?la=en, slide 29

Using 20-year average weather, Avista expects summer and winter peak to reach equal magnitudes in approximately 2040, a date within PSE's extended IRP planning period.

It is interesting that Avista provides analysis using 30-year average weather on the previous slide. This graph demonstrates the "cold bias" of using 30-year averages, as the winter forecast stays higher than summer for the duration of the study.

Stakeholders want to be sure that PSE is appropriately planning for summer growth. If trends indicate growing summer demand, perhaps investments in solar panels and energy storage could provide cost-effective solutions. PSE can help us understand what the challenges and opportunities are by providing clear data and analysis for all seasons in the IRP.

Sincerely,

Don Marsh

PSE IRP Consultation Update
Webinar 7: Demand Forecast, Resource Adequacy & Resource Need
September 1, 2020

9/22/2020

The following consultation update is the result of stakeholder suggestions gathered through an online Feedback Form, collected between August 25 through September 8, 2020 and summarized in the August 15, 2020 Feedback Report. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

Alternative compliance actions

PSE received feedback from Joni Bosh of Northwest Energy Coalition (NWEC) concerning increased use of conservation and demand response programs to meet the 20% alternative compliance metric as stated in CETA. PSE will add a sensitivity on increased conservation and demand response programs for the 2021 IRP.

PSE summer load forecast

PSE received feedback from Don Marsh of CENSE and Robert Briggs of Vashon Climate Action Group concerning PSE's summer load forecast. PSE is working on pulling the data together and a graphic of the 2021 IRP peak for both the summer and winter seasons. This graphic will be will be included in the IRP draft available on pse.irp/com to be submitted January 4, 2021 and/or the final IRP available on pse.com/irp to be filed with the WUTC on April 1, 2021. PSE realizes that its status as a winter peaking utility is relatively unique in the WECC region, and therefore performs all resource adequacy calculations for the entire year to take into consideration impacts of other regions on market conditions.

Temperature years

PSE received feedback from Don Marsh of CENSE, Joni Bosh of NWEC and Robert Briggs of Vashon Climate Action Group concerning the number of years of temperature data used to generate load forecasts and perform resource adequacy calculations. PSE would like to clarify that the temperature data used in these two aspects of IRP modeling are distinct, serve different purposes and, therefore, should not be indiscriminately grouped together.

Temperature data for the load forecasting purposes is used to understand and project climate trends over the modeling horizon. To address the impact of temperature data on the load forecast PSE will analyze a sensitivity on temperature and the demand forecast, as compared to the 30-year average normal used in the presented load forecast.

Temperature data for the resource adequacy model (RAM) is used to generate simulations over a range of conditions which could plausibly occur in the PSE service territory. The RAM requires many, many simulations to ensure statistically significant results in modeling highly stochastic processes. Therefore, the number of temperature years of data must be large enough to cover the range of temperature conditions likely to occur in the PSE service territory and generate enough simulations for accurate results. PSE currently uses 88 temperature years of data for the RAM model. PSE is researching peak temperatures and extreme weather conditions as part of the temperature sensitivity.

Washington Utilities and Transportation Commission feedback

Commission Staff provided feedback for the Webinar #7: Scenarios and Sensitivities on September 10. Due to the missed deadline, PSE is addressing the questions submitted on September 10 in this Consultation Update. The feedback, questions and comments from the WUTC concerning the Webinar #7 are presented below, followed by the PSE responses:

WUTC Staff: Slide 12: I'm curious about whether PSE is assessing CETA alternative compliance payments as a route to CETA compliance on a least-cost basis. Are the alternative compliance payments included as something like resource options in the portfolio expansion model? How is PSE modeling the various options – RECs, energy transformation projects, alternative compliance payments and additional generation?

PSE response: PSE plans to model a price forecast as a stand in for CETA alternative compliance unbundled RECs or Energy transformation projects. Some options can be either a CO_2 price forecast such as the California price or a REC price. PSE is seeking stakeholder feedback on the price forecast as the stand-in cost.

WUTC Staff: Slide 17: What goes into PSE's decision to change IAP2 participation levels from topic to topic? If stakeholders see potential problems with the information presented by PSE during an "INFORM" topic, is the company still open to receiving feedback?

PSE response: PSE determined the International Association for Public Participation (IAP2) participation level to the level on the spectrum PSE can commit to in the 2021 IRP process. The measure of success for IAP2 is not the level one chooses on the spectrum, but the level that can be achieved by PSE and the level PSE can maintain our promise to stakeholders. PSE greatly appreciates the feedback and participation of our stakeholders. For example, "INFORM" topics, PSE provides opportunities for questions and comments in the chat feature of GoToMeeting, during the meeting, as well as answering questions in the feedback report and addressing any follow-up in the consultation update.

WUTC Staff: Slide 27: It seems difficult to guess at whether some COVID-prompted energy usage shifts may persist, but it also seems unlikely that the post-COVID normal will be identical to the pre-COVID normal. Does PSE intend to adjust its long term energy usage pattern estimates based on a pre- and post-COVID analysis?

PSE response: PSE agrees that the COVID-19 pandemic event is significant and there is potential for a “new normal” regarding energy usage patterns. At this time, PSE has not yet observed what could be considered long-term usage pattern differences due to the pandemic. Once PSE determines that there has been a permanent shift in usage patterns, PSE will incorporate those into the forecast.

WUTC Staff: Slide 29: The table shows that a shorter timeframe for defining ‘normal’ has an outsized impact on cooling estimates. Warmer and dryer summers may not yet have an impact on PSE’s resource adequacy in the summer months, but could have a dramatic impact on the price of electricity. PSE discussed the RA component of its market reliance in this presentation, but did not cover the cost risk. How is that represented in the IRP? Does the IRP consider the prospect of escalating costs for market power as summers get hotter, and as thermal generators retire?

PSE responses:
To date concerning the modeling, no loss of load events occurs in the summer months in the Resource Adequacy Model (RAM). RAM only evaluates the capacity need with the balance between the supply and demand; cost is not included.

The cost risk of market reliance be will addressed in PSE’s stochastic modeling. PSE is still working on the cost risk around market reliance and the stochastic model will be presented at the December 9, 2020 IRP meeting.

WUTC Staff: Slide 60: Is GENESYS and the WPCM both run 7040 times, once for each RAM run?

PSE response: Yes, GENSYS and WPCM both consider the 88 temperature years and 80 hydro years, so there are 7040 simulations (88 x 80 = 7,040) in total.

WUTC Staff: Slide 61: Please refresh my memory about the COB import limit. What is the nature of the 3400 MW limit? Are there any plans to increase (or decrease) this limit? Also, how are connections to other regions – BC to NW, MT to NW, SW (AZ/NV/CA) to NW – modeled?

PSE response: Regional interties are part of the regional GENESYS model and PSE relies on the Northwest Power and Conservation Council’s assumption of 3400 MW limit. PSE then interconnects to the regional model with the 1500 MW limit to the Mid-C market.

WUTC Staff: Slide 63: What does temperature do in the RA model? Does temperature impact load or thermal performance?

PSE response: RAM considers 88 temperature years in the load forecast. Thermal plant outages are modeled in AURORA using the Frequency Duration. This takes into account the forced outage rate (%) and mean time to repair (hours). The outages are model for each generating unit individually with a probability of failure (FOR) and run for 260 different simulations of outages. The probability of an outage is not based on temperature.

WUTC Staff: Slide 63 (cont): What data does GENESYS need? Is that data provided in the software? Can it be modified? Can it be made publicly available?

PSE response: GENESYS uses the data from the Northwest Power and Conservation Council (NPCC), which is publicly available. The PNW regional generation and load forecast data relevant for the years 2022-2045 is publicly available. For the study years 2027 and 2031, PSE considers the load growth and retirements of units, which is obtained from NPCC staff.

WUTC Staff: Slide 63 (cont): What new resources are included as inputs into the RAM?

PSE response: In 2021 IRP, PSE will include the new resources and contracts obtained through the 2018 RFP.

WUTC Staff: Please provide some examples what is meant by “regional curtailment” and explain how these affect a model run.

PSE response: With the expected load growth and generation retirements, the capacity of supply will be, at times, less than the demand. That is the physical meaning of load curtailment. For example, during a peak hour, the regional resource capacity is 3000 MW but the regional load is 3001 MW, then a regional load curtailment occurs. During a PNW load curtailment event, there is not enough physical power supply available in the region, including available imports from California, for all of the region’s utilities to meet their loads plus operating reserves. The Wholesale Purchase Curtailment Model (WPCM) will “allocate” the regional capacity deficiency to the individual utilities. These individual capacity shortages are reflected through a reduction in the forecasted level of wholesale market purchases. On an hourly basis, the WPCM translates a regional load-curtailment event into a reduction in PSE’s wholesale market purchases.

WUTC Staff: Slide 71: What other contracts are expiring in 2026 and 2027 to cause the contraction of the “Contract” portion of the bars representing those years?

PSE response: Please see below table.

Resource (Contract)	Nameplate (MW)	Contract End Date
Twin Falls	20	3/8/2025
Centralia PPA	380[1]	12/31/2025
Colstrip 3 & 4	370[2]	12/31/2025
Electron	24	12/31/2026
2018 RFP new contracts	200	12/31/2026

NOTES
1. *The capacity of the TransAlta Centralia PPA is designed to ramp up over time to help meet PSE's resource needs. According to the contract, PSE will receive 280 MW from 12/1/2015 to 11/30/2016, 380 MW from 12/1/2016 to 12/31/2024 and 300 MW from 1/1/2025 to 12/31/2025.*
2. *Does not include the sale of unit 4.*

For the 2021 IRP, all contracts are expected to retire on the contract expiration date except for the Mid-C hydro contracts. In light of meeting the requirements of CETA, PSE assumes an extension of the Mid-C contracts and uses the current share as proxy to the extension. Terms and/or the possibility a contract extension will be determined closer to the actual expiration of the contracts.

WUTC Staff: Slide 71: Do PSE's existing hydro contracts include some contract mechanism that ensures PSE can obtain a renewal of the contracts as represented starting in 2028? Or is the company presuming that, whatever the negotiated cost ends up being, it's safe to assume that PSE will renew?

PSE response:

For the 2021 IRP, all contracts are expected to retire on the contract expiration date except for the Mid-C hydro contracts. In light of meeting the requirements of CETA, PSE assumes an extension of the Mid-C contracts and uses the current share as proxy to the extension. Terms and/or the possibility a contract extension will be determined closer to the actual expiration of the contracts.

Summary of all updates

PSE appreciates the feedback provided by stakeholders. In summary, the following changes will be implemented into the portfolio model or included in the proposed portfolio sensitivities:

- An increased conservation and demand response program sensitivity will be analyzed to explore the impact of using these measures to meet the CETA alternative compliance metrics.
- Summer peak demand forecasts will be included in IRP documentation as reference material.
- A temperature sensitivity will be analyzed which examines the impact to the demand forecast.

PSE is committed to keeping our stakeholders informed of our progress toward incorporating feedback into the 2021 IRP process.

Webinar 8, October 14, 2020

Natural Gas IRP: Design Peak Day, Resource Alternatives, Portfolio Modeling and Sensitivities, and Draft Results

Webinar #8: Natural Gas IRP
October 14, 2020 from 1:00 p.m. to 4:30 p.m. PST

Virtual webinar link: https://global.gotomeeting.com/join/911854509
Access code: 911-854-509

Topic	Lead
Welcome • Agenda review • Safety moment • How to participate • Speaker introductions	EnviroIssues
Natural gas system & **Natural gas portfolio modeling**	Elizabeth Hossner, Manager Resource Planning & Analysis, PSE Gurvinder Singh, Sr. Energy Resource Planning Analyst, PSE
5-minute break	
Draft portfolio results	Gurvinder Singh, Sr. Energy Resource Planning Analyst, PSE
Peak day planning standard	Gurvinder Singh, Sr. Energy Resource Planning Analyst, PSE
5-minute break	
Natural gas scenarios and sensitivities	Elizabeth Hossner, Manager Resource Planning & Analysis, PSE
Renewable natural gas background & customer Programs	Bill Donahue, Natural Gas Resources Manager, PSE
Wrap up and next steps • Next steps • Upcoming meeting schedule • Thank you's	EnviroIssues

Call-in telephone number (audio only): +1 (244) 501-3412

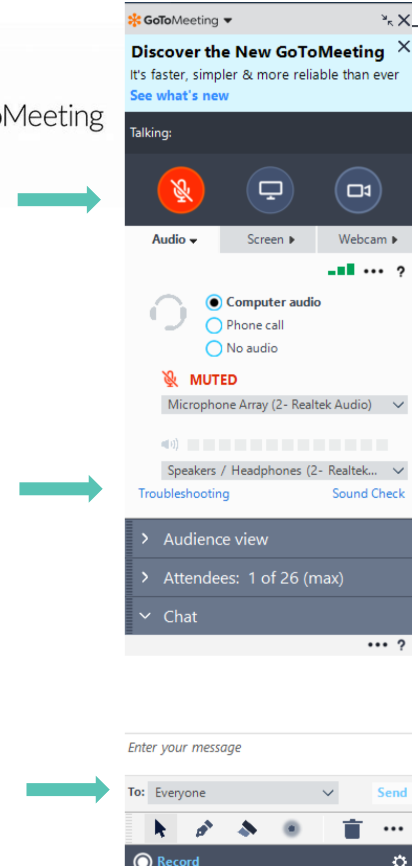
2021 IRP Webinar #8: Natural Gas IRP

Analyze Alternatives & Portfolios
Natural Gas Portfolio Model

October 14, 2020

Welcome to the webinar and thank you for participating!

GoToMeeting



Virtual webinar link: https://global.gotomeeting.com/join/911854509

Access Code: 911-854-509

Call-in telephone number: +1 (224) 501-3412

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Third-party recording is not permitted.

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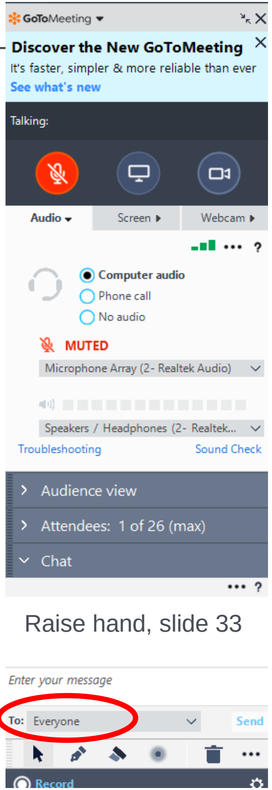
How to participate using Go2Meeting

Presentation Do's

- Mute your mic during the presentation
- You can participate in writing or verbally using the chat window
  - **In writing:** your question will be read
  - **Verbally:** type "Raise hand" and slide #, share with "Everyone"; please wait to be called on to ask your question
- Be considerate of others waiting to participate
- We will try to get to all questions



PUGET SOUND ENERGY

This session is being recorded by Puget Sound Energy. Third-party recording is not permitted.

Agenda

- Safety moment
- Natural gas IRP
  - portfolio modeling
  - draft portfolio results
  - peak day planning standard
  - scenarios and portfolio sensitivities
- Renewable natural gas (RNG) background and customer program

PSE PUGET SOUND ENERGY

Safety Moment: Fatigue prevention

As the daylight hours shorten and many of us are in long meetings indoors, consider these tips to prevent fatigue:

- Eat healthy choices often
- Get moving
- Sleep well
- Reduce stress to boost energy
- Talk with a friend
- Cut out/reduce caffeine
- Drink less alcohol
- Drink more water
- Consult a heath professional if you think there may be a health concern

PUGET SOUND ENERGY

Today's speakers

Gurvinder Singh
Senior Energy Resource Planning Analyst, PSE

Elizabeth Hossner
Manager Resource Planning & Analysis, PSE

Bill Donahue
Manager Natural Gas Resources, PSE

Alison Peters & Alexandra Streamer
Co-facilitators, EnviroIssues

Natural Gas
Portfolio Modeling

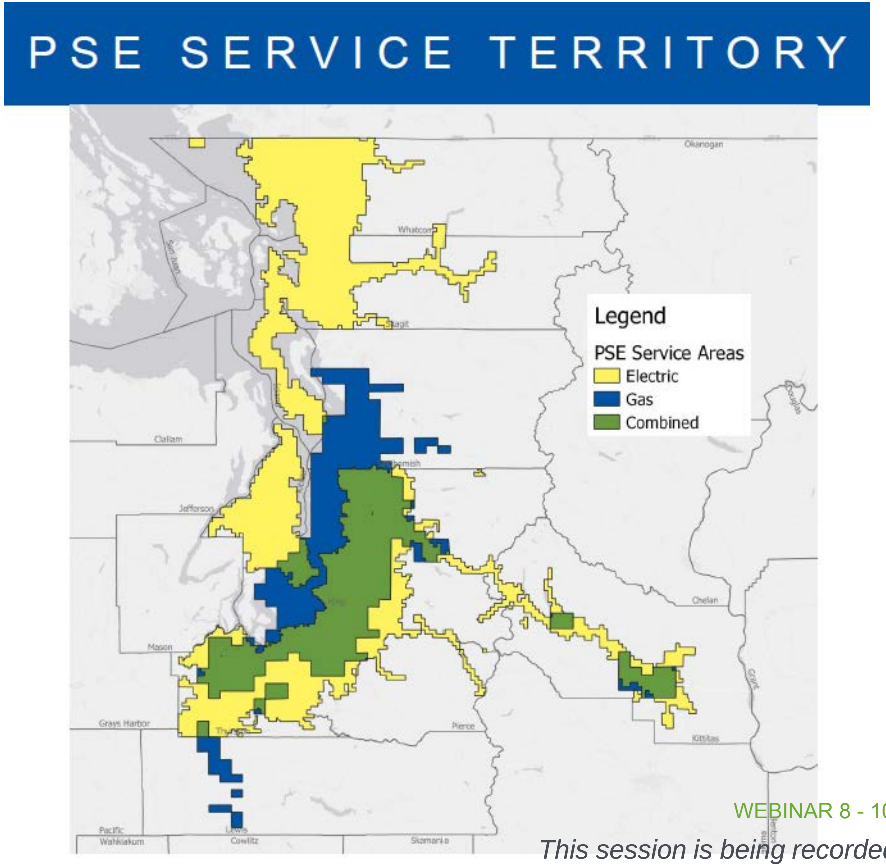
PUGET SOUND ENERGY

Participation Objectives

- PSE will inform stakeholders of the gas portfolio model, resource need, levelized gas prices and resource alternatives used in the 2021 IRP analysis

  IAP2 level of participation: INFORM

Natural gas analysis



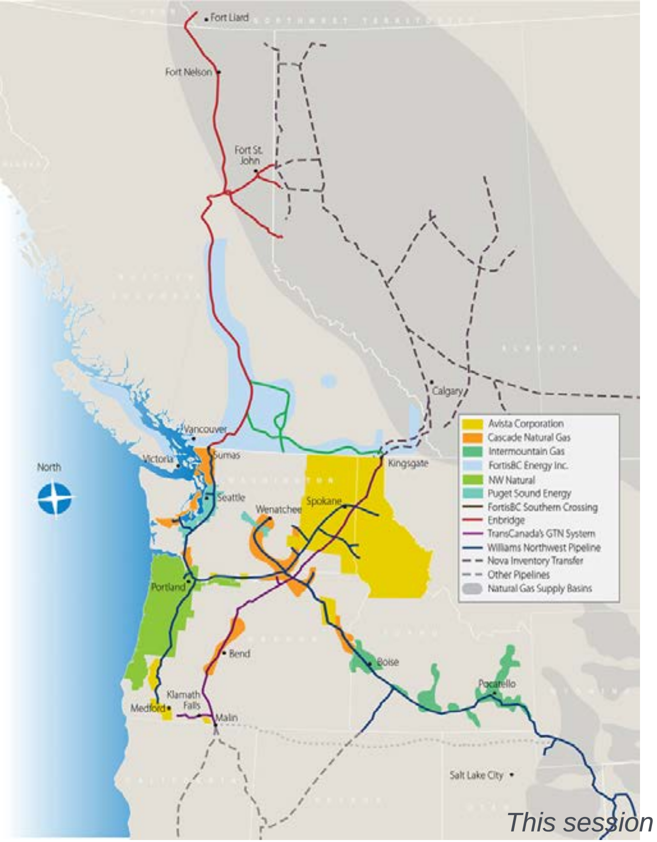
- More than 800,000 customers in Washington state depend on PSE for safe, reliable and affordable natural gas services.
- PSE's gas sales need is driven by peak day demand, which occurs in the winter when temperatures are lowest and heating needs are highest.

Infrastructure reliability

Natural gas transportation and distribution systems are not designed to include the type of redundant capacity that electric distribution systems. Equipment failure is rare, but it does occur, and there can be significant repercussions. For this reason, PSE builds flexibility and resiliency into the system in four ways.

1. **A conservative planning standard.** Peak day planning standard.
2. **Diverse transport resources**. A transport portfolio that intentionally sources gas equally from north and south of our service territory to preserve flexibility in the event of supply disruptions.
3. **Natural gas storage**. Storage minimizes the need and costs associated with relying on long haul pipelines to deliver gas on cold days; it allows more gas to be purchased in the typically less expensive summer season; and it can furnish gas supply in the event of a pipeline disruption.
4. **Cooperation with regional entities.** The Northwest Mutual Assistance Agreement (NWMAA) members agree to utilize, operate or control natural gas transportation and/or storage facilities in the Pacific Northwest, and they pledge to work together to provide and maintain firm service during emergency conditions and to restore normal service to their customers as quickly as possible after such events occur.

Regional overview – Natural gas basins and pipelines



Supply basins and hubs:

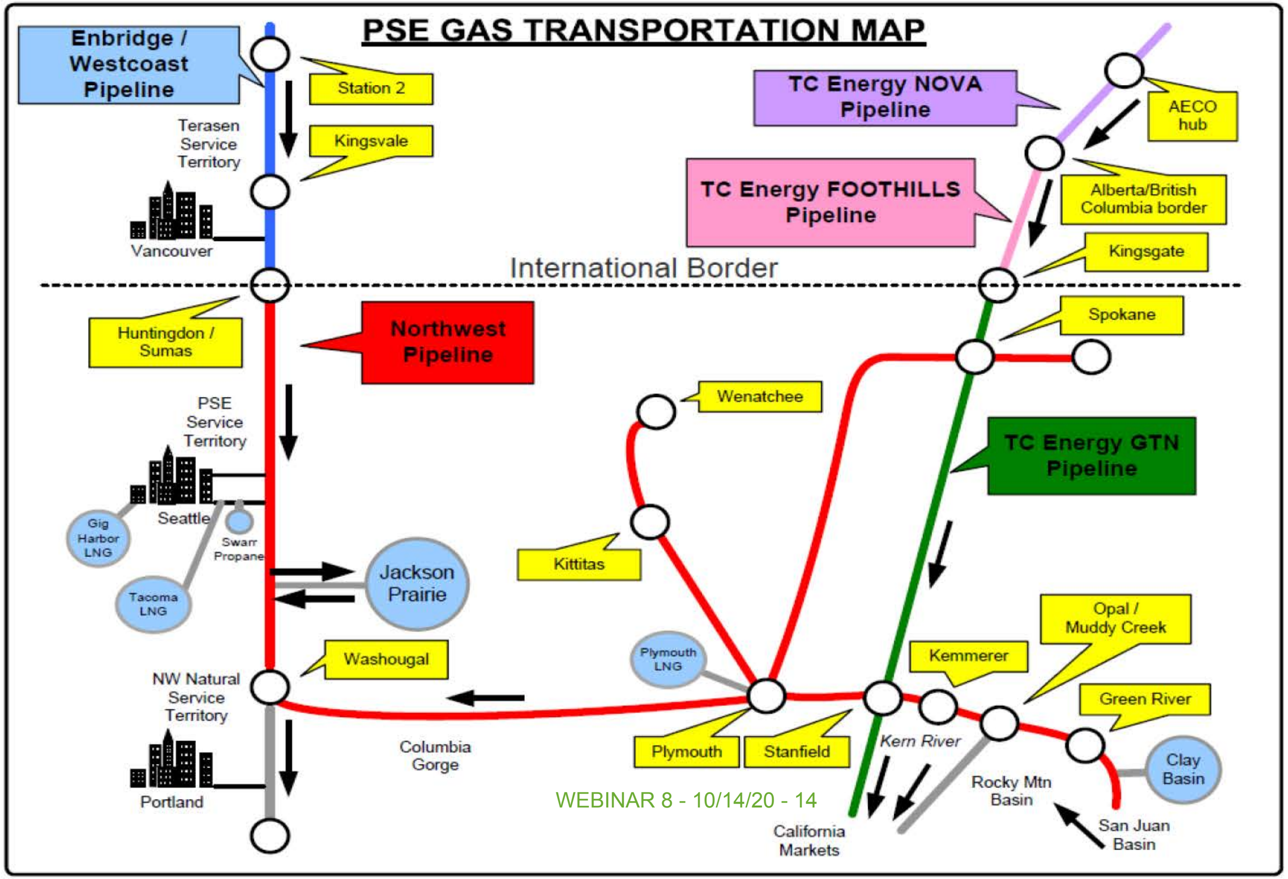
- BC-Station 2
- BC-Sumas
- Alberta- NIT (AECO)
- Alberta at Stanfield
- Rockies- including Clay Basin Storage

Pipelines

- Northwest
- Westcoast
- GTN/Foothills/NGTL
- Cascade

There are 91,503 miles of gas pipeline in the region (Washington, Oregon and Idaho).

PSE existing natural gas transmission and storage infrastructure



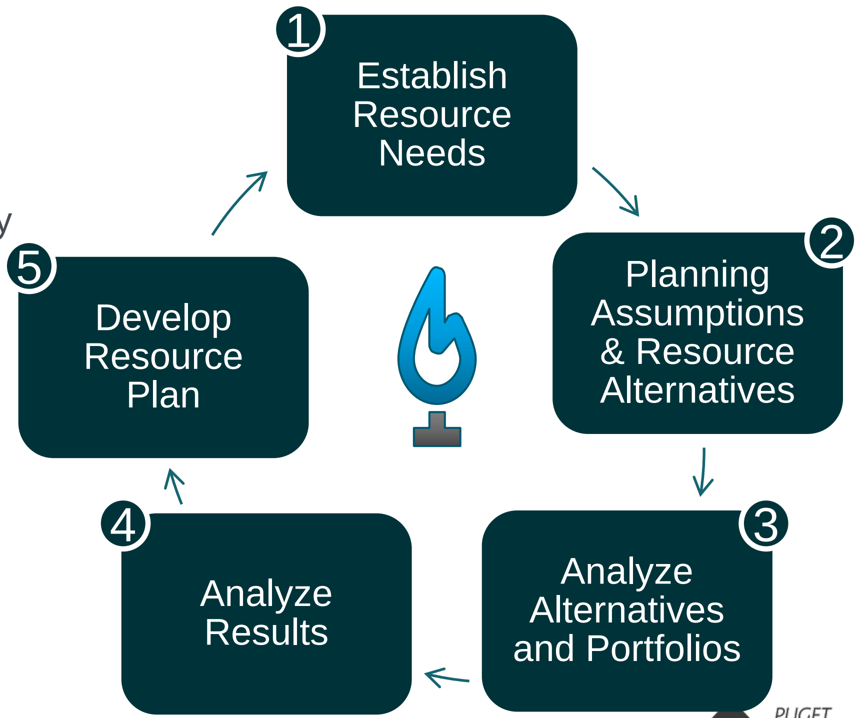
WEBINAR 8 - 10/14/20 - 14

PUGET SOUND ENERGY

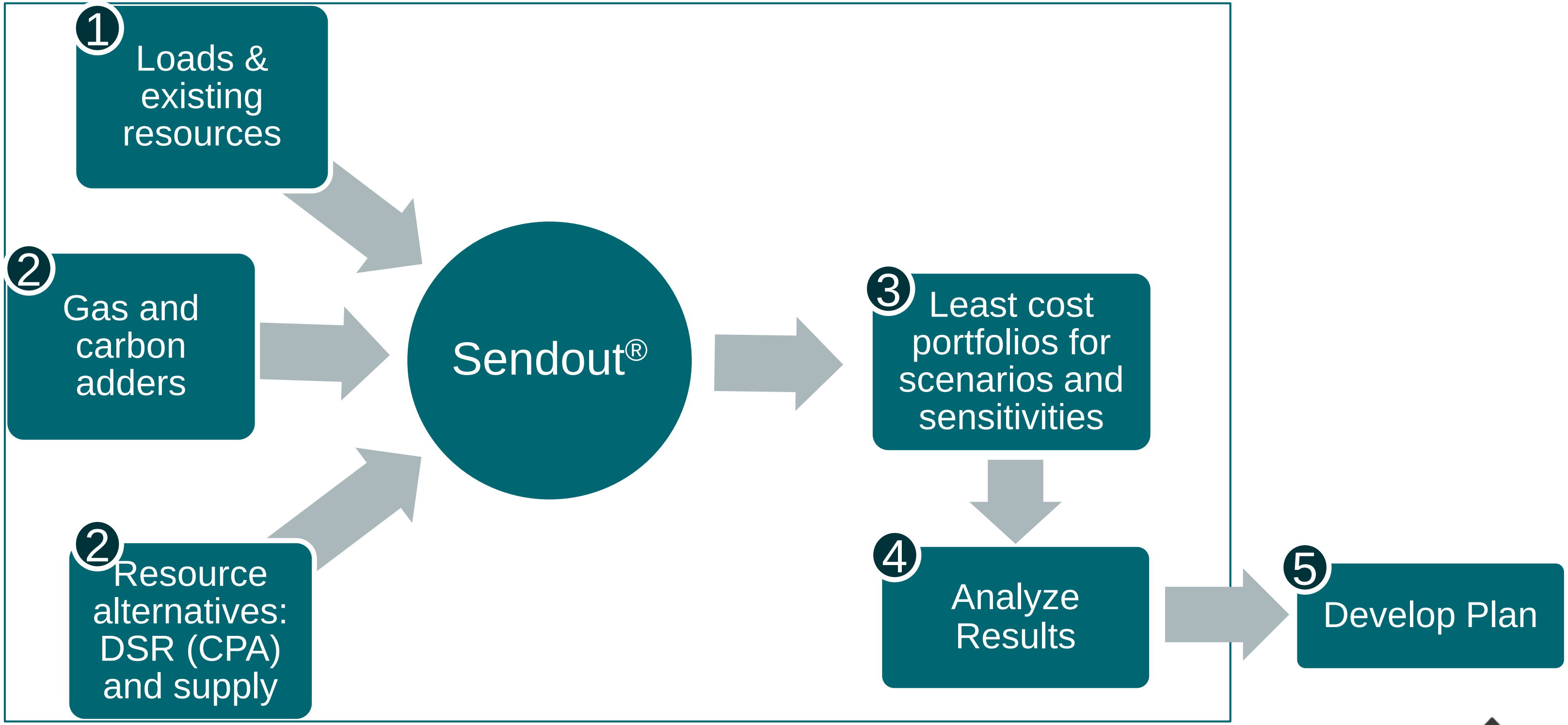
2021 IRP natural gas modeling process

The 2021 natural gas IRP will follow a 5-step process for analysis:

1. Analyze and establish resource need
2. Determine planning assumptions and identify resource alternatives
3. Analyze scenarios and sensitivities using deterministic and stochastic risk analysis
4. Analyze results
5. Develop resource plan



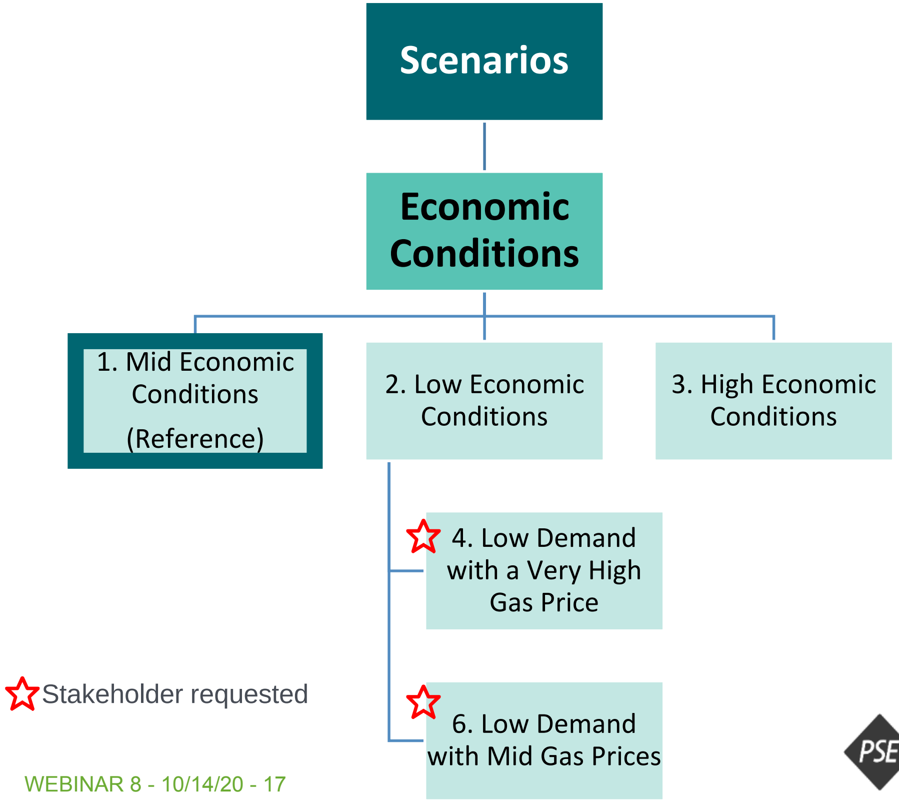
Gas portfolio modeling - SENDOUT®



Planning assumptions and resource alternatives

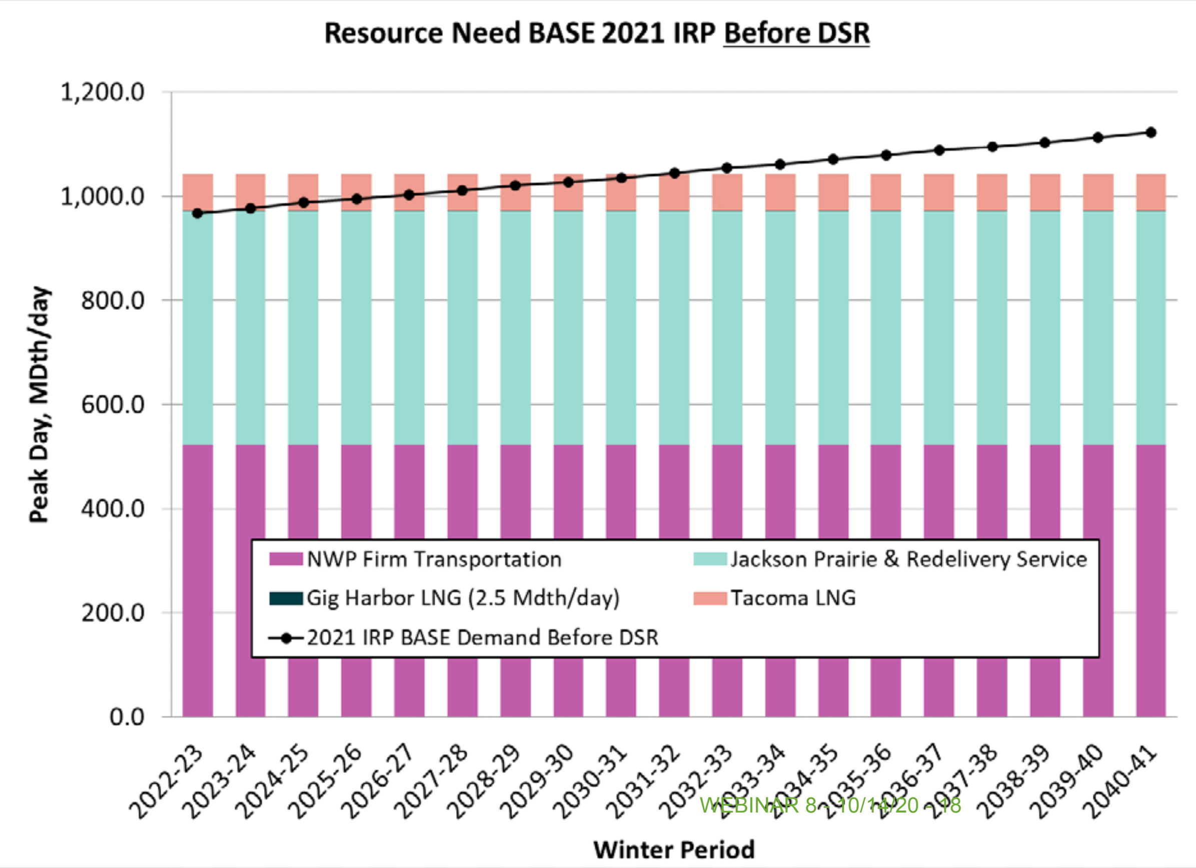
Natural gas scenarios

- Gas prices, carbon regulation and loads create different portfolio results.



PSE PUGET SOUND ENERGY

Gas resource need – base scenario

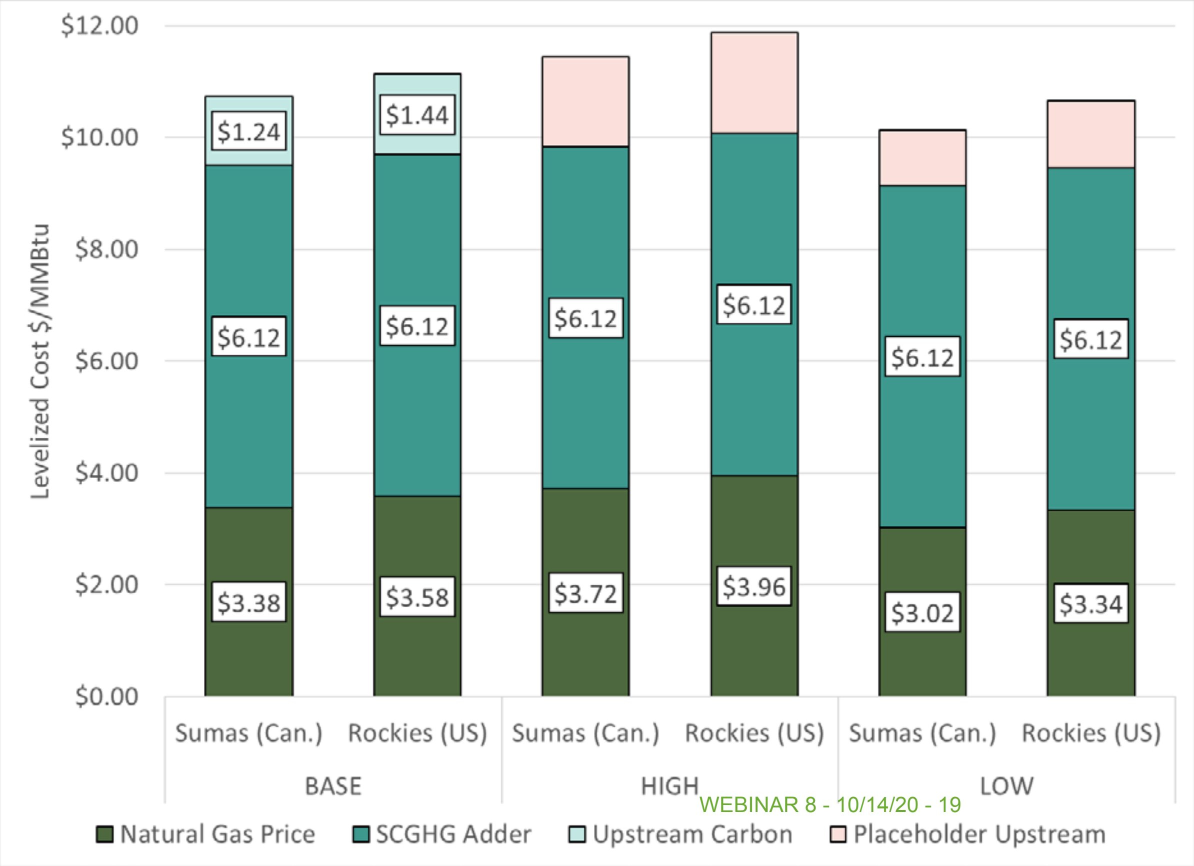


Notes:

1. Base scenario is used interchangeably in reference to the Mid-economic conditions.

2. Winter period is from November thru February of the following year.

Gas prices with SCGHG adders



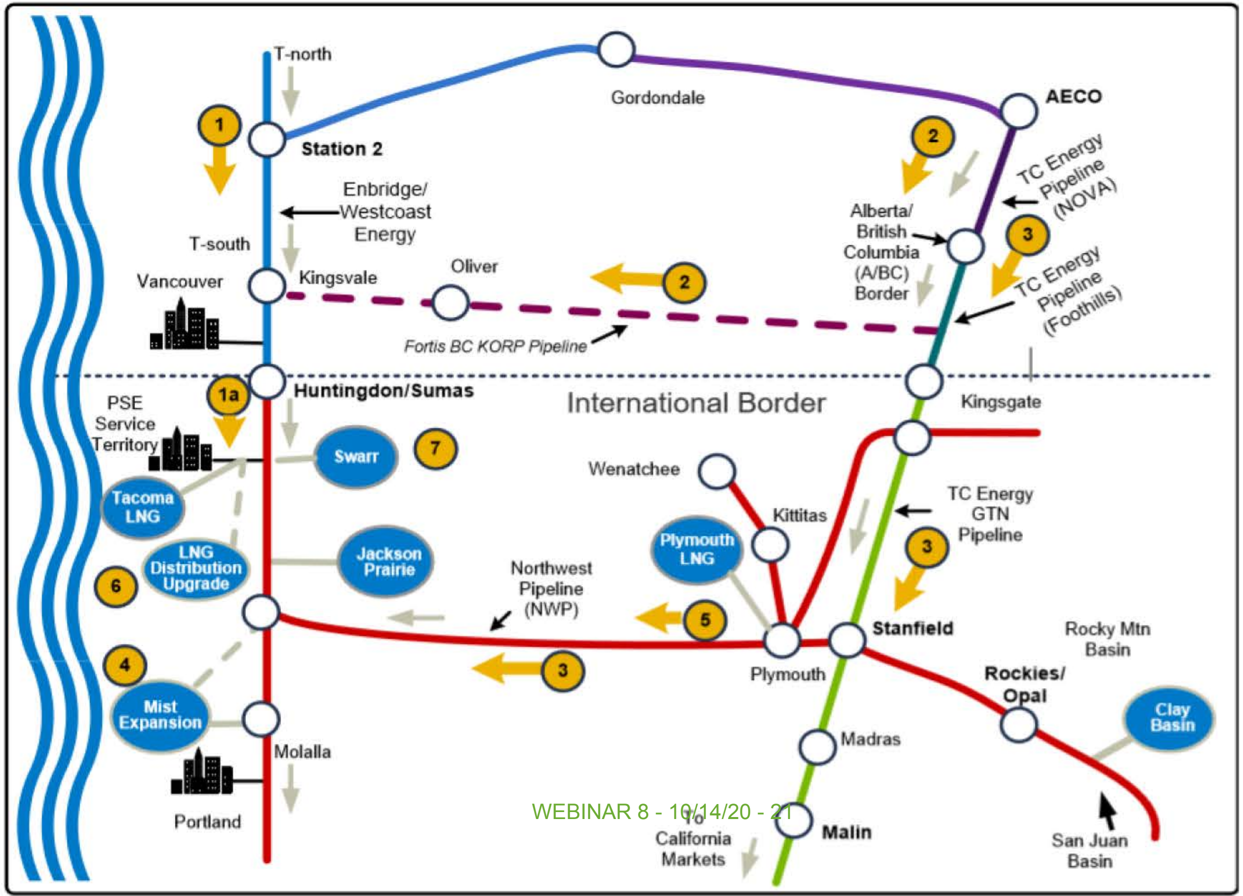
Notes:

1. The upstream adder for the High and Low will be calculated once the demand High and Low is ready. This chart shows a placeholder that will be updated at a later date.

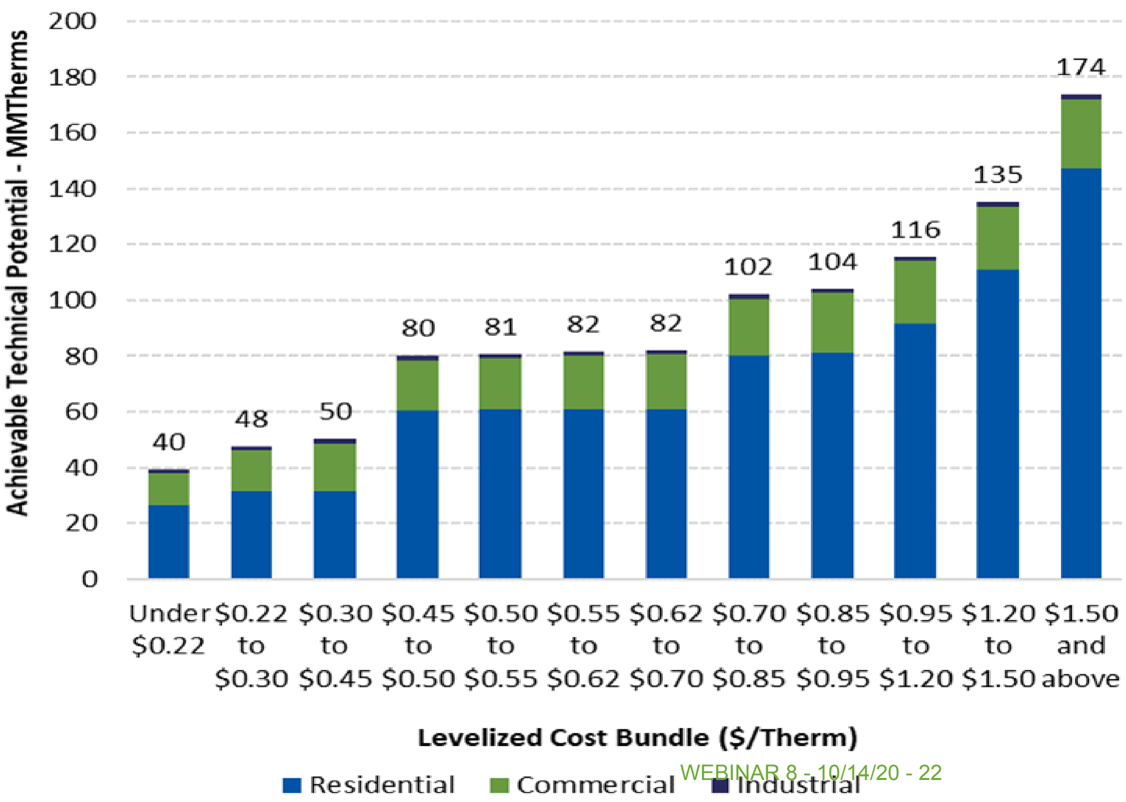
Resource alternatives

Option 1	Purchase northern British Columbia gas at Station 2 and transport via expanded capacity on Westcoast, along with an expansion of Northwest Pipeline (NWP).
	Option #1a – Purchase short term NWP TF-1 capacity from Sumas (2020-24 only)
Option 2	Purchase AECO gas and transport via expanded capacity on TC-AB (Nova) and TC-BC (Foothills) pipelines, along with the proposed Fortis BC Kingsvale -Oliver Reinforcement Project (KORP) and a NWP expansion from Sumas.
Option 3	Purchase AECO gas and transport via expanded capacity on NGTL, Foothills and GTN, along with a NWP Columbia Gorge pipeline expansion.
Option 4	MIST Storage Expansion – lease capacity from NW Natural with redelivery to PSE service territory using backhaul capacity resulting from a Sumas South Expansion.
Option 5	15 MDth per day firm Plymouth LNG service and firm NWP pipeline capacity from the Plymouth LNG plant to PSE
Option 6	Distribution system upgrade to allow greater utilization of LNG peaking - additional 16 MDTh per day
Option 7	Upgrade the existing Swarr LP-air facility to 30 MDth per day.

Resource alternatives - Schematic



Resource alternatives – Demand Side Resources (DSR)

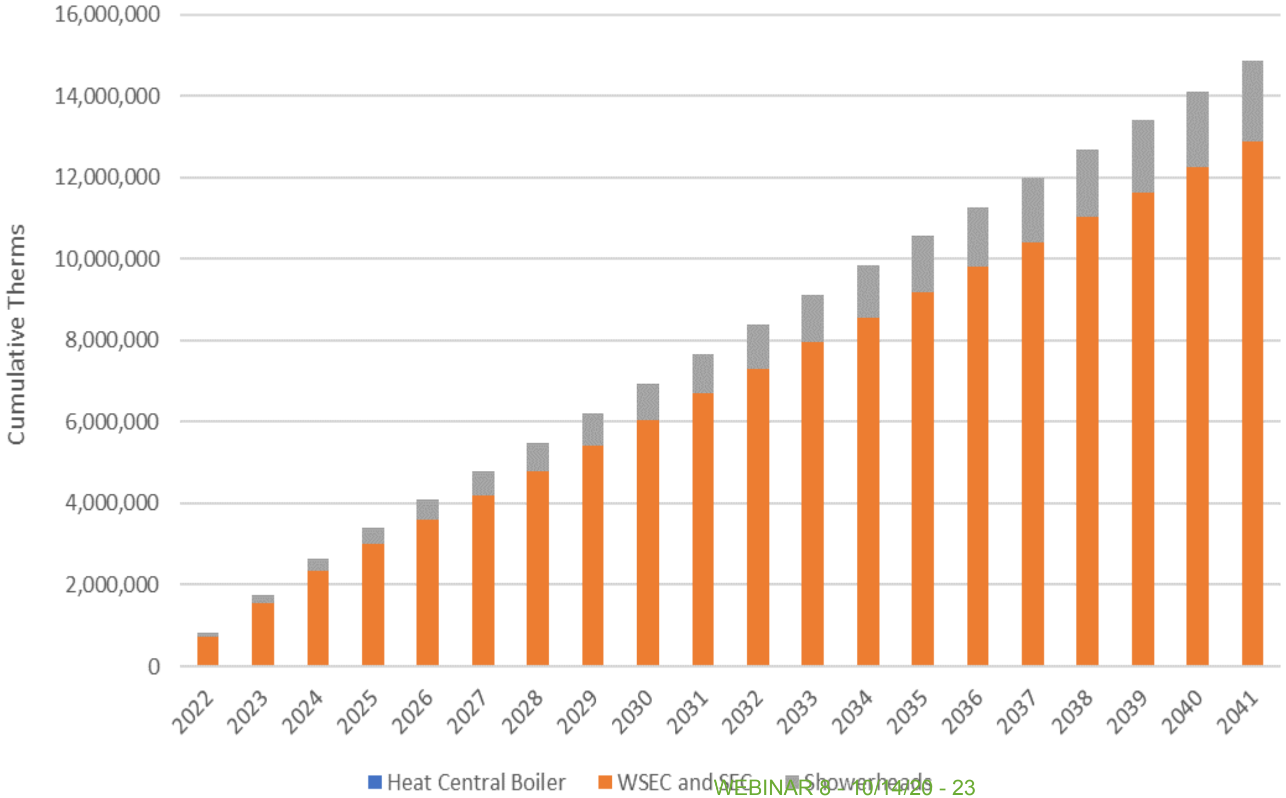


Notes:

1. This chart was presented in the July webinar and is the conservation supply curve developed by the Conservation Potential Assessment (CPA).

2. The supply curve is divided into various price points, also referred to as bundles, before it is input into the portfolio model.

Resource alternatives – DSR codes + standards



Note:

1. This chart represents the demand reduction from codes and standards, developed by the CPA.

2. It is input into the portfolio model as a reduction to the demand.


5-minute break
PUGET SOUND ENERGY

Draft Natural Gas Resource Portfolio Results – Base Scenario

Participation Objectives

- PSE will inform stakeholders of the draft natural gas portfolio results.

IAP2 level of participation: INFORM

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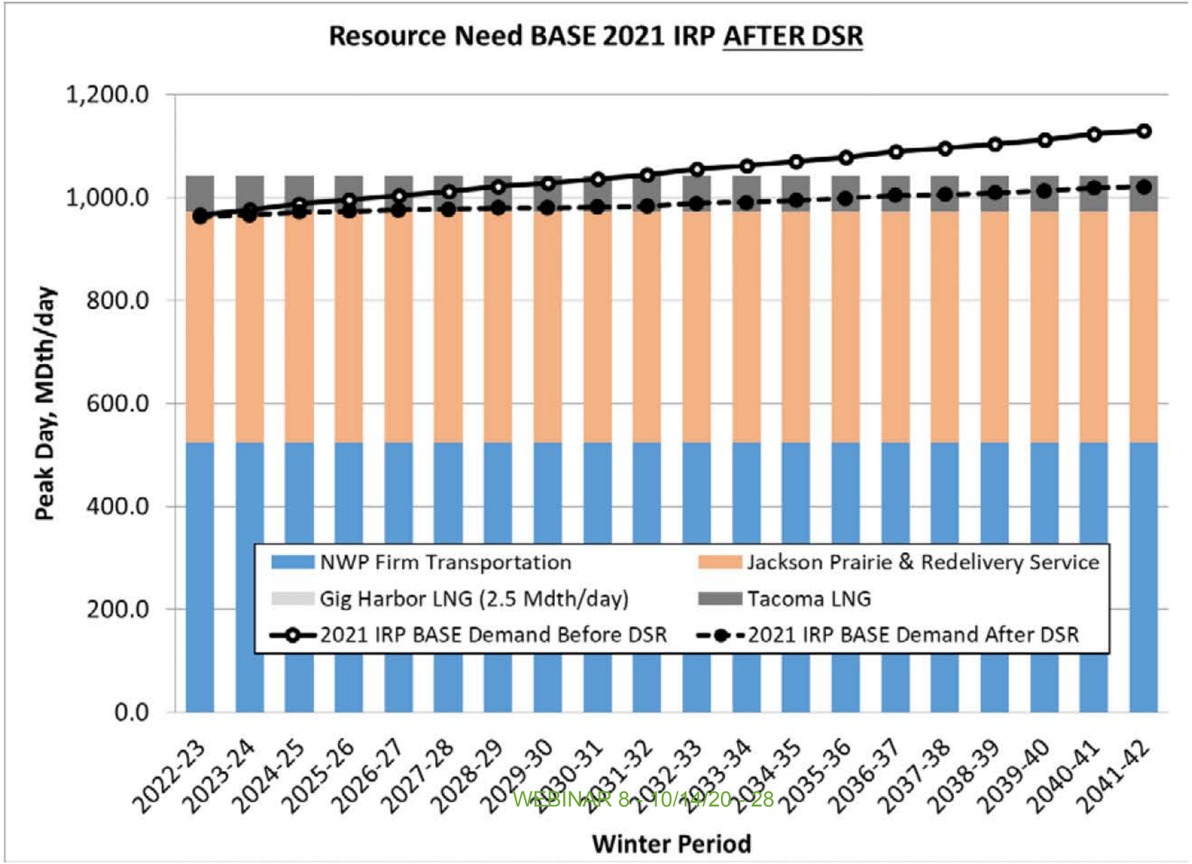
Draft Base Scenario Builds – Resource need filled by DSR

Winter Period	DSR (Incl Standard Bundle)	NWP Additions + Westcoast	Short Term NWP	KORP	Cross Cascades - New	Mist Storage	Ply LNG	LNG Tacoma Distr	Swarr
Option	DSR	#1	#1a	#2	#3	#4	#5	#6	#7
2022-23	4.8	-	-	-	-	-	-	-	-
2023-24	10.2	-	-	-	-	-	-	-	-
2024-25	16.0	-	-	-	-	-	-	-	-
2025-26	21.8	-	-	-	-	-	-	-	-
2026-27	27.9	-	-	-	-	-	-	-	-
2027-28	34.2	-	-	-	-	-	-	-	-
2028-29	40.8	-	-	-	-	-	-	-	-
2029-30	47.6	-	-	-	-	-	-	-	-
2030-31	54.6	-	-	-	-	-	-	-	-
2031-32	61.9	-	-	-	-	-	-	-	-
2032-33	66.4	-	-	-	-	-	-	-	-
2033-34	71.0	-	-	-	-	-	-	-	-
2034-35	75.7	-	-	-	-	-	-	-	-
2035-36	80.5	-	-	-	-	-	-	-	-
2036-37	85.2	-	-	-	-	-	-	-	-
2037-38	90.0	-	-	-	-	-	-	-	-
2038-39	94.7	-	-	-	-	-	-	-	-
2039-40	99.5	-	-	-	-	-	-	-	-
2040-41	104.2	-	-	-	-	-	-	-	-
2041-42	108.7	-	-	-	-	-	-	-	-

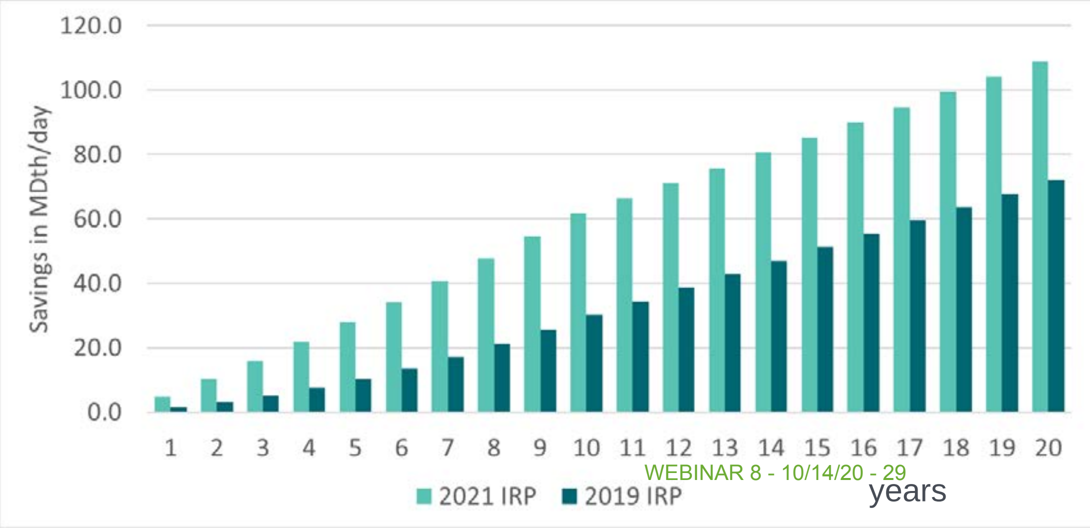
- Results reflect:
  - impact of lower demand forecast in 2021 IRP
  - more DSR in lower cost bundles
  - high total gas cost
- Cost-effective DSR is sufficient to cover future demand growth

Draft base scenario – DSR sufficient to meet future demand



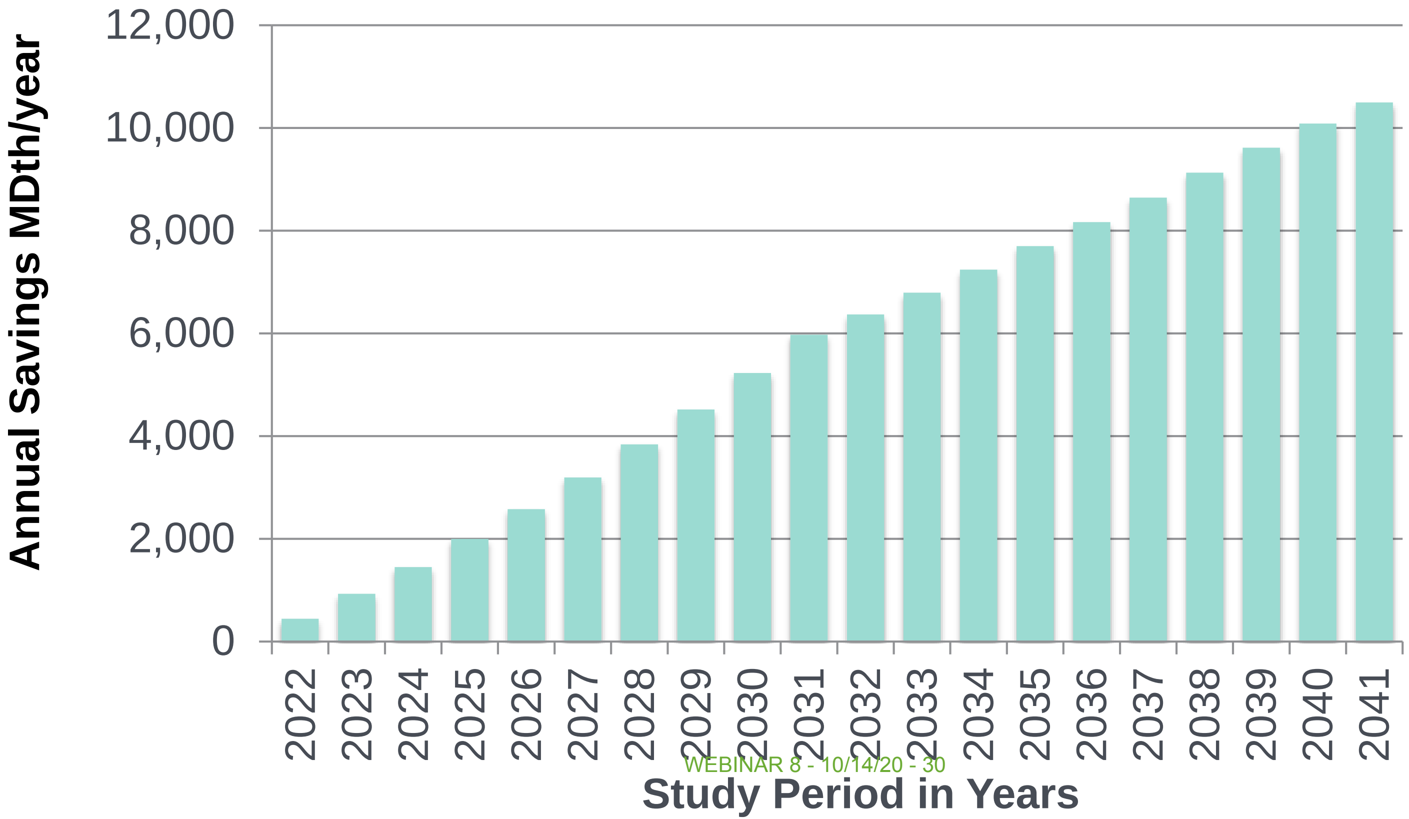
Draft base scenario – Cost effective DSR peak day capacity

Bundles	Base	Bundle
Residential Firm	9	$0.85 to $0.95
Commercial Firm	9	$0.85 to $0.95
Commercial Interruptible	6	$0.55 to $0.62
Industrial Firm	9	$0.85 to $0.95
Industrial Interruptible	9	$0.85 to $0.95



- Similar cost point bundle selected as 2019 IRP process result, but higher than 2017 IRP
- Higher savings due to shift of non-cost effective measures into lower cost bundles & higher gas cost

Draft base scenario – Cost effective DSR energy



PUGET SOUND ENERGY

Natural Gas Peak Day Planning Standard

Participation Objectives

- PSE will inform stakeholders of its natural gas peak day planning standard in the 2021 IRP analysis

IAP2 level of participation: INFORM

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Natural gas peak day planning standard overview

- Background: PSE’s gas planning standard
- Methodology for developing the standard
- Update with more recent temperature data
- Comparison with other gas utility planning standards

Background: peak day planning standard

- Gas utilities typically define a design peak planning standard in terms of firm load at a target Heating Degree Day (HDD)
- The target HDD is derived from an Average Daily Temperature using the following relationship:

  HDD = 65 - Average Daily Temperature

  where 65 deg. F is the HDD base temperature

- Example: if average daily temperature = 13^{o}
  Then, planning standard = 65 – 13 = 52 HDD

PSE's Design Peak Day Planning Standard

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Methodology

2005 IRP (LCP): PSE's performed a benefit/cost analysis to establish the temperature threshold for the design peak day planning standard

Benefits: Primarily avoided cost of lost load - relighting cost and customer value of reliability

Cost: Portfolio cost associated with higher planning standards

Reliability of gas service is very important

- Service must be manually restored to firm customers
- If PSE lost 10% of its firm customers, it could take 15-20 days to get service fully restored in a safe manner.

Estimating the Value of Reliability

Begin with a planning standard; e.g., 50 HDD (15º F)

What if temperature is colder, such as 51 HDD (14º F)?

- Estimate how many customers lost based on volume lost
- Estimate how many days to restore service
- Multiply number of customers out, per day, by value of lost load
- Multiply by likelihood of experiencing the colder temperature

= Probability weighted value of lost load

Repeat for 51 HDD to 52 HDD, etc., through 55 HDD

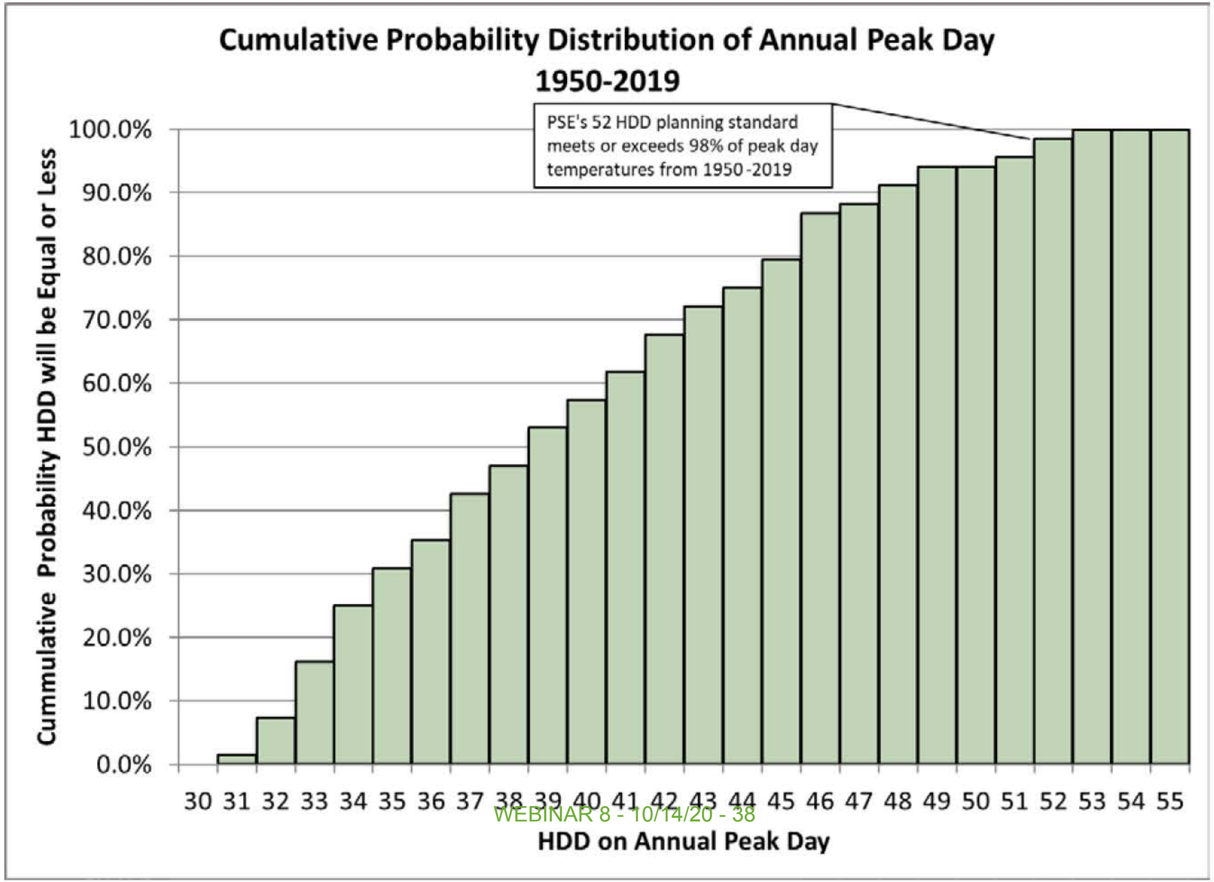
Results from benefit/cost analysis

Exhibit I-4
Incremental Benefits and Costs of Reliability

Planning Standard	Incremental Benefit	Incremental Cost	Benefit/Cost Ratio
48 HDD (17^{o} F)	$ 5,195,876	$238,645	21.8
49 HDD (16^{o} F)	$ 3,332,322	$260,798	12.8
50 HDD (15^{o} F)	$ 2,026,693	$423,036	4.8
51 HDD (14^{o} F)	$ 1,169,251	$209,789	5.6
52 HDD (13^{o} F)	$ 535,076	$455,153	1.2
53 HDD (12^{o} F)	$ 145,373	$1,684,778	0.1
54 HDD (11^{o} F)	$ -	$2,531,502	-
55 HDD (10^{o} F)	$ -	$2,831,158	-

Source: PSE's 2005 Least Cost Plan

Implied temperature criteria



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Pacific NW gas utility peak day planning standards

PNW Gas Utility	Peak Capacity Design Standard
NW Natural	NW Natural will plan to serve the highest firm sales demand day in any year with 99% certainty: 99^{th} percentile of annual peak days over last 100 years.
Cascade Natural	Coldest day during the past 30 years.
Avista Corp	Adjust the middle day of the five-day cold weather event to the coldest temperature on record for a service territory, as well as adjusting the two days on either side of the coldest day to temperatures slightly warmer than the coldest day.
Fortis NG	1 in 20 years temperature based on annual peak days over last 60 years.
PSE	98^{th} percentile of annual peaks days from 1950-2019

5-minute break

Natural Gas Scenarios and Sensitivities

Participation Objectives

- PSE will present possible scenarios or sensitivities for the gas analysis.
- Stakeholders to share input on possible scenarios or sensitivities around for the gas analysis

IAP2 level of participation: INVOLVE

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Stakeholder involvement

- PSE requested stakeholder involvement at the August 11 webinar to help create the list of portfolio sensitivities.

- PSE is now asking for stakeholders to help to prioritize the analysis.

- PSE will make best efforts to complete all the requested analysis, however some analysis may take longer than others to complete and it is possible that not everything can be finished to meet the IRP filing date.
  - PSE will start modeling with the highest priority items.

Stakeholder involvement

- The list of sensitivities is the current thinking and includes sensitivities identified so far.
- The list of sensitivities will be finalized after stakeholder involvement is incorporated.
- Multiple sensitivities will be modelled for most themes.
- Details are included in the spreadsheet and on following slides.

Stakeholder requested natural gas portfolio sensitivities

	Theme	Description	Corresponding number in spreadsheet
1.	Economic conditions	Low Demand with very high gas price	4
2.	Economic conditions	Low demand with mid gas price	6
3.	Conservation	6-yr ramp rate	14
4.	Conservation	8-yr ramp rate	15
5.	Conservation	Non-energy impacts (NEI)	16
6.	Conservation	Social discount rate	17
7.	CO_2 Regulation	High impact SCGHG	18
8.	CO_2 Regulation	CO_2 tax	22
9.	CO_2 Regulation	Use AR5 to model upstream emissions	21
10.	Demand Adjustments	Fuel switching from gas to electric	30
11.	Demand Adjustments	Fuel switching from electric to gas	33
12.	Demand Adjustments	Temperature Sensitivity	31
13.	Equity	Equity focused portfolio	45

Renewable Natural Gas Background and PSE Status

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PSE has and will continue to pursue direct carbon reduction

- **Continued energy efficiency investments**
  - PSE is incorporating Social Cost of GHG emissions in portfolio selection
  - Results to be determined through 2021 IRP
- **Renewable Natural Gas**
  - Klickitat landfill supply: ~ 2% of 2019 gas sales
  - Additional sources available
- **Voluntary Carbon Balance program for gas customers**
  - Current enrollment 14,500 customers and approx. doubling annually
- **Hydrogen**
  - Founding member Renewable Hydrogen Alliance
  - Tracking other development activities in the region
- **Leak reduction**
  - Includes enhanced repair and reporting requirements

PUGET SOUND ENERGY

Overview

State Legislation:
WA passed HB 1257 in 2019; bill promotes additional Renewable Natural Gas (RNG) supply

- Voluntary customer program:
  - PSE obligated to offer by tariff a voluntary RNG service available to all customers to replace any portion of natural gas otherwise provided
- Integration into core portfolio:
  - PSE is allowed to incorporate RNG for portion of natural gas sold/delivered to retail customers
  - Subject to commission review and approval
  - Program cost capped at 5% of amount charged to retail natural gas customers

Background on RNG

What is Renewable Natural Gas?

- Primarily methane blend from decomposition of organic materials as byproduct of waste disposal (e.g. waste water treatment facilities, landfills, dairy waste, etc.)
- RNG is functionally no different for delivery and usage than conventional natural gas
- Majority of RNG produced in WA is supplied as a vehicle fuel to CA to satisfy Low Carbon Fuel Standard (LCFS) and EPA Renewable Fuel Standard for refineries.

Environmental Benefits of RNG:

- On a life-cycle basis, RNG total emissions are significantly lower than those of natural gas
  - Methane is captured and refined, from otherwise decomposing organic waste and then combusted, yielding a much lower emissions profile

Drawbacks of RNG:

- High cost of connection, production, and gas scrubbing to pipeline specifications.
- Dependent on source, carbon reduction cost = $40-250 (average $144) per Mega Ton (MT) CO_2e
- Relative value driven by lucrative Calif. compliance market (LCFS and EPA-RFS2)
- Limited supply
  - WA consumed 300 (Billion Cubic Feet) (BCF) of natural gas in 2015
  - PSE estimates available feedstock supplies could replace ~3-5% of usage

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RNG has lower carbon intensity than natural gas

- Carbon intensity (CI) is measured in grams of carbon dioxide (CO_2) equivalent greenhouse gas (GHG) per Mega Joule (MJ)
- Considers CO_2, methane, nitrous oxide, Volatile Organic Compounds (VOCs) and carbon monoxide
- CI of RNG measured relative to “No Action”- examples:
  - If No Action, Dairy Waste (manure) is left in field and emits GHG to atmosphere
  - If No Action, by law, Landfill Gas would be collected and flared (converted to CO_2)

Global Warming Potentials of Greenhouse Gases: relative to CO2	
CO2	1
CH4	25
N2O	298
VOC	3.1
CO	1.6

	gCO2e/MJ					
RNG Carbon Intensity (generic resources)	**Nat.Gas BC/Rockies (65/35)**	**Dairy Waste**	**Food Waste**	**Green Waste**	**Landfill Gas**	**Waste Water TP**
Source - Supply (upstream)	13.8	-321.9	-112.2	-64.2	-34.2	-17.9
Use - Demand (boiler/furnace)	56.4	56.4	56.4	56.4	56.4	56.4
Total Carbon Intensity	**70.1**	**-265.5**	**-55.8**	**-7.9**	**22.2**	**38.5**
GHG Reduction						
gCO2e/MJ		**-335.6**	**-125.9**	**-78.0**	**-48.0**	**-31.6**
Natural Gas Offsets						
(one unit of RNG offsets __units of Nat Gas)		**4.8**	**1.8**	**1.1**	**0.7**	**0.5**

RNG potential in the Northwest

Major RNG Projects in Washington:

Project	Location	Plant Owner	COD	Purchaser	Market served	Dth / Yr.
Cedar Hills Landfill	Maple Valley, W.	Bio-Energy WA	2009	PSE	CA vehicle	1,600,000
Roosevelt Landfill	Roosevelt, WA	Klickitat PUD	2018	PSE	PSE system (1)	1,700,000
King County Wastewater	Renton, WA	King County	@1990	BP	CA vehicle (2)	250,000
City of Tacoma Wastewater	Tacoma, WA	City of Tacoma	2020	BP	CA vehicle	220,000

(1) 2/3 of volumes serve CA vehicle market through 2023, via BP
(2) PSE gas supply until @ 2018

Dth = decatherm; 10 therms or 1.055 GJ

MDth = thousand decatherms

BP = British Petroleum

Dth/d = decathem/day

Prospects:

PSE has identified approximately 15 other projects in WA and OR that may be economically feasible.

- Many small dairy-waste projects currently supply green power to PSE,
  - most wish to convert to making RNG,
  - all would require major investments to upgrade processing
  - most require expensive connection to pipelines
- PSE currently controls 2,200 MDth/yr, growing to 3,300 MDth/yr in 2024
- PSE identified prospects to provide an additional 3,700 MDth/yr for a total of approx. 5-6% of PSE natural gas deliveries per year.

PSE's RFP for RNG supply

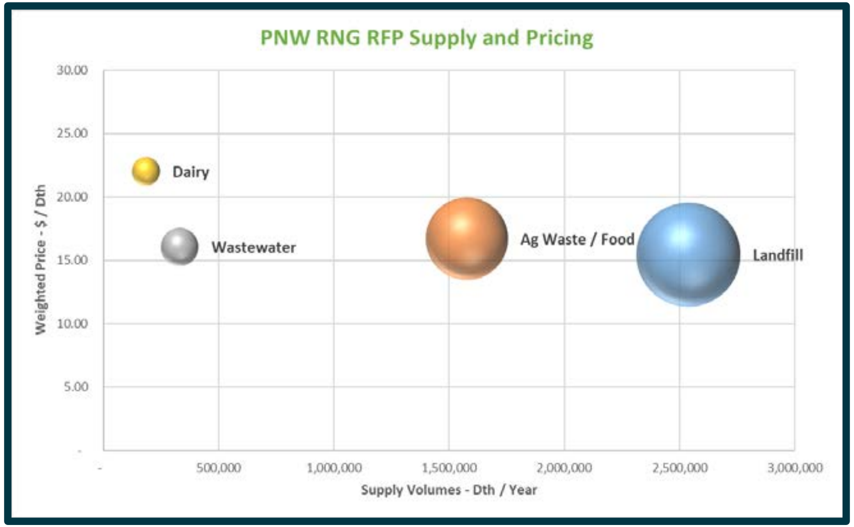
- In response to HB 1257, (effective in July, 2019) PSE issued a RFP to determine availability and pricing of RNG - targeted 20+ suppliers in November 2019
- PSE received 19 diverse responses, from CA, MI, OH, TX, and PNW

PNW Supply

- Price range: $15-27/Dth
- Volume: ~4,600 MDth/yr
  - o Available today: ~550 *MDth/yr*
  - o Most volume projected to be available by 2022

Other Supply

- Price range: $12-18/Dth
- Volume: ~2,900 MDth/yr
  - o Available today: ~1,000 MDth/yr
  - o Another ~550 MDth/yr available end-2020



- PSE Annual LDC sales + transport **deliveries** in **2018** exceeded **114,000 MDth**
- PSE Annual gas **demand** for electricity varies, but falls **between 20-40,000 MDth**

PSE's RNG acquisition

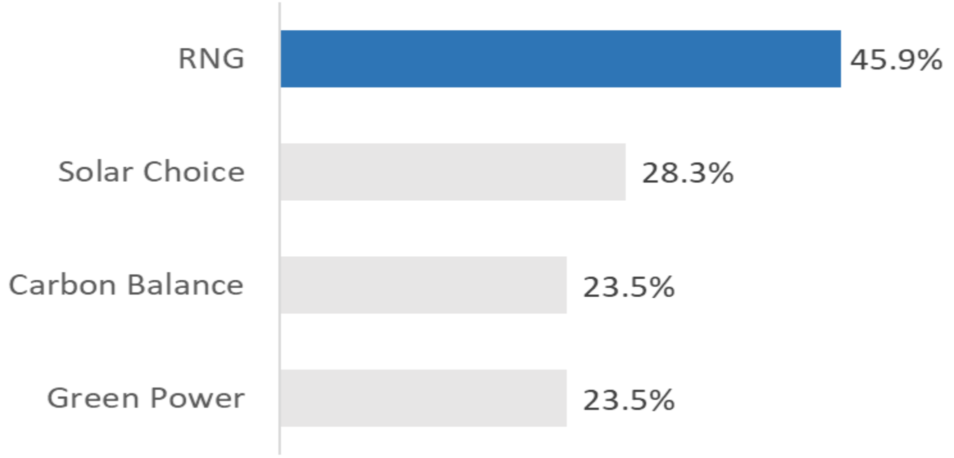
Roosevelt Landfill RNG

- **Location**: Roosevelt, WA along Columbia River
- **Project Ownership**: PUD No. 1 of Klickitat County (KPUD)
- **Gas Rights**: County owns landfill gas rights; assigned to KPUD in perpetuity
- **Landfill Ownership**: Republic Services (RS); supply optimization agreement exists between RS and KPUD
- **Contract:**
    - 20 year deal starting July 1, 2020
    - Fixed Price for term
    - Approx. 1,500 Dth/d until Oct 31, 2023 then full output of 4,500 + Dth/d
    - Unit contingent, with protection
- **Benefits:**
    - lowest reasonable cost RNG supply
    - Low risk- project fully operational
    - Already connected to pipeline-PSE can use its existing capacity
    - Low CI landfill RNG supply

Customer interest in subscription product

- Existing clean products gas participants (n=880) reported that they were likely to participate in voluntary RNG program, with about a third saying they would definitely participate and about half saying they would probably participate
- General customers reported that they were very interested in participating in a program like the subscription-style voluntary RNG program.

Survey question: If this RNG program was offered by Puget Sound Energy, how interested would you be in participating?



Next steps for PSE RNG program

- Continue development of customer RNG programs
- Continue development of regulatory rules with WUTC and stakeholders
- File with WUTC for approval of customer programs
- Implement customer programs
- Continue long-term planning, including assessment of potential use of RNG for generation under CETA

Questions & Answers

Tools for public participation

To keep you informed...

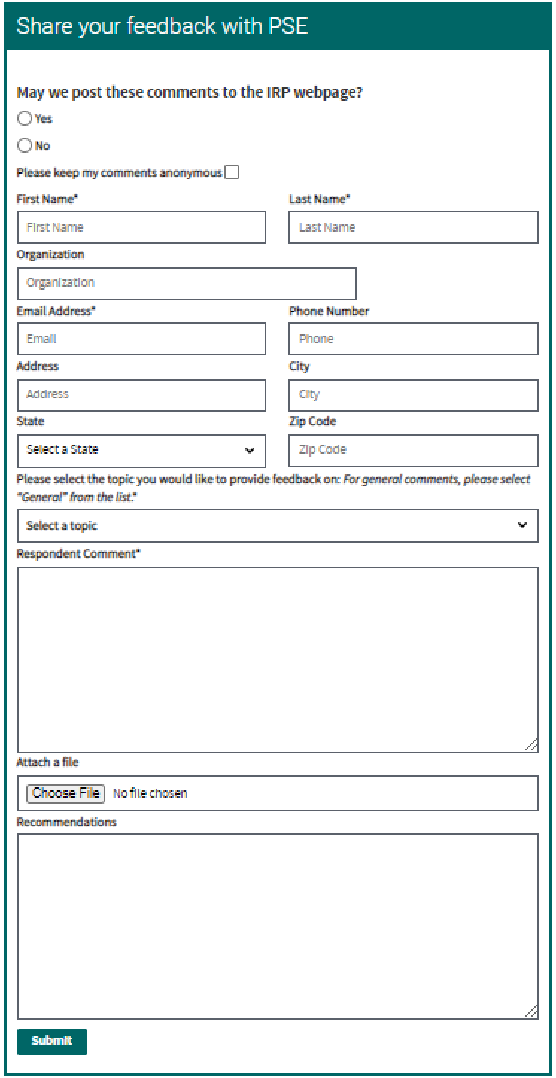
- Website postings
- Email notifications
- Briefings
- Feedback Reports
- Consultation Updates
- E-Newsletters
- Topical fact sheets

To seek your thoughts, ideas, concerns...

- Stakeholder interviews - *completed*
- Feedback webinars - *seven completed*
- Feedback reports - *seven completed*

Feedback Form

- An important way to share your input
- Available on the website 24/7
- Comments, questions and data can be submitted throughout the year, but timely feedback supports the technical process
- Please submit your Feedback Form <u>within a week of the meeting topic</u>



Share your feedback with PSE

May we post these comments to the IRP webpage?

Yes

No

Please keep my comments anonymous

First Name* — First Name

Last Name* — Last Name

Organization — Organization

Email Address* — Email

Phone Number — Phone

Address — Address

City — City

State — Select a State

Zip Code — Zip Code

Please select the topic you would like to provide feedback on: *For general comments, please select "General" from the list.**

Select a topic

Respondent Comment*

Attach a file

Choose File No file chosen

Recommendations

Submit

This session is being recorded by Puget Sound Energy.
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Feedback Form

- An important way to share your input
- Available on the website 24/7
- Comments, questions and data can be submitted throughout the year, but timely feedback supports the technical process
- Please submit your Feedback Form within a week of the meeting topic

Feedback Form → **Feedback Report** → **Consultation Update**

Feedback cycle

Action	Timing
Stakeholders can submit questions and feedback via the Feedback Form.	**Anytime, 24/7 online access**
PSE will share the meeting agenda, presentation slides and any supporting materials on the website.	**One week before each meeting**
A recording of the webinar and the transcript of the chat will be posted to the website so those who were unable to attend can review.	**One day after each meeting**
Feedback Forms related to the specific meeting topic are due.	**One week after each meeting**
A Feedback Report of all comments collected from the Feedback Form, along with PSE's responses, will be shared with stakeholders via the website.	**Two weeks after each meeting**
A Consultation Update, where PSE demonstrates how stakeholder feedback was applied, will be posted to the website.	**Three weeks after each meeting**

Thank you for your participation in PSE's 2021 IRP!

- To date, 145 unique individuals have participated in webinars
- Over 1,900 unique individual website users since May 2020
- 1,441 total audience members are receiving IRP newsletters
- 130 Feedback Forms received for the first 7 webinars
- Average message open rate of 20% for all newsletters sent between May and August 2020

Next steps

- Submit Feedback Form to PSE by **October 21, 2020**
- A recording and the chat from today's webinar will be posted to the website **tomorrow**
- PSE will compile all the feedback in the Feedback Report and post all the questions by **October 28, 2020**
- The Consultation Update will be shared on **November 4, 2020**

Details of upcoming meetings can be found at pse.com/irp

Date	Topic
October 20, 1:00 – 4:30 pm	Portfolio modeling and draft results Final power prices
November 4, 1:00 – 4:30 pm	Clean Energy Action Plan 10-year Distribution & Transmission Plan
December 9, 1:00 – 4:30 pm	Portfolio draft results Flexibility analysis Wholesale market risk

Note:

2021 IRP webinars schedule will be released in November 2020

Thank you for your attention and input.

Please complete your Feedback Form by October 21, 2020

We look forward to your attendance at PSE's next public participation webinar:

Portfolio modeling & draft results

Final power prices

October 20, 2020

Appendix

Resource alternatives – Pipeline costs

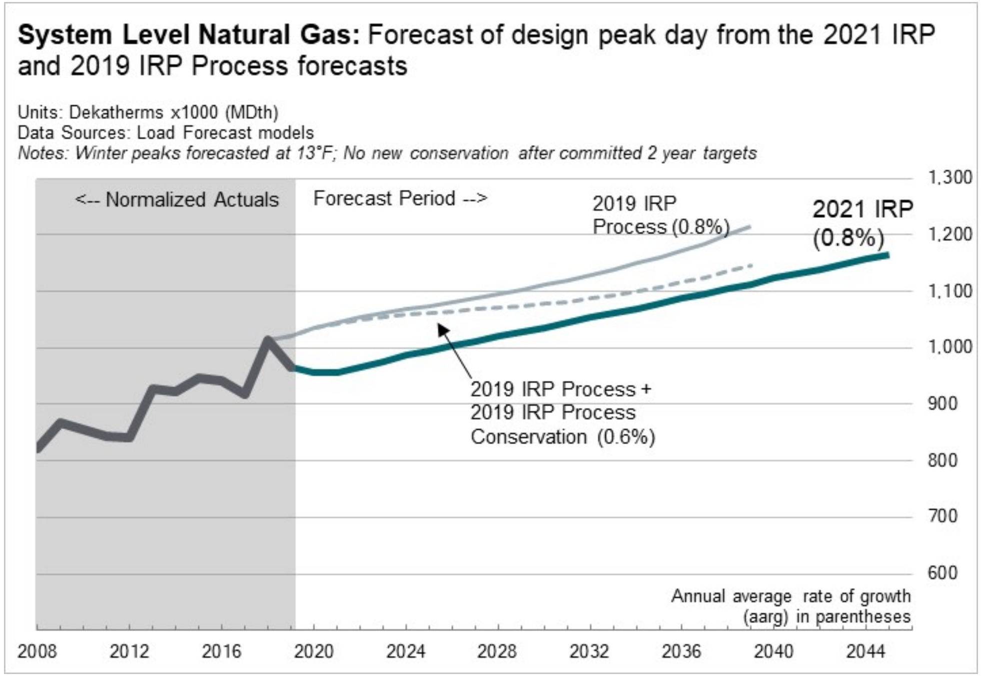
	Alternative	From/To	Capacity Demand ($/Dth/Day)	Variable Commodity ($/Dth)	Fuel Use (%)	Earliest Available	Comments
1	Westcoast + NWP Expansions	Station 2 to PSE	0.52 + 0.56	0.05 + 0.09	1.6 + 1.5	Nov. 2025	Westcoast expansion coupled with NWP expansion
1a	Short Term NWP TF-1	Sumas to PSE	0.38	0.09	1.5	Nov. 2021	Potential available from PSE Power Book, possible from 3rd parties
2	Fortis BC / Westcoast (KORP) + NWP Expansions	Kingsgate to PSE via Sumas	0.42 + 0.56	0.05 + 0.09	1.6 + 1.5	Nov. 2025	Prospective projects & estimated project cost - requires NGTL and Foothills
3	NGTL (Nova) Pipeline	AECO to Alberta / BC border	0.16	0	0	Nov. 2025	Prospective projects & estimated project cost - requires Foothills and GTN
3	Foothills Pipeline	Alberta / BC Border	0.12	0	1	Nov. 2025	Prospective projects & estimated project cost - requires NGTL and GTN
3	GTN Pipeline	Kingsgate to Stanfield	0.20	0.044	1.4	Nov. 2025	Prospective projects & estimated project cost - requires NGTL and Foothills.
3	NWP Columbia Gorge	Stanfield to PSE	0.80	0.005	2	Nov. 2025	Prospective project & estimated project cost - requires NGTL/Foothills/GTN.
4	Incremental NWP - Backhaul	I-5 to PSE	0.28	0.09	1.5	Nov. 2025	capacity resulting from NWP Sumas South Expansion; Demand Charge Winter Only rate requires Mist Storage
5	Long Term NWP TF-1	Plymouth to PSE	0.38	0.09	1.5	Apr. 2023	Maximum 15 MDth/d, available from 3rd Parties effective Apr. 2023
6	Tacoma LNG Distribution Upgrade	Tacoma LNG to PSE	0.23	0	0	Nov. 2025	Upgrade of the distribution system to connect the LNG plant to additional area of the PSE system

Resource alternatives – Storage costs

	Alternative	Storage Capacity (MDth)	Maximum Withdrawal Capacity (MDth/day)	Days of Full Withdrawal (days)	Max. Injection Capacity (MDth/day)	Earliest Available	Comments
4	Mist Expansion	1000	50	20	20	Nov. 2025	Prospective project, estimated size and costs, confidential- requires NWP backhaul capacity
5	Plymouth LNG	241.7	15	16	-	Apr. 2023	Existing plant - requires LT firm NWP capacity
7	Swarr	90	30	3	-	Nov. 2024	Existing plant requiring upgrades- on-system, no pipeline required

Webinar #7: Natural Gas: Peak demand forecast [System Level]

- 2021 IRP peak down 7% compared to 2019 IRP process forecast.
- Lower peak demand:
    - Lower residential customer and UPC growth.
    - Incorporating recent cold winters.
    - COVID-19 slows initial growth.
    - 2020/2021 conservation targets.
- Long term growth drivers:
    - New customer growth.
- The 2021 IRP peak forecast after DSR will be available once final DSR determined by the 2021 IRP process.



Webinar #5: Published emission rates

Natural Gas Supply Chain Upstream Life Cycle Emission Rates

Supply Chain Segment		GHGenius (Baseline Sensitivity), g/MMBtu				GREET (Upper Sensitivity), g/MMBtu			
		Carbon Dioxide	Methane	Nitrous Oxide	Carbon Dioxide Equivalent	Carbon Dioxide	Methane	Nitrous Oxide	Carbon Dioxide Equivalent
Natural Gas Extraction	**Extraction**	2,303.16	25.05	0.110	2,962.2	2,153.87	8.04	0.019	2,360.5
Extraction Fugitive		2.69	115.53	0.000	2,890.9	0.00	137.87	0.000	3,446.6
Natural Gas Processing	**Processing**	2,325.46	10.35	0.040	2,596.1	1,665.98	5.94	0.013	1,818.3
Processing Fugitive		1,101.04	0.00	0.000	1,101.0	702.06	6.17	0.000	856.3
Transmission - Distribution	**Transport & Storage**	1,192.80	2.29	0.009	1,252.8	1,650.74	63.04	1.385	3,639.4
Total		6,925.14	153.21	0.160	**10,803.0**	6,172.66	221.05	1.417	**12,121.1**

Source: Puget Sound Clean Air Agency, Final Supplemental Environmental Impact Statement (March 29, 2019)

Upstream Emission Rate - Sum of All Segments Expressed in CO2equivalent (CO2e)

PSE PUGET SOUND ENERGY

This session is being recorded by Puget Sound Energy.
Third-party recording is not permitted.

Webinar #8: Natural Gas IRP

10/15/2020

Overview

On October 14, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss the Natural Gas IRP. Additionally, participants were able to ask questions and make comments using a chat box provided by the Go2Meeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online. The recording for this webinar has been uploaded as two separate files. On the day of the webinar, the start of the meeting through Slide 20 was not initially recorded. To correct this error, PSE and EnviroIssues re-recorded this section on October 15, asked and answered all the questions asked from stakeholders the day before.

Attendees

A total of 48 stakeholders and PSE staff attended the webinar, plus another 3 attendees who called into the meeting and did not identify themselves (51 people total).

Attendees included: Allison Jacobs, Anne Newcomb, Ben Farrow, Bob Stolaski, Brian Grunkemeyer, Charlie Inman, Christine Bunch, Cody Duncan, Court Olson, Dan Kirschner, David Perk, David Tomlinson, Deborah Reynolds, Don Marsh, Elyette Weinstein, Fred Heutte, James Adcock, Josh Rubenstein, Kara Durbin, Kassie Markos, Kathi Scanlan, Larry Becker, Leanne Guier, Marty Saldivar, Matthew Doyle, Peter Moulton, Rachel Brombaugh, Robert Briggs, Shay Bauman, Srirup Kumar, Stephanie Chase, Ted Drennan, Virginia Lohr, and Willard Westre.

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 1:00 PM PDT and ended at 4:35 PM PDT.

Name	Time Sent	Comment
James Adcock	**1:05 PM**	Here we go again.
James Adcock	**1:09 PM**	That's fine -- let's get on with it.
Don Marsh	**1:21 PM**	I forgot... did customers lose gas service after the Enbridge incident? Or was PSE able to maintain service?
Bill Donahue	**1:22 PM**	PSE customers did not lose service
Don Marsh	**1:22 PM**	Thanks for the answer, Bill.
Court Olson	**1:39 PM**	Does Scenario #5 assume short term or long term gas shut down?
James Adcock	**1:39 PM**	On a "peak coldest winter day" what percent of Puget's supplied natural gas is going to Puget's NG electric generators?
Don Marsh	**1:40 PM**	Slide 16: was this forecast updated for the economic impacts of COVID?
Court Olson	**1:40 PM**	When is PSE going to realize that Gas demand will soon be declining as customers switch to clean electricity for heating space and water?
James Adcock	**1:42 PM**	What has been you Peakest Peak Day condition in terms of actual MDth/day, in the last 10 years?
Fred Huette	**1:44 PM**	also have a question Slide 16
Stephanie Chase	**1:46 PM**	Could you discuss the status of the Tacoma LNG project and when it is anticipated to be online?
Josh Rubenstein	**1:48 PM**	What carbon emissions reductions efforts are calculated into the resource forecast in slide 16?
Don Marsh	**1:52 PM**	Is the Tacoma LNG facility used for electric generation as well, or does it only supply PSE's gas customers?
Don Marsh	**2:01 PM**	Slide 17: question
Court Olson	**2:08 PM**	Your statement on the McKinsie analysis predicting a fall of of gas demand after 2030 seems to be in conflict with PSEs gas demand forcast curve. How do you resolve that conflict?
Fred Huette	**2:09 PM**	Is PSE considering the updated peer-reviewed study results concerning upstream emissions from BC and Alberta gas production and transportation? We submitted extensive detail in the electric IRP process.
Fred Huette	**2:11 PM**	slide 19: what is involved in upgrading from 50% to 100% firm for Station 2->Sumas? To your knowledge is Enbridge willing to offer that service?
Fred Huette	**2:12 PM**	slide 19: the cross-BC upgrades (it's Fortis most of the way as I recall, with about 250 mmcfd/d of current capacity) has been in discussion for many years. What is the current status?
Fred Huette	**2:17 PM**	slide 19: WIlliams/NW Pipeline declared a Deficiency Period starting Sep. 25 which is continuing and will result in "anomaly repairs" next week resulting in zero flow for several days. While this is a short term issue, to what degree is PSE including this kind of reliability risk in long term planning? http://northwest.williams.com/NWP_Portal/operations.action
Court Olson	**2:18 PM**	How does PSE intend to promote and implement gas conservation?
Anne Newcomb	**2:18 PM**	This looks like a lot of new NG capacity coming online. Are you expecting a spike in demand for existing customers and or new customers?
Court Olson	**2:21 PM**	Your slide 21 shows DSR impacts from mandated energy code standards. How do you reconcile this with the steadily increasing demand projection by PSE well into the future?

David Perk	**2:22 PM**	Thank you Don for raising this essential point.
James Adcock	**2:22 PM**	Comment: Puget by itself consumed the sustainable carbon footprint of one million human beings.
Josh Rubenstein	**2:22 PM**	Slide 20: How does the conservation cost bundling data incorporate the social cost of greenhouse gas emissions referenced in an earlier slide?
Virginia Lohr	**2:24 PM**	Slide 21: Are you assuming there will be no new codes or standards, such as those in Seattle, developed in future years?
Fred Huette	**2:29 PM**	In response to the facilitator: I'm happy to wait until after others who haven't asked questions, but we are asked to provide questions in this format and having done so, would like to hear at least initial responses.
James Adcock	**2:31 PM**	I think the "live" conversations are good, and again I would encourage PSE to start planning appropriate amounts of time in their IRP meetings, including time for more technical questions like Fred wants to ask. IRPs are supposed to be -- according to law -- about "Public Participation" NOT JUST PSE "Presentations" !
Fred Huette	**2:34 PM**	Also to note that I have to leave at 3 for an Oregon Department of Energy workshop. I will submit any questions not resolved in writing, but encourage PSE and the facilitation team to determine if this process is as efficient as it could be.
Court Olson	**2:36 PM**	You have collectively just admitted that gas demand will be falling off after 2030 due to utilities usage impacted by CETA rules. Surely the utilities get their gas from the same pipelines that you have shown us. So why is it that PSE is promoting increasing gas pipelines and gas storage facilities in Washington, when total gas demand (including from utilities) will surely be dropping after 2030?
Don Marsh	**2:38 PM**	PSE is not projecting increasing demand after DSR, so the "Resource Alternatives" will probably not be needed on slide 19.
Court Olson	**2:44 PM**	Energy code tightening every 3 years is required by existing Washington law. Every three years to 2031, the new building energy efficiency must tighten by about 9% on the afterage. Is this being included in your modeling?
Anne Newcomb	**2:55 PM**	Great question Court!
Srirup Kumar	**2:56 PM**	Would modular anaerobic digesters be eligible for conservation incentives offered to industrial, institutional and commercial clients?
Court Olson	**3:02 PM**	So glad to hear that there is no new gas resource need on the horizon!
Don Marsh	**3:02 PM**	25-26: question
Court Olson	**3:04 PM**	Whoops. Slide 26 still projects a net demand increase if I read it right. How do you reconcile the chart with what you just said that there is no demand increase seen on the horizon?

Anne Newcomb	**3:09 PM**	Slide 26. On March 19, 2020, the Governor signed HB 2311 - 2019-20, Amending state greenhouse gas emission limits for consistency with the most recent assessment of climate change science. It became effective on June 11, 2020. It states: "Based on the current science and emissions trends, as reported by the department of ecology and the climate impacts group at the University of Washington, the legislature finds that avoiding global warming of at least one and one-half degrees Celsius is possible only if global greenhouse gas emissions start to decline precipitously, and as soon as possible." Many of your responses to questions seem to assume we are in the same position climatically that we have been in for the past 50years, but we are not. Is PSE aware of this recent legislation and what are you doing to look not just at meeting your optimistic gas growth projection, but to reduce it?
James Adcock	**3:16 PM**	Comment: NG companies can and do make huge mistakes -- huge failures -- such as the California Aliso Canyon gas leak. I would hate to have a similar, or larger, failure at Tacoma LNG, which among other things would "take out" 30-40 schools.
Virginia Lohr	**3:23 PM**	Slide 30. You selected the IAP2 level of "Inform," the lowest level of public input, for the portion of this webinar on draft natural gas portfolio results. This level seems appropriate to me for simply presenting or informing us of the results of work you have done. You have also selected to use the IAP2 level of "inform" for a large portion of this webinar for: gas portfolio model, resource need, levelized gas prices, resource alternatives, and natural gas peak day planning standard. None of these topics involve just telling us results, but telling us how you plan to proceed. Why is this an appropriate level for an IRP meeting with many highly educated people volunteering their time to give useful and meaningful input for PSE to consider incorporating in your 20-year planning?
Don Marsh	**3:24 PM**	The Tacoma LNG facility is a big safety concern. If it is not absolutely essential (see slide 26), it is unethical to ask nearby residents to live with a potentially fatal risk of accident. PSE's website says "Our ethics: Doing the right thing." We expect PSE to follow its own ethics or take the words off its website.
James Adcock	**3:26 PM**	Slide 32 -- what additional "planning margin" in percentage -- if any -- does PSE build into their NG systems in addition to this 52 HDD planning standard?
Alison Peters	**3:28 PM**	Virginia, to your question about the inform level. This is the level where a sponsor such as PSE provides the public with the information needed to understand PSE's decision making process, including their forecasts. PSE welcomes questions about these topics before the webinar (in a Feedback Form) and we stop for clarifying questions frequently during this section. The Involve level for today will begin in just a minute - the next section.
James Adcock	**3:29 PM**	Slide 33 -- what additional planning margin, in percentage, is PSE building into their Natural Gas systems in response to PSE customer surveys that show that those customers put high value in keeping their gas on?
James Adcock	**3:32 PM**	Slide 35 Raise Hand.
Don Marsh	**3:33 PM**	Is slide 35 showing us 2005 data? Is it possible that things might have changed in the last 15 years?

Court Olson	**3:34 PM**	Slide 35 benefits do not apparently include the benefit of reduced GHG emssions, so this study needs to be replaced with a modern one that includes the social cost of carbon benefit.
Don Marsh	**3:34 PM**	Slide 36: question
Court Olson	**3:37 PM**	On Slide 37, has PSE studied the trend in changing cold peaks due to climate change in recent years? Doesn't that affect consumption and demand
James Adcock	**3:53 PM**	Puget is freezing me out because they know that 1950s weather data is no longer relevent re natural gas planning, as coldest winter days back then were 18 or more degrees colder than they are nowadays, due to large change in climate in PNW coastal weather -- PSE's region. As such, PSE's slide presented today -- which are based on 1950's weather data, are complete nonsense.
David Perk	**3:53 PM**	https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/Oct_20_webinar/Webinar%209:%20Updated%20sensitivities%20list.
Deborah Reynolds	**3:54 PM**	I agree that the peak day planning standards study should be fully described - what was provided in the slides today was a solid overview but not very detailed. The study should either be updated for 2020's customers and statutes, or supported as still accurate and useful.
Don Marsh	**3:56 PM**	How many portfolios can you study?
Court Olson	**3:56 PM**	I wonder how we can prioritize portfolio sensitivities? If we had to rank them, it might suggest that lower ranking sensitivities can be discarded, when that may not be the intent. Please give us guidance and the link to the place where we offer comments.
Virginia Lohr	**3:56 PM**	Please read my question I posted at 3:09. It addresses Elizabeth's question.
Don Marsh	**3:57 PM**	Raise hand
Don Marsh	**3:59 PM**	When I try to open the spreadsheet, it says "Can't open in protected view." I can't see it.
Brian Grunkemeyer	**4:00 PM**	I have the same spreadsheet problem as Don.
Deborah Reynolds	**4:01 PM**	I'm able to open the file in my native Excel desktop program. We've had some problems with this file when using it in Office 365 and Sharepoint Online.
Don Marsh	**4:01 PM**	I have Office 365. Hmm.
Alison Peters	**4:02 PM**	Don, I'm able to open it as well. For everyone else, it is linked to the meeting materials for 10/20.
Brian Grunkemeyer	**4:03 PM**	Got it. As Deborah hinted.. Run Excel. File -> Open -> Browse, then paste in the URL
Don Marsh	**4:04 PM**	Got it off the IRP website. Thanks.
Brian Grunkemeyer	**4:06 PM**	There is a colon ':' in the file name. That doesn't work well on Windows for reasons (NTFS streams). PSE, please consider not using :'s in file names in the future.
Don Marsh	**4:08 PM**	Good debugging, Brian! You must have worked at Microsoft once upon a time! :)
Brian Grunkemeyer	**4:09 PM**	I wrote .NET's FileStream class. You learn some things.
Court Olson	**4:09 PM**	Slide 46 & 47. How does PSE plan to produce Hydrogen? From methane or by elctrolysis?
Alison Peters	**4:09 PM**	Thank you, Brian. We can upload it again without the :

Srirup Kumar	**4:12 PM**	Slide 47: Does the 3-5% RNG estimate include the distributed RNG resources embedded in food, bev & ag waste?
Don Marsh	**4:19 PM**	Slide 52: question
Brian Grunkemeyer	**4:22 PM**	Bill, I'd like your gut feeling on this. What if you are only allowed to put carbon-neutral gas in the pipeline? Can your customers cover the fixed costs for the pipeline system at an acceptable cost?
Srirup Kumar	**4:22 PM**	Thank you. Following-on, would modular anaerobic digesters be eligible for conservation incentives offered to industrial, institutional and commercial clients?
James Adcock	**4:24 PM**	Why would you turn "Excess Electricity" into Hydrogen as opposed to Battery Storage or Pumped Hydro, or sell it to BPA for long term storage behind their dams as stored potential energy?
Peter Moulton	**4:24 PM**	WSU/Commerce assessment of RNG potential did take food/ag wastes into consideration, along with biomass gasification pathways. Conclusion was closer to 10% displacement potential if all pathways are taken into consideration...
Srirup Kumar	**4:22 PM**	Thank you.
Brian Grunkemeyer	**4:24 PM**	Thanks Bill. Just food for thought - please consider some policy goal like RNG-only by 2035. IE, say the Legislature incentivizes fuel switching, etc. It would be useful for PSE to have an answer to whether this might be an obtainable policy goal to set.
Peter Moulton	**4:28 PM**	I wouldn't characterize the ~10% estimate as "very optimistic," it's a realistic assessment of potential. Cost is different question...
Alexandra Streamer	**4:32 PM**	Link to Feedback Forms: https://pse-irp.participate.online/feedback-form
Srirup Kumar	**4:32 PM**	Note: a recent study by the Lawrence Livermore National Laboratories found that converting organic waste to clean fuels like renewable natural gas (RNG) holds the greatest potential for negative emissions at the lowest cost https://www-gs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdf
Srirup Kumar	**4:36 PM**	Thank you!

PSE IRP Feedback Report
Webinar 8: Natural Gas IRP
October 14, 2020

10/28/2020

The following stakeholder input was gathered through the online Feedback Form, from October 7 through October 21, 2020. PSE's response to the feedback can be found in the far-right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on November 4, 2020.

Feedback Form Date	Stakeholder	Comment	PSE Response
10/14/20	James Adcock	Please do your "mike checks" and other "technology presentation checks" *before* the start time of the meetings. There is no reason why you guys should be wasting everyone's time "fixing" things after the start time of the meeting. When you do so, you are implying that your time -- "PSE's time" -- is important, but that the time and energy of IRP participants is *not* important!	We thank our stakeholders for their patience and understanding. PSE regularly checks the technology and audio before meetings, however, sometimes technology fails. Even though PSE was able to recover the presentation in a timely manner, we apologize that this caused an inconvenience for our stakeholders.
10/14/20	James Adcock	Slide 36 -- PSE continues to use archaic "weather data" going back to the 1950's -- when the "coldest winter day" was as cold as zero degrees F. In the last 20 years "coldest winter day" has only been 18 degrees -- 18 HDD less! Can you please create an up-to-date version of Slide 36 which only uses "weather data" from at most the most recent last 20 years -- and then rely on that up-to-date information rather than relying on ancient out-of-date data for all of your NG planning efforts? When PSE continues to use ancient out-of-date weather data what PSE is really saying is: "Puget Continues to Deny the Reality of Climate Change!"	Thank you for your comment. As was discussed in the webinar, the gas planning standard is very different from the electric peak planning standard. This has to do with the long time, higher cost and increased safety concerns in the event of a gas outage. The planning standard for the natural gas portfolio is based on a cost/benefit analysis. While PSE will not update the cost/benefit analysis for this IRP, the gas planning standard is in line with industry standards and other gas utilities in the region. The gas-planning standard was successfully tested in early October 2019 when a pipeline ruptured in B.C. and PSE did not experience any gas service customer disruptions. For clarification, the coldest day in the weather data used by PSE is a 24-hour average temperature of 13 degrees, not zero.
10/14/20	James Adcock	Re: feedback about "natural gas sensitivities" -- I suggest creating a "natural gas sensitivity" based on weather data taken only from the last 20 years -- 2000 to 2020, rather than reaching back to archaic weather data from the 1950s.	Thank you for your comment. The effects of warming temperature trends on the demand forecast will be analyzed as a sensitivity that was presented in Webinar 9 on October 20, and has been included in the list of portfolio sensitivities. At the time of this Feedback Report, we have not yet reviewed stakeholder input regarding the temperature sensitivities.
10/14/20	Don Marsh, CENSE	During the October 14 webinar, PSE asked for stakeholder comment on the priority of the portfolio sensitivities (slide 43). I didn't find a way to provide this feedback other than this feedback form, so I hope this is the proper way to do it. My preferred sensitivities, in priority order, and reasoning are as follows: (top priority) 7. High impact SCGHG Reason: I believe PSE's current accounting of SCGHG (slide 17), while high, understates the true impacts of the Social Cost of Greenhouse Gas emissions, as indicated by more recent scientific studies. It is very likely that PSE's numbers will have to be revised upward in the next few years, so we should find out now what the implications will be. 9. Use AR5 to model upstream emissions PSE is using methane leakage rates that are low and not up to date, so the cost of methane emissions is also understated on slide 17. PSE will need to revise these numbers in coming years, so let's see what that will look like. 10. Temperature Sensitivity In every recent IRP meeting, and many of the 2019 meetings, James Adcock and several other stakeholders (including me) have criticized PSE for using up to 70 years of temperature data as a basis for forecasts. The climate is warming, and the effects are dramatic in the case of winter temperatures in the Pacific Northwest. Other states, like New York, are using 15-20 years of data to account for accelerating warming during the past couple of decades. I believe this will have a significant effect on PSE's forecasts, and it is time for us to understand what the magnitude of that effect actually is. 11. Equity focused portfolio Economically challenged customers are bearing the brunt of pollution and climate change. They are the least likely to benefit from clean energy technologies due to costs and the basic struggle to stay afloat financially in these difficult times. Although PSE is required to pursue least reasonable cost solutions, it	Thank you for sharing your preference concerning sensitivities. PSE looks forward to your participation in the selection of the portfolio sensitivities to be analyzed as part of the 2021 IRP. The survey opened on October 19 and remained open thru October 27. PSE's responses from the numbers you provided are as follows: 9. Thank you for your comment. AR5 to model upstream emissions is included in the sensitivity selection for the 2021 IRP. 10. PSE will be running a temperature sensitivity as a "must run" sensitivity. Temperature sensitivities options were presented and further discussed with stakeholders at the October 20 Webinar 9 meeting. Your request to use the most recent 15-years of data is included in our proposed sensitivities. 11. Thank you for your comment and concern. PSE shares your concern. PSE looks forward to stakeholder feedback during the November 16 webinar when we discuss the approach to the Highly Impacted Communities and Vulnerable Populations Assessment and the Clean Energy Action Plan. 12. Thank you for your comment. 13. Thank you for your comment. 14. Thank you for sharing your preference for applying the discount rate. 15. Thank you for sharing your thoughts on a CO2 tax. The idea for this sensitivity is to include a federal CO2 on top of the SCGHG currently being modeled. 16. Thank you for your comment.

Feedback Form Date	Stakeholder	Comment	PSE Response
		is also ethically bound to provide equitable solutions for all its customers. An equity focused portfolio accords with our values and respect for all customers. 12. 6-yr ramp rate It is very difficult to forecast what conservation opportunities will be available in 10 years. PSE says it is impossible to forecast technology and societal priorities in 20 years, and I agree! Six years is a reasonable horizon for these forecasts, so I support pursuing all available conservation in six-year increments. This also reflects the urgency of doing everything we can to avoid environmental catastrophe for future generations. 13. Fuel switching from gas to electric I believe fuel switching will accelerate as technology options become available and awareness builds that natural gas is not a "clean" fuel, but rather extremely detrimental to the well-being of people and the planet. In the past four years, my family has cut our gas use by a factor of five by installing an on-demand hot water heater, heat pump, and induction stove. There are several additional things we can do to cut our gas use even further. I believe this trend will start to take hold more broadly, and may be accelerated by new regulations at the city and county levels. 14. Social discount rate I believe the current discount rate is distorting the true value of DSR, which is a valuable tool in the implementation of CETA and CEIP. Let's see how much the discount rate is creating headwinds to adoption of more DSR. 15. CO2 tax If the administration changes (and this appears likely), interest in an equitable CO2 tax will increase. Let's understand what that would mean for PSE's planning efforts. 16. Non-energy impacts (NEI) In the spreadsheet, the description of this sensitivity is pretty vague, so I might increase its priority if I understood it better. I strongly believe that PSE needs a lot more Demand Response and conservation, and it is unfortunate that the company is trying to withdraw from its most recent RFP for DR resources. These resources are good for customers, beneficial for the environment, and improve reliability by relieving peak-induced stress on the grid. 17. Low Demand with very high gas price This sensitivity was not described in the spreadsheet, but I assume "very high gas price" includes a high SCGHG cost. If I had to bet, this is the most likely scenario we will experience in 2030. We should understand what the implications are. 18. 8-yr ramp rate This is a good sensitivity to study, but it's a small step from the current 10-year ramp rate. I prefer the more aggressive 6-year ramp rate to gain a good understanding of the effects of a shorter ramp rate. If PSE studies both the 6-year and 8-year ramps, we can get a better understanding of how incremental changes affect the costs and benefits. I don't expect to see a simple linear response. 19. Low demand with mid gas price Assuming low demand is good, but a mid gas price seems unlikely given what we know about SCGHG and upstream emissions. This study will provide an interesting contrast to sensitivity number 1, but it's not a high priority because it is seems unlikely to occur. (lowest priority) 11. Fuel switching from electric to gas This sounds dumb to me, but maybe we will find out how dumb by actually running the numbers. More information is always good. But if you're running out of time to study portfolios, this is the last thing you should spend scarce resources on. For each sensitivity studied, I ask PSE to produce a forecast like the one shown on slide 26. If the adjusted forecast is not lower than the one shown for "2021 IRP BASE Demand after DSR," please provide an explanation. For many sensitivities, the explanation will be obvious, but for some, stakeholders may need a little more insight.	17. Thank you for your comment. 18. Thank you for your comment. 19. Thank you for your comment. A stakeholder suggested a sensitivity of fuel switching from electric to gas. PSE has added all stakeholder requests to the list of sensitivities for further prioritization. Thank you for your comments. Thank you for your suggestion to include a similar graph as slide 17 for any sensitivity that affects the SCGHG Adder or Upstream Carbon cost. Your suggestion is being considered.

Feedback Form Date	Stakeholder	Comment	PSE Response
		For any sensitivity that affects the SCGHG Adder or Upstream Carbon cost, please show a graph like slide 17 so we can fully understand the assumptions. Full detail of how you arrived at the new costs (references to studies or existing/future regulations) should also be provided. Sincerely, Don Marsh, 2021 IRP Stakeholder	
10/14/20	James Adcock	Please respond now to the questions I raised in the chat box during the online meeting, where I "raised hand" but you continually refused to acknowledge that "raised hand." During the online Meeting PSE, while refusing to acknowledge my "raised hand" to ask a question, claimed that it is answering my previous-session questions after-the-fact in the Consultation Updates even if it did not answer my questions during the meeting. I have reviewed those Consultation Updates once again, and PSE is NOT in fact answering my questions, but rather -- if doing anything at all --- instead lumping a bunch of people's questions and concerns together, and instead of answering any of those questions, simply restating generically what PSE claims that it is doing already. Please actually respond specifically to the specific questions I asked in this meeting, and previous meeting's chat boxes. And please stop telling other participants in the online meetings that you answering my questions offline in the Consultation Updates, when in fact you are not answering my questions offline in the Consultation Updates.	PSE appreciates your participation and desires to make a space for all stakeholders and provide equal access. PSE regrets that you do not find the Feedback Reports and Consultation Updates adequate. PSE regrets that not all your questions have been addressed and that you do not think you are being provided enough opportunity to participate. PSE's intention to provide a means for all stakeholders to be heard and be part of the 2021 IRP record via the meeting recordings, Q&A Logs, Feedback Forms, Feedback Reports and Consultation Updates. PSE is also available via email at IRP@pse.com. PSE will not be going back to all past meeting records and ask that you consider alerting PSE of any specific gaps. Thank you for using the tools that PSE has provided to engage in this process. Thank you for your comments and continued participation.
10/19/20	David Perk 350 Seattle	House Bill 2311 aligned Washington's greenhouse gas reduction goals with the Paris Accord. In the near term, that requires a 45% reduction of statewide GHG emissions by 2030. The "Gas Resource Need" (slide 16) and "Draft base scenario –DSR sufficient to meet future demand" (slide 26) should reflect that reality. Moreover, HB 2311 requires relevant state agencies to report their reduction plans for the next biennia by June 1, 2022. As a major emitter, PSE will need to supply a plan to reduce its emissions. To work toward that goal the "Stakeholder requested natural gas portfolio sensitivities" (slide 43) should include a sensitivity that addresses the necessary GHG reductions.	PSE looks forward to reviewing the Department of Ecology's progress report at the end of this year, indicating statewide greenhouse gas emissions as well as emissions from relevant key sectors, such as the electricity and/or building sectors. PSE will review Ecology's report, as well as the overall statewide greenhouse gas emissions limits established in HB 2311, in considering potential sensitivities to run for the next IRP cycle.
10/19/20	Elyette Weinstein	As you know, E2SHB 2311 became law, effective June 11, 2020. It requires that, by 2030, Washington State utilities limit anthropogenic emissions of greenhouse gases to achieve a 45% reduction in such emissions below 1990 levels or 50 million metric tons. Please run a sensitivity that fully conforms to the above stated law based on emissions below 1990 levels and another with a reduction of 50 million metric tons. Thank you.	PSE looks forward to reviewing the Department of Ecology's progress report at the end of this year, indicating statewide greenhouse gas emissions as well as emissions from relevant key sectors, such as the electricity and/or building sectors. PSE will review Ecology's report, as well as the overall statewide greenhouse gas emissions limits established in HB 2311, in considering potential sensitivities to run for the next IRP cycle.
10/19/20	Doug Howell, Sierra Club	HB 2311 mandates new GHG targets for the state calling for 95% elimination of fossil fuel by 2050 and 45% reduction in fossil fuel by 2030. PSE needs to run a scenario or at least a sensitivity of how PSE is going to meet this 2030 interim target for its gas utility. In the last IRP meeting on the gas utility, PSE is planning on demand remaining relatively flat through	PSE looks forward to reviewing the Department of Ecology's progress report at the end of this year, indicating statewide greenhouse gas emissions as well as emissions from relevant key sectors, such as the electricity and/or building sectors. PSE will review Ecology's report, as well as the overall statewide greenhouse gas emissions limits established in HB 2311, in considering potential sensitivities to run for the next IRP cycle.

Feedback Form Date	Stakeholder	Comment	PSE Response
		2030. This is unacceptable. PSE needs to demonstrate a path forward to achieve the state climate goals. Run a scenario or at least a sensitivity showing a 45% reduction in gas use by 2030.	
10/20/20	Josh Rubenstein	To both PSE and the facilitators, the fact that you told the public that we were "involved" in the October 14th IRP meeting stretches the imagination. After three hours of "inform" we got to the one slide with "involve" level of IAP2 participation, at which point PSE said that based on the data they had presented they did not believe that further sensitivities analysis needed to be done on the gas forecasts. In other words, PSE asked us to agree that public involvement was unnecessary at the only point in their presentation where public involvement was planned. PSE and EnviroIssues staff responsible for this process lose credibility in the eyes of the public when you demonstrate no interest or ability to engage the public and instead choose to only "inform." In this case PSE, I heard you trying to cut out the public voice. How will you improve your public process to seek input, rather than ask for permission to not receive input? EnviroIssues, as the process experts in this situation, it is your job to uphold a process that is truly public. What will you do to improve the opportunities for public participation in the meetings you facilitate? In response to the question, PSE should prioritize every sensitivity that may lead to a reduction in global warming pollution. PSE ratepayers and the public have payed, are paying, and will continue to pay the social cost of PSE's carbon pollution. It's high time that PSE start working to reduce the demand for gas so that we PSE can begin reducing the damage you inflict on our climate and our society. If the first step in doing that means running sensitivity models, then you should do that rather than ask for permission not to. Improve public process and accountability to fully invite public input. When the public is seeking lower climate pollution, incorporate that into PSE's actions in a meaningful way. Model all the sensitivities for the gas IRP that could lead to lower gas usage or demand, so that PSE will feel that they have the information they need to lower and then eliminate regional reliance on fossil fuels.	Thank you for your thoughtful comments and suggestions concerning PSE's 2021 public participation process. PSE agrees that for future meetings we will consider placing, "involve" level topics as priority on the agenda to provide for more opportunity for engagement. PSE has decided the level of engagement for each topic to the level that we can commit concerning that topic. Thank you for your comments and suggestions concerning sensitivities.
10/21/20	Bill Westre, Union of Concerned Scientists	Slides 16 and 26: The business-as-usual presupposition behind these charts is illusory at best and not reflective of the reality of our current situation. We need to turn to science for a better perspective of what is real. The preponderance of reputable scientists have formed a consensus that we must eliminate all fossil fuel emissions by 2045. To not do so would lead to catastrophic consequences for citizens in every country. This is articulated in the IPCC Paris Agreement and its subsequent reports. The Federal Government may for the moment be attempting to get out of this agreement, but Washington State is committed to the Paris GHG reductions by the passage of HB 2311 last year. HB 2311 requires, with respect to year 2005, all GHG emissions be reduced by: 15% by July 1 2020 45% by 2030 70% by 2040 90% by 2050 These required emissions reductions apply to nearly all non-natural emissions including those by any corporation that produces or distributes methane which is the primary constituent of natural gas. The Bill also requires that by June 1st 2022 the relevant state agency must report to the Dept of Ecology the actions planned for the next biennia to meet these emission reduction targets. This date falls within the 4-year time construct of the 2021 IRP. As a major supplier of natural gas produced GHG emissions, PSE will surely be called on to submit its plan for these reductions. Question 1 - Is PSE willing to create a scenario that includes plan options that reflect the above listed reductions in the 2021 IRP? If not, why not?	Thank you for your comments and questions. PSE supports customer choice and we accommodate and support customers switching from gas to electric service. PSE looks forward to reviewing the Department of Ecology's progress report at the end of this year, indicating statewide greenhouse gas emissions as well as emissions from relevant key sectors, such as the electricity and/or building sectors. PSE will review Ecology's report, as well as the overall statewide greenhouse gas emissions limits established in HB 2311, in considering potential sensitivities to run for the next IRP cycle. The above response covers questions 1, 3, 4 and 5; thank you. Concerning question 2: PSE will be addressing this question in the Consultation Update on November 4, 2020.

Feedback Form Date	Stakeholder	Comment	PSE Response
		Question 2 – PSE alludes to its responsibility to respond to these requirements by referring to renewable gas, hydrogen, and gas-to-electric switching. What other options are available to PSE to make these reductions? Question 3 - Will PSE inform its customers of the required reductions and its long-term impact on them? Question 4 – Will PSE incorporate these requirements into its gas conservation plan? Question 5 – Will PSE intensify its conservation rebate incentives to help its customers make the required transitions.	
10/21/20	Virginia Lohr	I do not agree with PSE's proposal to run no gas sensitivities. You showed us one set of results that indicated you would be able to meet most of your gas load, but that does not guarantee you will. The future is uncertain, as Covid has clearly demonstrated, so not running alternate sensitivities to look at alternate possible futures seems clearly imprudent. During the meeting, I brought up HB 2311 - 2019-20: Amending state greenhouse gas emission limits for consistency with the most recent assessment of climate change science. It became effective on June 11, 2020. While this bill does not include specific language requiring PSE to take action, it does present the clear intent of the legislature to take strong action to reduce greenhouse gas emissions. It is not improbable that a bill similar to CETA but directed towards utilities that supply natural gas rather than focused on electricity, would be enacted. I strongly recommend PSE run a gas sensitivity based on the updated greenhouse gas emission reduction targets in HB 2311.	Thank you for your comments and recommendations. PSE looks forward to reviewing the Department of Ecology's progress report at the end of this year, indicating statewide greenhouse gas emissions as well as emissions from relevant key sectors, such as the electricity and/or building sectors. PSE will review Ecology's report, as well as the overall statewide greenhouse gas emissions limits established in HB 2311, in considering potential sensitivities to run for the next IRP cycle.
10/21/20	Anne Newcomb	Please add requirements of GHG reductions from E2SHB 2311 to PSE Natural Gas sensitivities. Requirements: Greenhouse Gas Emissions Reductions. Washington must limit anthropogenic emissions of greenhouse gases to achieve the following reductions for the state:? By 2020, reduce overall emissions of greenhouse gases in the state to 1990 levels, or 90.5 million metric tons. By 2030, reduce greenhouse gas emissions to 45 percent below 1990 levels, or 50 million metric tons. By 2040, reduce overall emissions of greenhouse gases in the state to 70 percent below 1990 levels, or 27 million metric tons. By 2050, reduce overall emissions of greenhouse gases in the state to 95 percent below 1990 levels, or 5 million metric tons, and achieve net-zero greenhouse gas emissions. Thank you for listening to Stakeholder comments and recommendations! It is unsettling for me to see PSE is still considering Natural Gas (NG) expansion, as shown in slide #19, even with new Washington state laws in place and more coming online to address Greenhouse Gas emissions.	Thank you for your comments and recommendations. Slide 18 shows all natural gas resource alternatives available to PSE, however, as we discussed later in the presentation, conservation meets future gas growth for the base scenarios and no natural gas expansion is needed for the base scenario.

Feedback Form Date	Stakeholder	Comment	PSE Response
		Hopefully PSE will add new WA state law requirements, including E2SHB 2311, to the 2021 IRP (NG) sensitivities to be run. Well wishes to all of you, Anne Newcomb Attached: http://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bill%20Reports/House/2311-S2.E%20HBR%20FBR%2020.pdf?q=20201022100749	
10/21/20	Robert Briggs, Vashon Climate Action Group	On March 19, 2020, Governor Inslee signed HB 2311, which updated the state's greenhouse gas emissions limits. Those emissions now need to be 45% below 1990 levels by 2030, 70% below 1990 levels by 2040, and 95% below 1990 levels by 2050. During the webinar, PSE proposed to abandon doing all gas sensitivity analyses because current gas resources appear adequate to meet near-term demand. I strong urge PSE to reject that idea. Given the clear legislative intent expressed in HB 2311, PSE needs to be planning its gas system to comply with state emissions limits. As the largest gas utility in the state of Washington, PSE needs to recognize the importance of its fully complying with state law to the state's credibility and reputation. I would argue that complying with state law should be included as a baseline assumption. I would think it financially imprudent for PSE to fail to include a reduction of gas emissions in conformance with HB 2311 at least as a scenario, given the clarity with which the Legislature has now spoken. Future legislation is likely to make these limits more stringent not less. There is also an equity dimension to this situation that PSE, the WUTC, and the Public Counsel's office need to take responsibility for managing. As the direct use of gas is abandoned in favor of electricity for both cost and GHG emissions reasons, there will be fewer and fewer gas customers to shoulder the costs of maintaining gas infrastructure. The need to recover those costs with fewer sales will drive up rates, leaving those least financially able to cope with the consequences of an essential energy service experiencing a financial death spiral. It is essential that PSE with oversight from the WUTC proactively manage the scaling back and orderly withdrawal of this service. How will PSE be able to manage this development, which now appears inevitable, if it continues to pretend that change is not coming? This process has large implications for the electric side of PSE's business. It seems important that the consequences for electricity demand of contracting gas service be fully explored in PSE's electric IRP as well. I recommend that PSE include a gas sensitivity that reflects a contraction of gas deliveries to direct users proportionate with their contribution to state greenhouse gas emissions and in conformance with the schedule for reductions specified in HB 2311.	Thank you for your comments and recommendations. PSE looks forward to reviewing the Department of Ecology's progress report at the end of this year, indicating statewide greenhouse gas emissions as well as emissions from relevant key sectors, such as the electricity and/or building sectors. PSE will review Ecology's report, as well as the overall statewide greenhouse gas emissions limits established in HB 2311, in considering potential sensitivities to run for the next IRP cycle.
10/21/20	Kyle Frankiewich, WUTC	Questions and comments from presentation were provided by reference slide number. Recommendations were provided as well.	Thank you for your questions and recommendations. PSE inserted each item below along with PSE's responses.
10/21/20	Kyle Frankiewich, WUTC	Slide 10: I'm not clear on why Enbridge is a good example of a "peak event." Is the company's argument that the level of overbuild / redundancy / resilience in the system was tested and performed well during a major infrastructure outage outside of PSE's control?	The Enbridge event was not characterized as a peak event, but rather an example of the value of diversity of the portfolio. There is no excess capacity in the upstream pipeline and storage system (all of it is contracted) so when one part fails PSE has to rely on other parts of the portfolio and other planned responses (curtailment of interruptible loads and lower priority firm loads) in order to maintain service on the gas system.

Feedback Form Date	Stakeholder	Comment	PSE Response
10/21/20	Kyle Frankiewich, WUTC	Slide 12: Seems that the NG line of business (LOB) more consistently sources gas from the Rockies than the electric LOB. Why is this? Broadly, since the low prices brought about through fracking, what is the historical ratio of sourcing from BC, Alberta and the Rockies?	The PSE Electric (Generation) LOB does not source any gas from the Rockies, and never has, as it does not hold any firm pipeline capacity from the Rockies. PSE began acquiring pipeline capacity for generation well after all capacity from the Rockies was fully contracted. While a few expansions from the Rockies to the Pacific NW have been proposed, none were economic or attracted enough interest to be built. The table below provides a summary of the natural gas supply sources for the natural gas utility and a second table for the natural gas for power (the natural gas generators for the electric utility).

Gas Supply source for PSEG and PSEE for 2010 through 2019

Supply sources are limited by the firm pipeline capacity held by each respective portfolio

PSE Gas Customer Portfolio by year:	BC at Station 2 or Sumas	Alberta in Alberta	US- Rockies & San Juan Basin	Total
2019	49.4%	19.2%	31.4%	100.0%
2018	49.0%	17.2%	33.8%	100.0%
2017	54.8%	19.1%	26.1%	100.0%
2016*	56.0%	21.0%	23.0%	100.0%
2015*	57.0%	24.0%	19.0%	100.0%
2014	57.1%	18.1%	24.8%	100.0%
2013*	56.0%	21.0%	23.0%	100.0%
2012*	51.0%	20.0%	29.0%	100.0%
2011*	49.0%	15.0%	36.0%	100.0%
2010	42.8%	18.7%	38.5%	100.0%

PSE Power Generation Portfolio by year:	BC at Station 2 or Sumas	Alberta in Alberta	Alberta at Stanfield	Total
2019	54.4%	19.7%	25.9%	100.0%
2018	72.2%	18.0%	9.8%	100.0%
2017	69.9%	21.8%	8.3%	100.0%
2016*	64.0%	20.0%	16.0%	100.0%
2015*	76.0%	1.0%	23.0%	100.0%
2014	91.2%	0.0%	8.8%	100.0%
2013*	88.0%	0.0%	12.0%	100.0%
2012*	93.0%	0.0%	7.0%	100.0%
2011*	83.0%	0.0%	17.0%	100.0%
2010	77.5%	0.0%	22.5%	100.0%

* no decimal places

Feedback Form Date	Stakeholder	Comment	PSE Response
10/21/20	Kyle Frankiewich, WUTC	Slide 14: The CPA was discussed in July, but the assessment itself was not shared, and the presentation did not focus much on the gas LOB. What kind of demand-side resources are evaluated? Are any demand response measures considered?	The draft report of the CPA will be ready and provided with the draft IRP in January 2021. The July webinar included a discussion of the results of the natural gas measures [see slides 57 to 64 from the slide deck for the July Webinar; Webinar 5]. There was no discussion of natural gas demand response, as there are no gas demand response programs being considered [see detailed reply below].
10/21/20	Kyle Frankiewich, WUTC	Slide 16: How many IRPs have assumed that the Tacoma LNG facility is necessary to meet the forecasted natural gas resource need in the near term? What is the current projected online date for the facility?	PSE anticipates the Tacoma LNG plant to begin commissioning and testing in late January 2021 and begin normal operation in Q1 2021. The 2017 IRP and the 2019 IRP process assumed the Tacoma LNG facility as necessary to meeting forecasted natural gas resource need for the IRP study period.
10/21/20	Kyle Frankiewich, WUTC	Slide 16: follow-up to Participant Adcock's question - How is PSE's electric LOB factored into planning for the company's gas LOB? Bill Donahue clarified that gas supply and transportation books are fully separated between the lines of business. Is the electric LOB a transportation customer in any way?	PSE will be addressing this question in the Consultation Update on November 4, 2020.
10/21/20	Kyle Frankiewich, WUTC	Slide 16: follow-up to Participant Olson's question - could PSE share the rate of voluntary cancellations of service for natural gas customers? Is there evidence of growing customer 'defection' (if that is the appropriate word) away from natural gas? Also, to echo Participant Adcock's question, we would appreciate a list of peak throughput days for each of the last winter seasons for added context in understanding the company's forecast.	PSE will be addressing this question in the Consultation Update on November 4, 2020.
10/21/20	Kyle Frankiewich, WUTC	Slide 18: While no projects were listed for the Tacoma LNG facility or the Jackson Prairie storage facility, there may be other projects that do not reach the system-level focus of this presentation which nonetheless would benefit from consideration in the IRP. What drives decision-making for potential investments in facilities used by PSE's natural gas utility function but also marketed to other wholesale customers?	Opportunities for utility scale natural gas resources are currently very limited. Option 6 on slide 18 is related to Tacoma LNG, which can be more fully utilized if distribution bottlenecks can be eliminated to allow more vaporized gas reach a wider customer base. The Jackson Prairie owners have determined that given current technology and our current understanding of the underground reservoir, further expansion of the project could cause inappropriate risk to the existing resource, so no expansion is currently proposed. The only resource that is offered (by PSE) to other parties is Tacoma LNG, and that shared use is what made the project cost-effective to PSE. The use of Tacoma LNG by Puget LNG LLC is complimentary not additive to PSE's use as a peaking resource. PSE would consider shared use of other resources if that led to lower costs for PSE customers, but none have been identified.
		Slide 20: Based on staff's current understanding (see recommendation 1), the mandate to acquire all cost-effective conservation includes PSE's transportation customers. Has PSE calculated a cost-effectiveness threshold for these customers? How is the company analyzing transportation customer potential?	PSE does not acquire any resources to provide gas or upstream capacity to serve transportation customers so there are no avoided costs to account for.
		Slide 20: All conservation must be considered in new gas CPAs. How is PSE analyzing and including conservation potential within the industrial customer class (see recommendation 4)? For clarification, what conservation offerings are currently offered to industrial customers who receive gas directly from PSE – that is, industrial customers who are not transportation-only customers?	The non-transport industrial customers are treated the same as non-transport commercial customers with respect to any conservation offerings. The non-transport customers all contribute to the conservation rider and are all eligible for conservation offerings.
		Slide n/a: This presentation did not present any distribution reinforcement projects proposed by PSE. What are PSE's thresholds for defining run-of-the-mill O&M reinforcements as compared to larger projects requiring IRP vetting? What systems are in place for distribution-level pipeline safety (San Bruno, Greenwood, Baltimore)?	Distribution system reinforcement projects are part of the distribution system planning process and are planned when minimum pressure/flow criteria are met on the system based on peak hour design day modeling. Potential solutions are then determined and run through a benefit/cost analysis to help to determine the preferred solution. These projects are typically capital projects. Similarly, most maintenance planning projects involve the replacement of an existing property unit and are therefore capital. There is not necessarily a threshold for funding the remaining O&M projects. O&M based programs may include a backlog of known projects or can be placeholders for unplanned projects for the current year. The funding level is established based on the program plan for reducing the backlog or historical trending for unplanned work. Distribution pipeline safety is governed by PSE's Distribution Integrity Management Program (DIMP). PSE currently has 34 DIMP Programs that identify and mitigate pipeline safety risk in the distribution system. Also, an annual review of the distribution system is conducted each year to identify new threats, prioritize risk, develop and implement risk reduction measures, and evaluate results and effectiveness.

Feedback Form Date	Stakeholder	Comment	PSE Response
		Slide n/a: Is DR considered in this IRP as a resource for the natural gas LOB? If I recall, DR was very briefly touched on verbally, but none of the slides discuss DR in the context of the NG LOB.	There is no natural gas DR included in the IRP. There is a DR pilot on the gas distribution system. As stated in the Webinar the gas planning in the IRP is on the gas transmission system that is upstream of the distribution system. Gas is nominated on a daily basis and thus DR which offset peak on an hourly basis on the distribution system does not impact the daily peak on the upstream system.
		Recommendation 1: Conservation, transportation customers, and HB 1257: Staff struggles to find an exclusion for gas transportation customers in the statutory language of RCW 80.28.380. We welcome any and all discussion and legal analysis that might support a conclusion one way or the other as the commission prepares to open a rulemaking on the implementation of this statute.	The purpose of the IRP is to "meet system demand with the least cost mix of natural gas supply and conservation." While RCW 80.28.380 does not include a specific exclusion for gas transportation customers, it is worth noting that PSE does not plan for the supply of natural gas commodity for gas transportation customers. Gas transportation customers procure natural gas commodity independently and separately from PSE's procurement of natural gas commodity for and on behalf of PSE's bundled gas customers. Gas transportation customers do not rely on PSE for the supply of natural gas commodity, and their rates recover the cost of the use of PSE's pipeline system to distribute the natural gas commodity they independently and separately procure from the interstate pipeline to the loads of the gas transportation customer. Additionally, these customers do not pay into PSE's energy efficiency tariff rider and, instead, independently procure their own energy efficiency services. The statutory language in RCW 80.28.380 does not appear to change this long-standing practice, which dates back to the 2002 Stipulation Agreement, Condition 38, which states that "No gas conservation program costs shall be allocated for recovery from natural gas transportation customers."
		Recommendation 2: Incorporation of social cost of greenhouse gas (SCGHG) in cost-effectiveness analysis, and HB 1257: As required by RCW 80.28.380, please provide a deeper explanation of how PSE's cost-effectiveness analysis properly includes all costs of greenhouse gas emissions established in RCW 80.28.395. PSE includes a description of the cost adders in slide 17. How does this $/MMBtu get included in the modeling? Does SENDOUT's modeling allow it to consider conservation measures compared to incremental gas consumption priced at the higher, SCGHG-inclusive $/MMBtu?	The total cost of natural gas used in PSE's modeling includes the SCGHG and the cost of upstream emissions added to the natural gas commodity price. Thus any incremental use of gas is priced at the total cost of natural gas and conservation alternatives in the model will offset this total price when selected.
		Recommendation 3: Upstream emissions – Council methodology: The NWPCC is including upstream emissions estimates for its analysis, including an estimate for US-produced natural gas that is significantly higher than the estimate PSE is using for its own modeling. Why is PSE using a different upstream emissions estimate?	PSE's estimate is based on the US EPA calculations and other studies that have been broadly accepted in the scientific community as discussed in detail in various IRP webinars. PSE and others provided significant feedback to NWPCC's methodology and their estimate was partially adjusted.
		Recommendation 4: Make CPA used for this IRP publicly available: I don't believe the company has shared the Conservation Potential Assessment for electric or gas resources. I understand that participants in the company's conservation-focused advisory group have also not yet seen the document or the underlying data. Please share this document and data (in native file format) with stakeholders by posting it on the IRP webpage, as was done for the 2019 progress report. If the company feels that the CPA should not be shared at this time, please explain why and set expectations for when stakeholders will be able to review the CPA. This would also help stakeholders understand how recent code and standard updates – for example, increasing building efficiency standards – are reflected in the modeling.	The CPA output conservation supply curve data for the gas and electric will be posted online along with this Feedback Report. The CPA draft report is not ready for posting at this time and will be submitted along with the IRP draft submittal expected in January 2021. It will include discussion of the codes and standards updates in the CPA.
		Recommendation 5: Peak day planning standard: We recommend that the company thoroughly explore the 2005 study that arrived at a peak planning standard of 52 HDD for the natural gas LOB. While we would encourage the company to refresh the study to include new resource options, contemporary climatological forecasts and new statutory requirements as applicable, we are open to the argument that the results of the study are still valid in guiding company decisions for 2020-2045. The company should defend its decision to refresh the study, or to not refresh it.	Based on stakeholder feedback we continue to review this planning standard. Any refresh of the benefit/cost study will take time to complete the market research needed to update the value of reliability to customers. There will also have to be consideration of the safety implications for revising the planning standard that will need further review. Due to these elements, it will not be feasible to update this study for the 2021 IRP, however, it is under review for update in the next IRP cycle. Our planning standard is in line with industry standards, including planning standards of the other gas utilities in the region. So while we agree to review a possible refresh, it will not be feasible for the 2020-2045 time period.

Feedback Form Date	Stakeholder	Comment	PSE Response
10/21/20	Kyle Frankiewich, WUTC	Feedback on gas sensitivities: While staff is interested in seeing the results of the sensitivities listed on slide 43, staff appreciates that there is a finite amount of analytical work that can be performed before the IRP must be filed, and that some scenarios will yield more compelling results than others. Staff has binned the sensitivities into the following three categories. Highest priority: 4, 9, 12, 13 Try to make the time: 2, 3, 7, 11 If there is time / if it is simple to do: 1, 4, 6, 8, 10	Thank you for sharing WUTC's priorities concerning gas sensitivities.
10/21/20	Robert Briggs, Vashon Climate Action Group	As someone who has been prodding PSE to take a serious look at hydrogen, I would like to help Bill Donahue in responding to James Adcock's question: "Why would you turn "Excess Electricity" into Hydrogen as opposed to Battery Storage or Pumped Hydro, or sell it to BPA for long term storage behind their dams as stored potential energy?" Batteries are great for dealing with most diurnal storage needs but are not economic for long-term storage. Similarly, hydro in the Northwest provides valuable balancing capability but not long-term storage. Aside from Grande Coulee, virtually all of the main-stem Columbia and lower Snake River dams are run-of-the-river and incapable of long-term storage. The only pumped storage capability in the system are the six pump/turbines in the Keys Plant at Grand Coulee providing just 314 MW, but again these are incapable of long-term storage. PSE should be looking at hydrogen for storage to complement batteries and pumped storage, not to compete with them. Hydrogen can provide long-term storage and meet PSE's needs for dispatchable renewable generation, obviating the need for fueling peakers with natural gas. An aggressive build-out of renewables in the Northwest will inevitably lead to surplus electricity far beyond what the region's power system currently has the capability to store. Making hydrogen can enable PSE to reduce the carbon content of the natural gas it delivers and to provide hydrogen for use as chemical feedstocks and transportation fuels. Any hydrogen PSE sells today would predominantly be displacing hydrogen that would have been manufactured from natural gas. Electrolyzers represent an ideal load for PSE to serve, as they can ramp up and down very quickly, are curtailable, and can run increasingly on zero marginal cost power that would otherwise be curtailed. According to Fortis BC, who is responding to a British Columbia mandate to decarbonize their gas system by 15% by 2030, at least 2/3 of that decarbonization will come through the introduction of renewable hydrogen into their natural gas system. Biogenic sources of methane are inadequate to meet the 15% requirement. Before the end of the decade hydrogen is expected to be flowing into the US through the Sumas hub, according to Fortis. I applaud PSE's foresight in becoming a founding member of the Renewable Hydrogen Alliance. I encourage PSE to continue looking at the role hydrogen can play in meeting decarbonization requirements for both their electric and gas IRPs.	Thank you for your comments and recommendations. As part of the electric IRP, several stakeholders have requested PSE to consider using an alternative fuel such as hydrogen for the peaker plants. The idea for the portfolio sensitivity is to turn the "excess electricity" into hydrogen so it can be used in the peaker plants for reliability instead of natural gas. PSE is currently researching this for the 2021 IRP.

Feedback Form Date	Stakeholder	Comment	PSE Response
Questions from the webinar requiring follow-up			
10/14/20	James Adcock	On a "peak coldest winter day" what percent of Puget's supplied natural gas is going to Puget's NG electric generators?	In the IRP modeling, we are only showing gas consumption for gas customers. The electric generation side has its own pipeline capacity and buys its own gas. Because PSE peak electric demand is also driven by cold temperature, the gas and electric generation demand can be coincident.
10/14/20	James Adcock	What has been you Peakest Peak Day condition in terms of actual MDth/day, in the last 10 years?	PSE will be addressing this question in the Consultation Update on November 4, 2020.
10/14/20	Fred Huette	Slide 19: the cross-BC upgrades (it's Fortis most of the way as I recall, with about 250 mmcfd/d of current capacity) has been in discussion for many years. What is the current status?	PSE's understanding is that Fortis would consider building the project if parties contract for enough capacity to justify the project. We understand that the minimum contracted volume is above 200,000 Dth/d. This project is not within PSE's control as it would require contracting by other parties in addition to any volumes requested by PSE.
10/14/20	Fred Huette	Slide 19: WIlliams/NW Pipeline declared a Deficiency Period starting Sep. 25 which is continuing and will result in "anomaly repairs" next week resulting in zero flow for several days. While this is a short term issue, to what degree is PSE including this kind of reliability risk in long term planning? http://northwest.williams.com/NWP_Portal/operations.action	PSE relies on 100% of Northwest Pipeline (NWP) availability to meet a design peak day. The type of Deficiency Period and the occurrence of anomaly repairs is not uncommon for any pipeline (and indicates that the pipeline is fulfilling its maintenance obligations) and all pipelines plan and undertake this work in off-peak periods when shippers can use other pipeline capacity. PSE has maintained a very flexible portfolio of resources that allows it to manage around the periodic disruptions.
10/14/20	Srirup Kumar	Thank you. Following-on, would modular anaerobic digesters be eligible for conservation incentives offered to industrial, institutional and commercial clients?	There could be incentives if the particular technology results in energy savings AND those savings are cost effective. More information on incentives for specific projects can be found here: https://www.pse.com/rebates/business-incentives/commercial-retrofit-grants

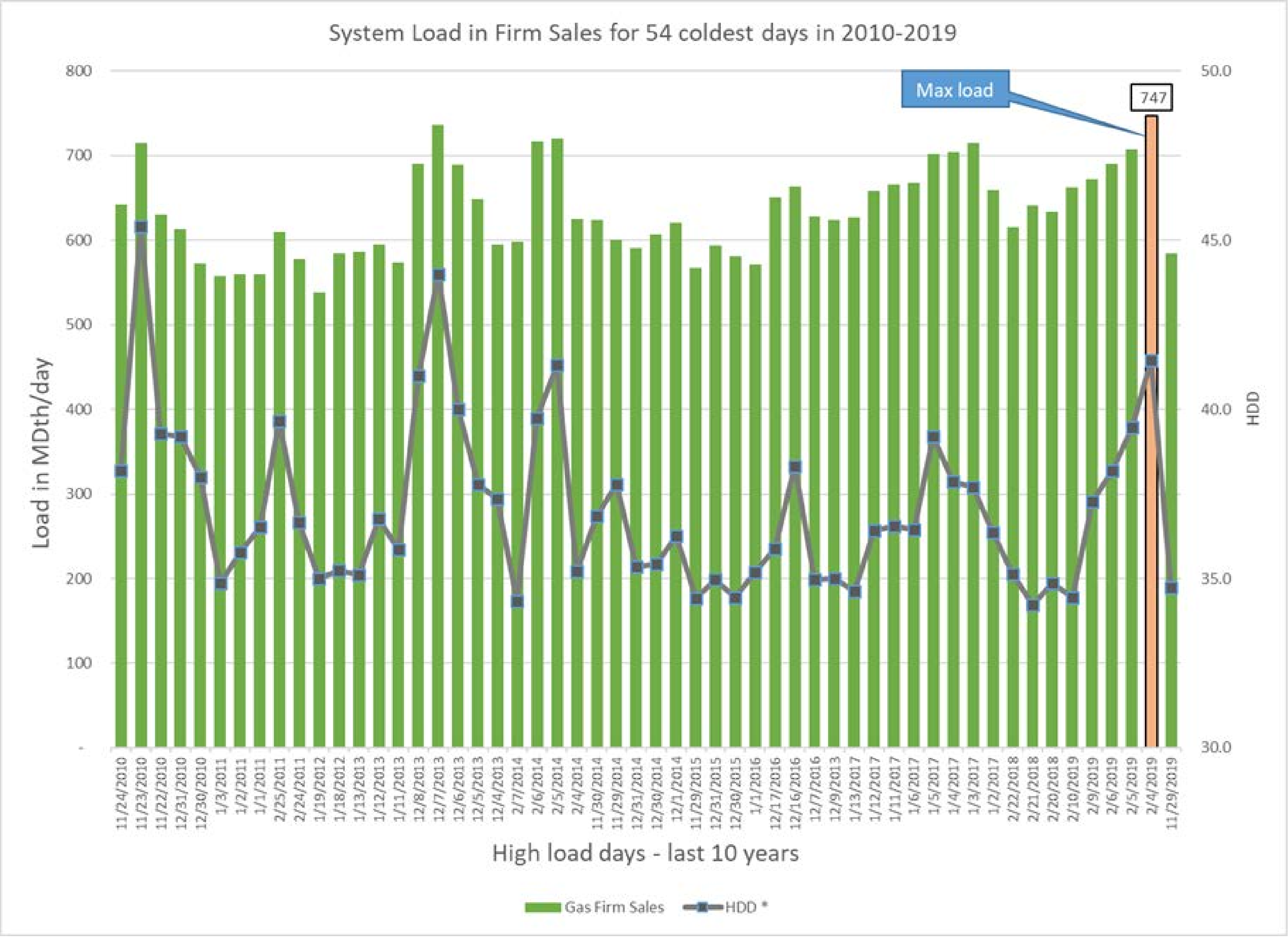
PSE IRP Consultation Update
Webinar 8: Natural Gas IRP
October 14, 2020

11/04/2020

The following consultation update is the result of stakeholder suggestions gathered through an online Feedback Form, collected between October 7 and October 21, 2020 and summarized in the October 28 Feedback Report. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

Temperature Sensitivities, planning standard and recent peak load data

PSE received a request to share the most recent 10 years of peak day load experienced by the gas system. The graph below includes the highest load days over the last 10 years along with the gas system load and associated HDD.



Natural gas for electric versus gas sales

PSE received feedback from Kyle Frankiewich (WUTC staff) as to how much of the electric line of business (LOB) is factored into the company's gas LOB, and whether the electric LOB is a gas transportation customer.

All of PSE gas-fired generation is connected directly to an upstream pipeline (either Northwest or Westcoast) or to Cascade Natural Gas Co. distribution system. Because the gas-fired generation and gas distribution system can have simultaneous peak design conditions, there is no opportunity for shared design day resources. The only opportunity for synergy between the two lines of business is that generation can utilize unused gas LOB pipeline or storage capacity in the low demand summer months (with compensation at fair-market value). In addition, the gas system can rely on the power generaton fleet to curtail gas generation use (and rely on power market supply instead) in an emergency pipeline failure event (e.g.: Enbridge/Westcoast event) in order to maintain pressure in the pipeline.

Gas customer defections

PSE received feedback from Court Olson and Kyle Frankiewich (WUTC) asking if PSE could share the rate of voluntary cancellations of service for natural gas customers and if there was evidence of "defection" away from natural gas service.

PSE has not seen evidence of customer defection. Our most recent 10K shows natural gas customer counts growing over the past there years. Relevant table from the 10K for the fiscal year ending December 31, 2019 (page 19) is provided below:

	Year Ended December 31,		
	2019	2018	2017
Natural gas operating revenue by classes (Dollars in Thousands):			
Residential	$ 613,617	$ 598,923	$ 686,438
Commercial firm	218,302	219,390	251,584
Industrial firm	15,698	17,247	20,077
Interruptible	18,381	21,113	24,317
Total retail natural gas sales	865,998	856,673	982,416
Transportation services	20,283	19,984	21,718
Decoupling revenue	2,296	6,115	3,522
Other decoupling revenue[1]	(29,737)	(37,022)	(22,862)
Other	16,531	4,998	12,965
Total natural gas operating revenue	$ 875,371	$ 850,748	$ 997,759
Number of customers served (average):			
Residential	782,413	772,130	761,010
Commercial firm	56,113	55,716	55,372
Industrial firm	2,304	2,308	2,330
Interruptible	367	393	398
Transportation	230	234	226
Total customers	841,427	830,781	819,336
Natural gas volumes, therms (thousands):			
Residential	605,313	571,265	621,915
Commercial firm	277,639	264,775	279,656
Industrial firm	22,915	23,890	25,500
Interruptible	45,176	47,275	49,249
Total retail natural gas volumes, therms	951,043	907,205	976,320
Transportation volumes	227,657	230,735	236,578
Total volumes	1,178,700	1,137,940	1,212,898

Natural gas conservation potential assessment (CPA)

PSE received feedback from Kyle Frankiewich (WUTC staff) concerning the the release of the draft CPA report and underlying CPA data for the natural gas IRP.

The draft CPA report will be included with the draft IRP filing on January 4, 2021. The CPA data used in the natural gas IRP is posted along with the Consultation Update in native file format as requested (MS Excel). The file is available on the IRP website.

Natural gas sensitivities

PSE received feedback from several stakeholders on their preferences for the natural gas sensitivities. These along with the response to the sensitivity survey from Webinar 9 will be used to develop the list of sensitivities.

Summary of all updates

PSE appreciates the feedback provided by stakeholders. In summary, the following changes will be implemented:

- PSE will post CPA data files on www.pse.com/irp and provide the draft CPA report as part of the 2021 IRP draft available on January 4, 2021.
- Based on the stakeholder feedback, PSE will analyze the following sensitivities for the natural gas IRP:

  21 - Use AR5 to model upstream emissions
  14 - 6-yr ramp rate
  17 - Social discount rate for DSR
  42 - Equity-focused portfolio

- PSE has also tentatively included the sensitivity number 16 titled Non-Energy Impacts in the list of ‘must-run’ sensitivities. The list of ‘must-run’ sensitivities for the Gas Portfolio is as follows:

  1 – Mid Economic Conditions
  2 – Low Economic Conditions
  3 – High Economic Conditions
  12 – Fuel Switching form gas to electric
  16 – Non-Energy Impacts
  31 – Temperature sensitivity on load

Webinar 9, October 20, 2020

Electric Portfolio Modeling Process, Final Electric Power Prices, Electric Sensitivities, Inputs and Observations from Draft Results

Webinar #9: Electric IRP
October 20, 2020 from 1:00 p.m. to 4:30 p.m. PST

Virtual webinar link: https://global.gotomeeting.com/join/172534125
Access code: 172-534-125
Call-in telephone number (audio only): +1 (224) 501-3412

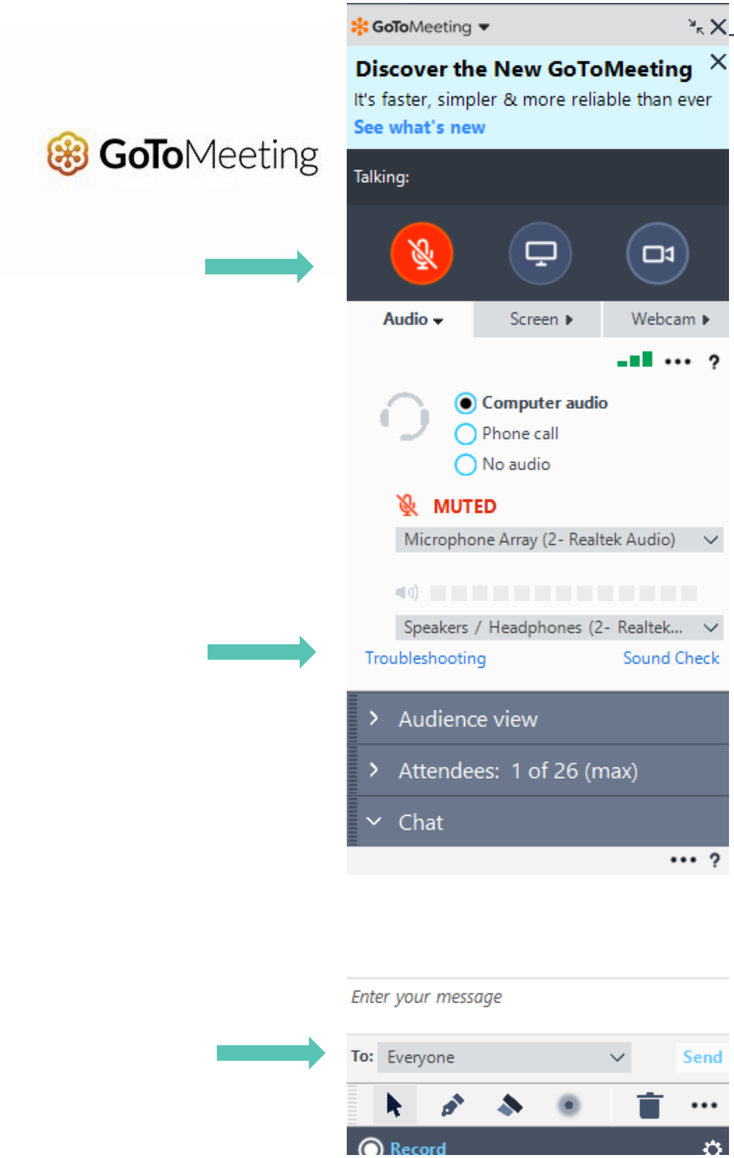
Topic	Lead
Welcome • Agenda review • Safety moment • How to participate • Speaker introductions	EnviroIssues
Electric IRP Process Portfolio Model Final Resource adequacy analysis Final Resource need	Elizabeth Hossner Manager Resource Planning & Analysis, PSE Zhi Chen Senior Resource Planning Analyst, PSE Jennifer Magat Senior Resource Planning Analyst, PSE
5-minute break	
Electric IRP Process continued Final electric price forecast Planning assumptions Resource Alternatives	Charles Inman Associate Resource Planning Analyst, PSE Tyler Tobin Resource Planning Analyst, PSE Elizabeth Hossner Manager Resource Planning & Analysis, PSE
5-minute break	
Electric Portfolio Sensitivities Temperature sensitivity	Elizabeth Hossner Manager Resource Planning & Analysis, PSE Eric Fox Director Forecast Solutions, Itron Allison Jacobs Senior Economic Forecast Analyst, PSE
Wrap up and next steps • Next steps • Upcoming meeting schedule • Thank you's	EnviroIssues

2021 IRP Webinar #9: Electric IRP

Analyze Alternatives & Portfolios
Electric Portfolio Model

October 20, 2020

Welcome to the webinar and thank you for participating!



Virtual webinar link: https://global.gotomeeting.com/join/172534125

Access Code: 172-534-125

Call-in telephone number: +1 (224) 501-3412

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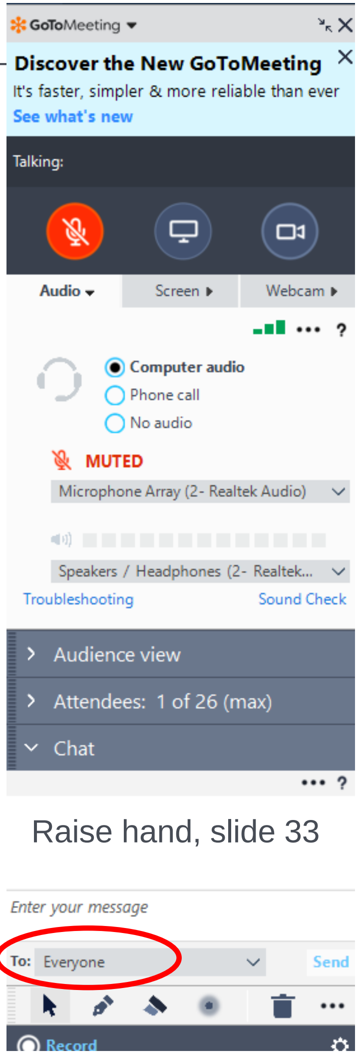
- Mute your mic during the presentation
- You can participate in writing or verbally using the chat window
    - **In writing:** your question will be read
    - **Verbally:** type "Raise hand" and slide #, share with "Everyone"; please wait to be called on to ask your question
- Be considerate of others waiting to participate
- We will try to get to all questions



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Agenda

- Safety moment
- Electric portfolio model
- Electric IRP Process
  - Resource need
  - Planning Assumptions
- Portfolio sensitivities
  - Temperature sensitivity

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Safety Moment: Emergency preparedness

1. Get a kit – Learn the essential supplies to put in your family's survival kit.

2. Make a plan – Plan effectively for you and your family in case of an emergency.

3. Be informed – Understand which disasters are likely to occur in your area and what you must know to stay safe.

Today's Speakers

Elizabeth Hossner
Manager Resource Planning & Analysis, PSE

Zhi Chen
Senior Resource Planning Analyst, PSE

Jennifer Magat
Senior Resource Planning Analyst, PSE

Tyler Tobin
Resource Planning Analyst, PSE

Charles Inman
Associate Resource Planning Analyst, PSE

Alison Peters & Elise Johnson
Co-facilitators, EnviroIssues

Allison Jacobs
Senior Economic Forecast Analyst, PSE

Eric Fox
Director Forecast Solutions, Itron

IRP data available on the website

- Generic resource costs
  - https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/May_28_Webinar/Generic_Resource_Cost_Summary_PSE%202021%20IRP_post-feedback_v1.xlsx
- Demand Side Resources
  - https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/July_14_webinar/Webinar_4_Demand-Side-Resources_Presentation.pdf
- Social cost of greenhouse gases
  - https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/July_21_webinar/Emission_Price_Calculations_workbook_2019_(Inflation-Update).xls
- Demand forecast
  - https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/September_1_meeting/PSE_2021_IRP_Demand_Forecast_2022-2045_09012020.xlsx

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IRP data available on the website

- List of portfolio sensitivities
  - https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/Oct_20_webinar/Webinar%209%20Updated%20sensitivities%20list.xlsx
- Electric price forecasts
  - https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/June_10_Webinar/Webinar_2_Electric-Price-Forecast_presentation.pdf
  - https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/Oct_20_webinar/Webinar%209:%20Final%20electric%20power%20prices.xlsx
- Upstream GHG Emissions
  - https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/July_21_webinar/Attachment_7_Upsteam_Methane_Emission_Workbook.xlsx
- Transmission Constraints Presentation
  - https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/June_30_webinar/Webinar_3_Transmission_Constraints_presentation.pdf

PUGET SOUND ENERGY

Electric portfolio model

Participation Objectives

- PSE will inform stakeholders on the electric portfolio model

IAP2 level of participation: INFORM

IRP electric portfolio model process

Inputs

- Variable operations & Maintenance (VOM)
- Fixed operations & Maintenance (FOM)
- Plant operating characteristics
- capital costs
- PSE monthly load forecast
- hourly load shape
- Normal Peak Load
- Planning Margin (peak need)
- Peak capacity credit (ELCC)
- Renewable need
- Transmission constraints
- Decommissioning cost for existing resources
- Flexibility Benefit

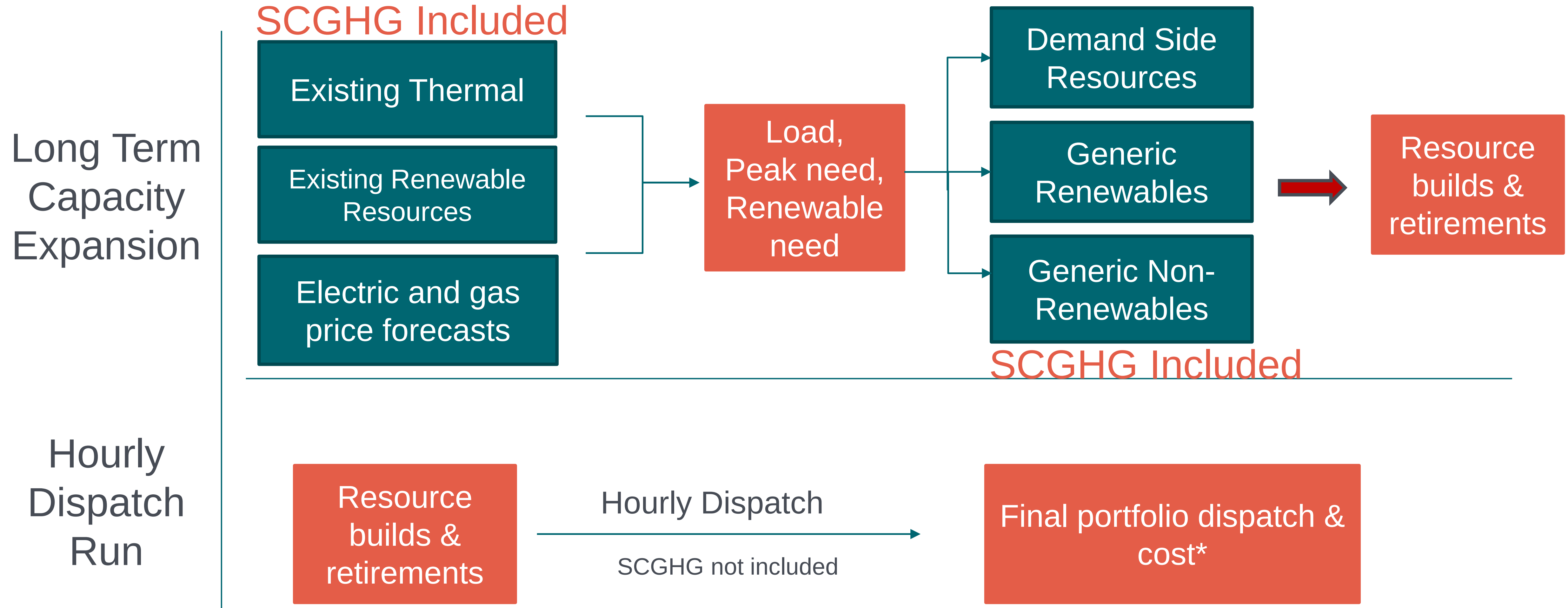
Social cost of carbon added to existing and new thermal resources and market purchases as a cost adder

Mid-C power prices → Long term capacity expansion for PSE only → **New builds and retirements** → Hourly dispatch for PSE only → **Portfolio dispatch & cost**

AURORA

AURORA

SCGHG as a cost adder in AURORA



*Note: the final portfolio cost will include with and without SCGHG

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The Long Term Capacity Expansion model (LTCE)

- As the population grows, and energy demand with it, utilities must increase their generating capacity in order to keep pace with the growth.

- A Long Term Capacity Expansion (LTCE) model is used to forecast the installation and retirement of resources over a long-term planning horizon in order to keep pace with growth.

- To complete the LTCE modeling process, PSE uses a program called AURORA
  - AURORA is an algebraic solver software provided by Energy Exemplar, and is an industry-standard tool used to perform power system models.
  - The AURORA solver uses a *Mixed Integer Programming (MIP)* method to complete the modeling process.

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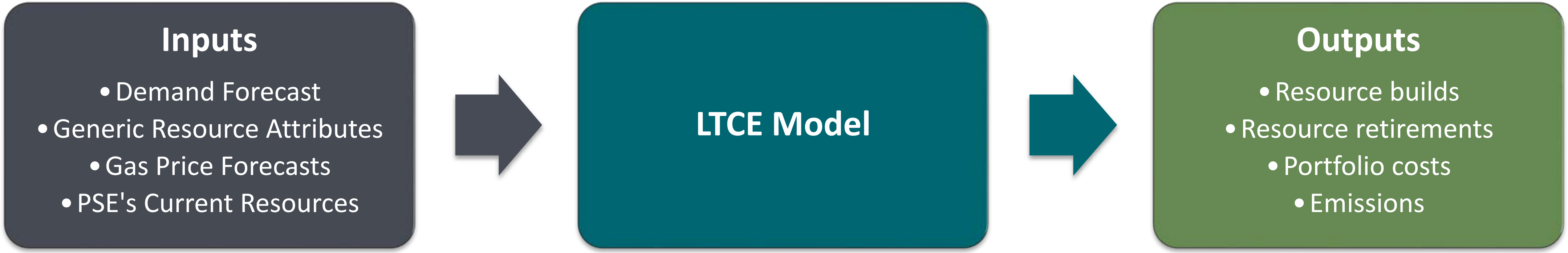
LTCE Inputs and Outputs

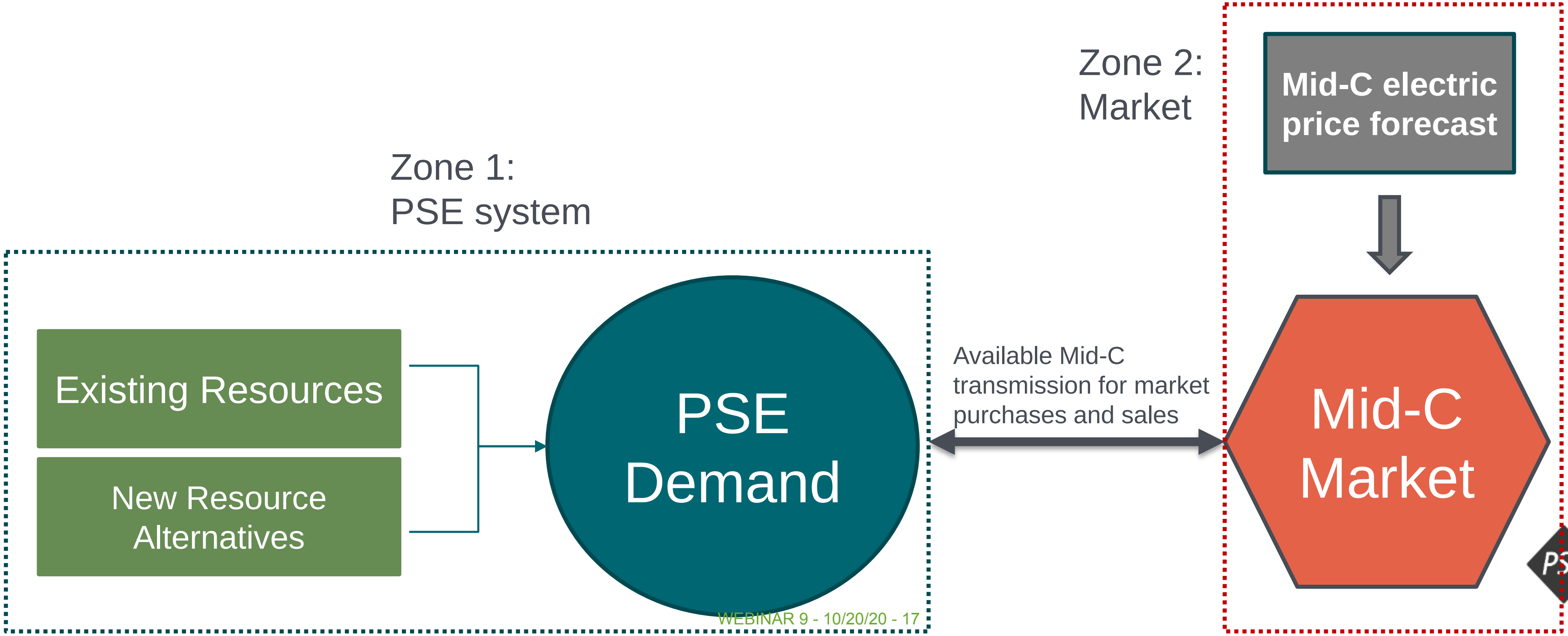


- The LTCE model uses data inputs from internal PSE sources (the load forecast, current resources) as well as external sources (generic resource costs, gas price forecasts)

- These inputs are entered into the LTCE model in order to simulate potential resource additions and retirements, as well as portfolio costs.

LTCE – system diagram

- PSE models a 2-zone system in the AURORA LTCE model
- The 2-zone system allows the limitation of the Mid-C market to available transmission
- All resources are located in the PSE zone to make sure they dispatch to PSE demand



LTCE Model – Mixed Integer Programming

- In order to solve the complex power system models, AURORA employs **Mixed Integer Programming** (MIP).

- MIP solving methods are a combination of Linear Programming and Integer Programming methods.
    - Linear Programming – The optimization of an objective function that is subject to certain constraints.
    - Integer Programming – The optimization of an objective function where some of the values are restricted as integer values (-1, 0, 1, 2, etc.)

- MIP methods are the best suited to handling power system and utility models, as the decisions and restraints faced by utilities are both discrete (how many resources to build, resource lifetimes, how those resources connect to one another) and non-discrete (the costs of resources, renewable profiles, emissions limitations).

Optimization modeling – objective function

The objective is formulated as the total net present value (NPV) of the production, fixed, and build costs to meet all of the requirements.

- The MIP will search to find the mix of resources (both existing and new build/retrofit options) over time that satisfies all energy and demand requirements while minimizing the total NPV.
- The solver uses an iterative simulation process until the total portfolio costs converge.

Optimization Modeling – resource value

- Aurora determines resource value from the difference between market price and resource cost. This determination is performed for every hour for every resource in the region. Thus, a very accurate value is developed which takes into account system value during all time periods (i.e., on-peak, off-peak and other hours; and during daily, seasonal, and annual periods)

Total resource cost = the present value (PV) of resource costs over the life of the plant (n) – market revenue (market price at time of generation)

$$Resource\ value = \sum_{t=1}^{n}(capital\ cost_t + fixed\ cost_t + variable\ cost_t + fuel\ cost_t + transmission\ cost_t\ ) - Market\ Revenue_t$$

PUGET SOUND ENERGY

LTCE model constraints

- In order to accurately represent the PSE service territory and resource additions, **constraints** must be placed on the model to produce a reasonable output.

- Multiple constraints are placed on the model in order to make the system behave as closely as possible to PSE:

Constraint Type	Purpose
Resource Characteristics	Forces resources to behave as they would in reality
Transmission Limits	Limits Mid-C market purchases based on real conditions
Demand Forecast (Energy need)	Shows the model the demand profile it must meet
Resource Adequacy (Peak Need)	Ensures that the final portfolio meets RA standards
Renewable Requirement	Forces the model to be CETA and RPS compliant

PUGET SOUND ENERGY

SCGHG in the LTCE model – Fixed Cost Adder

PSE will be using the SCGHG as a **Fixed Cost Adder** as a baseline in the modeling process.

- When considering a resource to build, an economic forecast of the resource is performed.
- The total emissions generated by the resource in the forecast are summed together, and the SCGHG is applied to that total.
- The SCGHG penalties generated by that resource are factored in as a fixed cost over the life of that resource before a build decision is made.

$$Resource\ value = \sum_{t=1}^{n} (capital\ cost_t + fixed\ cost_t + variable\ cost_t + fuel\ cost_t + transmission\ cost_t\ ) - Market\ Revenue_t$$

PUGET SOUND ENERGY

Electric IRP process

Participation Objectives

- PSE will inform stakeholders on the IRP process
    - Final resource adequacy analysis
    - Final resource need
    - Final planning assumptions

IAP2 level of participation: INFORM

2021 IRP modeling process

The 2021 IRP will follow a 6-step process for analysis:

1. Analyze and establish resource need
2. Determine planning assumptions and identify resource alternatives
3. Analyze scenarios and sensitivities using deterministic and stochastic risk analysis
4. Analyze results
5. Develop resource plan
6. 10-year Clean Energy Action Plan

1 Establish Resource Needs

Three types of resource need are identified:

1. Peak capacity need
   - Physical peak need refers to the resources required to ensure reliable operation of the system. It is an operational requirement that includes three components: customer peak demand (demand forecast), planning margins (LOLP modeling) and operating reserves.

2. Renewable need
   - Washington State's Clean Energy Transformation Act (CETA) requires PSE to meet specific percentages of our load with renewable resources or renewable energy credits (RECs) by specific dates.

3. Energy need
   - Energy need refers to the resources required to meet customer demand in every hour. How the demand is met changes by scenario and is dependent on how resources are dispatched versus buying on the market.

1 Establish Resource Needs

Resource Adequacy Analysis

Electric peak capacity need: 2027

881 MW resource need for 5% LOLP

Reliability metrics at 5% LOLP:

Metric Name	Base System, No Added Resources	System at 5% LOLP, 881 MW Added
LOLP	63.60%	4.99%
EUE	4533 MWh	381 MWh
LOLH	11.06 hours/year	0.76 hours/year
LOLE	2.18 days/year	0.12 days/year
LOLEV	2.93 events/year	0.14 events/year

1 Establish Resource Needs

Resource Adequacy Analysis

Electric peak capacity need: 2031

1,361 MW resource need for 5% LOLP

Reliability metrics at 5% LOLP:

Metric Name	Base System, No Added Resources	System at 5% LOLP, 1361 MW Added
LOLP	97.09%	5.00%
EUE	16335 MWh	372 MWh
LOLH	43.42 hours/year	0.79 hours/year
LOLE	9.65 days/year	0.12 days/year
LOLEV	11.99 events/year	0.17 events/year

1 Establish Resource Needs

Resource Adequacy Analysis

Effective Load Carrying Capability (ELCC) for 5% LOLP relative to Perfect Capacity

ELCC = $-(\text{Need}_2 - \text{Need}_1)$/Change

Example:
Base case, Need1 = 500 MW
Add 100 MW nameplate renewable
Need2 = 475 MW
ELCC = –(475 MW – 500 MW)/100 MW = 25%

Resource	IRP 2019 Process ELCC	IRP 2021 ELCC 2027	IRP 2021 ELCC 2031
Existing Wind	10%	16%	16%
Green Direct – WA West Wind	36%	37%	34%
Green Direct – WA East Solar	2%	9%	8%

1 Establish Resource Needs

Resource Adequacy Analysis

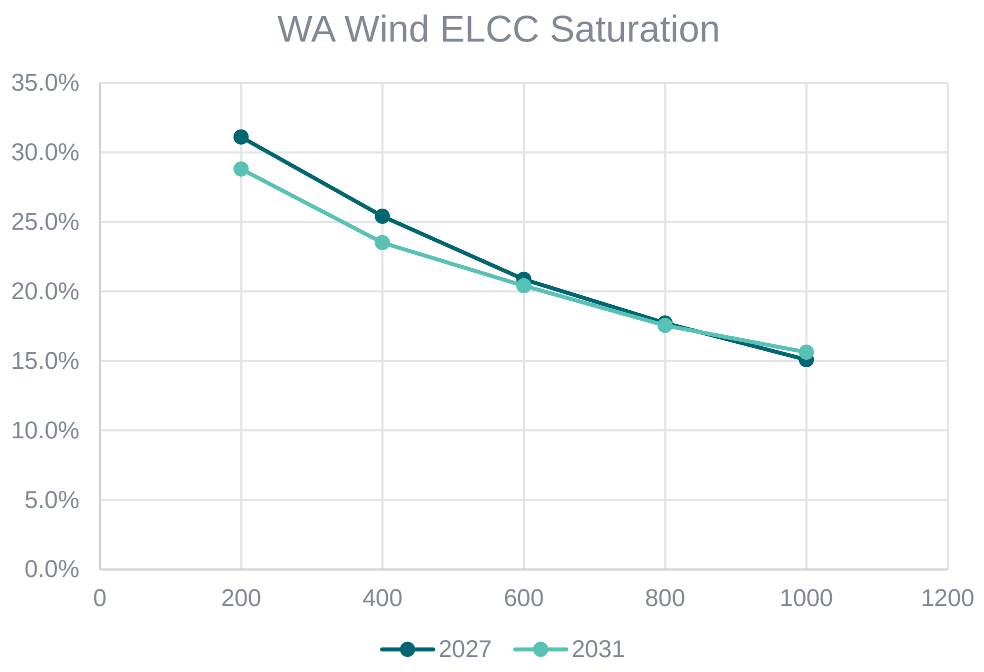
Effective Load Carrying Capability (ELCC) for 5% LOLP relative to Perfect Capacity

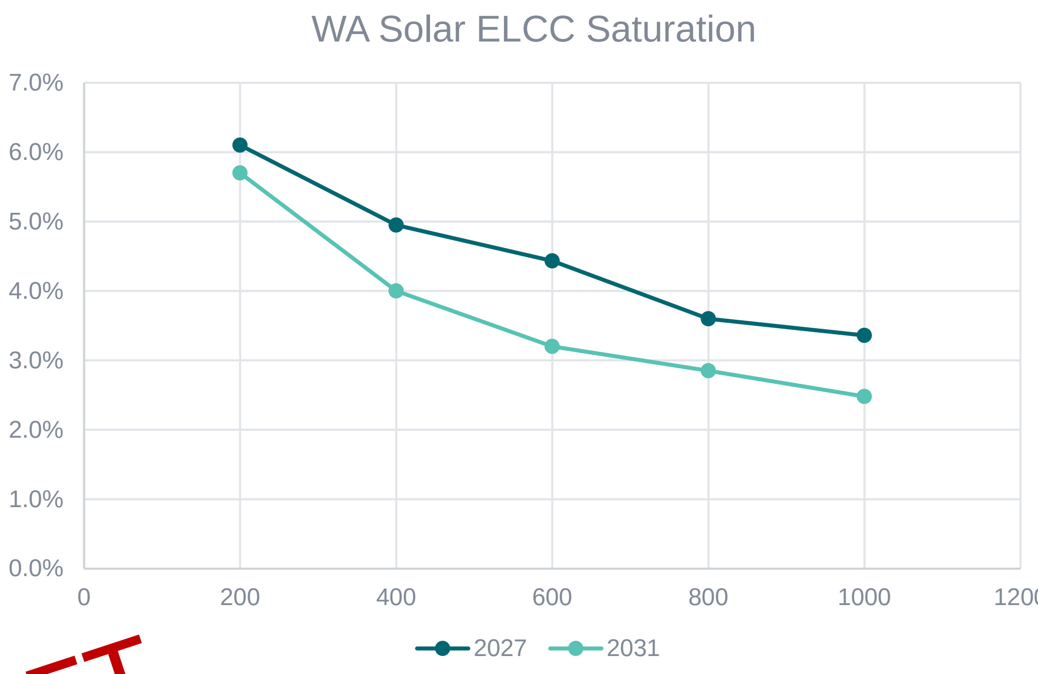
Resource	2019 IRP Process ELCC	IRP 2021 ELCC 2027	IRP 2021 ELCC 2031
Generic WY-East Wind	-	57%	57%
Generic WY-West Wind	-	22%	22%
Generic MT-East Wind	42%	33%	34%
Generic MT-Central Wind	-	46%	44%
Generic Offshore Wind	48%	43%	47%
Generic ID Wind	-	26%	25%
Generic WA Wind	6%	17%	17%
Generic WY-East Solar	-	9%	11%
Generic WY-West Solar	-	10%	10%
Generic ID Solar	-	6%	10%
Generic WA-East Solar	1%	7%	7%

1 Establish Resource Needs

Resource Adequacy Analysis

Effective Load Carrying Capability (ELCC) for 5% LOLP relative to Perfect Capacity





DRAFT

1 Establish Resource Needs

Resource Adequacy Analysis

Effective Load Carrying Capability (ELCC) for 5% LOLP relative to Perfect Capacity

Energy Limited Resource	IRP 2019 ELCC EUE at 5% LOLP	IRP 2021 ELCC 2027 EUE at 5% LOLP	IRP 2021 ELCC 2031 EUE at 5% LOLP
Lithium-Ion Battery 2 hr, 82% RT efficiency	19%	13%	16%
Lithium-Ion Battery 4 hr, 87% RT efficiency	38%	28%	34%
Flow Battery 4 hr, 73% RT efficiency	36%	24%	31%
Flow Battery 6 hr, 73% RT efficiency	46%	32%	40%
Pumped Hydro Storage 8 hr, 80% RT efficiency	37%	27%	32%

DRAFT

1 Establish Resource Needs

Planning Margin (expressed as percent) is determined as:

Planning Margin = (Peak Need – Normal Peak Load) / Normal Peak Load

Where Peak Need (in MW) is the resource capacity that meets the reliability standard established in a probabilistic resource adequacy model (Peak Capacity Need from LOLP) in addition to the peak capacity contribution from existing resources (Total Resources) and short-term Mid-C bilateral market purchases.

	Winter Peak 2027	**Winter Peak 2031**
Peak Capacity Need to meet 5% LOLP	881 MW	1,361 MW
Total Resources Peak Capacity Contribution	3,650 MW	3,641 MW
Short-term Market Purchases	1,492 MW	1,497 MW
Peak Need	5,983 MW	6,459 MW
Normal Peak Load	4,949 MW	5,199 MW
Planning Margin	**21.7%**	**25.0%**

Note: planning margin includes contingency and balancing reserves

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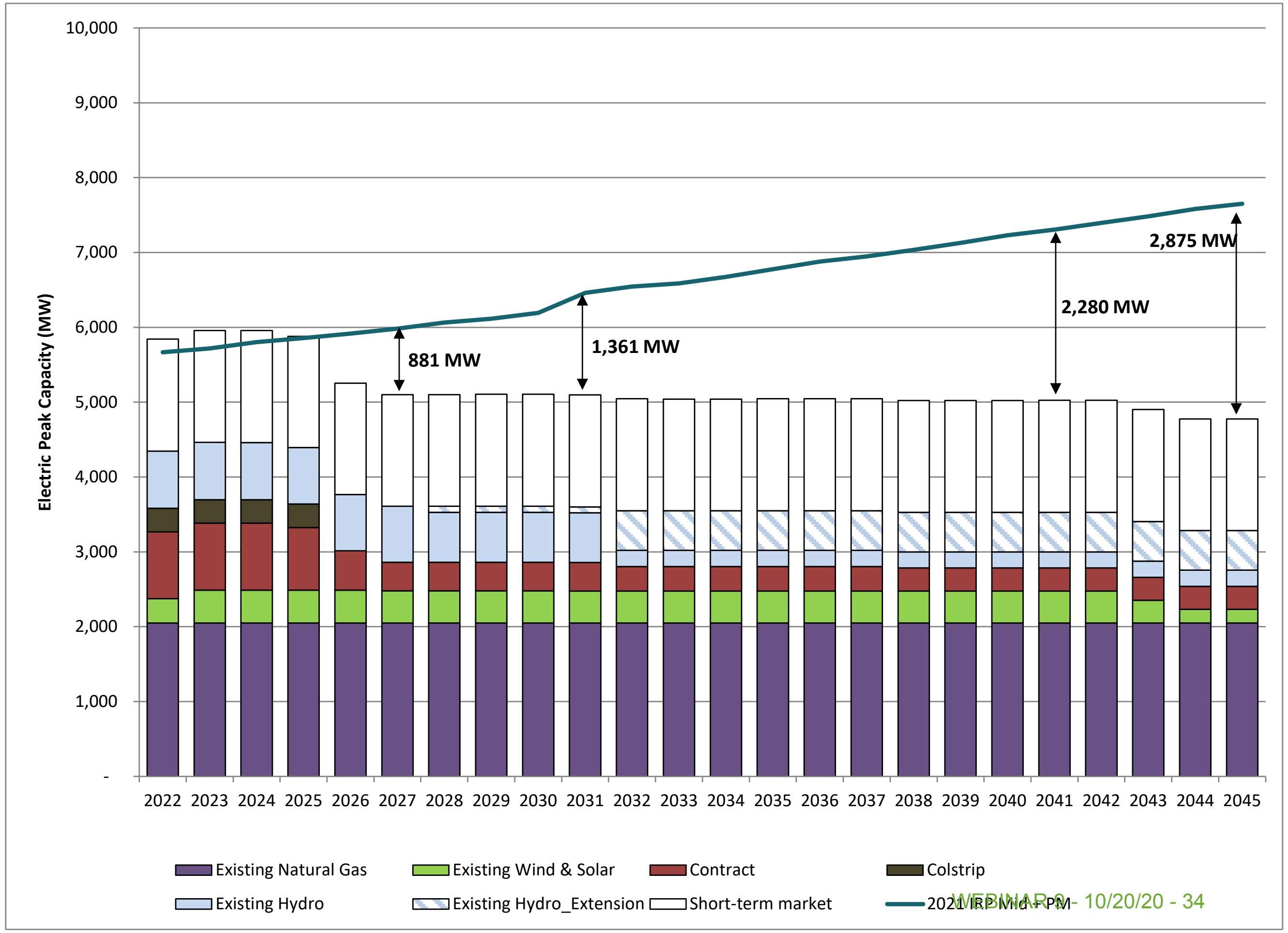
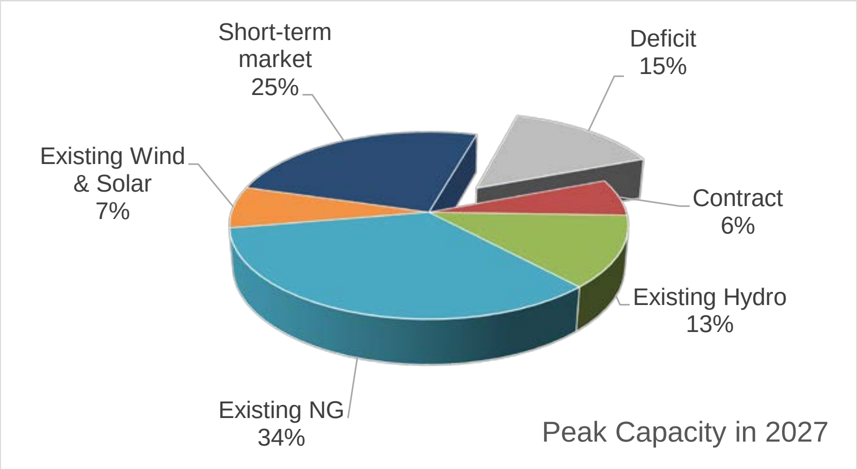
Establish Resource Needs

Electric peak hour capacity resource need

Projected peak hour need and effective capacity of existing resources.





Note: 2021 IRP peak capacity need does not include any demand side resources. Demand side resources will be determined as part of the 2021 IRP and include conservation (energy efficiency), codes and standards, distribution efficiency, or demand response.

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1 Establish Resource Needs

Electric renewable need

PSE's estimated need for non-emitting or renewable energy by 2030

	MWh
2030 estimated sales before conservation	24,004,160
Conservation*: codes and standards, solar PV	(774,387)
Customer programs *Green Power, Green Direct	(849,644)
Estimated sales net of conservation and customer programs	20,800,505
80% of estimated sales net of conservation	16,640,404
Existing non-emitting resources *Assume normal hydro conditions and P50 wind & solar	(8,390,019)
Need for new non-emitting resources	8,250,385

*Note: 2021 IRP renewable need does not include any new energy efficiency. Cost effective energy efficiency will be determined as part of the 2021 IRP. Since codes and standards and solar PV are must take bundles, they have been included in the base calculation to get the net renewable need.

After existing resources, PSE still needs over 8.2 million MWh of new non-emitting resources or demand-side resources to get to at least 80% of electric sales.

1 Establish Resource Needs

Electric renewable need

This example is for illustrative purposes only. The 2021 IRP will optimize the mix of resources with conservation.

For example a 100 MW renewable resource such as wind at 30% capacity factor will produce 100*8760*0.30 = 262,800 MWh/year.

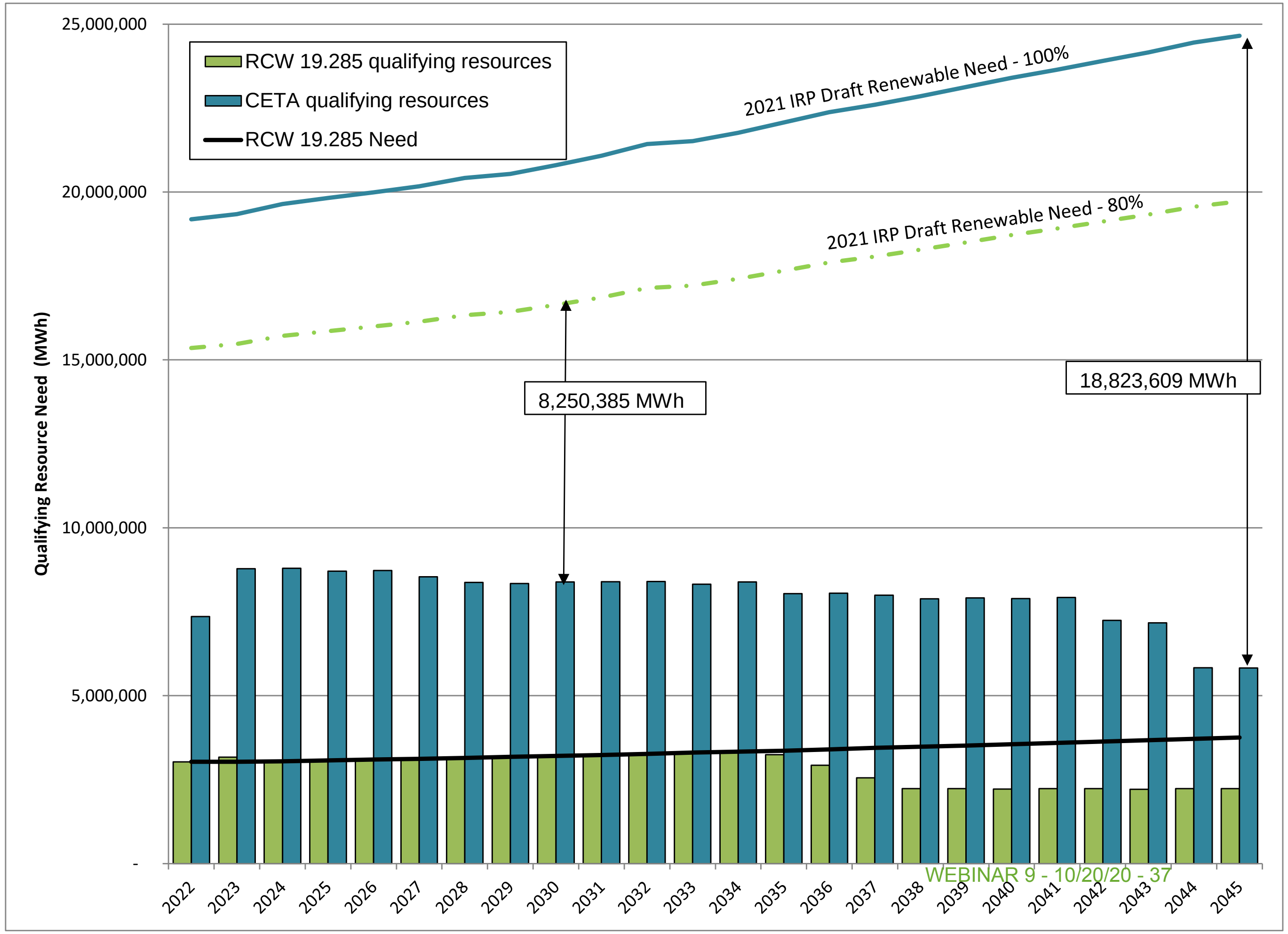
- In order to produce 8,250,385 MWh/year with a 30% capacity factor resource, we would need 3,139 MW nameplate.
- This is an additional 3,139 MW on top of the current 2,363 MW of existing non-emitting resources.

Annual Capacity Factor	MWh/year for 100 MW	MWh target at 80%	Nameplate (MW) Needed
30%	262,800	8,250,385	3,139
44%	385,440	8,250,385	2,140
27%	236,520	8,250,385	3,488
12%	105,120	8,250,385	7,848

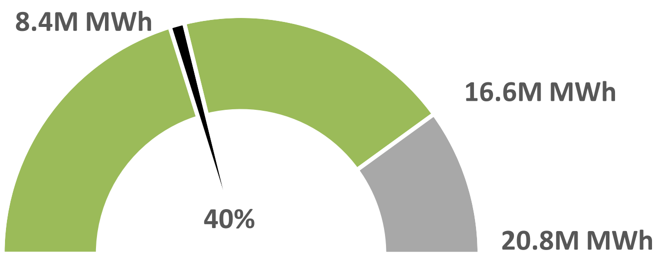
1 Establish Resource Needs

Electric renewable need

Renewable resource need/REC need for RCW 19.285 and CETA



CETA Eligible Resources for 2030 Target



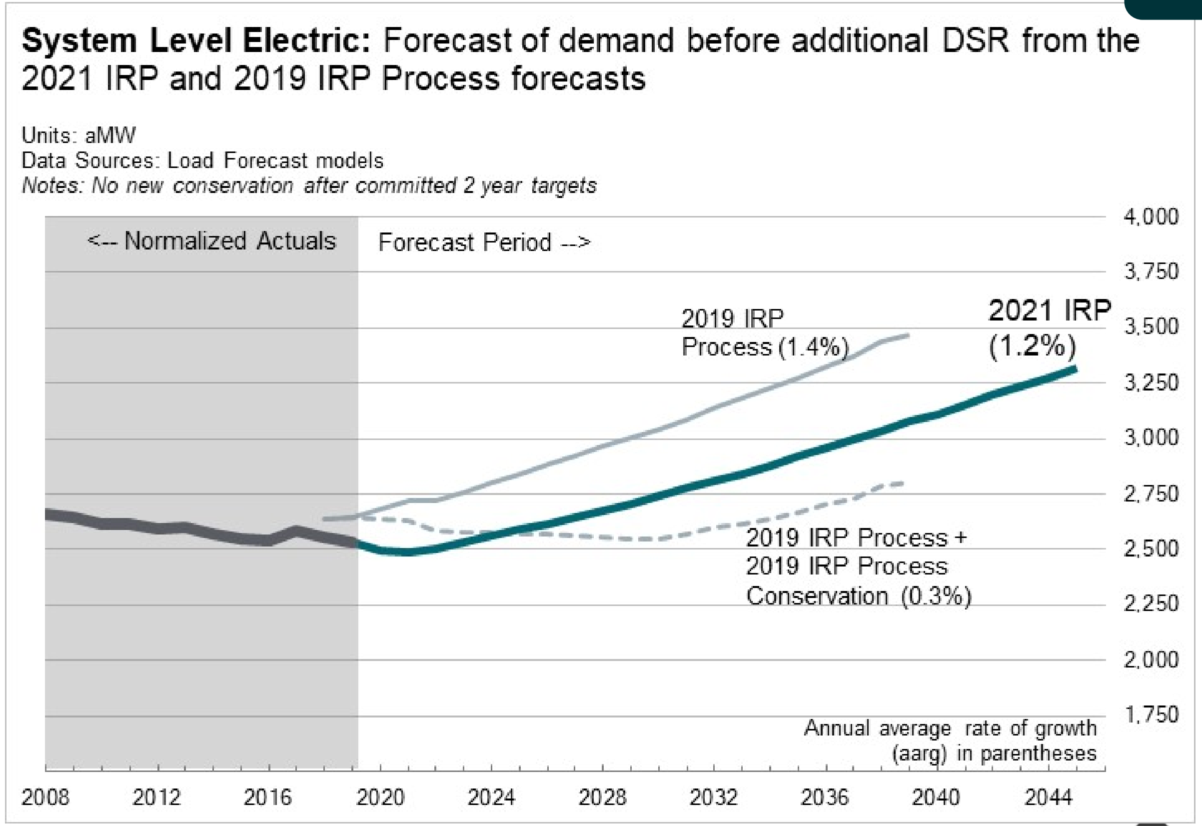
Note: 2021 IRP renewable need does not include any demand side resources. Demand side resources will be determined as part of the 2021 IRP and include conservation (energy efficiency), codes and standards, distribution efficiency, or demand response.

PSE PUGET SOUND ENERGY

Establish Resource Needs

Electric energy need: presented on September 1, 2020

- Positive customer growth, steady UPC, and EVs yield demand growth, before DSR.
  - Applying DSR will result in an "after DSR" forecast with lower growth than "before DSR."
- Conservation targets for 2020/21 decreases load materially (standard IRP methodology, ~50% of initial 2022 forecast change).
- Lower growth than 2019 IRP process forecast due to:
  - Lower customer growth (commercial significantly).
  - Lower UPC forecast (all non-residential).
- The 2021 IRP demand forecast after DSR will be available once final DSR determined by the 2021 IRP process.



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5-minute break

2 Planning assumptions and resource alternatives

This category encompasses everything needed to run the portfolio analysis

Electric price forecast

Natural gas price forecast

Social Cost of Greenhouse Gases

New resource alternatives

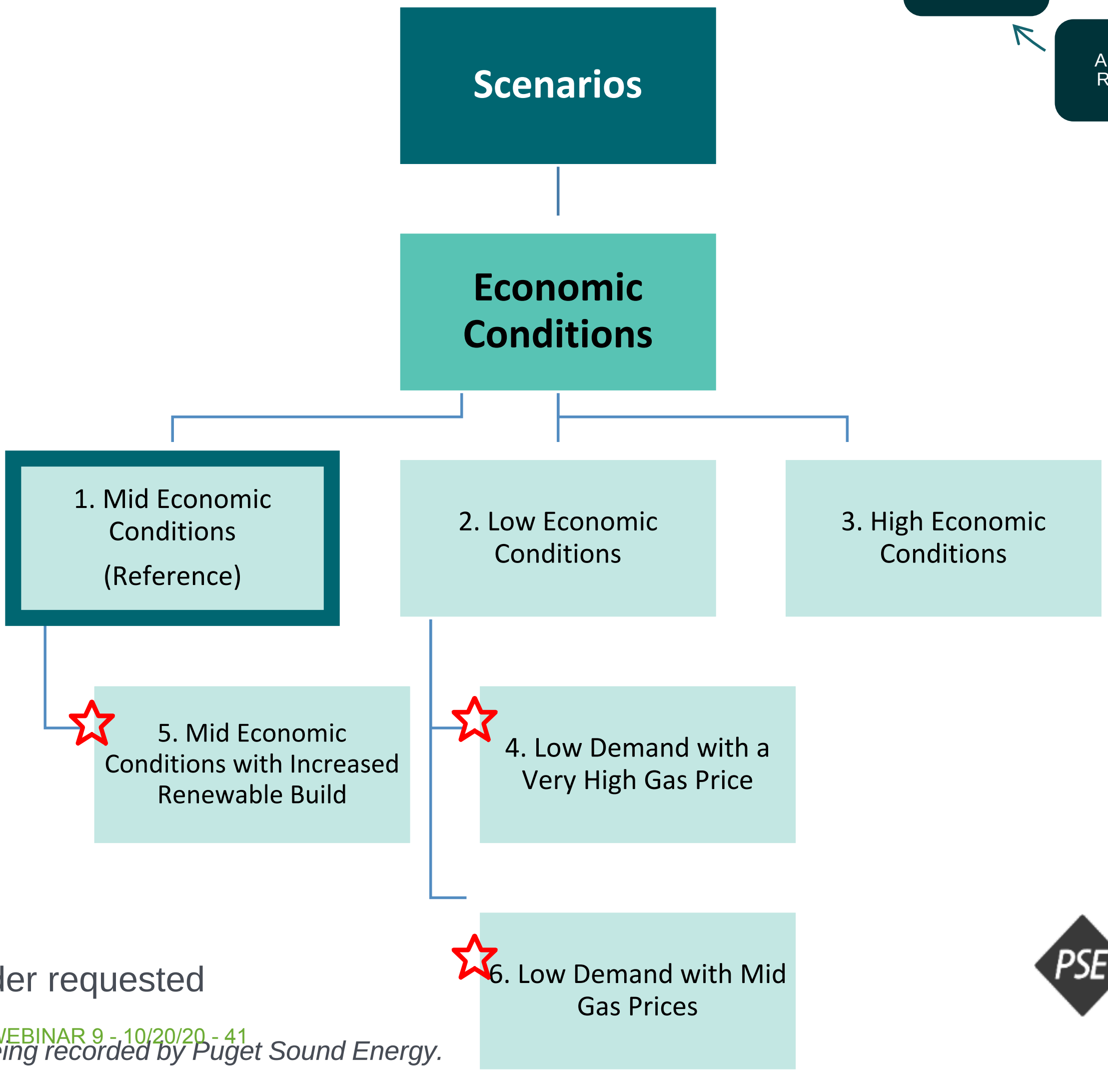
Transmission constraints

Flexibility benefit

❷ Planning assumptions and resource alternatives

Electric price scenarios

- Gas prices, carbon regulation and regional loads create different wholesale electric prices, which affect the relative value of different resources.
  - Electric price **scenarios** create future market conditions
  - **Sensitivities** test different PSE portfolio resources in the market

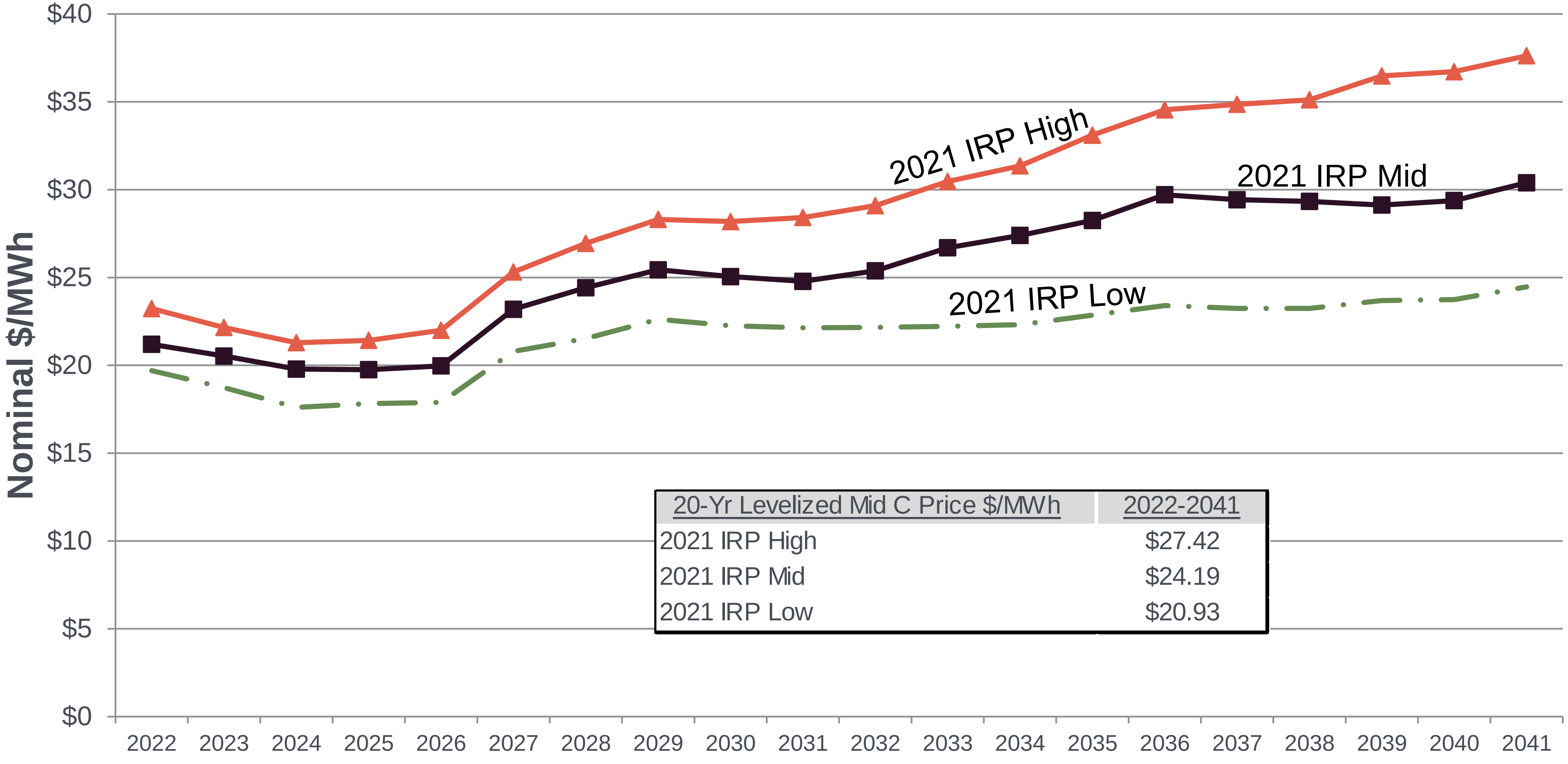


☆Stakeholder requested

PSE PUGET SOUND ENERGY

2 Planning assumptions and resource alternatives

Electric price forecasts: presented June 10, 2020 and updated with stakeholder recommendations



20-Yr Levelized Mid C Price $/MWh	2022-2041
2021 IRP High	$27.42
2021 IRP Mid	$24.19
2021 IRP Low	$20.93

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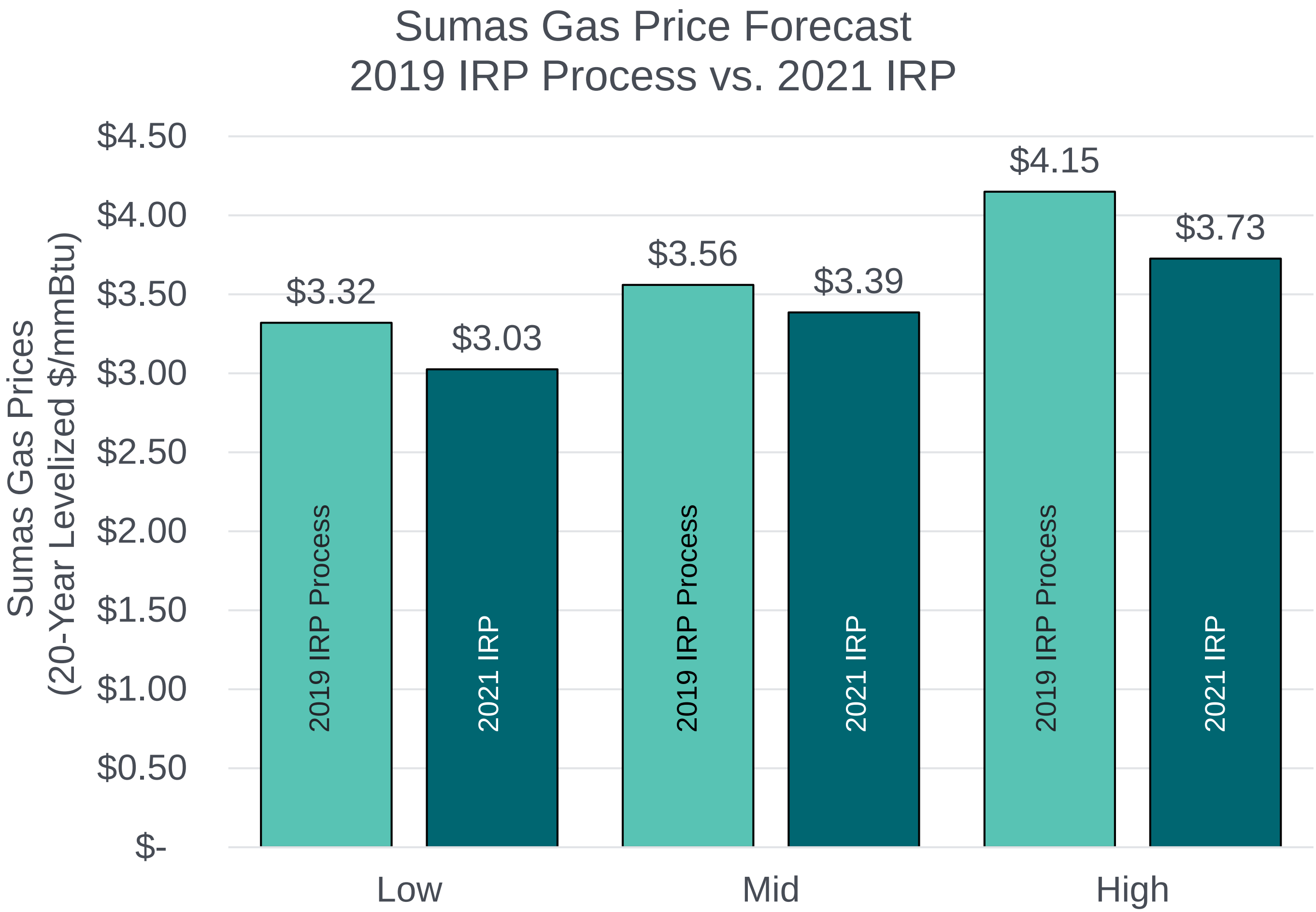
2 Planning assumptions and resource alternatives

Natural gas price forecast at Sumas



2021 IRP mid natural gas price

→ From 2022-2025, three-month average of forward marks for the period ending June 30, 2020

→ Beyond 2025, Wood Mackenzie long-run, fundamentals-based gas price forecasts that were published in Spring 2020.

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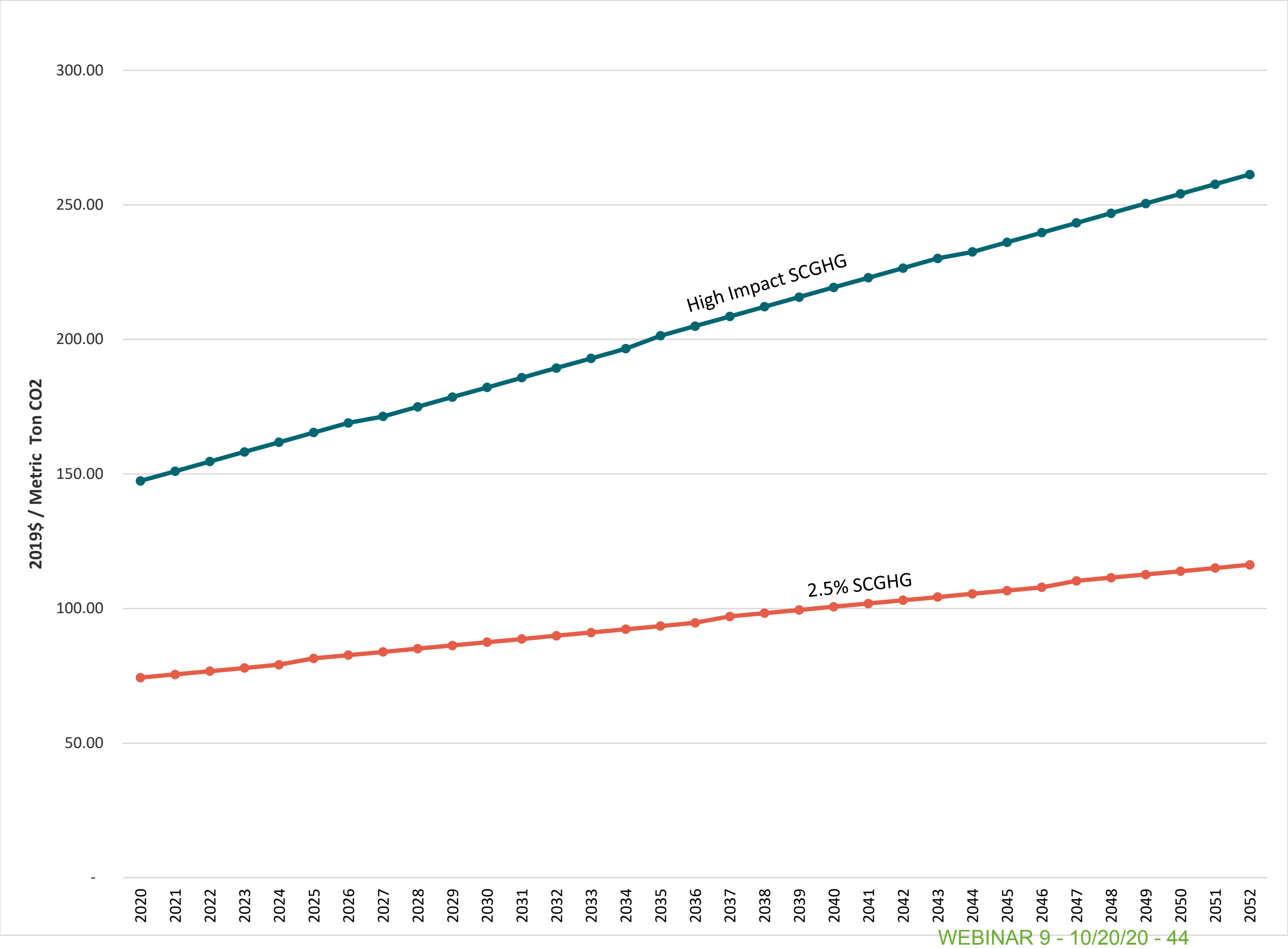
2 Planning assumptions and resource alternatives

Social cost of greenhouse gases (SCGHG): presented July 21, 2020



- SCGHG represented as the two and one-half percent discount rate, listed in table 2, technical support document: Technical update of the social cost of carbon for regulatory impact analysis under Executive Order No. 12866, *published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016*
- Inflation factor provided by the Washington Utilities and Transportation Commission (UTC) https://www.utc.wa.gov/regulatedIndustries/utilities/Pages/SocialCostofCarbon.aspx

2 Planning assumptions and resource alternatives

[Upstream CO2 emission for natural gas plants: presented July 21, 2020]

Upstream emissions added to emission rate of NG plants

GHGenius: 10,803 g/MMBtu = 23 lbs/MMBtu

Upstream emissions added to emission rate of NG plants

Example:

New NG plant emission rate:	117 lbs/MMBtu
Upstream emission rate:	23 lbs/MMBtu
Total emission rate:	140 lbs/MMBtu

2 Planning assumptions and resource alternatives

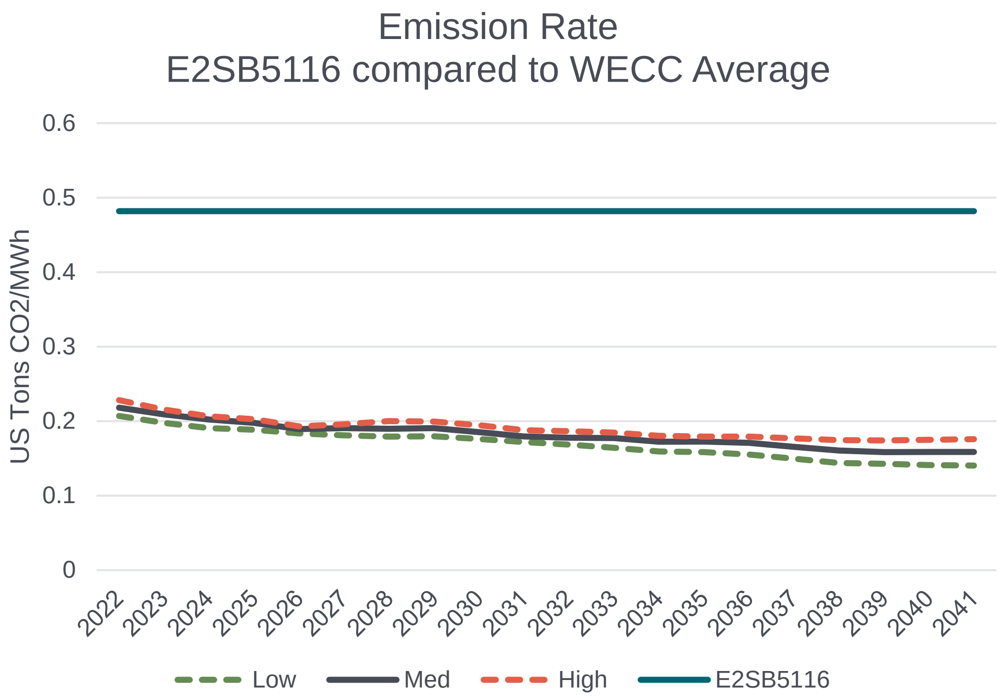
Emission rate for market purchases

Emission rate for unspecified market purchases.

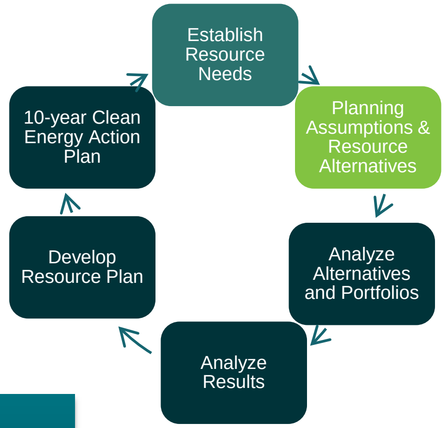
- Section 7 of E2SB5116, paragraph 2 states to use 0.437 metric tons CO_2/MWh for unspecified market purchases

Comparison of emission rate from E2SB5116 and the WECC average CO_2 rate.

➢ WECC average CO_2 rate calculated form AURORA WECC wide runs for the electric price forecast

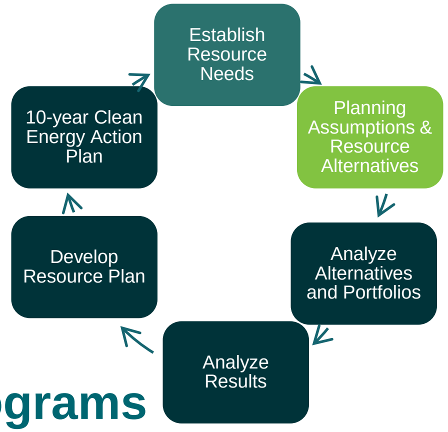


2 Planning assumptions and resource alternatives



Demand-side resource alternatives

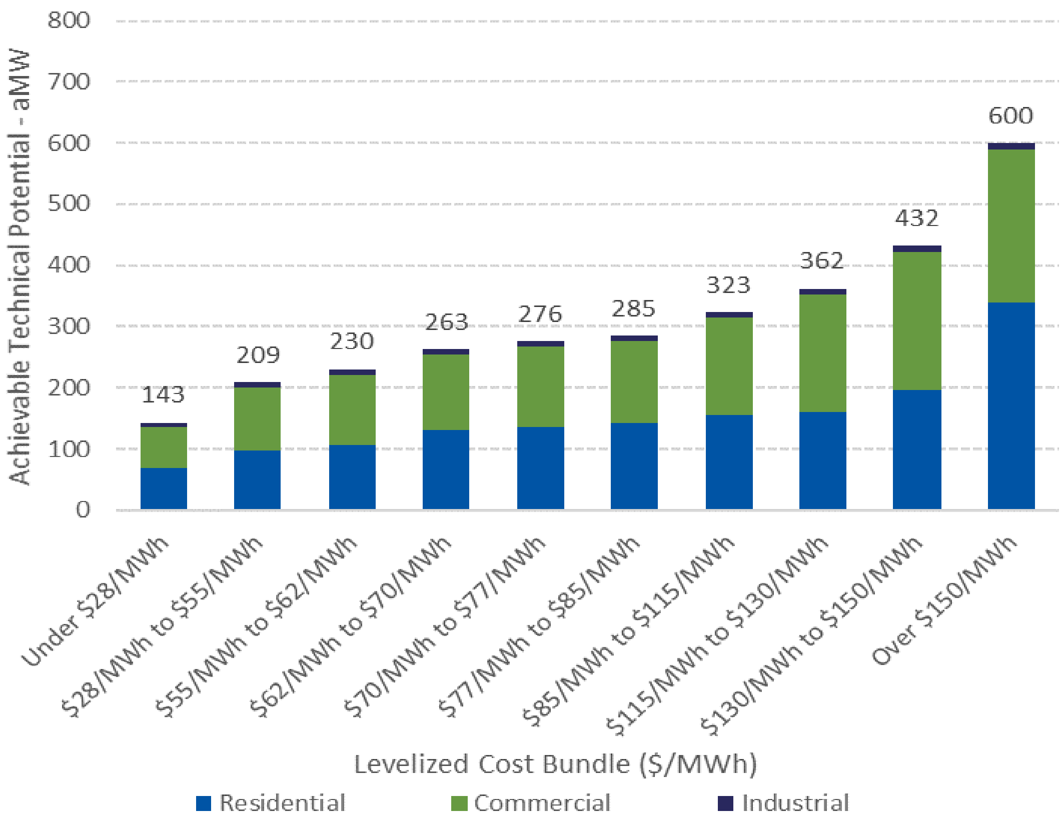
- Energy Efficiency
- Demand Response
- Distribution Efficiency
- Codes and Standards
- Distributed Solar PV (net metering)



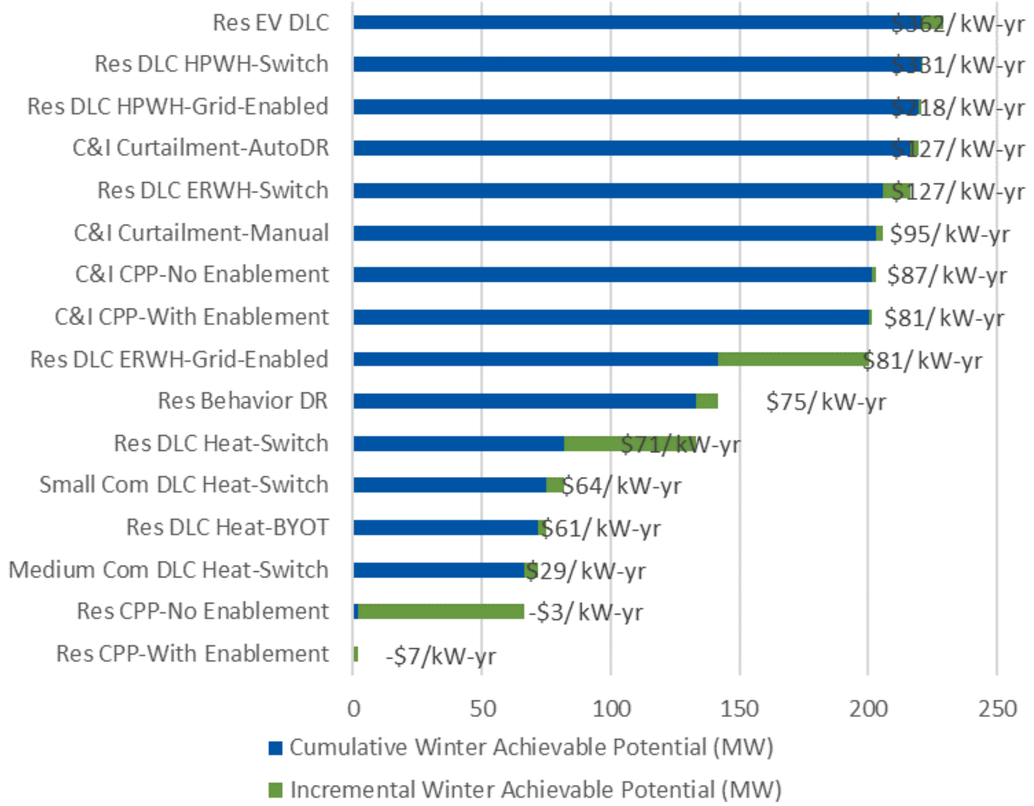
2 Planning assumptions and resource alternatives

Demand-side resource alternatives: presented on July 14, 2020

Energy Efficiency Supply Curve



Demand Response Programs



2 Planning assumptions and resource alternatives

Supply-side resource alternatives: presented May 28, 2020

Gas plants

- 1 – Combined cycle combustion turbines baseload gas plant (CCCT)
- 2 – Simple cycle combustion turbine peaking plant (frame peaker)
- 3 – Reciprocating internal combustion engines peaking plant (recip peaker)

Renewable resources

- Solar (utility scale)
  - 4 – WA West
  - 5 – WA East
  - 6 – Idaho
  - 7 – WY East
  - 8 – WY West
  - 9 – MT Central
  - 10 – MT East
- 11 – Solar (Distributed)
- Wind – onshore
  - 12 – WA East
  - 13 – Idaho
  - 14 – WY East
  - 15 – WY West
- 16 – Offshore Wind
- 17 – Biomass

Energy storage

- Battery storage
  - 18 – 2-hr Lithium Ion
  - 19 – 4-hr Lithium Ion
  - 20 – 4-hr Flow
  - 21 – 6-hr Flow
- 22 – Pumped Storage Hydro (PSH)

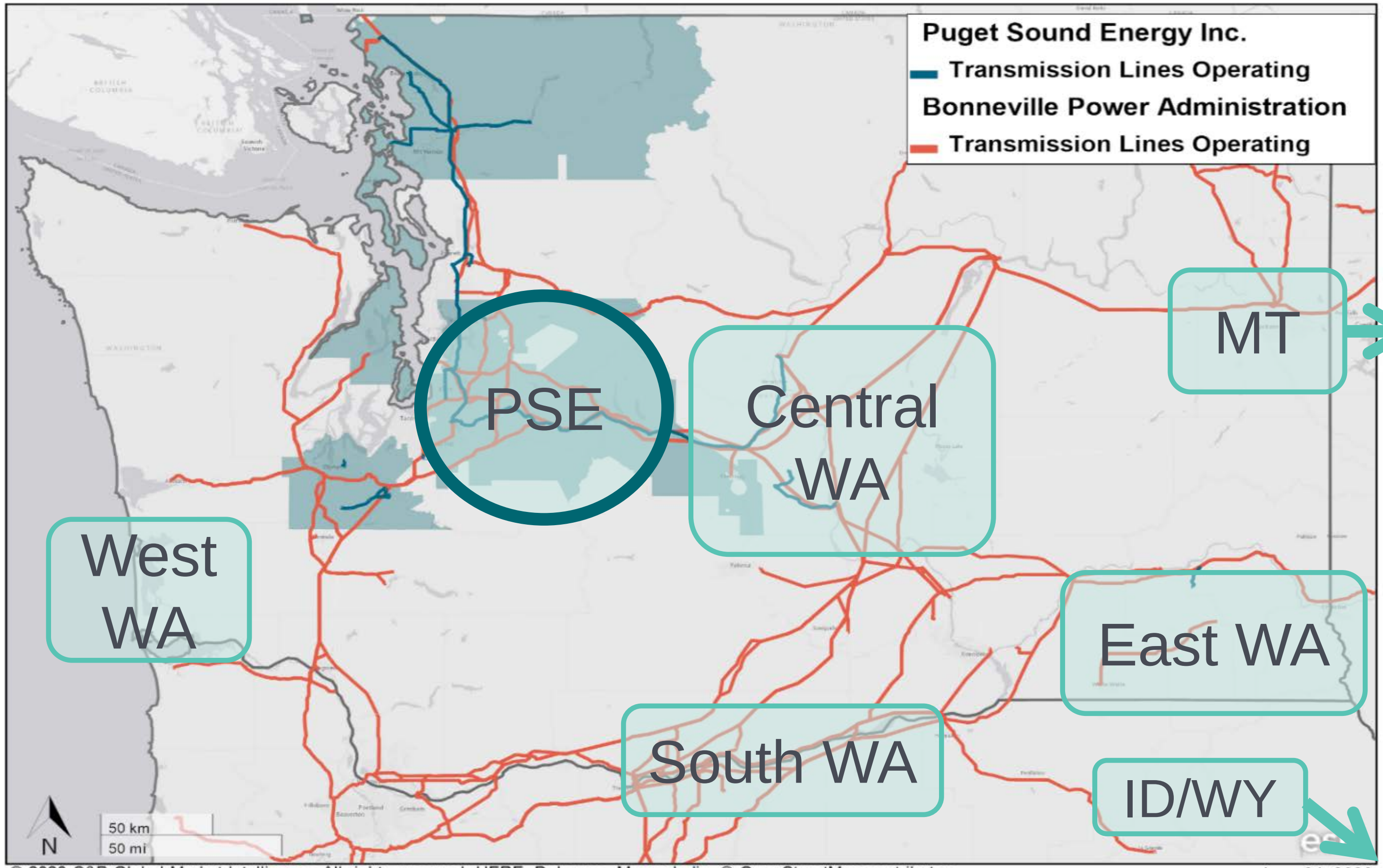
Combined resources

- 23 – WA Solar + battery
- 24 – WA Wind + battery
- 25 – MT wind + PSH

This session is being recorded by Puget Sound Energy.
Third-party recording is not permitted.

2 Planning assumptions and resource alternatives

Transmission constraints: presented on June 30, 2020



June 04, 2020

Resource Group Region	Added Transmission (MW)			
	Tier 0	Tier 1	Tier 2	Tier 3
PSE territory (a)	(b)	(b)	(b)	(b)
Eastern Washington	unconstrained	300	675	1,515
Central Washington	unconstrained	250	625	875
Western Washington	unconstrained	0	100	635
Southern Washington/Gorge	unconstrained	150	705	1,015
Montana	565	350	565	565
Idaho / Wyoming	600	0	400	600
TOTAL	generally unconstrained	1,050	3,070	5,205

Notes:
(a) Not including the PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed
(b) Not constrained in resource model, assumes adequate PSE transmission capacity to serve future load

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❷ Planning assumptions and resource alternatives

Resource Group Region	Onshore Wind	Offshore Wind	CCCT	Frame	Recip	Biomass	Distributed Solar	Utility Solar	Pumped Storage	Battery	Wind + Battery	Solar + Battery
	Generic Resource											
PSE territory*			x	x	x	x	x	x		x		
Eastern Washington	x					x		x	x		x	x
Central Washington	x					x		x	x		x	x
Western Washington	x	x				x		x				
Southern Washington/Gorge	x					x		x	x		x	x
Montana	x								x			
Idaho / Wyoming	x							x				

*Not including the PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed

Annual Average Capacity Factor (%)	
Washington Wind	36.7
Montana-East Wind	44.3
Montana-Central wind	39.8
Wyoming-East Wind	47.9
Wyoming-West Wind	39.2
Idaho Wind	33.0
Offshore Wind	34.8
Washington-West Distributed Solar	13.6
Washington-East Utility Solar	24.4
Wyoming-East Solar	27.3
Wyoming-West Solar	28.0
Idaho Solar	26.4

2 Planning assumptions and resource alternatives

Sub-hourly system flexibility cost savings

- PLEXOS is an hourly and sub-hourly chronological production simulation model that utilizes mixed-integer programming (MIP) to simulate unit commitment of resources at a day-ahead level, and then simulate the re-dispatch of these resources in real-time to match changes in supply and demand on a 5-minute basis.

- For the sub-hourly cost analysis using PLEXOS, PSE will first created a current portfolio case based on PSE's existing resources.

- Then test each resource in the portfolio and calculate the cost difference in the real-time re-dispatch from the current portfolio case.

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3 Analyze portfolios and alternatives

- Analyze scenarios and sensitivities using deterministic and stochastic risk analysis

- The portfolio model is an optimization model that determines the mix of supply and demand-side resources that meets the objective function to minimize total portfolio cost while meeting all the constraints.

- The purpose of the stochastic analysis is to understand how uncertainty affects findings

3 Analyze portfolios and alternatives

Draft results for mid economic conditions portfolio

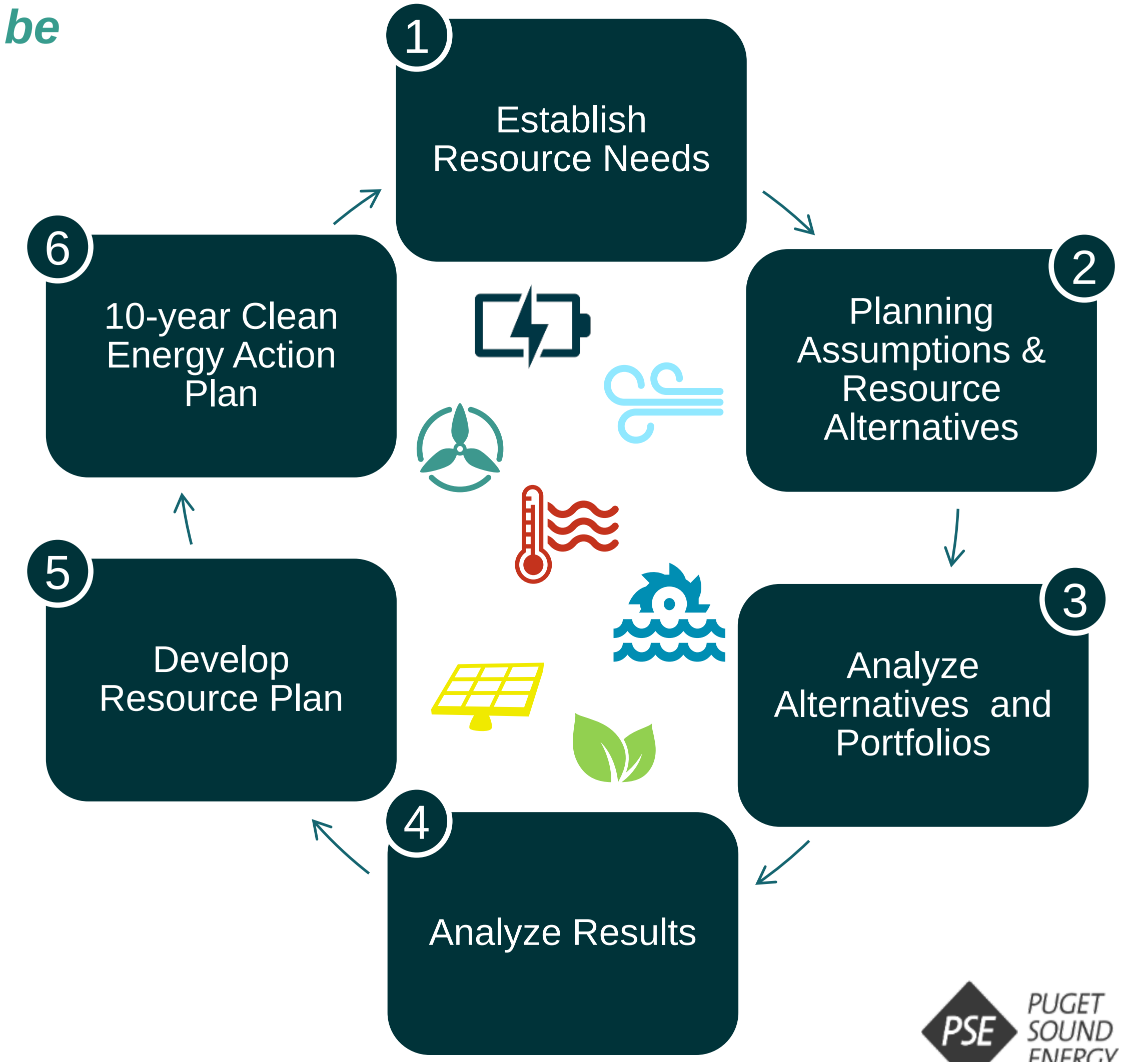
- Results are draft and represent current place in modeling process
- Increased renewable and conservation over the 2017 IRP due to CETA requirements.
- The 2021 IRP is modeling over 25 unique supply-side resources, the most modeled in any PSE IRP.
- With a lower demand forecast the renewable need and peak need are lower than the 2019 IRP process, so over all less resources added to the portfolio.
  - ➢ Updated wind curves to reflect newer technology resulted in a higher average capacity factor for wind and a switch from solar to wind in the portfolio builds

2021 IRP modeling process

Updated draft results and draft resource plan will be discussed at the December 9 IRP meeting.

The 2021 IRP will follow a 6-step process for analysis:

1. Analyze and establish resource need
2. Determine planning assumptions and identify resource alternatives
3. Analyze scenarios and sensitivities using deterministic and stochastic risk analysis
4. Analyze results
5. Develop resource plan
6. 10-year Clean Energy Action Plan



5-minute break

Electric portfolio sensitivities

Participation Objectives

- PSE will present possible scenarios or sensitivities for the electric analysis.
- Stakeholders to share input on prioritization on scenarios or sensitivities for the electric analysis

IAP2 level of participation: INVOLVE

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Stakeholder involvement

- PSE requested stakeholder involvement at the August 11 webinar to help create the list of portfolio sensitivities.

- With stakeholder input, the list has grown to 47 portfolio sensitivities.

- PSE is now asking for stakeholders to help to prioritize the analysis.

- PSE will make best efforts to complete all the requested analysis, however some analysis may take longer than others to complete and it is possible that not everything can be finished to meet the IRP filing date.
  - PSE will start modeling with the highest priority items.

Voting process to prioritize the list

- PSE values your participation in the 2021 IRP and asks that you provide feedback in the form of a survey, which will be opening soon and closed October 27.

- In this survey we ask that you select the 10 sensitivities you feel hold the highest importance to the IRP assessment. This does not mean that PSE is only going to complete 10 sensitivity assessments. The number of selections was chosen to ensure a meaningful prioritization of options could be calculated.

- PSE has pre-selected 15 sensitivities that represent different themes and will help inform the IRP process. These are called “must run” sensitivities.

- Link to survey to be provided

“Must run” portfolio sensitivities

Description	Corresponding number in spreadsheet
Mid economic conditions	1
Low economic conditions	2
High economic conditions	3
Renewable over generation test	7
Reduced market reliance at peak	8
"Distributed" Transmission/build constraints, Tier 2	10
Firm transmission as a % of nameplate	13
SCGHG as an “externality cost” - dispatch cost in portfolio model only	19
Alternative fuel for peakers	25
Gas generation out by 2045	27
Must take DR and battery storage first, then optimize	29
Fuel switching from gas to electric	30
Temperature sensitivity *will vote on 3 different approaches	31
SCGHG only, fixed cost adder	38
2% cost threshold	43

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Alternative Definition of Normal Temperatures

- The load forecast assumes normal temperatures for the forecast period.

- Several approaches for consideration:
  1. Trended normal based on historical observed trends (Itron)
  2. Normal based on most recent 15 years
  3. Northwest Power and Conservation Council's climate model temperature assumption

- Comparison of three approaches

- Normal temperatures are translated into normal heating and cooling degree days for the model.

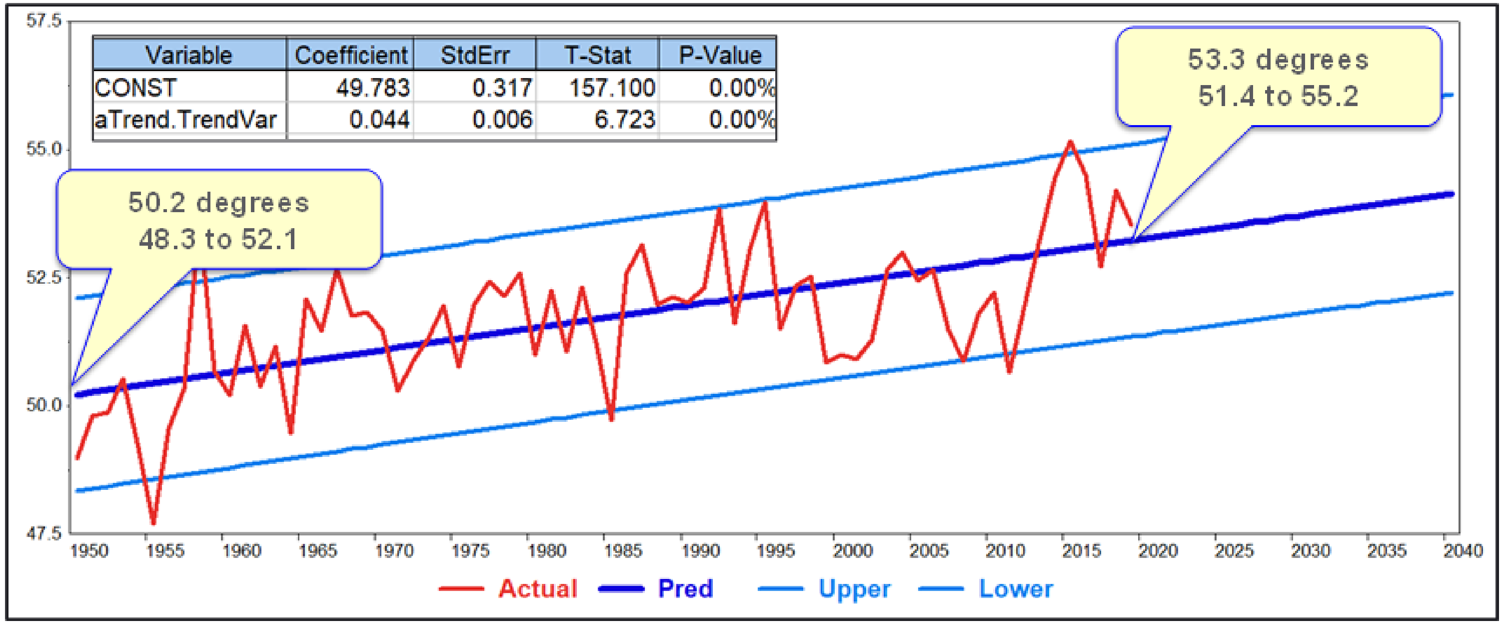
- HDD base 65: if daily average temperature < 65, then 65 - temperature
  if daily average temperature > 65, then 0
- CDD base 65: if daily average temperature > 65, then temperature - 65
  if daily average temperature < 65, then 0

Approach 1: Itron Temperature Trend Study

- Puget Sound initiated study in light of the significant work on understanding the regional impact of climate change
  - River Management Joint Operating Committee (RMJOC)
  - Northwest Power and Conservation Council (NWPCC)

- Study Objectives
  - Evaluate historical temperature trends (Seattle-Tacoma International Airport)
  - Compare PSE’s observed temperature trends to other regions and climate impact studies
  - Translate temperature trends to Heating and Cooling Degree Days for modeling

Since 1950 Average Temperature Has Been Increasing

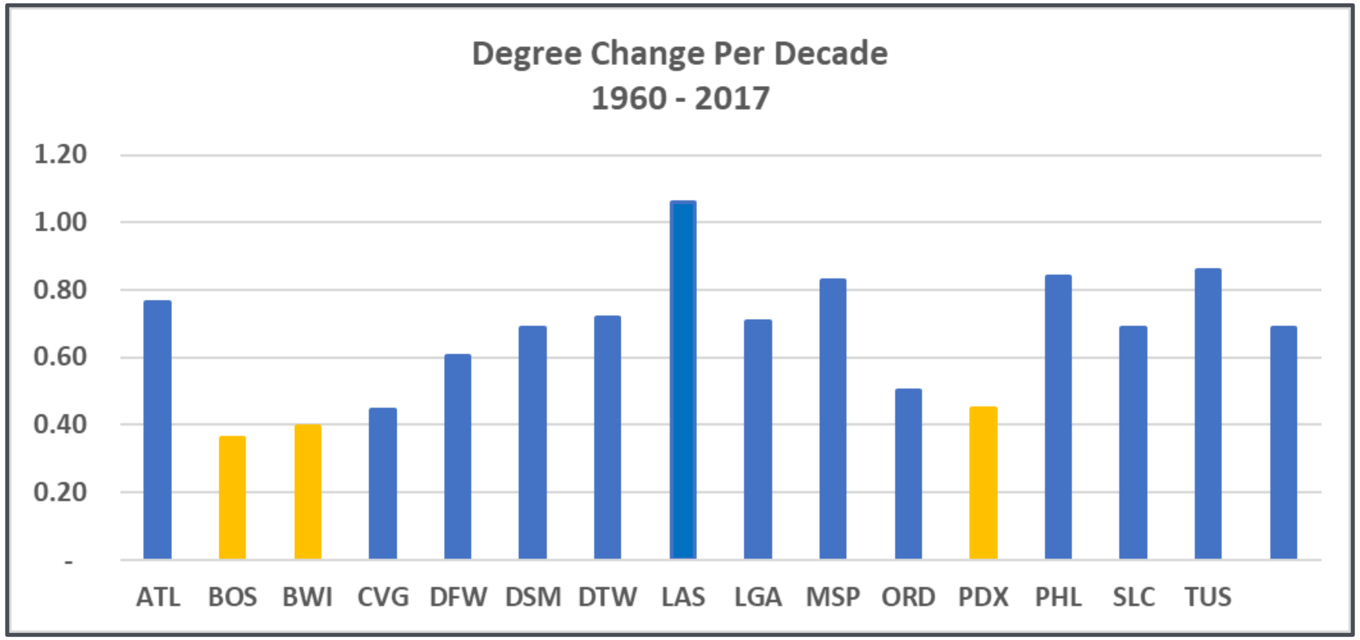


- Statistically significant trend
- Trend coefficient of .044 implies average temperatures increasing .044 per year or 0.44 degrees per decade. Depending on start year, temperature trend varied from 0.33 to 0.47, average is 0.40 degrees per decade.

Consistent with U.S. Temperature Trends

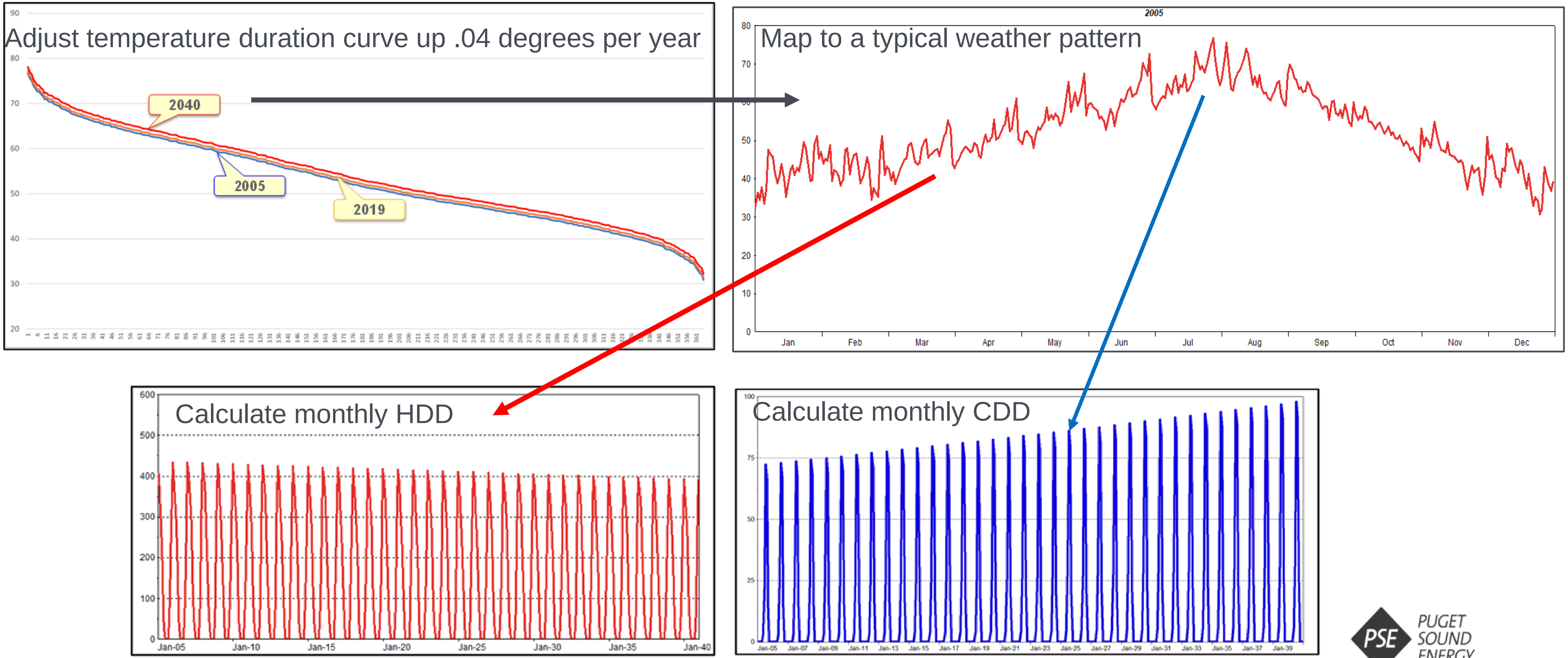
PIER Study - Estimated Temperature Change
1960 - 2017

City	Station	TempChg	Per Decade
Atlanta	ATL	4.36	0.76
Boston	BOS	2.06	0.36
Baltimore	BWI	2.25	0.39
Cincinnati	CVG	2.53	0.44
Dallas-Fort Worth	DFW	3.44	0.60
Des Moines	DSM	3.93	0.69
Detroit	DTW	4.09	0.72
Las Vegas	LAS	6.05	1.06
New York (LGA)	LGA	4.03	0.71
Minneapolis	MSP	4.72	0.83
Chicago	ORD	2.86	0.50
Portland	PDX	2.55	0.45
Philadelphia	PHL	4.78	0.84
Salt Lake City	SLC	3.92	0.69
Tucson	TUS	4.89	0.86
Median		**3.93**	**0.69**



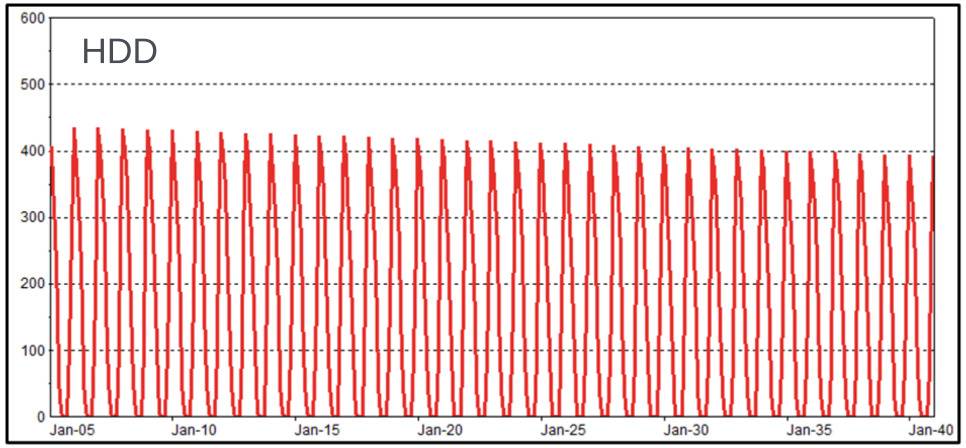
On the Evolution of U.S. Temperature Dynamics, July 2019. Francis Diebold, University of Pennsylvania, Glenn Rudebusch, FRB San Francisco. Penn Institute for Economic Research (PIER). https://economics.sas.upenn.edu/pier/working-paper/2019/evolution-us-temperature-dynamics

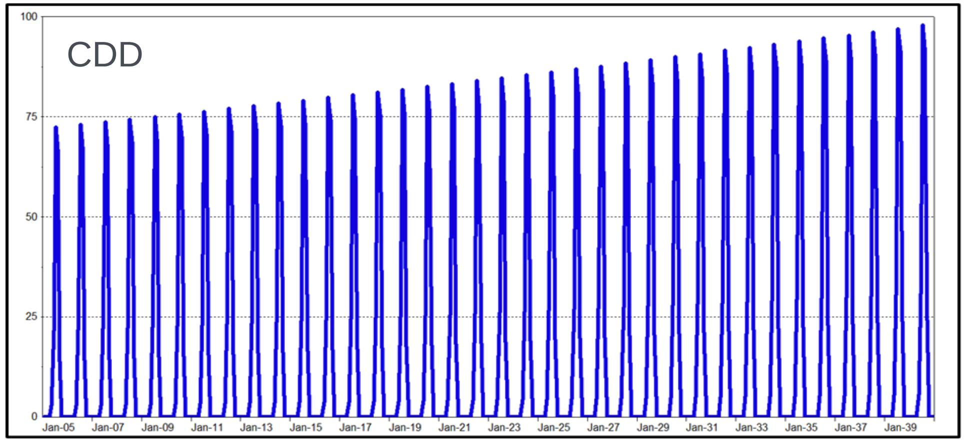
Translation of Temperature Trend to Normal Degree-Days



Trended Normal Heating and Cooling Degree Days

- Increasing temperature trend translates into decline in expected number of HDD and increase in number of CDD



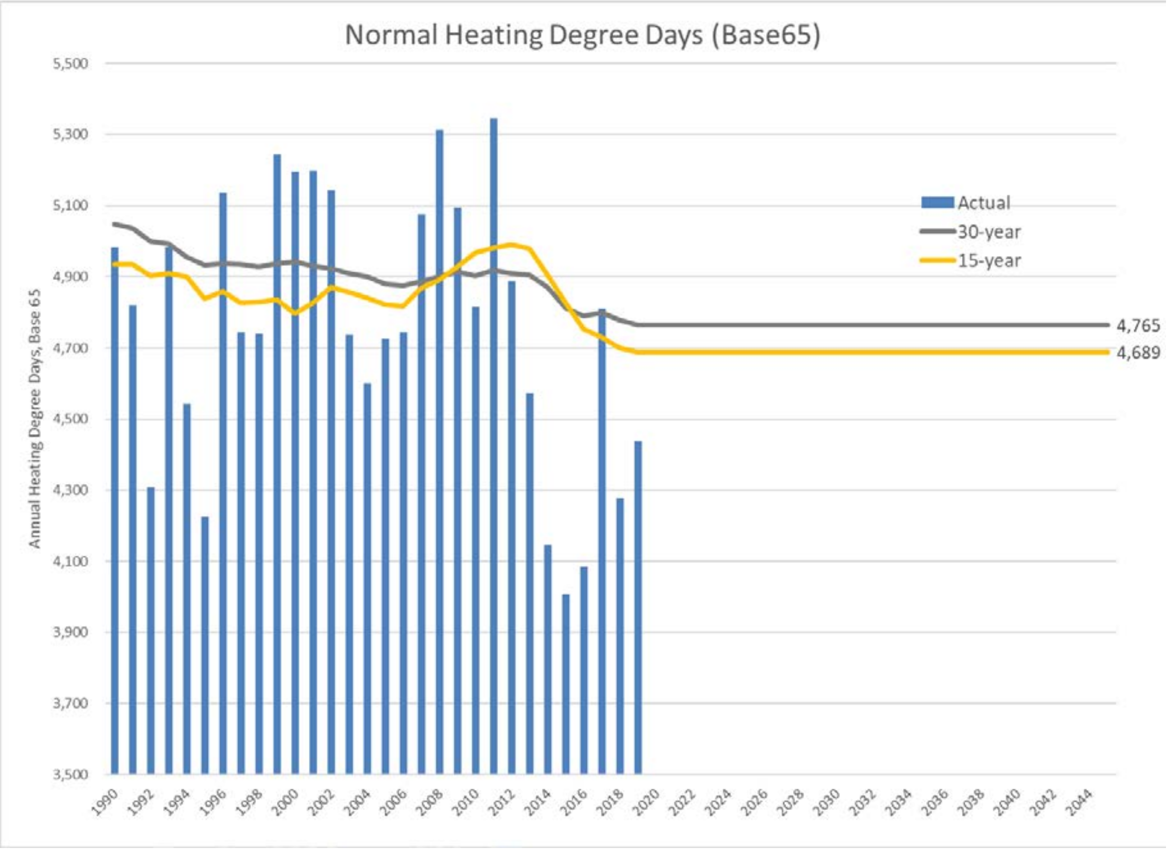


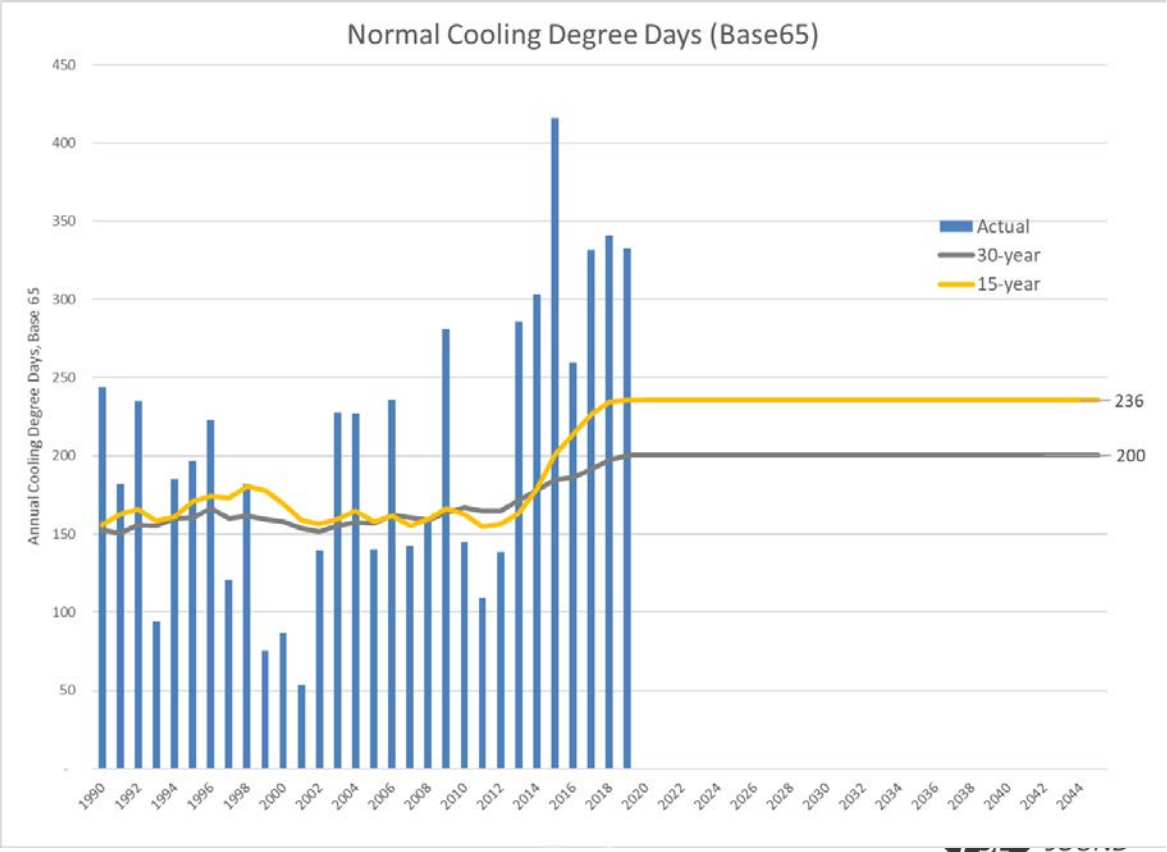
2020 Normal HDD65		
Month	**30-Year**	**Trended**
Jan	714.3	695.5
Feb	638.8	636.2
Mar	586.7	567.9
Apr	450.2	431.9
May	287.2	269.3
Jun	159.9	144.4
Jul	53.8	43.6
Aug	44.7	34.7
Sep	135.2	120.3
Oct	389.5	370.6
Nov	580.6	562.4
Dec	743.8	725.0
Total	**4,784.8**	**4,601.6**

2020 Normal CDD65		
Month	**30-Year**	**Trended**
Jan	-	-
Feb	-	-
Mar	0.2	-
Apr	0.7	-
May	6.9	9.8
Jun	25.7	30.2
Jul	78.5	89.6
Aug	71.6	82.5
Sep	16.8	21.6
Oct	-	-
Nov	-	-
Dec	-	-
Total	**200.3**	**233.7**

Approach 2: Normal degree days based on most recent 15 years

- Same methodology as current normal definition, except reducing the historical period for the calculation from 30 to 15 years.

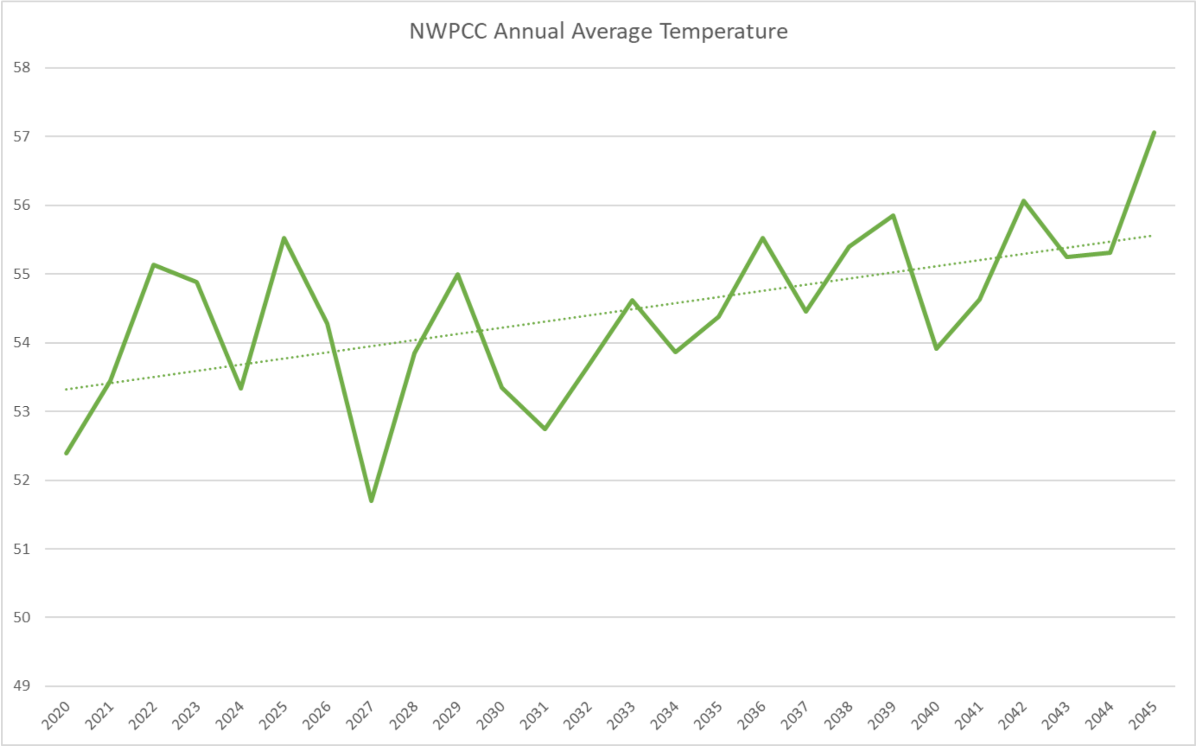




ENERGY

Approach 3: Northwest Power and Conservation Council climate change temperature model

- NWPCC developed Seattle-Tacoma temperature series incorporating a warming trend.
- The temperature series assumes warming of 0.9 degrees per decade (2020-2045).
- Approach: Calculate trended normal degree days using this temperature series.



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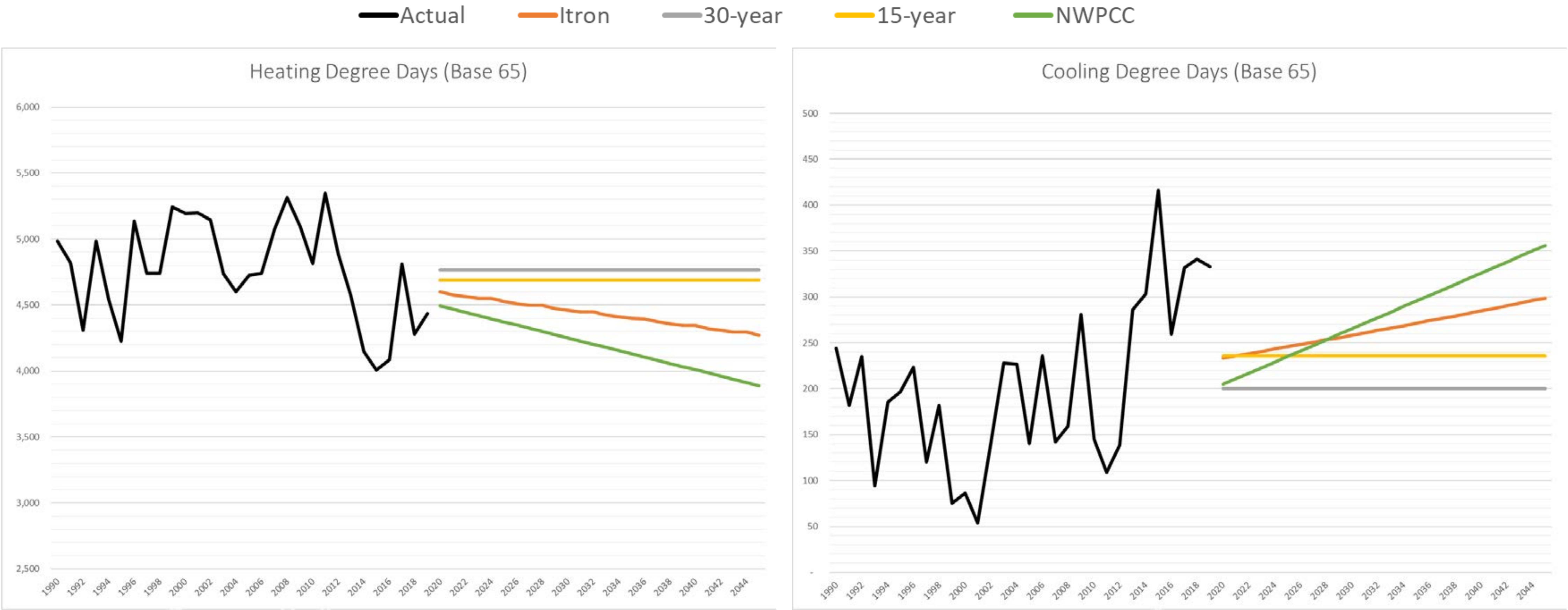
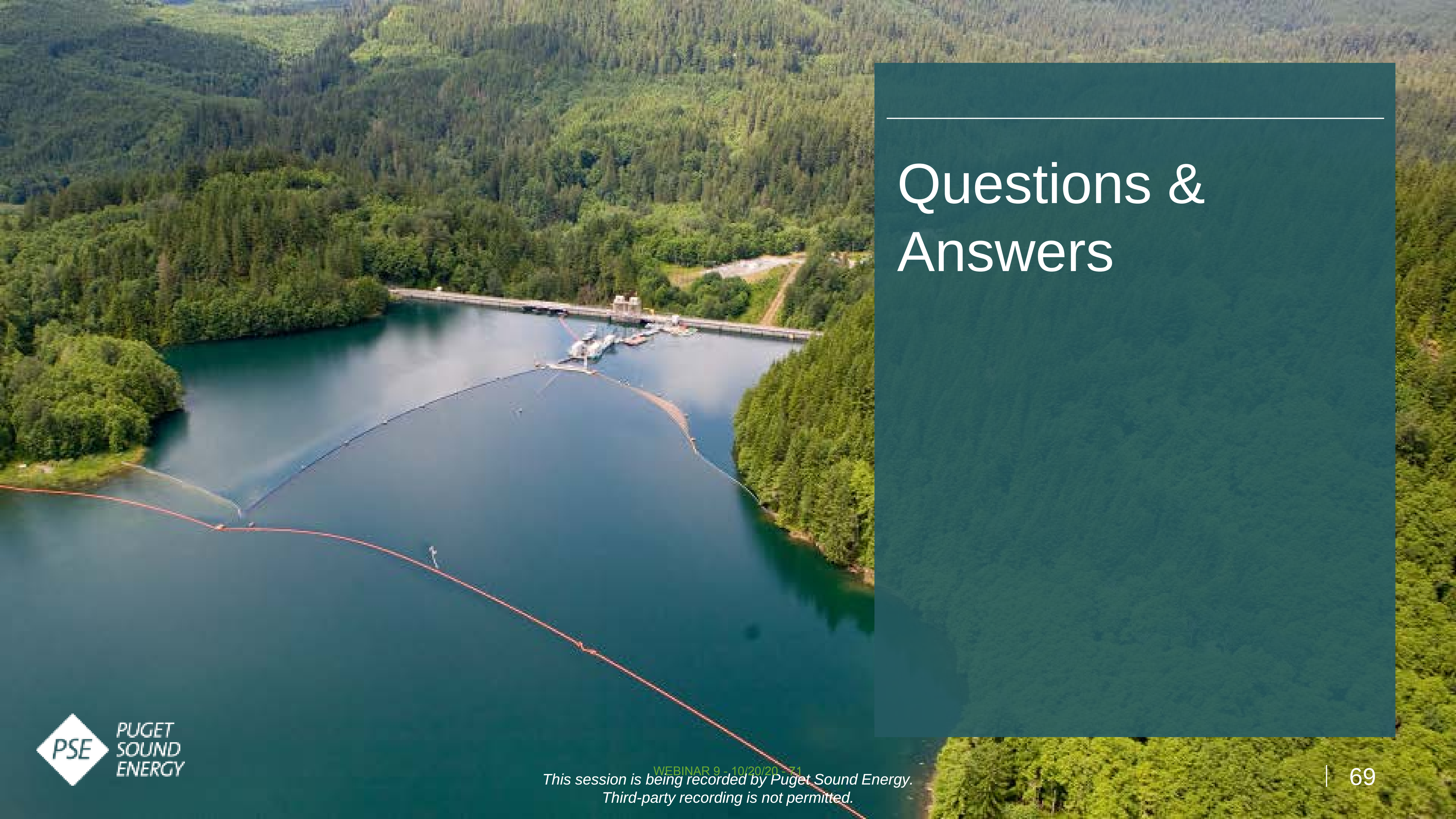
Comparison of Normal Degree Days



Heating degree days (HDD) are a measure of how *cold* the daily averages temperature are for a given month or year.
Cooling degree days (CDD) are a measure of how *warm* the daily average temperatures are for a given month or year.



Questions & Answers

Tools for public participation

To keep you informed...

- Website postings
- Email notifications
- Briefings
- Feedback Reports
- Consultation Updates
- E-Newsletters
- Topical fact sheets

To seek your thoughts, ideas, concerns...

- Stakeholder interviews - *completed*
- Feedback webinars – *seven completed*
- Feedback forms – *seven completed*

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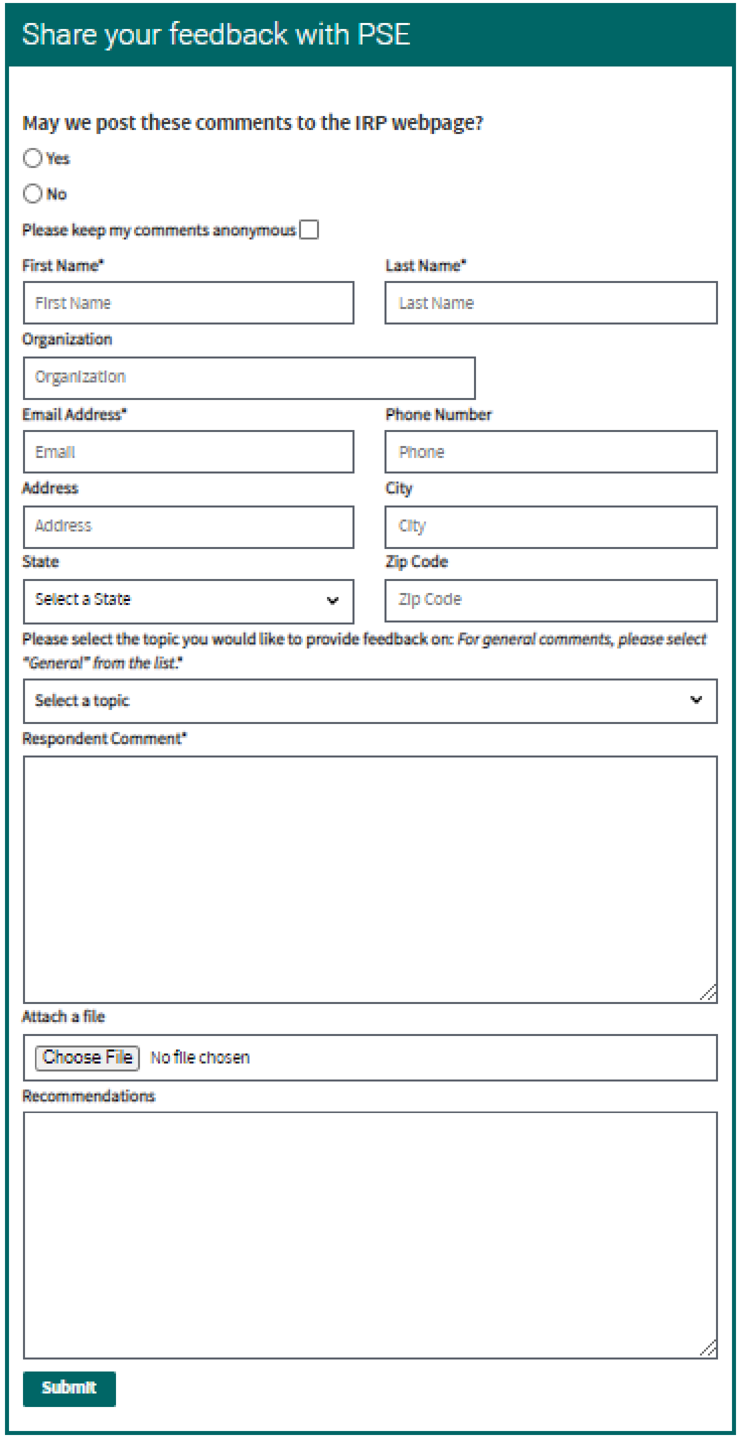
Feedback Form

- An important way to share your input
- Available on the website 24/7
- Comments, questions and data can be submitted throughout the year, but timely feedback supports the technical process
- Please submit your Feedback Form <u>within a week of the meeting topic</u>


Share your feedback with PSE

May we post these comments to the IRP webpage?

- Yes
- No

Please keep my comments anonymous

First Name* — First Name

Last Name* — Last Name

Organization — Organization

Email Address* — Email

Phone Number — Phone

Address — Address

City — City

State — Select a State

Zip Code — Zip Code

Please select the topic you would like to provide feedback on: *For general comments, please select "General" from the list.*

Select a topic

Respondent Comment*

Attach a file

Choose File No file chosen

Recommendations

Submit

Feedback Form

- An important way to share your input
- Available on the website 24/7
- Comments, questions and data can be submitted throughout the year, but timely feedback supports the technical process
- Please submit your Feedback Form within a week of the meeting topic

Feedback Form → Feedback Report → Consultation Update

Feedback cycle

Action	Timing
Stakeholders can submit questions and feedback via the Feedback Form.	**Anytime, 24/7 online access**
PSE will share the meeting agenda, presentation slides and any supporting materials on the website.	**One week before each meeting**
A recording of the webinar and the transcript of the chat will be posted to the website so those who were unable to attend can review.	**One day after each meeting**
Feedback Forms related to the specific meeting topic are due.	**One week after each meeting**
A Feedback Report of all comments collected from the Feedback Form, along with PSE's responses, will be shared with stakeholders via the website.	**Two weeks after each meeting**
A Consultation Update, where PSE demonstrates how stakeholder feedback was applied, will be posted to the website.	**Three weeks after each meeting**

Thank you for your participation in PSE's 2021 IRP!

- To date, 145 unique individuals have participated in webinars
- Over 1,900 unique individual website users since May 2020
- 1,441 total audience members are receiving IRP newsletters
- 130 Feedback Forms received for the first 7 webinars
- Average message open rate of 20% for all newsletters sent between May and August 2020

Next steps

- Submit Feedback Form to PSE by **October 27, 2020**
- A recording and the chat from today's webinar will be posted to the website **tomorrow**
- PSE will compile all the feedback in the Feedback Report and post all the questions by **November 3, 2020**
- The Consultation Update will be shared on **November 10, 2020**

Details of upcoming meetings can be found at pse.com/irp

Date	Topic
November 16 1:00 – 4:30 pm	Clean Energy Action Plan 10-year Distribution & Transmission Plan Highly Impacted and Vulnerable Communities Assessment
December 9, 1:00 – 4:30 pm	Portfolio draft results Flexibility analysis Wholesale market risk

Note: A revision to the 2021 IRP webinar schedule will be released soon

PSE PUGET SOUND ENERGY

Thank you for your attention and input.

Please complete your Feedback Form by October 27, 2020

We look forward to your attendance at PSE’s next public participation webinar:

Clean Energy Action Plan and

10-year Distribution and Transmission plan

November 4, 2020

IRP POWER PRICES

EXCEL SPREADSHEET

Click this link to download the spreadsheet:

https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/Oct_20_webinar/Webinar%209:%20Final%20electric%20power%20prices.xlsx

Webinar #9: Electric Portfolio Modeling Process, Final Power Prices, Electric Sensitivities, and Inputs and Observations from Draft Results

10/21/2020

Overview

On October 20, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss the electric portfolio modeling process, final power prices, electric sensitivities, and inputs and observations from draft IRP results. Additionally, participants were able to ask questions and make comments using a chat box provided by the Go2Meeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 54 stakeholders and PSE staff attended the webinar, plus another 8 attendees who called into the meeting and did not identify themselves (62 people total).

Attendees included: Anders Glader, Anne Newcomb, Ben Farrow, Bill Pascoe, Brian Fadie, Brian Grunkemeyer, Charlie Black, Charlie Inman, Chris Wissel-Tyson, Cody Duncan, Cory Kupersmith, Court Olson, Deborah Reynolds, Don Marsh, Doug Howell, Elyette Weinstein, Eric Fox, Fred Heutte, Graham Horn, James Adcock, Joni Bosh, Joshua Rubenstein, Kathi Scanlan, Katie Ware, Kevin Jones, Kyle Frankiewich, Larry Becker, Mark Tourangeau, Nate Sandvig, Robert Briggs, Stephanie Chase, Steven Griffith, Ted Drennan, Virginia Lohr, Wendy Gerlitz, and Willard Westre.

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 1:00 PM PDT and ended at 4:35 PM PDT.

Name	Time Sent	Comment
Alison Peters	**12:59 PM**	Welcome to the webinar. We're glad you're here.
Charlie Black	**1:06 PM**	Good afternonn. Which topics will be at "Inform" level and which topics will be at "Involve" level?
Deborah Reynolds	**1:07 PM**	Good afternoon, all
Elise Johnson	**1:10 PM**	Hi Charlie! In order of presentation: Electric Portfolio Model is inform; Electric IRP Process is inform; Electric Portfolio Sensitivities is involve
James Adcock	**1:14 PM**	Slide 11 "What does for PSE Only" mean?
James Adcock	**1:16 PM**	Slide 12 "Is the 'Hourly Dispatch Run' part of PSE's modeling efforts?"
Charlie Black	**1:17 PM**	I have a question about Slide 12.
Kathi Scanlan	**1:24 PM**	Slide 11: Thank you for the overview of the electric portfolio model process, including inputs. Would you please indicate which inputs are ready and any others that are still under development. When will these values be discussed with the advisory group, e.g. flexibility benefit
Fred Heutte	**1:33 PM**	Question on slide 18…
James Adcock	**1:38 PM**	+1 Fred
James Adcock	**1:40 PM**	Comment: PSE's idea of the "Real Market Conditions" is that the actual real market will never in the future include actual costing of SCGHG. I think that is a bad assumption, leading potentially to "stranded assets."
Anne Newcomb	**1:46 PM**	Yay!!!
James Adcock	**1:47 PM**	Slide 25 Raise Hand.
Doug Howell	**1:47 PM**	Slide 25 raised hand
Don Marsh	**1:49 PM**	Question on loss of load in summer. And summer forecast.
James Adcock	**1:51 PM**	Slide 29 Raise Hand.
Fred Heutte	**1:52 PM**	I have a comment about the ELCC assessment.
Kyle Frankiewich	**1:53 PM**	1:53 PM: slide 30: I don't understand EUE represented as a percentage, or, if the percentages are ELCC, I don't understand what EUE means in the column labels
Bill Pascoe	**1:54 PM**	Slides 28 & 30 raise hand
Doug Howell	**1:55 PM**	I'm off mute
Doug Howell	**1:55 PM**	The screen says I am off mute
James Adcock	**2:01 PM**	+1 Doug
Alison Peters	**2:08 PM**	Please mute your lines. We are getting some background noise.
Fred Heutte	**2:08 PM**	Here's the reference to the PG&E/SCE/SDG&E July 2020 submission to the California PUC on ELCC values of solar/wind/hybrid resources, based on work by Astrape Consulting: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5868-E.pdf
Mark Tourangeau	**2:09 PM**	Wouldn't a stand alone storage resource have an even greater positive impact on ELCC when it can integrate multiple renewable resources and not be tied to a specific resource for charging for ITC purposes. Additionally, they can provide ancillary services and frequency response.

Fred Heutte	**2:11 PM**	In summary, Astrape's analysis using the SERVM model shows wind ELCC going from 33% to 58% when paired with storage for the BPA region. There isn't data for BPA for solar (not sure why), but for the other regions in California and the West, solar PV with tracking ELCC goes from single digit percentages to nearly 100% with associated storage.
Kyle Frankiewich	**2:14 PM**	slide 30: i believe pumped storage projects are being marketed in slices other than the full 500MW project; that is, PSE could purchase some smaller share of the project instead of the whole thing. Would adjusting the size of the proxy resource cause this analysis to change?
Joni Bosh	**2:19 PM**	Is this planning margin for 2027 higher than in the last IRP - I recall some margin around 18%? Slide 31
Joni Bosh	**2:24 PM**	Non-emitting and renewable have specific definitions in CETA and do not overlap. Can you clarify your terms on slide 33
Nate Sandvig	**2:31 PM**	I have a question
R. C. Olson	**2:33 PM**	Why is DSR not included in the load forecast on slide 36, and when will we see that included in a projected load.
Alison Peters	**2:33 PM**	A reminder to mute please. We are hearing a keyboard in the background.
James Adcock	**2:38 PM**	Comment: Yes meeting PSE's wind needs will take a lot of acreage, but comparing to the size of a major city like Seattle isn't very meaningful given that Washington State has about 850 times the acreage of say Seattle.
R. C. Olson	**2:39 PM**	So when will we see a real demand forecast that includes DSR?
James Adcock	**2:40 PM**	Comment re "storage" -- I don't understand why "storage" cannot be provided via contract with BPA, when "storage" is one of the products called out by federal law that BPA must make available to utilities, including IOUs.
Fred Heutte	**2:48 PM**	Comment: land requirements for wind and solar vary a lot depending on the specific locale, but let's assume 50 acres/MW for wind (with about a 1-2% surface utilization rate) and 8 acres/MW for solar (with a much higher utilization rate but some shared activities possible). For 2000 MW of capacity, that would require 100,000 acres for wind and 16,000 for solar. 100,000 acres is about 150 square miles, and the state of Washington is 71,000 sq mi. I don
Fred Heutte	**2:49 PM**	I don't think the raw amount of land is really the issue, more it's about the right balance between optimizing renewable energy facility placement and other economic, environmental and cultural risk factors.
James Adcock	**2:49 PM**	Yes I agree that wind farm placement is a difficult process to do "right."
Doug Howell	**2:50 PM**	Question on slide 43 - what is GWP factor assumption?
Kevin Jones	**2:50 PM**	Slide 42 - Are the High Impact SCGHG costs from the same document that contains the 2.5% discount SCGHG costs?
Doug Howell	**2:52 PM**	I am trying to clarify and I am no longer on mute but you cannot hear me. Can the organizers un-mute me?
Alison Peters	**2:53 PM**	When we stop again, Doug, we'll bring you off mute.
Elise Johnson	**2:54 PM**	Hi Doug, sorry about that. We are showing you as unmuted like you were before.

Fred Heutte	**2:54 PM**	Fred Heutte (NWEC) (to Everyone): 2:54 PM: On slide 43, NWEC continues to state that the upstream emissions rate is based on obsolete analysis, for both US and Canadian sources of natural gas. We have provided extensive documentation summarized in our parallel comment to the Northwest Power and Conservation Council at: **https://www.nwcouncil.org/sites/default/files/2020_0616_2.pdf**
Bill Westre	**2:56 PM**	S- 47 Where is MT wind shown
Bill Westre	**2:58 PM**	S-48 Please use 750 MW for MT instead of 565 - the Colstrip sale is not approved yet
Don Marsh	**2:58 PM**	S-49 question.
Kathi Scanlan	**2:58 PM**	Slide 49 - please read footnote, it's cutoff
Charlie Black	**2:59 PM**	On Slide 49, why are CCCTs only assumed to be available from within the PSE service area?
Alison Peters	**2:59 PM**	The footnote: *Not including the PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed
Fred Heutte	**3:00 PM**	Question about slide 49
Kyle Frankiewich	**3:00 PM**	slide 47: please describe the distributed solar resource option.
Bill Pascoe	**3:01 PM**	Slide 48 raise hand
Bill Westre	**3:01 PM**	Raise hand
Doug Howell	**3:04 PM**	Would you build a peaker outside of PSE service territory?
Fred Heutte	**3:06 PM**	PNNL annual capacity factor estimates for Oregon offshore wind range from 61% at Port Orford (south coast) to 49% even as far north as Astoria. **https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-29935.pdf**
Doug Howell	**3:09 PM**	True. Litigation parties and public comment clearly shows opposition to PSE's sale of transmission
Fred Heutte	**3:19 PM**	Question on slide 52
Brian Grunkemeyer	**3:19 PM**	My understanding is CETA requires you to expand your DR capabilities. How are you modelling that in the IRP?
Kyle Frankiewich	**3:20 PM**	Brian is correct that PSE is required to acquire all cost-effective demand response. I share his concern that PSE's current consideration of demand response may not be sufficient.
Brian Grunkemeyer	**3:25 PM**	No, Demand Response
Doug Howell	**3:33 PM**	I ask for sensitivities for a ramp rate on conservation for both 6-years and 8-years. I am okay with you now dropping the 6-year ramp rate to make room for other sensitivities.
James Adcock	**3:33 PM**	Slide 60 raise hand.
Virginia Lohr	**3:34 PM**	When will we be able to discuss what it is the survey?

Robert Briggs	**3:39 PM**	This is a belated follow-up to discussion surrounding your treatment of social cost of carbon as a fixed cost. Perhaps there are semantic issues that are causing lingering confusion. When you are evaluating the smallest increment of an energy conservation resource in your optimization to decide whether to include it or not in the least-cost portfolio, is that measure evaluated against the cost of energy it saves or is it evaluated against the energy cost savings plus the avoided social cost of greenhouse gas emissions?
Virginia Lohr	**3:39 PM**	Please answer my question.
Kyle Frankiewich	**3:39 PM**	slide 59: i imagine some sensitivities will require more extensive modification of the modeling environment than others. Will the relative complexity of a given sensitivity be a part of PSE's decision-making process?
Elise Johnson	**3:40 PM**	Hi Virginia! We see your question and will get to it when we pause for questions.
Brian Grunkemeyer	**3:42 PM**	Slide 60 - Who cools their house to 65 degrees? Shouldn't you be using say 75 degrees for your CDD base?
Don Marsh	**3:42 PM**	Slide 60: question
James Adcock	**3:55 PM**	Slide 64 raise hand.
Anne Newcomb	**3:56 PM**	Someone is unmuted
Fred Heutte	**3:57 PM**	Comment on slide 66
James Adcock	**3:59 PM**	Slide 66 raise hand.
Kyle Frankiewich	**4:01 PM**	slide 67: please expand on the differences between the Council's study and itron's review
Brian Grunkemeyer	**4:02 PM**	(You can ignore my comment on slide 60)
Robert Briggs	**4:02 PM**	Have you evaluated which base temperature correlates best with PSE's aggregate load? I note that cooling degree hours at base 80°F is frequently use for residential space cooling loads.
Robert Briggs	**4:07 PM**	Comment: The reason why the NWPCC's method is likely the best choice is because most climate models suggest nonlinear responses to climate forcing.
Virginia Lohr	**4:09 PM**	For Sensitivity 22 on modeling federal carbon pricing, I compared the August spreadsheet to the new one so I could see how PSE had changed it based on public input. The new spreadsheet has a brief note on what I said, but it does not have a note that the person who is listed as asking for this sensitivity agreed with me. More alarming is that there is no change in what PSE is proposing to model. I looked at the survey this morning, and for sensitivity 22, it does not say what federal price you will use. I assume that the same has also been done for other sensitivities, but I haven't checked those. How can I and others know if we want to select this sensitivity without knowing what carbon pricing you will actually use?
Charlie Black	**4:11 PM**	Raise hand on carbon tax assumptions.
James Adcock	**4:20 PM**	Note my objection: PSE cuts me off almost immediately, but allows other to continue talking indefinitely.
Alison Peters	**4:20 PM**	Fair point, Jim. Thank you.
Alison Peters	**4:23 PM**	If you haven't had a chance to ask your question on the sensitivities, please type it into the chat so we can move it to the Feedback Report.

		Everything typed in will get a written response. Please identify things that are time sensitive so you can participate in the survey.
Don Marsh	**4:23 PM**	If I were concerned only with reliability, I would vote for NWPCC's model that increases by 0.9 degrees per decade. BUT that may cause huge impacts on COST and ENVIRONMENTAL IMACT. We must wisely choose to consider ratepayers, disadvantages groups, and the health of our planet. Therefore, I want to vote for accuracy, not over build based on inaccurate models. I can't tell if NWPCC is reasonable or not.
James Adcock	**4:25 PM**	+1 Fred's comments -- the changes in the climate of the coastal PNW *does not* look like the changes in the rest of the US, coastal PNW has *uniquely* experienced large increases in the temperatures, and hourly temperatures, of coldest winter days.
Virginia Lohr	**4:29 PM**	You currently cannot complete the survey to say what sensitivities you prefer without also selecting one of their 3 temperatures options.
R. C. Olson	**4:29 PM**	Have any of the analyses considered the increased use of air conditioning with air filtering to reduce the indoor air quality impact from forrest fire smoke?
James Adcock	**4:29 PM**	Re Market prices -- but PSE does not have a responsibility to "guarantee" the prices of the entire PNW, but rather *only* has a responsibility to their own ratepayers. Since Puget now has much more mild coldest-winter-day conditions -- a large change compared to other utilities, PSE should not have to "cover" for other utilities. PSE is responsible to reasonable to "cover" their own exposure to market -- but that is a "market" analysis -- it is no excuse for Puget to get their own modeling of climate change in the own region "wrong."
James Adcock	**4:30 PM**	Note my objection: PSE has frozen me out again.
Kyle Frankiewich	**4:31 PM**	What are the topical fact sheets?

The following stakeholder input was gathered through the online Feedback Form, from October 13 through October 27, 2020. PSE's response to the feedback can be found in the far-right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on November 10, 2020.

PSE appreciates the strong response to our stakeholder survey on sensitivity prioritization, we gathered over 140 individual responses. PSE is in the process of reviewing the information and what these selections mean for the IRP process. A summary will be provided for the November 10 Consultation Update.

Feedback Form Date	Stakeholder	Comment	PSE Response
10/19/20	James Adcock	Per your new stated requirements at the previous IRP meeting, I am hereby giving you a "heads up" asking you to "reserve time" to discuss and meaningfully answer technical questions on the following items below: Page 12 Robust technical discussion of the appropriateness of PSE including SCC in the first half of their modeling, but not in the second half of their modeling. Page 24-25, 30 Peak capacity need, etc. Robust technical discussion about what range of years of weather data PSE is using in modeling peak capacity need, and in PSE's modeling of LOLP, EUE, LOLH, LOLE, and LOLEV, and whether or not those range of years of "weather data" modeling are still appropriate or not, given the large effect of climate change on the items. In general discussion of issues of Peak Capacity Planning in the context of existing CETA law and Proposed CETA regulations in the follow section: UE-191023 OTS-2679.1 "PART VIII-PLANNING" WAC 480-100-620 (10) (b) at least one scenario modeling future climate change including changes to HDD and CDD. IE PSE would be required to stop using archaic pre-climate-change weather data from the 1930s through the 1950s in their modeling of peak capacity needs, and instead would need to include modeled future weather data including the effects of even more future climate change, with even lower "coldest winter day" expectations than the weather happening in the most recent two decades. Point of Order Question/Issue: At the previous IRP Meeting PSE represented that they had been answering my question in the Consultation Updates. I went back, again, and reread those Consultation Updates and PSE is not, in fact answering my questions, but rather generically lumping my name in with a bunch of other IRP participants who had questions, and then instead of answering anyone's questions is simply restating, in a kindergarten-level hand-wavy manner the material PSE already presented at the previous IRP meeting. I want an opportunity to correct the misrepresentation that PSE made about me at the previous meeting stating that PSE has been answering my questions in the Consultation Update, and that I simply had not been reading those answers. That representation PSE made about me in public at the previous IRP meeting is simply false, and I want to be able to correct that PSE misrepresentation made about me. James Adcock, electrical engineer	Thank you for using the Feedback Report system to help structure Webinar discussion. On July 21, PSE held a meeting on the role of the Social Cost of Greenhouse Gases (SCGHG) in the modeling process. Materials from that webinar and technical discussion can be found on the PSE IRP website at www.pse.com/irp. The Consultation Update for the July 21 Webinar is also available online. During the September 1 Webinar, the Resource Planning team defined how the peak capacity need, Loss of Load Probability (LOLP), Expected Unserved Energy (EUE), Loss of Load Hours (LOLH), Loss of Load Expectation (LOLE), and Loss of Load Events (LOLEV) would be defined. Materials from that webinar can be found on the PSE IRP website. PSE will be evaluating adjustments to the Heating Degree Day (HDD) and Cooling Degree Day (CDD) values in a temperature sensitivity in order to address concerns over which temperature years are used for IRP modeling. Thank you for your commentary on how PSE has been using the Feedback Report system. PSE groups questions by theme in Consultation Updates to streamline the document and reduce the amount of repeated information. Every effort is made to respond to every Feedback Form to best of PSE's ability.

Feedback Form Date	Stakeholder	Comment	PSE Response
10/20/2020	James Adcock	Note my objection: PSE has again, for 12 years running, deliberately "frozen out" my questions re PSE "weather modeling" now including their extremely small proposed changes due to "climate change." Puget said in so many words they would allow me to ask my questions at the end of the session, and then refused to do so. In contrast to what PSE is proposing, Seattle-area has had huge changes in "coldest winter days" especially coldest winter hours, and PSE's proposed (and not really explained) tiny changes in HDD do not capture what has actually happened already in terms of "coldest winter days" warming trends. I suggest again, that PSE simply use the most recent 20 years of actual weather data, which already is almost 60,000 hourly data points for the winter alone. I certainly would suggest in no cases whatsoever should PSE be using weather data prior to 1970, where that ancient weather data has no relevance -- in terms of coldest winter days -- to what the Puget Sound region is experiencing in recent decades. Finally I ask that Puget give much more detailed technical information about how they plan to use one of their "choice-of-three" minor changes and what range of years of actual historical data they plan to use to develop their (as shown in slide 64) "typical weather patterns." And I attach a log-histogram plot of the three most-recent 20-year periods in the PNW, using actual real weather data, showing how much "coldest winter days" have already increased in temperature, and showing, in comparison, average or median winter day temperatures have barely changed at all. But PSE wants to "correct" for those small average barely-changed winter day temperatures -- while completely ignore the huge changes, the huge warmings, in "coldest winter days" -- and those "coldest winter days" in turn determine PSE peak capacity needs. **Please see attached: James Adcock attachment feedback form dated October 20**	PSE will be evaluating adjustments to the HDD and CDD values in a temperature sensitivity analysis in order to address this concern. PSE will use the revised temperature forecast, discussed on slide 64 of the October 20 Webinar, to generate a 'temperature sensitivity demand forecast'. This demand forecast then flows into several components of the IRP model including demand for the portfolio model, the renewable need calculation and the resource adequacy model. One of the choices for this sensitivity is a 20-year trend. PSE also presented other choices, which included work by Itron, Inc. In this analysis, they found that the 23-degree peak used is well within the confidence interval.
10/21/2020	Willard Westre, Union of Concerned Scientists	Slide 48 PSE currently owns a 750MW share of the Colstrip Transmission line giving it access to Central and Eastern Montana. The proposed sale of Colstrip #4 includes transfer of 185 MW of that capacity to NWE, leaving 565 MW available to PSE with an option to lease back capacity from NWE. However, that sale has not yet been approved by the WUTC. In either case, PSE can have access to the full 750 MW of transmission capacity. 750 MW should be used in all further analyses if the performance advantage of Montana wind is to be fully and fairly evaluated. The 185MW difference is also the subject of a yet-to-be-selected scenario. Question: Will PSE use 750MW instead of 565MW in its Aurora and later analyses combined with the Firm Transmission Scenario even if the 185 MW Scenario is not selected and analyzed? If not why not?	Thank you for your comments. Given the recent change of status of the Colstrip Unit 4 sale, PSE will model 750 MW of transmission to the Colstrip region of Montana for all IRP modeling scenarios and sensitivities (i.e. 750 MW will be the base assumption for the IRP).
10/26/2020	Virginia Lohr, Vashon Climate Action Group	This comment is about the validity of PSE's Sensitivities Survey. I have experience with writing surveys for valid research. For the Sensitivities section of PSE's survey, people are given a choice of selecting between 1 and 10 options. This is appropriate, since not everyone may want to select 10 Sensitivities. If 10 were required, respondents might feel they had to select ones they did not understand or care about, so they might decide not to do the survey or they might select enough to get to 10 choices, and PSE would have no way of knowing which they actually were asking PSE to run or which ones were just to fulfill the requirement of reaching 10 responses. While the format selected for responding to Sensitivities seems appropriate, the information provided in the choices is not. For example, Sensitivity 22 says it will use a federal price on carbon, but does not say what that price PSE has settled on to use in the run. PSE received input on this Sensitivity in August from me about the proposed rate of $15 being low, and particularly, about the proposed rate of increase of only inflation being inappropriate. I mentioned two specific proposals as possible alternatives. No one opposed my suggestion. Even Vlad Gutman-Britten, the person who PSE had listed in the spreadsheet	Thank you for your comments. PSE has received your other feedback pertaining to sensitivity #22, stating that the federal carbon tax should be set to $15 per ton, then escalate $10 per ton per year plus an adjustment for inflation. PSE is currently vetting this recommendation against existing proposals for federal carbon taxation. PSE will confirm the final tax rate in the Consultation Update. PSE suggests that the spreadsheet provided was a means of portraying the intent of each sensitivity. PSE made the spreadsheet available to all stakeholders and reviewed it during the IRP Webinars. The many specific details necessary to actually model each sensitivity are impossible to include in such a summary document. The survey was written to extract as much stakeholder feedback as possible in an efficient, timely manner. Three temperature sensitivity options were offered by PSE as achievable for the 2021 IRP process given time

Feedback Form Date	Stakeholder	Comment	PSE Response
		as suggesting this option, agreed with me. PSE noted that I requested this change. At the Oct. 20 webinar, PSE said they were still consulting staff about what rates to use. To not have made that decision by now is unreasonable. People cannot make reasonable choices when they do not what those choices actually mean. The biggest problem with the survey is that it requires people to answer Questions 6 and 7. Skipping these questions is not an option. These questions have choices that artificially force people to select one of PSE's limited answers, because there are no options such as "other" with a chance to enter a reason. There is no reason to force all survey respondents to make a choice between biodiesel and hydrogen in Question 6, especially if they did not select Sensitivity 47 about using biodiesel and hydrogen. If people do not understand different ways to model temperature, there is no reason to force them in Question 7 to select among PSE's three options. If respondents do understand all three temperature options and think they are all invalid, they are still forced to select one, perhaps causing PSE to think erroneously that the respondents would be happy with the selected choice. The survey format PSE selected forces respondents to make choices on these questions if they want their Sensitivity choices to be recorded; PSE has no way to interpret responses on these questions or on the Sensitivities. For example, if respondents don't feel they know enough to answer these questions and don't want to bias answers to them, they may decide not to complete the survey, so PSE will not receive sensitivity choices from some people, which means PSE won't hear from as many stakeholders as they could have. If respondents instead decide to make up answers to Questions 6 and 7 so that their Sensitivity choices are recorded, PSE will get invalid answers, which means that the results from those questions will be worthless. The survey as written could invalidate all of the results. Responses to Questions 6 and 7, in particular, are meaningless, and PSE should simply delete them; PSE should not report them or use them to make any decisions. PSE certainly should avoid saying things such as, "Participants preferred we run the sensitivity with biodiesel over hydrogen" if biodiesel receives the most votes. It is not appropriate to say, "Stakeholders liked the Northwest Power and Conservation Council's climate model temperature assumption" even if everyone selected it. PSE has no idea why anyone checked any of those boxes. Responses on the Sensitivities should be considered preliminary and a meeting with participants at the IAP2 level of Involve should be scheduled before sensitivity runs are made. Details of what PSE is actually proposing to model should be presented and a reasonable and sufficient amount of time should be scheduled for stakeholders to ask questions and make suggestions. PSE's responses should not be silence or thanking us for our input. If PSE really is proposing to run stakeholder suggested sensitivities, then they should actually be what stakeholders have requested.	and resource constraints. PSE hoped to gain insight into which of these three sensitivities best aligned with stakeholder opinions and used the survey to collect this information. PSE was not looking for alternative responses. Many stakeholders have been very vocal in IRP meetings, feedback forms and e-mails to IRP staff requesting that PSE use a 20-year trend. PSE listened to stakeholders and included this as one of the options. In addition to this stakeholder request, PSE has hired a consulting firm, Itron, to perform a separate analysis on temperature and PSE also researched the work done by the Northwest Power and Conservation Council which was included as one of the options. Outcome of the survey will be shared in the November 10 Consultation Update. Results of the sensitivities will be available for stakeholder discussion at future Webinars.
10/27/2020	Willard Westre, Union of Concerned Scientists	Slide 28 Question 1 - What is meant by Perfect Capacity? In earlier IRP sessions PSE agreed to use seasonal capacity factor data concurrent with the seasonal peak load in its process. Surely, seasonal capacity factors should also be used in the RA analysis as well. This is critical to understanding how each resource responds to each season's potential loss of capacity. Question 2 – Will PSE use seasonal capacity factors in the RA analysis? The capacity factors seem to vary in the IRP process each time they are tabulated. Question 3 – What are the current sources for these values? Slides 28-30 The Resource Adequacy data and especially the Draft ELLC data seems to be greatly oversimplified compared with its importance in the overall analysis. Question 4 – Will the draft IRP contain all the relevant data for each resource including saturation curves, seasonal capacity factors, MWh outputs, MW needed, comparative results, etc. so that this phase of the analysis can be clearly understood and appreciated? Slide 47 Apparent error: the MT-East and Central resources are wind not solar. Slide 49 Apparent error: The MT-Central and MT-East values appear to be transposed.	Thank you for your feedback. PSE's responses from the numbers you provided are as follows: 1) PSE's resource adequacy model (RAM) performs a stochastic assessment of when resources are available under a variety of load and hydro conditions. All resources have availability constraints limiting their ability to meet peak need conditions (e.g. the wind isn't blowing or a thermal plant forced outage). Perfect Capacity is a modeling tool used to simplify the measurement of shortfall in the RAM, whereby an imaginary resource has 100% availability, all the time; so it can always meet the peak need. 2) Yes, hourly resource profiles are used within the Resource Adequacy model, so seasonality is inherent in the data. 3) This is the first time, during the 2021 IRP process, that ELCC values have been provided. ELCC (Effective Load Carrying Capability) differs from NCF (Net Capacity Factor), which has been presented several times of the 2021 IRP process. However, values do evolve over the IRP process and are subject to change as the modeling process is finalized, PSE recommends checking the most recently published material to keep up to date. The ELCC values published in the October 20 Webinar are DRAFT and will likely be revised prior to final publication.

Feedback Form Date	Stakeholder	Comment	PSE Response
			4) Yes, saturation curves will be presented at a later time. ELCC values, including saturation curves, are still being developed and refined. 5) Apologies for the typographic error on the slide, MT-East and MT-Central are wind resources, not solar resources. 6) The table on slide 49, is correct. The annual net capacity factors for MT-Central wind is 39.8% and MT-East wind is 44.3%.
10/27/2020	Katie Ware, Renewable Northwest	**Please see attachment: Renewable Northwest letter feedback form dated October 27**	Thank you for your feedback. PSE's responses from the numbers you provided are as follows: 1) PSE has questions about the specifics of this request. After further communication with Katie Ware and Renewable Northwest, a complete answer will be provided in the Consultation Update to be released on November 10. Please note that the ELCC values shown are draft. 2) The ELCC of solar increased from the 2019 IRP process. The calculation of ELCC depends on a lot of factors, such as the location, size, load, and methodology. PSE would caution against indiscriminant comparisons of ELCC values between different utilities because of the myriad of variables between utility resource portfolios, load shapes and geography. For example, a higher capacity usually comes with a lower ELCC in the saturation curves. For battery storage and pumped hydro storage, PSE uses the EUE as the criteria in the ELCC calculation, use of different resource adequacy metrics may result in different results. 3) PSE will be evaluating adjustments to the HDD and CDD values in a temperature sensitivity analysis in order to address this concern. PSE will use the revised temperature forecast, discussed on slide 64 of the October 20 Webinar, to generate a 'temperature sensitivity demand forecast'. PSE will also make appropriate adjustments to the resource adequacy analysis to reflect the temperature adjustments to load.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Questions and comments from presentation. Slide numbers may have differed between the .pdf posted and the one used in the webinar. Apologies if some of my slide numbers are off by one:	Thank you for your questions and recommendations. PSE inserted each item below along with PSE's responses.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 11: Thank you for the overview of the electric portfolio model process, including inputs. Please indicate which inputs are ready and any others that are still under development. When will these values be discussed with the advisory group, e.g. flexibility benefit?	Slide 11: PSE is still in the process of completing a QA/QC process and does not yet have a summary of all the inputs available. The following topics have been covered in past Webinars and the details are available through presentation materials and related reports and attachments. In addition to filing an updated schedule for the Work Plan, PSE uses the IRP website and regular stakeholder email communication to notify stakeholders of changes. The flexibility benefit analysis has been delayed and will be discussed during the December Webinar. Other upcoming topics include: Clean Energy Action Plan, Clean Energy Implementation Plan, Highly Impacted Communities and Vulnerable Populations Assessment, wholesale market risk, portfolio results and resource plan, and distribution and transmission plans.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 12: It appears that the SCC fixed cost additions for existing and generic thermal resources are calculated separately and included in the LTCE model run. Is this correct? What steps are taken to calculate these SCC fixed costs? If practicable, please describe these steps in a process map similar to that on slides 11 and 12, or augment slide 12 to include the steps taken to calculate the fixed cost SCC adders.	Slide 12: The SCGHG adder is calculated during the LTCE simulation. A dispatch forecast for each thermal resource is generated during the LTCE run as the optimizer assesses addition of new resources. The SCGHG is calculated from this dispatch forecast and is added to the lifetime cost of each thermal resource. This is the SCGHG adder, which incorporates realistic, economic dispatch of the thermal resource while incorporating the SCGHG into portfolio build decisions (resource planning). A description of the process is available in the July 21 presentation located on the PSE IRP website.
10/27/2020	Kyle Frankiewich, Washington Utilities and	Slide 14: What would happen if the SCGHG was included as an adjustment to the gas price forecast, as the company proposes to do with the natural gas line of business? This is likely substantively similar to including the SCGHG in dispatch, or may sidestep the company's concern with the SCC-in-dispatch approach by avoiding an hour-by-hour dispatch modeling approach. Is there an advantage to including	Slide 14: Adding the SCGHG to the fuel price would have a similar effect to calculating the SCGHG as a dispatch cost. Both cases would encourage the model to reduce the dispatch of thermal resources, which is not desirable, because the SCGHG is not a real cost, but a planning adder. A real-world dispatch is important for making sensible build decisions, which is the intended goal of the IRP. Applying the SCGHG to the fuel works

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<tr><th>Feedback Form Date</th><th>Stakeholder</th><th>Comment</th><th>PSE Response</th></tr>
<tr><td></td><td>Transportation Commission</td><td>SCGHG as a fuel cost adder? I presume this has been considered and discarded in favor of the other two approaches, and would appreciate an explanation for why.</td><td>for the natural gas portfolio because the model is purchasing fuel to meet demand; it is simply a commodity cost and the model is not dispatching any resources. Whereas in the electric portfolio, natural gas plants are dispatched based on fuel and market prices.</td></tr>
<tr><td>10/27/2020</td><td>Kyle Frankiewich, Washington Utilities and Transportation Commission</td><td>Slide 15: Looking back at historical actuals, what percentage of PSE's purchased power in a typical year comes from or through MidC? Does PSE purchase significant amounts of power from other parties? Does most of this power get wheeled to MidC, or can it be wheeled through BPA from point of interconnection? At what scale – both in scale of MWh and in temporal distance – does PSE transact with other directly interconnected BAs such as SnoPUD, SCL or Tacoma Power? I presume that any trading is done on a short-term or balancing basis, and it is reasonable to simplify the modeling by excluding PSE's neighbor BAs from long-term capacity planning, but want to confirm that this is the case.</td><td>Slide 15: Short-term wholesale energy purchases for 2019 is 23.7% of total energy supply and 26.9% in 2018. See the table below for Puget Sound Energy's electric supply resources and energy production for years ended December 31, 2019, and 2018 as reported in the company's 10-K filing. PSE purchases energy from a variety of entities at the Mid-C trading hub.
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<tr><th></th><th colspan="4">Peak Power Resources At December 31,</th><th colspan="4">Energy Production At December 31,</th></tr>
<tr><th></th><th colspan="2">2019</th><th colspan="2">2018</th><th colspan="2">2019</th><th colspan="2">2018</th></tr>
<tr><th></th><th>MW</th><th>%</th><th>MW</th><th>%</th><th>MWh</th><th>%</th><th>MWh</th><th>%</th></tr>
<tr><td>Purchased resources:</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Columbia River PUD contracts[1]</td><td>687</td><td>14.5%</td><td>674</td><td>14.3%</td><td>2,642,177</td><td>10.2%</td><td>3,468,702</td><td>13.7%</td></tr>
<tr><td>Other hydroelectric</td><td>72</td><td>1.5</td><td>72</td><td>1.5</td><td>272,653</td><td>1.0</td><td>315,948</td><td>1.2</td></tr>
<tr><td>Other producers</td><td>285</td><td>6.0</td><td>284</td><td>6.2</td><td>3,276,502</td><td>12.7</td><td>3,406,627</td><td>13.6</td></tr>
<tr><td>Wind</td><td>56</td><td>1.2</td><td>56</td><td>1.2</td><td>123,368</td><td>0.5</td><td>131,270</td><td>0.5</td></tr>
<tr><td>Short-term wholesale energy purchases</td><td>N/A</td><td>—</td><td>N/A</td><td>N/A</td><td>6,144,663</td><td>23.7</td><td>6,822,927</td><td>26.9</td></tr>
<tr><td>Total purchased</td><td>1,100</td><td>23.2%</td><td>1,086</td><td>23.2%</td><td>12,459,363</td><td>48.1%</td><td>14,145,474</td><td>55.9%</td></tr>
<tr><td>Company-controlled resources:</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Hydroelectric</td><td>250</td><td>5.3%</td><td>250</td><td>5.3%</td><td>712,727</td><td>2.8%</td><td>914,540</td><td>3.6%</td></tr>
<tr><td>Coal[3]</td><td>677</td><td>14.3</td><td>677</td><td>14.4</td><td>4,347,639</td><td>16.8</td><td>4,184,950</td><td>16.5</td></tr>
<tr><td>Natural gas/oil</td><td>1,931</td><td>40.8</td><td>1,908</td><td>40.6</td><td>6,692,188</td><td>25.9</td><td>4,152,359</td><td>16.4</td></tr>
<tr><td>Wind</td><td>773</td><td>16.3</td><td>773</td><td>16.5</td><td>1,667,489</td><td>6.4</td><td>1,932,378</td><td>7.6</td></tr>
<tr><td>Other[2]</td><td>2</td><td>—</td><td>2</td><td>—</td><td>—</td><td>—</td><td>—</td><td>—</td></tr>
<tr><td>Total company-controlled</td><td>3,633</td><td>76.8%</td><td>3,610</td><td>76.8%</td><td>13,420,043</td><td>51.9%</td><td>11,184,227</td><td>44.1%</td></tr>
<tr><td>Total resources</td><td>4,733</td><td>100.0%</td><td>4,696</td><td>100.0%</td><td>25,879,406</td><td>100.0%</td><td>25,329,701</td><td>100.0%</td></tr>
</table></td></tr>
<tr><td>10/27/2020</td><td>Kyle Frankiewich, Washington Utilities and Transportation Commission</td><td>Slide 19: The modeled transmission limit and Mid-C market purchase price and availability assumptions must be validated for the resulting LTCE results to be valid. I look forward to hearing more about the company's consideration of the price and reliability risk inherent in market reliance. Will this be covered on the Dec 9 meeting?</td><td>Slide 19: PSE is actively researching its market reliance and the availability of resources at the Mid-C market. Draft results of this research will be discussed at a future Webinar.</td></tr>
<tr><td>10/27/2020</td><td>Kyle Frankiewich, Washington Utilities and Transportation Commission</td><td>Slide 20: One of the values brought by DR and EE is energy savings achieved during off-peak hours enables hydro resources to hold more water and potentially contribute more to peak events. This hydro 'storage' effect would support an increased capacity impact for EE and DR, though given PSE's relatively limited hydro resources, this impact may be small. Are PSE's analytical tools able to model this interactive effect? Are there limitations to PSE's owned hydro and long-term hydro contracts that would prevent PSE from "trading" energy for capacity? We understand this may be part of the company's RA analysis, or may be a part of the flexibility analysis which has been moved to the December meeting.</td><td>Slide 20: PSE's portfolio model includes a seasonal hydro availability forecast. Included in this hydro forecast are hourly upper and lower hydro shaping bounds, which are established by contractual and statutory limitations on PSE's hydro resources. Therefore the model does allow hydro resources to interact with other components of the portfolio such as DR and EE, but only to a limited degree.</td></tr>
<tr><td>10/27/2020</td><td>Kyle Frankiewich, Washington Utilities and</td><td>Slide 25: Why did the company choose to run its RA analysis focusing on the years 2027 and 2031? Slide 32 shows a substantial resource gap in 2026.</td><td>Slide 25 (1): CETA legislation states that the Clean Energy Action Plan (CEAP) must include a resource adequacy assessment. PSE elected to a conduct a 10-year resource adequacy study (October 2031 – September 2032) to fit the 10-year CEAP timeline. PSE has historically conducted a 5-year assessment as well, and elected to retain this date range as well (October 2027 – September 2028). The modeled year follows the hydro year and allows the full winter and summer seasons to stay intact for the analysis.</td></tr>
</table>

Feedback Form Date	Stakeholder	Comment	PSE Response
	Transportation Commission		
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 25: I understand based on previous presentations that the RA analysis results described here are generated using hydro and temperature data stretching back 80+ years. Will the company's weather sensitivities include running the RA analysis with varying weather and hydro datasets? If yes, the table in slide 25 would be a useful way to understand the impact of any weather and hydro input variation. If no, why not?	Slide 25 (2): PSE will complete a temperature sensitivity, which will impact the demand forecast used in the resource adequacy model, and therefore the resource adequacy results. A similar table to that shown on slide 25 will accompany the sensitivity results.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 25: Does the RA model customize the load target to correlate with weather data? Put another way, is the RAM load forecast responsive to weather and hydro inputs?	Slide 25 (3): Loads are responsive to weather inputs. For the RA analysis 88 years of historic weather are run through the load model to create 88 years of load responses to temperatures. (These 88 load draws also include changes to the economic and demographic variables in the load model.) Loads are not sensitive to hydro conditions.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slides 25-26: While absent from the slides, the company shared that an update to the load forecast has resulted in some modeled loss-of-load events occurring during the summer. Please provide more information regarding this new modeled result. What changed within the load forecast that prompted increased load in the summer months? How will this reliability risk during the higher-priced summer peak months be reflected in the company's market reliance risk analysis? Would the company's adjustments to contemplate global warming likely increase the frequency of summer loss-of-load events?	Slides 25-26: The demand forecast shared in the October 20 Webinar is consistent with the demand forecast shown in the September 1 Webinar. However, an inconsistency with demand forecast dataset used for RA modeling was identified and aligned. PSE regrets that our comments in the meeting which only related to the RA data set gave the appearance that the demand forecast was changed. There are no changes in the demand forecast presented on September 1. Effects of market reliance will be analyzed as part of the forthcoming stochastic portfolio analysis. Effects of forecasted temperature will be analyzed as part of the forthcoming temperature sensitivity.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 30: DR resources share many similarities with energy storage. Has the company calculated an ELCC for any DR resources? Relatedly, is there an ELCC for energy efficiency, inclusive of the interactive effect with holding hydro? This interactive effect is not unique to energy efficiency, but perhaps most relevant for demand-side resources.	Slide 30: ELCC values will be calculated for all resources considered in the 2021 IRP. These values will be shared as they become available.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 31: How much of the planning margin includes contingency and balancing? With more renewables, the need for dispatchable resources may drive system need or planning margin increases more than load growth. Will this issue be explored in the context of the flexibility analysis or the resource adequacy analysis? Does PSE anticipate that the flexibility analysis may prompt specific resource acquisitions independent of the LTCE modeling, as is done at a smaller scale for must-take EE/DR/storage resources identified through distribution planning?	Slide 31: Contingency and balancing components of the planning margin are embedded within the Peak Capacity Need calculated using the RAM. Given the stochastic nature of this model, it is difficult to tease apart specific components of the Peak Capacity Need. Both contingency and balancing reserves are calculated for each hour and vary depending on resources and load. **<u>Operating Reserves</u>** North American Electric Reliability Council (NERC) standards require that utilities maintain "capacity reserves" in excess of end-use demand as a contingency in order to ensure continuous, reliable operation of the regional electric grid. PSE's operating agreements with the Northwest Power Pool, therefore, require the company to maintain two kinds of operating reserves: contingency reserves and regulating reserves. **Contingency Reserves.** In the event of an unplanned outage, NWPP members can call on the contingency reserves of other members to cover the resource loss during the 60 minutes following the outage event. The Federal Energy Regulatory Commission (FERC) approved a rule that affects the amount of contingency reserves PSE must carry – Bal-002-WECC-1 – which took effect on October 1, 2014. The rule requires PSE to carry reserve amounts equal to 3 percent of online generating resources (hydro, wind and thermal) plus 3 percent of load to meet contingency obligations. The terms "load" and "generation" in the rule refer to the total net load and all generation in PSE's Balancing Authority (BA). **Balancing and Regulating Reserves.** Utilities must also have sufficient reserves available to maintain system reliability within the operating hour; this includes frequency support, managing load and variable resource forecast error, and actual load and generation deviations. Balancing reserves do not provide the same kind of

Feedback Form Date	Stakeholder	Comment	PSE Response
			short-term, forced-outage reliability benefit as contingency reserves, which are triggered only when certain criteria are met. Balancing reserves must be resources with the ability to ramp up and down instantaneously as loads and resources fluctuate each hour. **Flexibility Benefit.** The flexibility benefit (or cost) is applied to all resources modeled in the IRP and therefore has an impact on resource build decisions; however, decisions are not made solely on the results of the flexibility analysis.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 33: Does "Conservation: codes and standards" mean solely C&S impacts identified as free / must-take resources in the CPA, or does the -775,387 MWh figure include any programmatic conservation acquisitions? To confirm, are these codes and standards strictly ones that are fully adopted and known, and do not include any prospective standards? Also, is "solar PV" the estimate for customer-acquired rooftop solar, or something different?	Slide 33 (1): The "Conservation: codes and standards, solar PV" is combination of savings from codes and standards that are on the books, no prospective codes and standards in consideration are included, and the solar PV is the customer-acquired and owned. Both are zero cost to the portfolio and are must take resources.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 33: Does the assumption of normal hydro and P50 output for wind and solar align with the Council's methodology?	Slide 33 (2): PSE's method for calculating renewable need is consistent with methodology set forth in RCW 19.285 the Energy Independence Act which establishes the Washington Renewable Portfolio Standard. PSE understands the Northwest Power and Conservation Council renewable need methodology may differ slightly to account for the many, varying RPS requirements in effect throughout the WECC.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 46: I'm glad to hear that PSE is planning its conservation bundling to get more granularity around the anticipated cost-effectiveness threshold. Many conservation measures are associated with new buildings, and new building starts often correlate with regional economic activity. What percentage of each conservation bundle is associated with new construction EEMs? Are there separate EE/DR supply curves for low / mid / high load forecast scenarios? How does PSE's handling of this interactive effect compare with NWPCC?	Slide 46 (1): The portion of the 20-year potential that is related to new construction is about 83 aMW or about 14%. The high demand forecast is about 9% higher than the mid demand forecast in the 20th year. Thus the impact from the creating a separate CPA based on the high demand forecast is in the range of 1.3%. With a high demand forecast, the 83 aMW in new construction related savings may be around 90 aMW, or an increase in the overall total potential of 1.25%. Similarly, the low demand forecast would result in 2.3% lower savings potential in the 20th year of analysis. These are well within the error range of the savings forecast.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 46: The DR programs explored here presumably have some start-up costs, some continued expenses that may or may not scale with the size of the program, and possibly a program start and end date. How does PSE model these costs? How long are these programs assumed to exist? Is there a reinvestment option selectable by PSE's LTCE model at a DR program's end-of-life? What ramp rates are assumed for each DR resource?	Slide 46 (2): The DR programs each have start-up costs and ongoing costs. Start-up costs will be incurred in the early years when the savings may not even be available, that relationship between the gap of start-up costs and start of savings, is maintained when the portfolio model delays the start date. These programs are assumed to have a 20 year life. The ramp rates assumptions are based on the program type and are embedded in the CPA. The CPA draft report is not ready for posting at this time and will be available along with the IRP draft on January 4, 2021.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 47: I appreciate the consideration of distributed solar as an option, but believe there are other DERs, and combinations of DERs, which could be competitive and should be considered in PSE's modeling. See recommendation below.	Slide 47: Please see the response to the WUTC recommendation for DERs below.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 48: I did not realize until this meeting that PSE uses the word "unconstrained" to mean "assuming zero cost Tx for any resources in this zone." Thank you for the clarification. This helps me understand the value of running the Tx tiers. DERs will likely have outsized value in a Tx-constrained model run. Please remind me – what kind of Tx costs are assigned to proxy resources in regions considered unconstrained in Tier 0? I presume that there are at least BPA wheeling costs, and there may be a limit to the amount of wheeling available. How is this handled in PSE's modeling?	Slide 48 (1): To clarify, "unconstrained" does not mean "zero cost". Unconstrained means there is no limit on the number of resources which may be built in that region. All resources include a Fixed Transmission Cost, which represents BPA's wheeling costs. These costs were discussed in the June 30 Webinar and are available for review in the presentation materials. Sensitivity analysis using Tiers 1, 2 and 3 are intended to help understand where potential transmission constraints may exist in the future. The Webinar recording is available here.

Feedback Form Date	Stakeholder	Comment	PSE Response
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 48: I second Participant Westre's comment that the MT wind Tx topography should reflect what is currently held by PSE, and should not reflect a sale that has not been approved. This assumption should be a part of the base case, rather than a one-off sensitivity.	Slide 48 (2): Given the recent change of status of the Colstrip Unit 4 sale, PSE will model 750 MW of transmission to the Colstrip region of MT for all IRP modeling scenarios and sensitivities (i.e. 750 MW will be the base assumption for the IRP).
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 49: It seems that PSE should have access to wind production data that would allow it to provide wind capacity factors unique to each of the four WA zones – West, Central, South and East. How different are the wind profiles for each of these zones?	Slide 49: Yes, it is likely the model may be sensitive to the various wind regimes present throughout Washington State. For the purposes of this IRP, PSE will continue to use the one generic Washington wind shape for eastern, southern and central Washington. This was presented at the June 30 Webinar that is available for review on the PSE IRP website. These resources may be considered in future IRPs, but time does not allow for development of unique wind shapes for the 2021 IRP.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 50: I'm glad to hear PSE is analyzing its load and resources at the subhourly level. I'm unclear – what will the results of this flexibility analysis look like? Is it a flexibility value adjustment? Does Plexos include total portfolio costs as an output?	Slide 50: The PLEXOS model is a production cost model, so PSE will evaluate the change in costs associated with adding new resources to the portfolio. If the cost decreases, then this will be a flexibility benefit and reflected in the portfolio model as a savings. The PLEXOS model will also output flexibility violations such as the count (number of events) and the size (MWh). We can then see the violations in the base portfolio and how those violations change when adding new resources to the portfolio.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 57-58: I imagine some sensitivities will require more extensive modification of the modeling environment than others. Will the relative complexity of a given sensitivity be a part of PSE's decision-making process? How does PSE intend to use the results of the sensitivities survey?	Slide 57-58: Yes, some sensitivities require more extensive modifications to the IRP models and this fact will be taken into consideration as sensitivity analyses are processed. However, the benefit to the overall IRP process (i.e. what can be learned from the analysis) is the most important factor in determining if the sensitivity will be completed. PSE is also giving extra weight to sensitivities in which stakeholders have shown increased interest. The survey is intended to measure stakeholder interest in the various sensitivities suggested throughout the 2021 IRP cycle. Given the finite amount of time and resources available to complete the IRP, some sensitivities analyses may not be completed.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 60: Some of Eric Fox's datapoints presented verbally, such as the results of the survey of what weather assumptions and climate changes adjustments are commonly used in the utility sector, would be useful as part of the written record. How are temperature trends translated into HDDs and CDDs?	Slide 60: The methodology and results of the Itron analysis, along with the survey information that Eric Fox referenced, will be provided in the written record as part of the IRP book. Daily temperatures are translated into HDDs and CDDs using the formulas on Slide 60 of the October 20 Webinar.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 66: This type of analysis is very useful, and the principles should be applicable to the natural peak day planning standard used in the gas IRP analysis as well. I would appreciate extending these tables as far back in time as the data allows, to help us understand any broader trends or patterns.	Slide 66: As was discussed in the October 14 Webinar, the gas planning standard is very different from the electric peak planning standard. This has to do with the long time, higher cost and increased safety concerns in the event of a gas outage. The planning standard for the natural gas portfolio is based on a cost/benefit analysis.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 68: This comparison of forecasts is a very useful pair of graphs. Thank you for putting these together. A similar comparison across these four approaches putting the modeling approach, data inputs for historical weather, and other inputs influencing these trend estimates such as assumed global carbon emissions, would also be quite helpful.	Slide 68: Thank you for the comment, PSE is working on pulling together this data and will include a full write up in the draft IRP report to be uploaded to www.pse.com/irp on January 4, 2021.
10/27/2020	Kyle Frankiewich, Washington	Slide n/a: How does PSE intend to use the results of the weather approach survey?	Slide n/a: The results of the temperature sensitivity survey question will be used to help parameterize the temperature sensitivity completed for the 2021 IRP. PSE intends to model the temperature forecast by the method selected by stakeholders through the survey, as described during the October 20 Webinar.

Feedback Form Date	Stakeholder	Comment	PSE Response
	Utilities and Transportation Commission		
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	CPA: I don't believe the company has shared the Conservation Potential Assessment for electric or gas resources. I understand that participants in the company's conservation-focused advisory group have also not yet seen the document or the underlying data. Please share this document and data (in native file format) with stakeholders by posting it on the IRP webpage, as was done for the 2019 progress report. To the extent any of these materials are considered commercially sensitive, the company may request confidential treatment. If PSE contends that the CPA should not be shared at this time, please explain why and set expectations for when stakeholders will be able to review the CPA. This would also help stakeholders understand how recent code and standard updates – for example, increasing building efficiency standards – are reflected in the modeling.	CPA: Detailed CPA results were shared in the July 14 Webinar and are available online. The CPA output conservation supply curve data for the gas and electric will be posted online soon. The CPA draft report is not ready for posting at this time and will be available along with the IRP draft on January 4, 2021. It will include a discussion of the codes and standards updates in the CPA.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Flexibility as Oct 20 public input meeting topic: I thought I had made a mistake in my notes, but later realized the topic of flexibility was removed from this IRP meeting agenda recently. The work plan on file with the commission still has the topic included for this meeting as of October 20. While stakeholders have been waiting to discuss flexibility for a while now, staff also appreciates that it would be difficult to present the flexibility analysis if that analysis is not substantively completed. Still, from a public participation perspective, setting expectations for stakeholders with as much notice as possible, and keeping folks informed when changes must be made, can only help to build trust between the company and participants.	Flexibility: PSE has filed an updated work plan with the WUTC on October 27, 2020, which detailed the altered presentation schedule. PSE makes every effort to adhere to schedules, but occasionally additional work may be required to present meaningful results to the public.
		Expanded analysis of hybrid renewable resources: Staff echoes Participant Heutte's recommendation to review recently published analyses of the value streams provided by hybrid wind+storage or solar+storage resources in the region, and to verify that the many costs and benefits of these resources are accurately reflected in PSE's modeling tools.	Hybrid Resources: PSE has reviewed the materials submitted by NWEC on hybrid resources. As such, PSE has included three hybrid resources in the 2012 IRP: WA solar + battery, WA wind + battery and MT wind + pumped hydro storage. Costs for these resources were aligned with NWEC expectations during the feedback process following the May 28 Webinar.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	DERs as resource option: RCW 19.280.030(h) requires "A forecast of distributed energy resources that may be installed by the utility's customers and an assessment of their effect on the utility's load and operations." If I recall correctly, PSE is including a forecast of customer-adopted solar as an adjustment to its load forecast, but other than that, the company is not engaging in a targeted exploration of the potential impact of DERs on PSE's system. Studies have been done showing the potential for DER programs to delivery positive outcomes for the utility, participating customers and non-participating customers. In addition, utilities in the northeast and in California have demonstrated that, for example, customer-sited small-scale storage can provide significant value to all. Given that conservation may be cost-effective at a $100+/MWh LCOE, it strains credulity to assume that no DER-based resource options might exist which could bring value to the system. Some of these resources are proposed as sensitivities in the survey – sensitivities 35, 41 and 46, for example. Does PSE contend that these resource options should not be considered within the base case and all sensitivities? If so, why?	DERs: PSE is modeling DERs in several capacities as explained throughout this 2021 IRP process. These capacities include: 1) Solar PV as reflected as a demand side resource (i.e. customer purchases solar modeled in the CPA). These details were presented in the July 14 Webinar. 2) Residential western Washington PV solar (rooftop) is included as a generic resource to the 2021 IRP and documented during the May 28 Webinar feedback process. 3) Targeted development of PSE acquired non-wires development including solar PV, batteries, demand response, energy efficiency and combined heat and power as discussed in August 11 Webinar. 4) Demand response programs were discussed in July 14 Webinar as part of the Demand Side Resources Webinar. 5) Batteries within PSE system as a generic resource are documented in the May 28 Webinar feedback process. Also, sensitivities with altered forecast cost curves for DERs and altered customer solar PV adoption are scheduled to be run for the 2021 IRP process.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Feedback on electric sensitivities: While staff is interested in seeing the results of all proposed sensitivities, staff appreciates that there is a finite amount of analytical work that can be performed before the IRP must be filed, and that some scenarios will yield more compelling results than others. As we've mentioned before and above, some of these sensitivities would be appropriate for inclusion in the company's collection of standard assumptions.	Sensitivities: PSE intends to model as many sensitivities as possible for the 2021 IRP process. As results are developed, PSE will consider further alterations to the standard assumptions in future IRP cycles.

<table>
<tr><th>Feedback Form Date</th><th>Stakeholder</th><th>Comment</th><th>PSE Response</th></tr>
<tr><td>10/26/2020</td><td>Don Marsh, et al, CENSE</td><td>Dear IRP Team and Commission Staff,

A dozen stakeholders participating in the development of PSE’s 2021 IRP were alarmed to learn that the company is seeing possible loss of load during summer peaks.

The attached letter asks for further information and disclosure of the summer peak demand forecast that is producing these risks to PSE’s customers.

Sincerely,

Don Marsh

Please see attachment: Don Marsh letter feedback form dated October 26</td><td>Thank you for your comments and clarifying questions. Answers to your questions are provided below.

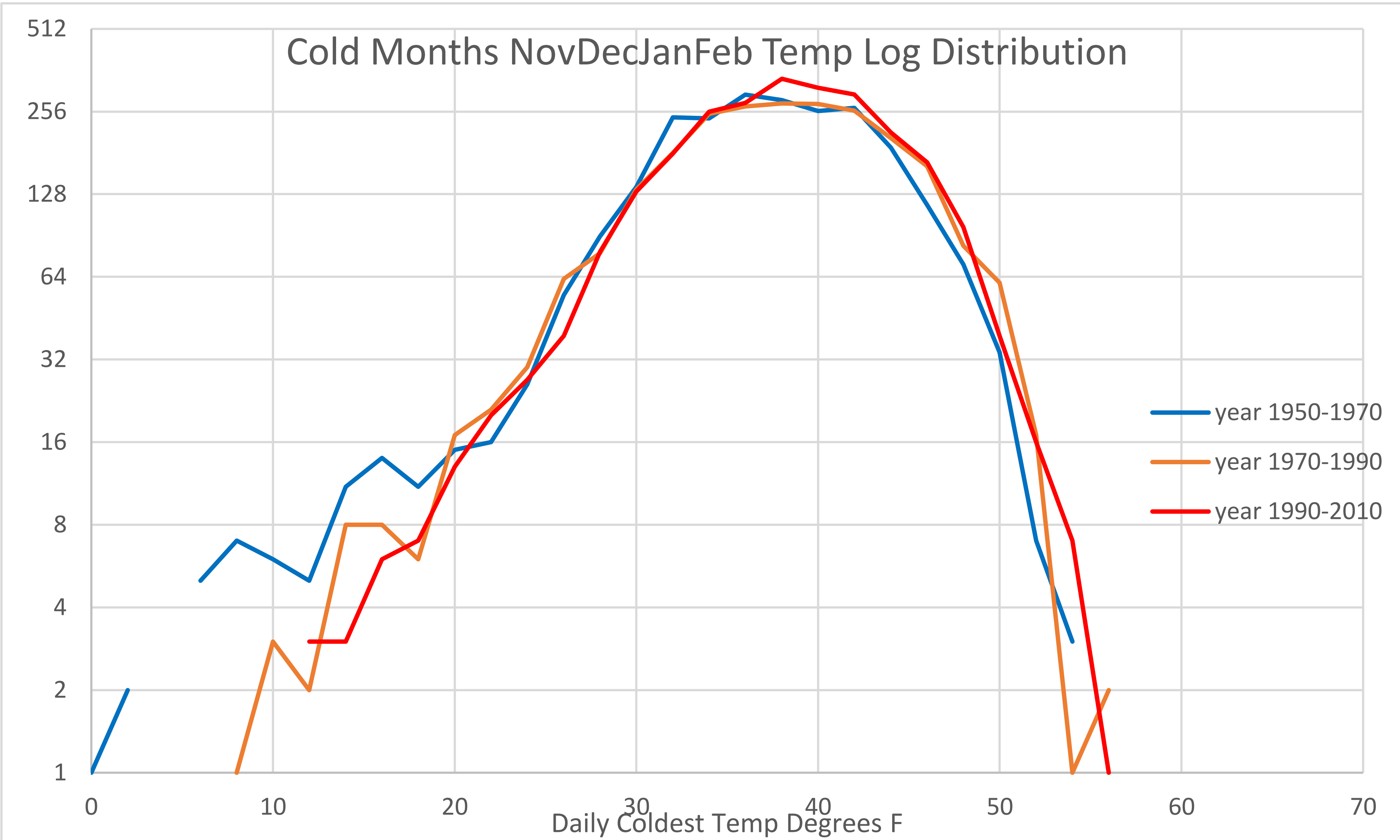
1) PSE is working on pulling the data together and a graphic of the 2021 IRP peak for both the summer and winter seasons. This graphic will be will be included in the IRP draft available at www.pse.com/irp on January 4, 2021. PSE realizes that its status as a winter peaking utility is relatively unique in the WECC region, and therefore performs all resource adequacy calculations for the entire year to take into consideration impacts of other regions on market conditions.
2) The resource adequacy assessment is conducted for two case years, 2027 and 2031. Loss of load events are observed in both test cases, however, there were only 3 events in the year 2027 and 4 events in 2031 were observed in summer over the 7040 simulations composed of 8760 hours per simulation. (see tables below)
3) The tables below shows the monthly loss of load hours across the 7040 simulations of the Resource Adequacy assessment. At most, 1 hour loss of load is observed in the 2031 case (amid 7040 simulations of 8760 hours each). A loss of load does not indicate the magnitude of the event.
4) PSE will perform a temperature sensitivity, which includes alterations to the Resource Adequacy Model (RAM) to examine the impact of increased summer loads.
5) The purpose of the IRP process is to assess various portfolio options to mitigate against forecast resource constrained conditions. Results of the IRP, in particular the temperature sensitivity, will be available for review in the draft IRP Report on January 4, 2021. Stakeholders will be able to provide feedback on the draft IRP throughout January.
<table>
<tr><th colspan="3">2027 Case</th></tr>
<tr><th>Month</th><th>Loss of Load (h) base</th><th>Loss of Load (h) at 5% LOLP</th></tr>
<tr><td>1</td><td>4712</td><td>2682</td></tr>
<tr><td>2</td><td>3050</td><td>2227</td></tr>
<tr><td>3</td><td>4</td><td>0</td></tr>
<tr><td>4</td><td>0</td><td>0</td></tr>
<tr><td>5</td><td>0</td><td>0</td></tr>
<tr><td>6</td><td>0</td><td>0</td></tr>
<tr><td>7</td><td>1</td><td>0</td></tr>
<tr><td>8</td><td>2</td><td>0</td></tr>
<tr><td>9</td><td>0</td><td>0</td></tr>
<tr><td>10</td><td>0</td><td>0</td></tr>
<tr><td>11</td><td>20</td><td>9</td></tr>
<tr><td>12</td><td>424</td><td>219</td></tr>
</table>
<table>
<tr><th colspan="3">2031 Case</th></tr>
<tr><th>Month</th><th>Loss of Load (h) base</th><th>Loss of Load (h) at 5% LOLP</th></tr>
<tr><td>1</td><td>3794</td><td>2247</td></tr>
<tr><td>2</td><td>3932</td><td>3029</td></tr>
<tr><td>3</td><td>14</td><td>4</td></tr>
<tr><td>4</td><td>0</td><td>0</td></tr>
<tr><td>5</td><td>0</td><td>0</td></tr>
<tr><td>6</td><td>3</td><td>0</td></tr>
<tr><td>7</td><td>3</td><td>1</td></tr>
<tr><td>8</td><td>0</td><td>0</td></tr>
<tr><td>9</td><td>0</td><td>0</td></tr>
<tr><td>10</td><td>0</td><td>0</td></tr>
<tr><td>11</td><td>15</td><td>5</td></tr>
<tr><td>12</td><td>305</td><td>148</td></tr>
</table></td></tr>
<tr><td>10/27/2020</td><td>Don Marsh, CENSE</td><td>Dear IRP Team,

Please see the attached letter expressing concerns by stakeholders and participants in PSE's Sensitivity Survey. We object to the forced choice among three flawed sensitivity options. We suggest a different method that corrects these flaws and more accurately models changing temperatures in our region.

Please see attachment: Don Marsh letter feedback form dated October 27</td><td>Thank you for your feedback. PSE is in the process of reviewing the proposed temperature sensitivity methodology documented in your letter. PSE needs more time to evaluate an appropriate course of action. A response will be included in the November 10 Consultation Update.</td></tr>
<tr><td>10/27/2020</td><td>Brian Fadie, NW Energy Coalition</td><td>Please see attachment: NWEC letter feedback form dated October 27</td><td>Thank you for your comments. PSE’s responses are summarized below.</td></tr>
</table>

Feedback Form Date	Stakeholder	Comment	PSE Response
			• Given the recent change of status of the Colstrip Unit 4 sale, PSE will model 750 MW of transmission to the Colstrip region of Montana for all IRP modeling scenarios and sensitivities (i.e. 750 MW will be the base assumption for the IRP). • In sensitivity #20 - Mid economic conditions with SCGHG as a dispatch cost in electric prices and portfolio model - the SCGHG will be calculated as variable cost for all emitting resources. The SCGHG is also included in the electric price forecast (as a tax) so the SCGHG will be included in the power price forecast and therefore also be present in market purchases. • In PSE's IRP model, market sales are limited to the transmission capacity available between PSE and the Mid-C Market. Social cost of greenhouse gas costs are included as an adder to market purchases, but not included as adders to market sales since it is possible to sell the power outside of Washington State.
10/29/2020	Nate Sandvig	**Please see attachment: Rye Development letter feedback form dated October 29**	Thank you for your comments. PSE's responses are summarized below. • ELCC values should be expected year to year. PSE updates many portfolio assumptions in the Resource Adequacy Model including but not limited to resource and contract changes, load forecast and regional market assumptions. These changes can result in significant changes in ELCC year to year. The ELCCs provided in the October 20 Webinar are still draft and expected to be updated. However, PSE will evaluate both battery and pumped hydro storage at 100 MW nameplate capacity to reduce the impact of saturation effects on large scale PHES. • PSE values the input of its stakeholders and has such provided a venue for stakeholders to voice which sensitivities they feel are important to the IRP process. PSE also recognizes that the IRP fulfills important regulatory requirements and that certain analyses are essential to meet these requirements. PSE places the highest importance on these analyses to ensure the IRP accomplishes its numerous objectives. • PSE acknowledges that one of the limitations of renewable generation (particularly wind and solar resources) is land-use consideration. PSE has not imposed any land-use-based build limitation into the 2021 IRP model; but aims to include such constraints in future IRP cycles.
Questions from the Webinar requiring follow-up			
10/20/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 30: I believe pumped storage projects are being marketed in slices other than the full 500MW project; that is, PSE could purchase some smaller share of the project instead of the whole thing. Would adjusting the size of the proxy resource cause this analysis to change?	For the 2021 IRP, PSE will evaluate both battery and pumped hydro storage at 100 MW nameplate capacity to reduce the impact of saturation effects on large scale pumped hydro storage.
10/20/2020	Robert Briggs	When you are evaluating the smallest increment of an energy conservation resource in your optimization to decide whether to include it or not in the least-cost portfolio, is that measure evaluated against the cost of energy it saves or is it evaluated against the energy cost savings plus the avoided social cost of greenhouse gas emissions?	The social cost of greenhouse is included as a cost adder to thermal resources and market purchases. All resources including non-emitting and renewable resources, thermal plants, and conservation, are evaluated for their total resource value and compared to other resources. For the thermal plants, the resource cost is increased for the SCGHG.
10/20/2020	Robert Briggs	Have you evaluated which base temperature correlates best with PSE's aggregate load? I note that cooling degree hours at base 80°F is frequently use for residential space cooling loads.	We model temperature sensitivity at the class level, not at the system level. The modelling for the weather sensitivities classes uses one or more base temperatures for calculating heating degree days (HDDs). Some classes use one or more base temperatures for calculating cooling degree days (CDDs). The calculation of HDD65 and CDD65 was shown for illustrative purposes. We take a class based approach because classes like the commercial class may cool their buildings to a lower temperature than residential customers.

Feedback Form Date	Stakeholder	Comment	PSE Response
10/20/2020	Virginia Lohr, Vashon Climate Action Group	For Sensitivity 22 on modeling federal carbon pricing, I compared the August spreadsheet to the new one so I could see how PSE had changed it based on public input. The new spreadsheet has a brief note on what I said, but it does not have a note that the person who is listed as asking for this sensitivity agreed with me. More alarming is that there is no change in what PSE is proposing to model. I looked at the survey this morning, and for sensitivity 22, it does not say what federal price you will use. I assume that the same has also been done for other sensitivities, but I haven't checked those. How can I and others know if we want to select this sensitivity without knowing what carbon pricing you will actually use?	PSE suggests that the spreadsheet provided was a means of portraying the intent of each sensitivity. The many specific details necessary to actually model each sensitivity are impossible to include in such a summary document.
10/20/2020	Court Olson	Have any of the analyses considered the increased use of air conditioning with air filtering to reduce the indoor air quality impact from forest fire smoke?	The peak demand forecast assumes an A/C saturation path, but PSE is not running any explicit sensitivities on an increased A/C saturation. That said, the base demand forecast is derived from and calibrated to recent seasonal history. This means we are capturing the current level of air purification demand in our usage models (to the extent of the last few years), but it is not modeled as an explicit end use with a particular trended saturation path.
10/20/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	What are the topical fact sheets?	A topical fact sheet is an International Association for Public Participation (IAP2) tool that provides a description of a project, and in PSE's case, made available on the web. When developing the public participation plan, PSE intended to use topical fact sheets as a way to distribute information to stakeholders. However, to date, PSE has not distributed any topical fact sheets.


Cold Months NovDecJanFeb Temp Log Distribution
512
256
128
64
32
16
8
4
2
1
0
10
20
30
40
50
60
70
Daily Coldest Temp Degrees F
year 1950-1970
year 1970-1990
year 1990-2010

October 27, 2020

Puget Sound Energy
IRP Team

RE: Feedback of Renewable Northwest, Electric Portfolio Model
Puget Sound Energy's October 20, 2020, Webinar Relating to the Electric Portfolio Modeling Process, Final Power Prices, Electric Sensitivities, and Inputs and Observations from Draft Results.

I. INTRODUCTION

Renewable Northwest thanks Puget Sound Energy ("PSE") for this opportunity to provide feedback as a stakeholder in PSE's 2021 Integrated Resource Plan ("IRP"). This feedback is a response to PSE's October 20, 2020, webinar regarding the Electric Portfolio Modeling Process, Final Power Prices, Electric Sensitivities, and Inputs and Observations from Draft Results for the 2021 IRP.

Renewable Northwest participated in the webinar on October 20, 2020. Below, we provide feedback based on PSE's "2021 IRP Webinar #9: Electric IRP" slide deck.

II. FEEDBACK

Renewable Northwest requests clarification respecting the determination of effective load carrying capability (ELCC) values documented on slides 27, 28, and 30, for resources being modeled for PSE's 2021 IRP.

While we recognize that ELCC values are system-dependent, PSE's values for solar, battery storage, and pumped hydro storage are lower than we would expect to see relative to ELCC values for other resources in the Northwest. For example, Portland General Electric's ELCC values in its 2019 IRP are a first-in value of approximately 16% for solar, a first-in to last-in range of approximately 85% down to 49% for 8-hour pumped hydro storage, and a first-in to last-in range of approximately 63% down to 40% for 4-hour battery storage.[1]

To understand why PSE's values are significantly lower, we request additional detail into the methodology and values underlying PSE's ELCC calculations. Specifically, we request that PSE make available the following information:

1. A 12x24 matrix of the peak demand or hours with the highest loss of load probability which were used to calculate the ELCC values for all resources.[2]
2. An explanation of contributing factors to PSE's unusually low ELCC values for solar, battery storage, and pumped hydro storage.

Renewable Northwest also anticipates the results of the must-run temperature sensitivity on load, because climate change-based temperature and load forecasts should reflect an increasing trend toward summer peaking conditions, which in the future may increase the risk of resource deficiencies and/or capacity shortfalls.[3]

III. CONCLUSION

Renewable Northwest thanks PSE for its consideration of this feedback. We look forward to continued engagement as a stakeholder in this 2021 IRP process.

Sincerely,

/s/ Katie Ware
Katie Ware
Washington Policy Manager
Renewable Northwest
katie@renewablenw.org

[1] Portland General Electric 2019 Integrated Resource Plan at 165, Figures 6-4 and 6-5, *available at* https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2019-integrated-resource-plan.pdf?la=en,

[2] *See*, *e.g.*, Energy+Environmental Economics (E3), "Capacity Value Framework & Allocation Options," Oregon Public Utilities Commission (UM 2011) at slide 39 (Jul. 9, 2020), *available at* https://edocs.puc.state.or.us/efdocs/HAH/um2011hah17397.pdf

[3] See, e.g., Northwest Power and Conservation Council, Resource Adequacy Advisory Committee (RAAC), "Resource Adequacy Assessment for 2025 and 2027," (Oct. 6, 2020), available at https://nwcouncil.app.box.com/s/ljkswnhndlxvbd3ij1w1m49t4x0wcwv6 (Preliminary results of RACC's resource adequacy assessment for 2025 reflect a regional trend of capacity shortfalls in the summer when considering the effects of climate change.)

Dear IRP Team and Commission Staff,

During PSE's October 20 IRP webinar, PSE Senior Resource Planning Analyst Zhi Chen told stakeholders that the company has identified scenarios that could cause loss of load during summer peak hours. According to Chen, this is the first time this threat has appeared in PSE's Resource Adequacy models.

During the next five minutes of the meeting, Chen mentioned this deficiency three times. See the webinar video and transcript at https://transcripts.gotomeeting.com/#/s/d7ecc1b7d9689a1fec71cbe7b97332c254c5fbf4024d765cd416acdca1234b9a (starting at time stamp 01:05:00).

Stakeholders asked for further details about the deficiency, but PSE provided no additional information. We would like to know how large the deficiency is, when it first appears, and what kind of solutions might mitigate the problem. Is an increasing summer demand forecast driving the issue? What assumptions were included in the forecast? Would demand response help mitigate the problem? Energy storage? More rooftop solar?

We are concerned because power outages during the hottest days of the year present a significant risk to PSE's customers. Food can spoil in refrigerators, and customers with health conditions may be especially burdened.

Was PSE aware of this deficiency when it asked the UTC to delay its RFP for demand response resources? During that hearing, PSE told the Commission that the company sees no demand increases for the next five years. Also, PSE has never issued an RFP for *summer* demand response.

We are concerned about what might happen if emergencies arise after the IRP is published. If hasty acquisitions or curtailments are required, these may not accord with best planning practices.

We ask PSE to provide this information while stakeholders can still participate and comment:

1. Provide the summer peak forecast used to produce this conclusion.
2. Show when the deficiency first occurs.
3. Show the magnitude of the deficiency.
4. Describe any sensitivities that will be studied to address the deficiency.
5. Inform stakeholders which resources will be considered to mitigate the problem.

IRP stakeholders help ensure that our utility's long-term energy plan serves the interests of ratepayers. To fulfill this mission, stakeholders need full disclosure of any conditions that may impact the reliability, cost, and environmental impact of our energy supply.

Sincerely,

Don Marsh, CENSE
James Adcock, Citizen at large
David Perk, 350 Seattle
Norm Hansen, Bridle Trails
Fran Korten, Climate Action Bainbridge
Kevin Jones, Vashon Climate Action Group
Doug Howell, Sierra Club
Court Olson, Optimum Building Consultants
Warren Halverson, CENSE
Jane Lindley, Act 4 Climate
Rob Briggs, Vashon Climate Action Group
Elyette Weinstein, Ratepayer

Dear IRP Team and Commission Staff,

We, the undersigned stakeholders and participants in the development of PSE's 2021 IRP, strongly object to PSE's "Sensitivity Prioritization Survey," which forces participants to choose among three temperature sensitivity options:

1. Itron's trended normal temperature based on historical trends
2. Normal temperature based on the most recent 15 years of temperature data
3. Northwest Power and Conservation Council's climate model temperature assumption

Participants are not allowed to submit the survey without choosing one of these options, but each option has significant drawbacks.

The first choice, Itron's trended normal analysis, is based on average Heating/Cooling Degree Days. This shortcut may miss peak demand issues that could lead to loss of load. We prefer a thorough stochastic analysis of hourly demand and generation to identify vulnerabilities.

The second option would use the most recent 15 years of temperature data to perform weather normalization. However, this method was shown to produce somewhat unstable and counterintuitive results. Fixing the temperature for the next 25 years is not realistic, since the trends show that temperatures are gradually rising.

The third choice, based on NWPCC's climate models, may overstate temperature changes in the Puget Sound region. Itron showed that temperature changes have been moderate for coastal communities due to the stabilizing thermal effects of the nearby ocean. A generic model that applies to all Pacific Northwest states may require PSE to build costly infrastructure in anticipation of temperatures that will never occur.

We request a temperature sensitivity that seeks to model reality more accurately:

1. To identify peak demand issues, perform a full stochastic analysis using Aurora and/or Plexos rather than average Heating/Cooling Degree Days.
2. Model winter temperatures rising at 0.0193 degrees per year (based on 1970-2016 trends).
3. Model summer temperatures rising at 0.0468 degrees per year (based on 1970-2016 trends).
4. If PSE would prefer to use the last 30 years to calculate the temperature increase, we would support that. Please report the annual temperature adjustment and how PSE determined it.
5. To model climate impacts on hydro availability, use hydro capacity values from the most recent "climate change and operational corrected" historical models from BPA (published about a month ago).

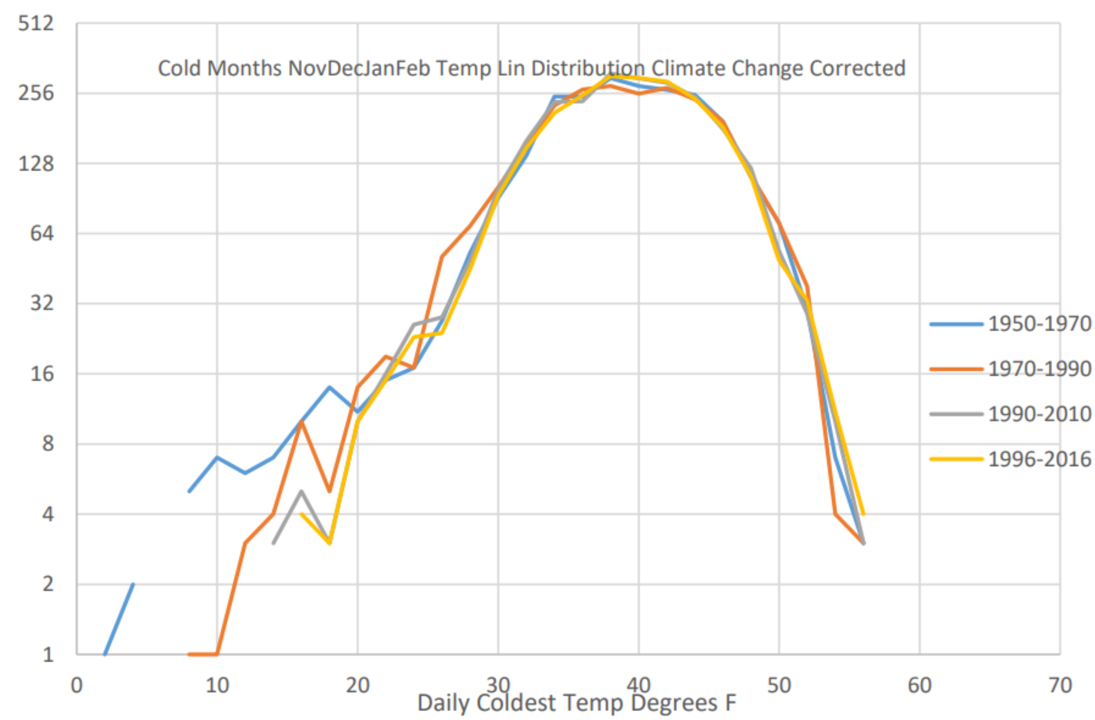
The temperature sensitivity study should produce forecasts for energy consumption and peak demand, for both winter and summer. If any forecast finds capacity deficiencies, please specify the size of the deficiency and when it first appears in the forecast. The model should indicate which resources would be used to resolve the deficiency in a cost-effective manner.

Methodology

To replicate (or improve) our proposed annual temperature adjustments, we describe the method we used to calculate the summer and winter adjustments above.

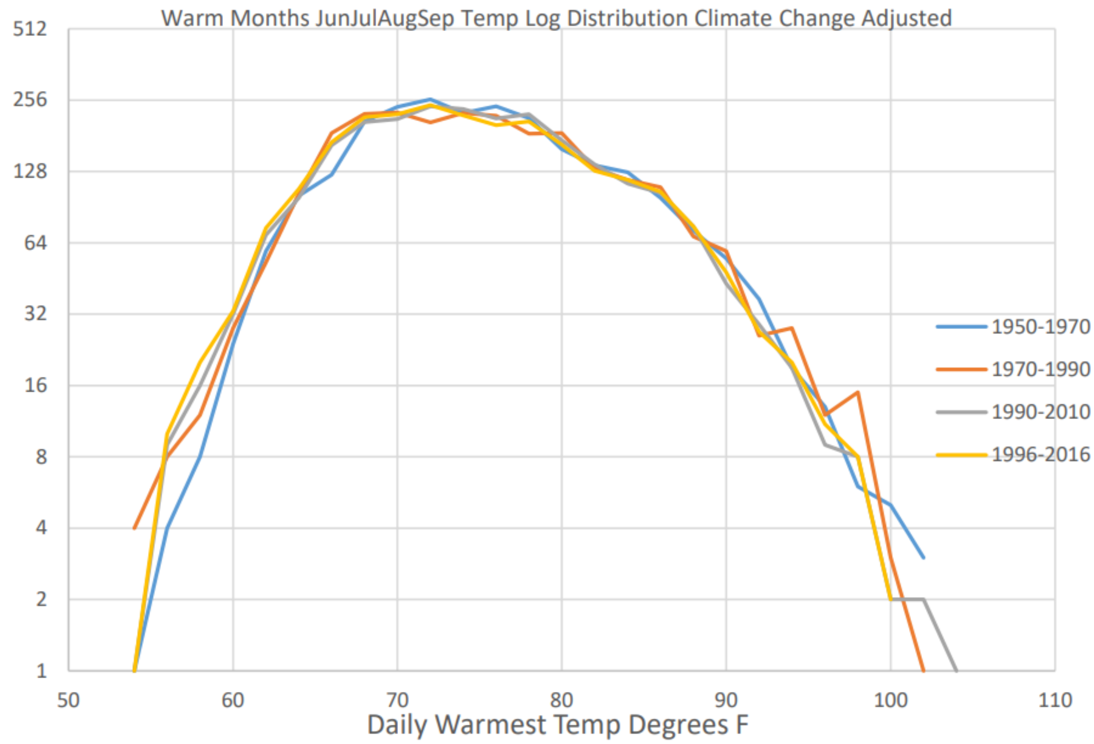
For winter, we produced log histograms of minimum temperatures for all the days of November-February for the following time periods: 1950-1970, 1970-1990, 1990-2010, 1996-2016. The later curves move gradually to the right, indicating increasing temperature. Using a linear least squares metric, we aligned the curves using an increase of 0.0.193 degrees per year.

The aligned curves look like this:



As you can see, the coldest temperatures of the blue 1950-1970 curve cannot be aligned using a simple linear adjustment, because climate change has practically eliminated temperatures colder than 13 degrees in recent decades. **Please assure us that modeling for this sensitivity uses no temperature data from before 1970.**

The same calculation was performed for warm temperatures during the days of June-September. To align the histogram curves, an adjustment of 0.0468 degrees per year produced the best alignment:



If PSE has a better method of determining an annual temperature adjustment, we are willing to consider a well-reasoned alternative. Some adjustment is needed. In some cases, the adjustment must be applied to historical data as well as forecasts.

Conclusion

For many years, stakeholders have criticized PSE's use of old temperature data in resource analysis, leading to a "cold bias" that has contributed to inaccurate demand forecasts. PSE has offered to perform a temperature sensitivity to address the problem. A reasonable and transparent sensitivity will help everyone understand the 2021 forecast and anticipate future changes in electric demand.

We ask PSE to perform the sensitivity we describe here, or at least conduct another survey to allow stakeholders to express a preference between our sensitivity and the winning sensitivity in the current survey.

Sincerely,

Don Marsh, CENSE
David Perk, 350 Seattle
Court Olson, Optimum Building Consultants
Sue Stronk, Ratepayer
Michael Laurie, Watershed LLC
Curt Allred, Ratepayer
Janis Medley, Ratepayer
Kevin Jones, Vashon Climate Action Group

James Adcock, Citizen At Large
Kate Maracas, Sound Energy Group
Rob Briggs, Vashon Climate Action Group
Fran Korten, Climate Action Bainbridge
Norm Hansen, Bridle Trails
Barbra Braun, Ratepayer
Valerie Costa, 350 Seattle
Lori Elworth, Ratepayer

NW Energy Coalition
Comments on and Requests
Regarding PSE 2021 IRP Webinar #9:
Electric IRP Sensitivities, October 20, 2020

October 27, 2020

Elizabeth Hossner
Manager Resource Planning & Analysis
Puget Sound Energy

Dear Elizabeth:

NW Energy Coalition (NWEC) appreciates the opportunity to ask questions about and make suggestions regarding Puget Sound Energy's (PSE's) proposed portfolio scenarios and sensitivities to address in analysis in the Integrated Resource Planning (IRP) effort. Our comments focus on the proposed sensitivities in the excel file "Updated sensitivities list" presented during the October 20th webinar.

Currently, sensitivity 32, titled "Add 185 MW Colstrip Transmission," is the only sensitivity meant to analyze what would happen if PSE's proposed sale of 185 megawatts of its Colstrip Transmission System ownership to NorthWestern Energy/Talen Energy is not successful. The description notes, "Results from this sensitivity will show a portfolio optimized around the assumption that this transmission will be available." Given recent developments in the regulatory approval dockets in both Washington and Montana, which have made it more unlikely than likely that this sale will be approved as proposed (if at all), we encourage PSE to assume in all but one sensitivity going forward that the 185 MW of Colstrip transmission will be available. Restated, it would now be more appropriate to include a single sensitivity in which the sale takes place while all other sensitivities assume the sale does not take place.

Evidence of this change in circumstances include the strong recommendations against the sale from Utilities and Transportation Commission staff, the Public Counsel Unit, and nearly every other party in the Washington docket.[1] Because of the strength of these testimonies, the Montana Public Service Commission postponed public listening sessions on the sale "Following developments in Washington that could stall NorthWestern Energy's effort to buy a greater stake in Colstrip Unit 4...".[2] The Montana PSC specifically cited the UTC staff recommendation to deny the sale as part of the reason for its decision.

If the IRP continues to assume in almost all sensitivities that the Colstrip transmission sale will be approved, there is significant risk that those results (and thus almost the entire IRP) will include a substantial flaw that could have been prevented.

[1] See UTC docket UE-200115
[2] See Oct. 23, 2020 Montana PSC press release, "PSC POSTPONES PUBLIC LISTENING SESSION ON COLSTRIP UNIT 4 ACQUISITION," found at: http://psc.mt.gov/Portals/125/Documents/news/pr/2020PR/20201022%20Postponed%20CU4%20Listening%20Session.pdf

We also have questions about sensitivity 20. We support having this sensitivity included in the analysis, but it is not clear from the information on the excel spreadsheet exactly how the sensitivity will be calculated. We would urge that sensitivity 20 apply the SCGHG as a variable cost for all emitting generators in all model runs as well as to all market purchases of unspecified or emitting resources for Washington customers. In addition, if the calculation of the forward price curve will be done separately from the portfolio analysis, then the SCGHG should also be applied to the new thermal resources included in that calculation.

More generally, it is also not clear in any of the scenarios or sensitivities how the IRP process addresses the possible sale of electricity to out-of-state customers. How does the IRP modeling treat market sales from resources it selects? Is there a limit placed on how much electricity can be sold to non-PSE customers from any generator? In a past IRP cycle, PSE staff had commented that new proposed peaker resources could be run more often than needed for Washington customers, intending the “excess” electricity be sold into the market in order to lower costs to customers. We can understand that market sales may occur, as market conditions dictate, from resources selected to meet Washington customer’s needs, but would not understand an intentional overbuild of resources with the intent of producing market sales. The greenhouse gas emissions from such an overbuild would be counter to the intent of CETA. We would appreciate an explanation of what kind of costs and values will be applied in the modeling to proposed generators, such as the GHG adders required by other states, the number of hours new facilities would operate beyond the hours needed to serve Washington customers, the assumed prices of market sales, or other similar assumptions.

Thank you for your consideration.

Joni Bosh
Joni@nwenergy.org

Fred Huette
Fred@nwenergy.org

Brian Fadie
Brian@nwenergy.org

NW Energy Coalition
811 1st Avenue, Suite 305
Seattle, WA 98104

Rye Development

220 NW 8th Ave. Portland, OR 97209

October 29, 2020

Puget Sound Energy
355 110th Ave NE
Bellevue, WA 98004

Re: Comments of Swan Lake and Goldendale
Puget Sound Energy Integrated Resource Plan
October 20, 2020 Meeting

The companies working to develop the Swan Lake and Goldendale pumped hydro storage projects ("Swan Lake and Goldendale") greatly appreciate the information provided by Puget Sound Energy ("PSE" or the "Company") at the October 20, 2020 Integrated Resource Plan ("IRP") webinar (the "October Meeting")[1] and the opportunity to provide feedback. These comments highlight three areas where Swan Lake and Goldendale would like to better understand PSE's modeling and/or analysis approach. First, the Effective Load Carrying Capability ("ELCC") for pumped hydro storage is lower than appears reasonable. Next, Swan Lake and Goldendale would like to stress that PSE's analysis should prioritize sensitivities that are consistent with Washington State policies and goals, and in particular its Clean Energy Transformation Act ("CETA") requirements. Finally, Swan Lake and Goldendale caution that PSE must secure its much needed capacity without overbuilding renewables, which could require extraordinary new land use demands throughout the region.

The ELCC Value for Pumped Hydro Storage is Low

PSE's current ELCC calculations for pumped hydro storage range from 27 and 32 percent, which Swan Lake and Goldendale find to be quite low. As PSE itself notes in the October Meeting materials, the same ELCC in PSE's last IRP was 37 percent.[2] This variance raises questions. In an effort to better understand PSE's modeling, Swan Lake and Goldendale raise the following issues for consideration to ensure that all of the unique benefits associated with pumped hydro are accurately reflected in PSE's analysis.

Swan Lake and Goldendale are interested in seeing PSE's analysis of how pumped hydro storage compares to batteries along different saturation curves. As discussed at the October Meeting, PSE is basing its preliminary ELCC calculations on a much smaller increment of batteries than for pumped hydro storage. Comparing a 25 MW battery to a 500 MW storage project unfairly pushes pumped storage further down the ELCC saturation curve, resulting in a biased comparison. While it is true that pumped storage projects are generally larger in minimum size than battery projects,

1 *Electric Portfolio Modeling Process, Final Power Prices, Electric Sensitivities, and Inputs and Observations from Draft Results*, webinar available at https://pse-irp.participate.online/get-involved.

2 *2021 IRP Webinar #9: Electric IRP, Analyze Alternatives & Portfolios, Electric Portfolio Model* at 30 (Oct. 20, 2020) [hereinafter *Slide Deck*] (showing ELCC EUE at 5% LOLP as 27% in 2027 and 32% in 2031).

PSE's analysis ignores the reality that PSE would not necessarily need to own or contract for the full capacity of a project. PSE may find that modeling smaller slices of a pumped hydro storage project results in a higher capacity contribution for pumped storage and lower overall cost of a portfolio that includes pumped storage. We trust that this is what PSE plans to do in its portfolio optimization, but it would be helpful, even in these preliminary studies, to put different technologies on level ground to allow for fair comparisons. We recommend that PSE provide ELCC results for 100 MW blocks of both battery and pumped hydro storage projects.

Moreover, PSE may not be looking at state of charge properly, which could explain part of the lower than expected ELCC values. If the highest priority for pumped storage is reliability, then PSE would always have the ability to charge it for its longest available durations, eight hours or more. Understanding that PSE will always prioritize reliability over economic optimization, adjustments to the state of charge modeling may be appropriate. Swan Lake and Goldendale would like to better understand PSE's perspective on how pumped hydro storage would be used operationally to understand if the ELCC modeling reflects those operational assumptions. Stated another way, assuming PSE is uninterested in economic arbitrage during winter months where there is a higher loss of load probability, PSE should confirm its ELCC modeling to reflect those operational priorities.

Finally, Swan Lake and Goldendale suggest that PSE's stochastic analysis underestimates the risk of a particular variable resource not being available when needed for reliability compared to a resource like pumped storage. PSE's modeling should also consider extended cold snaps, or other highly correlative weather events, where pumped hydro storage is likely to outperform other technologies. This is an important aspect of resource diversity. Wide variations from year to year are arguably mitigated by looking at averages, but Swan Lake and Goldendale urge PSE to better explain how it is valuing the lack of variability associated with pumped hydro storage from year to year.

Sensitivities Must Reflect CETA and Other State Goals

Swan Lake and Goldendale appreciate that PSE previously requested stakeholder input to create the list of sensitivities that PSE will use to test its resource portfolios. PSE should be applauded for encouraging stakeholder involvement in this way. At the Meeting, PSE indicated that it now had 47 potential portfolio sensitivities. PSE also shared that it would not be possible to analyze all of these sensitivities before the April 1, 2020 filing deadline and therefore requested additional input from stakeholders to help PSE prioritize its analysis.[3]

Swan Lake and Goldendale participated in PSE's survey, but are not sure how much value should be attached to representative stakeholder voting. Some of the sensitivities were misaligned with and/or not representative of Washington's carbon goals. The Company should focus on sensitivities that support the direction of State policy over potentially more popular stakeholder pet sensitivities.

3 *See Slide Deck* at 57.

PSE Should Also Consider Land Use Issues Pertaining to A Potential Renewables Overbuild

Swan Lake and Goldendale want to highlight a recent Energy+Environmental Economics ("E3") study that concluded the elimination of electric sector GHG emissions in the Greater NW would lead to exponential cost increases and would be impractical due to the massive renewable overbuild that would be necessary to meet the corresponding capacity needs.[4] This is particularly relevant given the passage of CETA and how unlikely any new gas projects are in the region. According to E3, the amount of land that would be needed to eliminate GHG emissions from the Greater NW electric sector by 2050 would range between 20 and 100 times the area of Portland and Seattle combined.[5] PSE should work to meet its carbon reductions without overbuilding. As a reminder, Central Montana wind has a different shape than Eastern Montana wind, which has a different shape than Southern Oregon; pumped hydro storage can help optimize diverse resource shapes and is therefore uniquely situated to help PSE avoid overbuilding.

Swan Lake and Goldendale appreciate the opportunity to comment during PSE's 2021 IRP process and look forward to working with PSE during the Washington Utilities and Transportation Commission proceedings.

Sincerely,

/s/ Nathan Sandvig

Nathan Sandvig
nathan@ryedevelopment.com

cc: Michele Kvam, michele.kvam@pse.com

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4 Resource Adequacy in the Pacific Northwest, Serving Load Reliability Under a Changing Resource Mix at 42-57 (Jan. 2019), available at https://static1.squarespace.com/static/5e9fc98ab8d9586057ba8496/t/5ee52f8fdd4fcc4948f809e2/1592078233508/E3_NW_RA_Presentation-2018-01-05.pdf.

5 *Id.* at 57.

PSE IRP Consultation Update

Webinar 9: CETA Assumptions, Demand Forecast, Resource Adequacy, Resource Need

October 20, 2020

11/10/2020

The following consultation update is the result of stakeholder suggestions gathered through an online Feedback Form, collected between October 13 and October 27, 2020 and summarized in the November 3 Feedback Report. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

PSE thanks Kare Ware and Sashwat Roy (Renewable Northwest) for follow-up discussions concerning the loss of load probability question on November 6, 2020.

Temperature trends and temperature sensitivity

PSE received feedback from James Adcock, Katie Ware (Renewable Northwest), Kyle Frankiewich (WUTC Staff) and Don Marsh (CENSE) regarding the temperature years used to model PSE's load forecast and in the resource adequacy model. Stakeholders suggest that more recent temperature data (i.e. most recent 20 years) should be used to inform PSE models to limit the impact of colder weather observed in older records and accentuate warming trends present in more recent records.

PSE has committed to completing a temperature sensitivity for the 2021 IRP which will address the concerns raised by stakeholders. PSE has proposed three options for modeling temperature data for the temperature sensitivity:

1. Trended normal based on historical observed trends (trended normal analysis completed by Itron Inc.)
2. Temperature normal based on most recent 15 years of temperature data
3. Northwest Power and Conservation Council's climate model temperature assumption

More information on these options is available for review in the October 20 Webinar presentation. A stakeholder survey was conducted between October 19 and October 27 to collect feedback on which temperature option was of greatest interest. The results of the survey indicate the stakeholders suggest using the Northwest Power and Conservation Council ("NPCC" or "the Council") climate model temperature assumption (option 3). The full results of the survey are presented below.

Don Marsh and a group of stakeholders also prepared and presented an additional temperature sensitivity methodology as part of the feedback process. During this IRP process, many stakeholders provided recommendations in IRP meetings, feedback forms and e-mails to IRP staff requesting that PSE use the most recent 15 or 20-years of temperature data. PSE listened to stakeholders and included the most recent 15 years of temperature data as one of the options for stakeholder consideration. In addition to this stakeholder request, PSE has hired a consulting firm, Itron, to perform a separate temperature analysis and PSE also researched the work done by the Council on climate change modeling. Both of these analyses were included as additional options for temperature sensitivity analysis during the October 20 Webinar and in the sensitivity survey. Over 140 stakeholders responded to the sensitivity survey and 93 stakeholders selected the Council's climate change model temperature assumptions. PSE will follow the stakeholders' recommendation to use the Council's climate change model tempertuare assumptions and will consider the materials presented by Don Marsh et al for future IRP cycles.

The Northwest Power Conservation Council (the "Council") is using global climate models that are downscaled to forecast temperatures for many locations within the Pacific Northwest. PSE has chosen to look at one of these models. The Council weighs temperatures by population from metropolitan regions throughout the Northwest. However, PSE received data from the Council that is representative of SeaTac airport. This data is, therefore, consistent with how PSE plans for its service area and this data is not mixed with temperatures from Idaho, Oregon or Eastern Washington. The climate model data provided by the Council is hourly data from 2020 through 2049. This data resembles a weather pattern where the temperatures fluctuate over time, but generally trend upward. For the load forecast portion of the temperature sensitivity, PSE proposes to smooth out the fluctuations in the temperatures and increase the heating degree days (HDDs) and cooling degree days (CDDs) over time at 0.9 degrees/decade, which is the rate of temperature increase found in the Council's climate model.

Montana transmission capacity

PSE received feedback from Willard Westre (Union of Concerned Scientists), Kyle Frankiewich (WUTC Staff) and Brian Fadie (Northwest Energy Coalition) concerning the transmission capacity between PSE service territory and the Colstrip region of Montana. In the June 30 Webinar, and again in the October 20 Webinar, PSE presented an upper transmission capacity limit of 565 MW to Montana. At the time these values represented the most-likely transmission capacity available to PSE in the region. Since the presentation of these materials, negotiations for sale of PSE's portion of Colstrip Unit 4 have ceased. Therefore, PSE will model 750 MW of available transmission capacity to Montana for the 2021 IRP process as the base assumption.

PSE has also proposed modeling of several transmission constrained sensitivities for the 2021 IRP process. These sensitivities are structured around transmission tiers, which represent uncertainty of availability of transmission capacity. The change in Montana transmission capacity will influence BPA transmission redirect assumptions for the Eastern Washington region. These changes are summarized in the table below.

Resource Group Region	Added Transmission (MW) Tier 0	Tier 1	Tier 2	Tier 3
PSE territory (a)	(b)	(b)	(b)	(b)
Eastern Washington	Unconstrained	300	675	~~1,515~~ 1,330
Central Washington	Unconstrained	250	625	875
Western Washington	Unconstrained	0	100	635
Southern Washington/Gorge	Unconstrained	150	705	1,015
Montana	~~565~~ 750	350	565	~~565~~ 750
Idaho / Wyoming	600	0	400	600
TOTAL	generally unconstrained	1,050	3,070	5,205

(a) Not including the PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed
(b) Not constrained in resource model, assumes adequate PSE transmission capacity to serve future load

Sensitivity survey and selection

PSE received questions from Virginia Lohr (Vashon Climate Action Group), Kyle Frankiewich (WUTC Staff) and Nate Sandvig (Rye Development) concerning how the sensitivity prioritization survey would be used. PSE considers the sensitivity survey a tool to help collect stakeholder sentiment on each of the many sensitivities purposed over the course of the 2021 IRP process. PSE intends to use the results as a guideline for prioritizing which sensitivities to run as part of the IRP modeling process. Other factors such as difficulty, length of time and value to the entire IRP process will also be considered as sensitivities are processed.

The full results of the survey are provided below.

ELCC values

PSE received feedback from Willard Westre (Union of Concerned Scientists), Katie Ware (Renewable Northwest), Kyle Frankiewich (WUTC Staff) and Nate Sandvig (Rye Development) concerning the ELCC values presented in the October 20 Webinar. As PSE indicated during the webinar, the ELCC values presented are draft and subject to change over the course of the IRP modeling process. Furthermore, more refined values, including saturation curves, will be provided at a later date.

Specific concerns on the relative value of battery energy storage systems to pumped hydroelectric storage will be addressed with publication of ELCC values for both resources at a nameplate of 100 MW at a later date.

Summer loss of load events

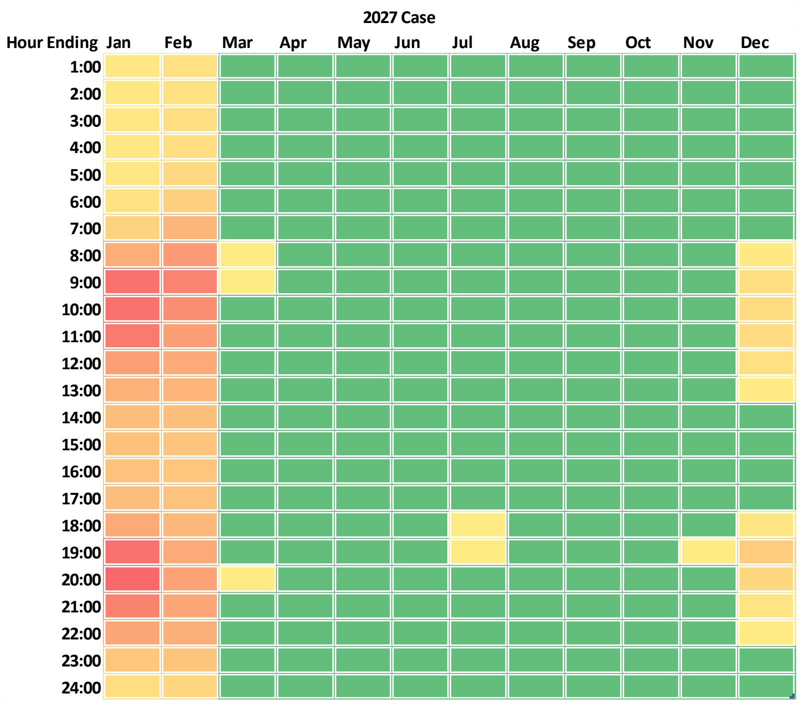
PSE received feedback from Katie Ware (Renewable Northwest), Kyle Frankiewich (WUTC Staff) and Don Marsh (CENSE) concerning summer loss of load events. PSE would like to clarify that the demand forecast for the 2021 IRP process has not changed since its presentation during the September 1 Webinar. However, an inconsistency with the demand forecast dataset used for Resource Adequacy modeling was identified and aligned. PSE regrets that our comments in the meeting, which only related to the Resource Adequacy dataset, gave the appearance that the demand forecast was changed.

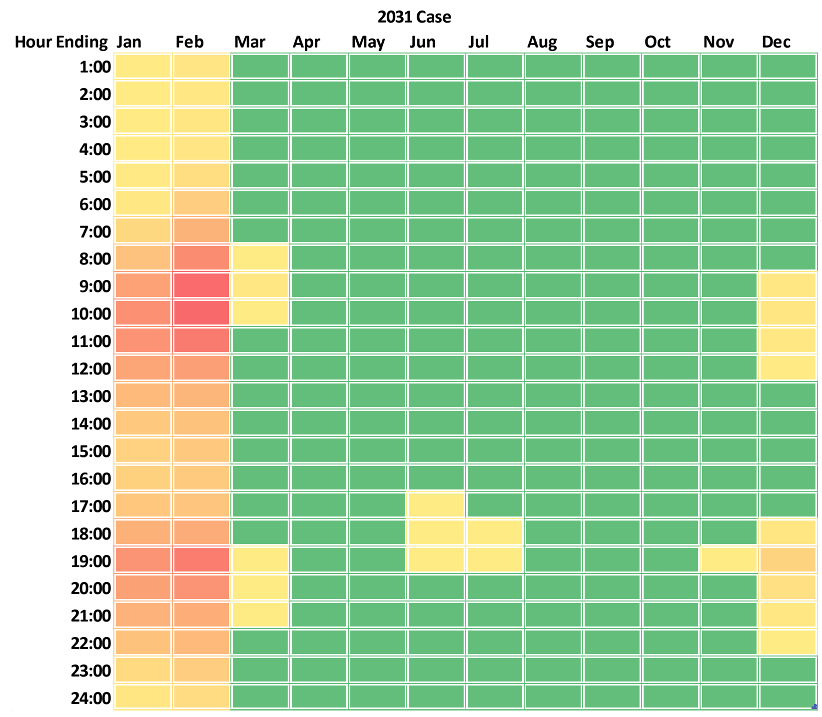
The summer-time loss of load events discussed during the meeting represent a very small fraction of the total loss of load events encountered over the course of a full year as shown in the tables below for the two test case years 2027 and 2031. A loss of load event can be caused by many factors which include temperature, demand, hydro conditions, plant forced outages, and variation in wind and solar generation. All of the factors are modeled as stochastic inputs simulated for 7,040 iterations. As mentioned previously, the data shared at the October 20 webinar are draft. PSE has been reviewing the data used for the resource adequacy model and found an inconsistency with the correlations for wind and solar data. PSE has fixed the correlations and is working on updating the peak capacity need and effective load carrying capability (ELCC) values. The table below has been updated since the November 3 feedback report to include the updates to the wind and solar correlations.

2027 Case			2031 Case		
Month	Loss of Load (h) base	Loss of Load (h) at 5% LOLP	Month	Loss of Load (h) base	Loss of Load (h) at 5% LOLP
1	4846	2893	1	3860	2387
2	3296	2553	2	4267	3365
3	10	5	3	40	14
4	0	0	4	0	0
5	0	0	5	0	0
6	10	0	6	12	5
7	3	2	7	4	2
8	0	0	8	4	0
9	0	0	9	0	0
10	0	0	10	0	0
11	5	1	11	9	1
12	474	275	12	325	160

Notes: Tables represent the results of 7,040 simulations where each simulation is composed of 8760 operating hours. Tables do not describe the magnitude of any loss of load event, just that the event occurred.

Katie Ware (Renewable Northwest) had also requested a 12x24 of the loss of load probability as part of this feedback cycle. Given the methodology of the Resource Adequacy Model, PSE is not able to produce hour by hour probabilities, so instead these plots represent a relative heat map of the number hours of lost load binned by month and hour of day.





Sensitivity prioritization survey results

Thank you for your active engagement in the IRP process, PSE collected results from over 140 individual respondents with this survey.

Sensitivity Selection Results

Rank	Sensitivity Number and Description	Number of Responses
1	35 - EV battery to grid – stakeholder requested, webinar - models inclusion of an electric vehicle-to-grid resource as a generic resource	132
2	21 - Use AR5 to model upstream emissions – social cost of greenhouse gases / CO2 price – upstream emissions will be quantified using the AR5 methodology rather than the AR4 methodology	129
3	14 - 6-yr ramp rate – conservation – reduces the conservation measures ramp from 10 years to 6 years	126
4	32 - Add 185 MW Colstrip Transmission – stakeholder requested, webinar - models additional transmission from the Colstrip substation to PSE service territory	126
5	17 - Social discount rate for DSR – conservation – reduces the discount rate of demand side resources from 6.8% to 2.5%	124
6	39 - SCGHG only (dispatch cost) – stakeholder requested, webinar - models the social cost of greenhouse gases as a dispatch cost in the absence of other CETA targets	122
7	36 - Time of use pricing – stakeholder requested, webinar - models inclusion of time of use pricing for conservation and demand response programs	121
8	41 - Private solar input testing – stakeholder requested, feedback form – models inclusion of subsidy for solar and electric storage resources	121
9	42 - Equity-focused portfolio - stakeholder requested, feedback form – a minimum of 50% of new resources must be located in WA State and expansion of community solar programs	120
10	46 - Virtual Power Plants (VPP) – stakeholder requested, feedback form – VPPs are used to manage distributed energy resources	116
11	26 - 100% renewable resources by 2030, no gas generation – emissions reduction – models more aggressive renewable resource adoption and all gas plants would be retired by 2030	24
12	28 - Carbon reduction – emissions reduction – all natural gas plants retired by 2045 and run-time limits imposed to meet carbon emission targets	22
13	18 - High SCGHG – social cost of greenhouse gasesgreen house gases / CO2 price – models a higher social cost of greenhouse gases than specified by CETA	18
14	9 - "Highly Distributed" Transmission/build constraints, Tier 1 – transmission constraints / build limits - models a significantly transmission constrained system	17
15	11 - "Highly Centralized" Transmission/build constraints, Tier 3 – transmission constraints / build limits - models a lightly transmission constrained system	13
16	12 - Transmission/build constraints - time delayed (option 2) – transmission constraints / build limits - models an expanding transmission system over time	13
17	47 - Alternative fuel #2 for peakers – stakeholder requested, feedback form – a must-run sensitivity of either biodiesel OR hydrogen as an alternative fuel for peaker plants will be modeled, this sensitivity is a vote to model BOTH biodiesel and hydrogen as sensitivities	13
18	20 - Mid economic conditions with SCGHG as dispatch cost in electric prices and portfolio model – social cost of greenhouse gases / CO2 price – models the social cost of greenhouse gases as dispatch cost in both the power price and portfolio models	12
19	33 - Fuel switching from electric to gas – stakeholder requested, webinar - decreases demand in electric portfolio and increases demand in gas portfolio	12
20	5 - Mid economic conditions plus Increased Renewable Build – economic conditions - power price forecast adjusted to model 100% renewable energy goal in Oregon	11
21	16 - Non-Energy Impacts (NEI) – conservation – increases the value of non-energy impacts from adoption of conservation and demand response measures	11
22	24 - SCGHG as a tax in WA, OR, CA – social cost of greenhouse gases / CO2 price – models the social cost of greenhouse gases plus a regional CO2 tax of $15/ton (adjusted for inflation over time) in WA, OR and CA	10
23	37 - Holistic conservation approach – stakeholder requested, webinar - additional information needed to complete this sensitivity	10
24	22 - Mid economic conditions with SCGHG as a fixed cost plus a federal CO2 tax – social cost of greenhouse gases / CO2 price – models the social cost of greenhouse gases plus a federal CO2 tax	8
25	6 - Low demand with mid gas prices – economic conditions – low demand in both power price and demand forecasts and "most-likely" gas price forecast	6
26	15 - 8-yr ramp rate – conservation – reduces the conservation measures ramp from 10 years to 8 years	6
27	44 - 2% Cost threshold - stakeholder requested, feedback form – must take DR and Battery storage first, then optimized other builds – other stakeholder requested - resource additions are constrained to the CETA 2% cost cap, must build demand response and battery storage before gas plants	6
28	4 - Low Demand with a Very High Gas price – economic conditions – mix of low demand and very high gas price forecasts	5
29	45 - 2% cost threshold, renewable Over-generation Test – stakeholder requested, feedback form – resource additions are constrained to the CETA 2% cost cap, PSE market sales are prohibited	5
30	23 - High economic conditions with SCGHG as dispatch cost in electric prices and portfolio model – social cost of greenhouse gases / CO2 price – models the social cost of greenhouse gases as dispatch cost with higher than expected power price, demand and gas price forecasts	2
31	34 - High economic conditions with SCGHG as dispatch cost in portfolio model only – stakeholder requested, webinar - models social cost of greenhouse gases as a dispatch cost under higher than expected power price, demand and gas price forecasts	2
32	40 - Tweaks to resource cost assumptions – stakeholder requested, feedback form – models altered resource cost assumptions on generic resources (further detail forthcoming from WUTC staff)	2

Sensitivity #25 Alternative fuel #1, fuel selection

Rank	Alternate Fuel	Number of Responses
1	Hydrogen	140
2	Biodiesel	16

Sensitivity #31 Temperature sensitivity, temperature methodology

Rank	Temperature Methodology	Number of Responses
1	3. Northwest Power and Conservation Council's climate model temperature assumption	93
2	2. Temperature normal based on most recent 15 years of temerpature data	43
3	1. Trended normal based on historical observed trends (trended normal analysis completed by Itron Inc.)	20

Summary of all updates

PSE appreciates the feedback provided by stakeholders. In summary, the following changes will be implemented:

- The temperature sensitivity will be modeled using the Council's methodology.
- The Montana transmission capacity will be set to 750 MW.
- Sensitivity prioritization has been informed by the stakeholder survey results, as shown above.
- Hydrogen will be included as an alternate fuel choice in the Alternative Fuel #1 sensitivity (sensitivity #25, must-run).

Webinar 10, November 16, 2020

Clean Energy Action Plan and Clean Energy Implementation Plan, Economic, Health and Environmental Benefits Assessment and Delivery System and Grid Modernization Needs

Webinar #10: Clean Energy Action Plan, Highly Impacted Communities and Vulnerable Populations Assessment, Delivery System and Grid Modernization Needs

November 16, 2020 from 1:00 p.m. to 5:00 p.m. PST

Virtual webinar link: https://global.gotomeeting.com/join/413142693

Access code: 413-142-693

Topic	Lead
Welcome • Agenda review • Safety moment • How to participate • Speaker introductions	EnviroIssues
Clean Energy Action Plan & Clean Energy Implementation Plan	Irena Netik, Director, Resource Planning & Analytics Ben Farrow, Director, Clean Energy Strategy, PSE
Highly Impacted Communities and Vulnerable Populations Assessment	Tyler Tobin, Resource Planning Analyst, PSE
5-minute break	
Delivery System and Grid Modernization Needs	Jens Nedrud Manager System Planning, PSE Elaine Markham Manager, Grid Modernization Strategy & Enablement, PSE
Wrap up and next steps • Next steps • Upcoming meeting schedule • Thank you's	EnviroIssues

2021 IRP Webinar #10: Electric IRP

10-year Clean Energy Action Plan
Electric Portfolio Model

November 16, 2020

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Welcome to the webinar and thank you for participating!

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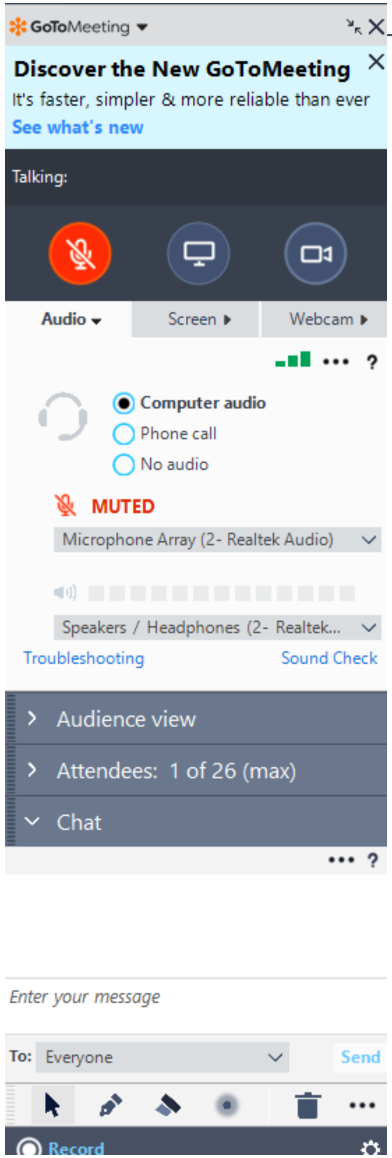

Virtual webinar link: https://global.gotomeeting.com/join/413142693

Access Code: 413-142-693

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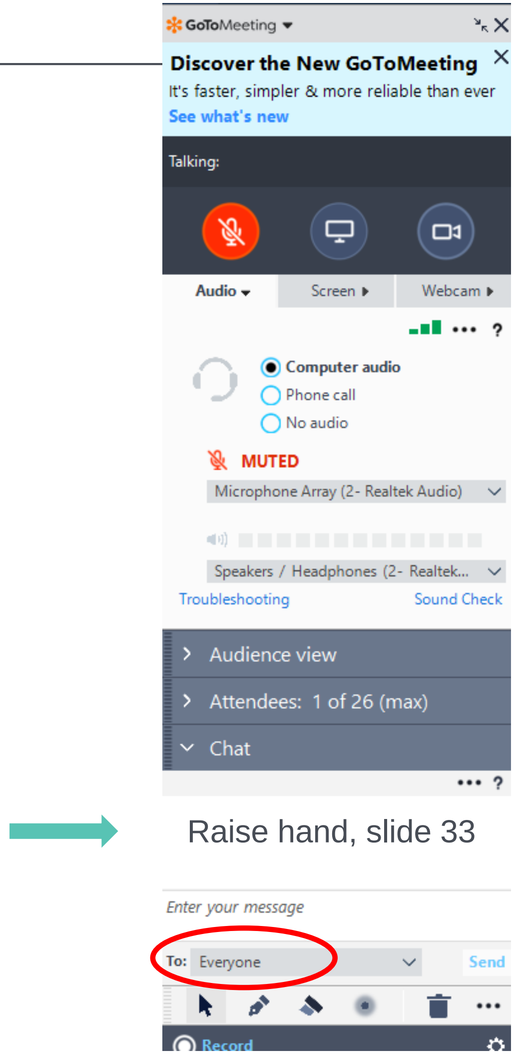
    - **In writing:** your question will be read
    - **Verbally:** type "Raise hand" and slide #, share with "Everyone"; please wait to be called on to ask your question
- Be considerate of others waiting to participate
- We will try to get to all questions



PUGET SOUND ENERGY

Agenda

- Safety Moment
- Clean Energy Action Plan and Clean Energy Implementation Plan
- Economic, Health and Environmental Benefits Assessment of Current Conditions
- Delivery System and Grid Modernization Needs

Safety Moment: Driving safety

Across the US, driving fatalities are up in many states despite a smaller number of vehicles on the road. Here are some tips to make sure your next trip is safe:

Inspect your vehicle before leaving on your journey. Check such things as:

- Tire pressure
- Working headlights and signals
- Sufficient levels of gas and windshield washer fluid
- Availability of first aid kits and fire extinguishers

And while driving be sure to:

- Follow posted speed limits
- Wear your seat belt
- Do not use your phone or other mobile device and
- Never drive under the influence of alcohol or drugs

PSE PUGET SOUND ENERGY

Today's Speakers

Irena Netik
Director, Resource Planning & Analysis, PSE

Ben Farrow
Director, Clean Energy Strategy, PSE

Tyler Tobin
Resource Planning Analyst, PSE

Jens Nedrud
Manager, System Planning, PSE

Elaine Markham
Manager, Grid Modernization Strategy & Enablement, PSE

Alexandra Streamer & Elise Johnson
Co-facilitators, EnviroIssues

Electric IRP process overview

2021 IRP modeling process

The 2021 IRP will follow a 6-step process for analysis:

1. Analyze and establish resource need
2. Determine planning assumptions and identify resource alternatives
3. Analyze scenarios and sensitivities using deterministic and stochastic risk analysis
4. Analyze results
5. Develop resource plan
6. **10-year Clean Energy Action Plan**

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2021 IRP process timeline

Meeting dates are available on [pse.com/irp](pse.com/irp) and will be updated throughout the process. This is a tentative timeline subject to revision.

Clean Energy Action Plan & Clean Energy Implementation Plan

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Participation Objectives

- PSE will review elements of draft CEAP and CEIP rules and next steps with stakeholders

  IAP2 level of participation: INFORM & CONSULT

- PSE will involve stakeholders in identifying initial metrics used to inform the Economic, Health, and Environmental Benefits Assessment

  IAP2 level of participation: INVOLVE

IRP Stakeholder Feedback Approach

<u>November 2020 IRP webinar</u>

- ❖ Obtain input on the initial metrics for Economic, Health and Environmental Benefits Assessment intended to assess:
  - ❖ Current conditions, with an emphasis on ensuring Highly Impacted Communities and Vulnerable Populations benefit and are not burdened by the transition to clean electricity
  - ❖ Public health
  - ❖ Environmental benefits and burdens
  - ❖ Energy security and resiliency

<u>Future IRP webinar</u>

- ❖ Share outcome of stakeholder feedback on initial assessment results, portfolio results and draft resource plan and the development of proposed Indicators
- ❖ Solicit additional input on proposed Indicators for the 2021 IRP

PUGET SOUND ENERGY

CETA rulemaking update

Washington’s Clean Energy Transformation Act (CETA) includes:

- Electricity standards for 2025, 2030 and 2045
- Ensuring all customers benefit from the transition to clean energy

CETA rulemaking continues:

- October 14: Draft rules published on IRP, Clean Energy Action Plan and Clean Energy Implementation Plan
- November 12: Deadline for written comments on draft rules
- December 9: UTC rule adoption hearing

New CETA Requirement: equitable distribution of energy and non-energy benefits

WAC 480-100-610 Clean Energy Transformation Standards (4)

(c) Ensure that all customers are benefiting from the transition to clean energy through:

(i) The equitable distribution of energy and non-energy benefits and reduction of burdens to vulnerable populations and highly impacted communities;

(ii) Long-term and short-term public health and environmental benefits and reduction of costs and risks; and

(iii) Energy security and resiliency.

Note: underlined terms are defined on next slide

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Related Definitions from CR 102 UE-190698 and UE-191023 Rules

Energy Burden: means the share of annual household income used to pay annual home energy bills.

Equitable Distribution: a fair and just, but not necessarily equal, allocation of benefits and burdens from the utility's transition to clean energy. Equitable distribution is based on disparities in current conditions. Current conditions are informed by, among other things, the assessment described in RCW 19.280.030(1)(k) from the most recent integrated resource plan.

Highly impacted community: means a community designated by the department of health based on the cumulative impact analysis required by RCW 19.405.140 or a community located in census tracts that are fully or partially on "Indian country," as defined in 18 U.S.C. Sec. 1151.

- Department of Health's cumulative impact analyses available by the end of 2020

Vulnerable populations: means communities that experience a disproportionate cumulative risk from environmental burdens due to: Adverse socioeconomic factors, including unemployment, high housing and transportation costs relative to income, access to food and health care, and linguistic isolation; and sensitivity factors, such as low birth weight and higher rates of hospitalization.

Indicator: means an attribute, either quantitative or qualitative, of a resource or related distribution investment.

The new planning cycle

A phased planning process of increasing specificity that incorporates past planning standards and adds new CETA standards: to phase out coal, meet GHG neutral standard by 2030 and clean energy standard by 2045.

Filed jointly as the IRP

IRP — The IRP identifies PSE's energy, capacity, and renewable energy need ***through 2045***, potential options to meet those needs, and models the energy, capacity, and cost of meeting those needs.

Clean Energy Action Plan — The CEAP identifies the lowest reasonable cost resource plan PSE will pursue over the next ***10 years*** to meet the energy capacity, and renewable energy needs, considering risk and equity.

Clean Energy Implementation Plan — The CEIP identifies the specific and interim targets consistent with the plan in the CEAP, and the actions the company will take over the next ***4 years*** to achieve the specific and interim targets.

Reporting — Reporting identifies the actual progress the company makes and the cost incurred over the past year.

What is the **Clean Energy Action Plan**?

- A 10-year plan that
  - Achieves **clean energy transformation standards** at the lowest reasonable cost
  - Ensures that **all customers are benefiting from the transition to clean energy**
- Filed with the WUTC as part of the IRP and acknowledged by the WUTC
- First draft plan is due on January 4, 2021 and final on April 1, 2021

- Specific CEAP elements included in IRP rules:
  - Cost-effective conservation potential assessment
  - Resource adequacy requirement
  - Cost-effective demand response
  - Renewable & non-emitting resources and distributed energy resources
  - Social cost of greenhouse gas emissions as a cost adder
  - Need for expansion of transmission and distribution facilities
  - Estimate of benefit and burden reduction

PUGET SOUND ENERGY

What is the **Clean Energy Implementation Plan**?

- Sets specific targets, interim targets, and specific actions for a 4-year period
- First plan is due October 1, 2021 and covers calendar years 2022-2025
- Clean Energy Implementation Plans establish:
  1. Interim targets for the 4-year period: percentage of retail sales of electricity supplied by non-emitting and renewable resources
  2. Specific targets for the 4-year period:
     - Demand response
     - Energy efficiency
     - Renewable energy
  3. Specific actions for the 4-year period, ***based on the Clean Energy Action Plan*** and interim and specific targets
- Clean Energy Implementation Plans are filed with the UTC, and the UTC will approve, deny, or can modify the plans

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Developing our CEIP: engaging advisory groups and customers

Equity Advisory Group – new!

Draft WAC 480-100-655 (1)(b)

“The utility must maintain and regularly engage an external **equity advisory group to advise the utility on equity issues** including, but not limited to, vulnerable population designation, equity indicator development, data support and development, and recommended approaches for the utility's compliance with WAC 480-100-610 (4)(c)(i). The utility must encourage and include the **participation of environmental justice and public health advocates, tribes, and representatives from highly impacted communities and vulnerable populations** in addition to other relevant groups;”

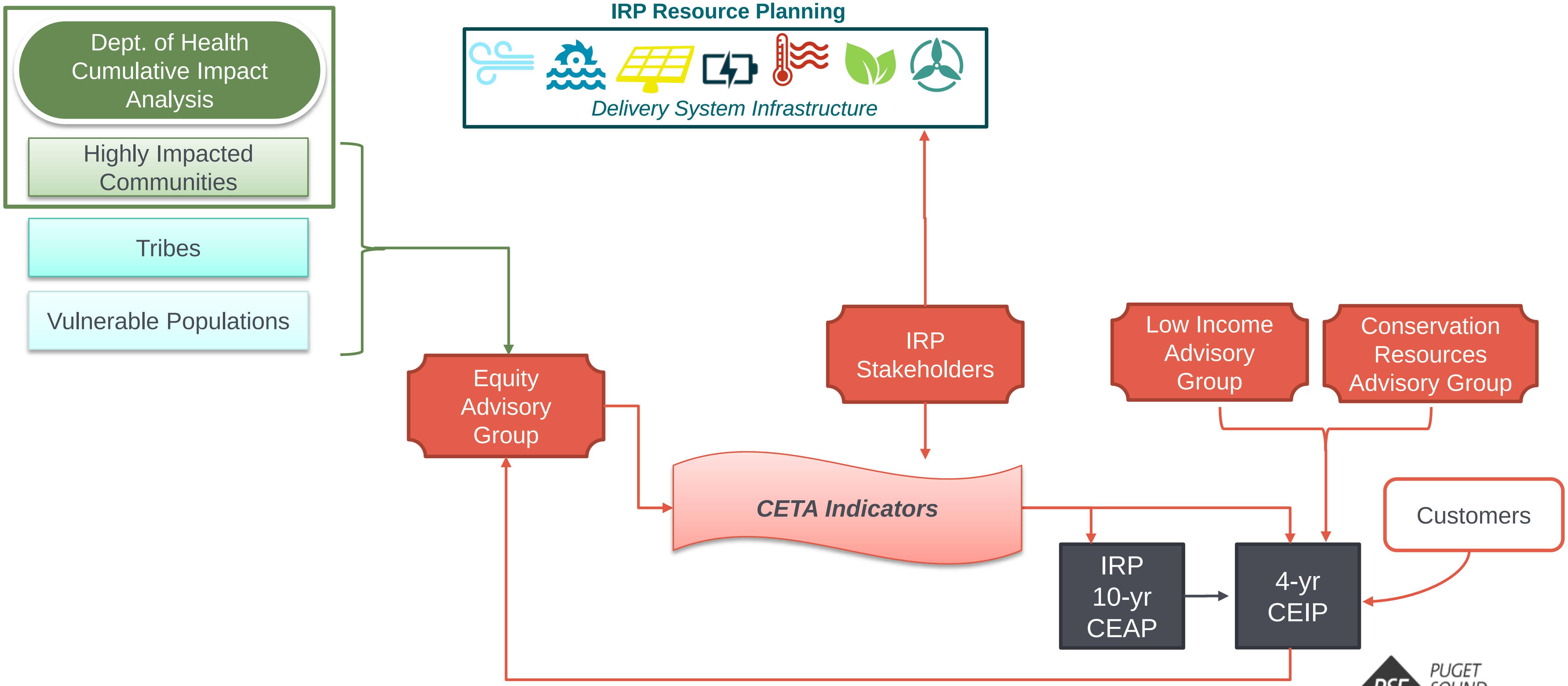
PSE’s existing advisory groups

- Low Income Advisory Group
- Conservation Resources Advisory Group
- IRP Advisory Group

Customers, including:

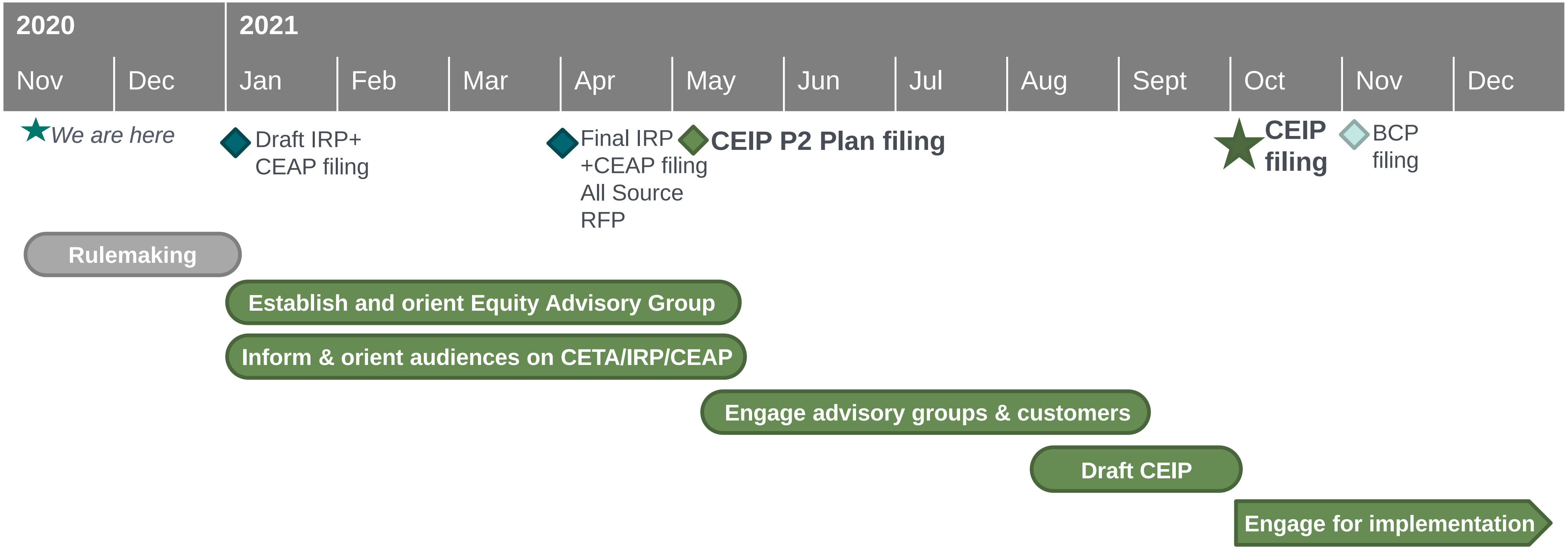
- Residential, commercial and industrial
- **Question to stakeholders:** *Are there other customer groups we could engage in the public participation process?*

Stakeholder groups involved in the CEAP and CEIP



PSE PUGET SOUND ENERGY

CEIP: Public Participation (P2) Plan considerations



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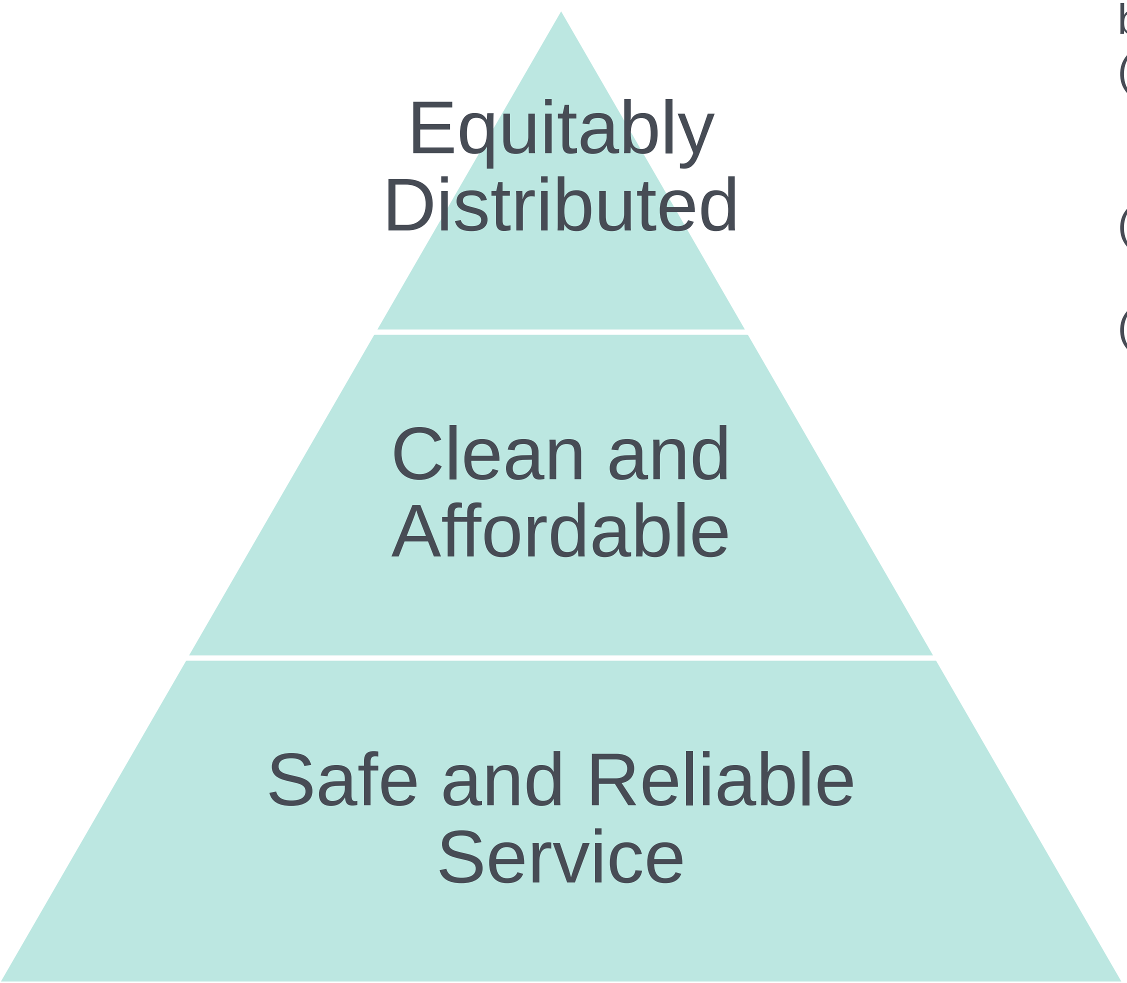
Meeting CETA goals



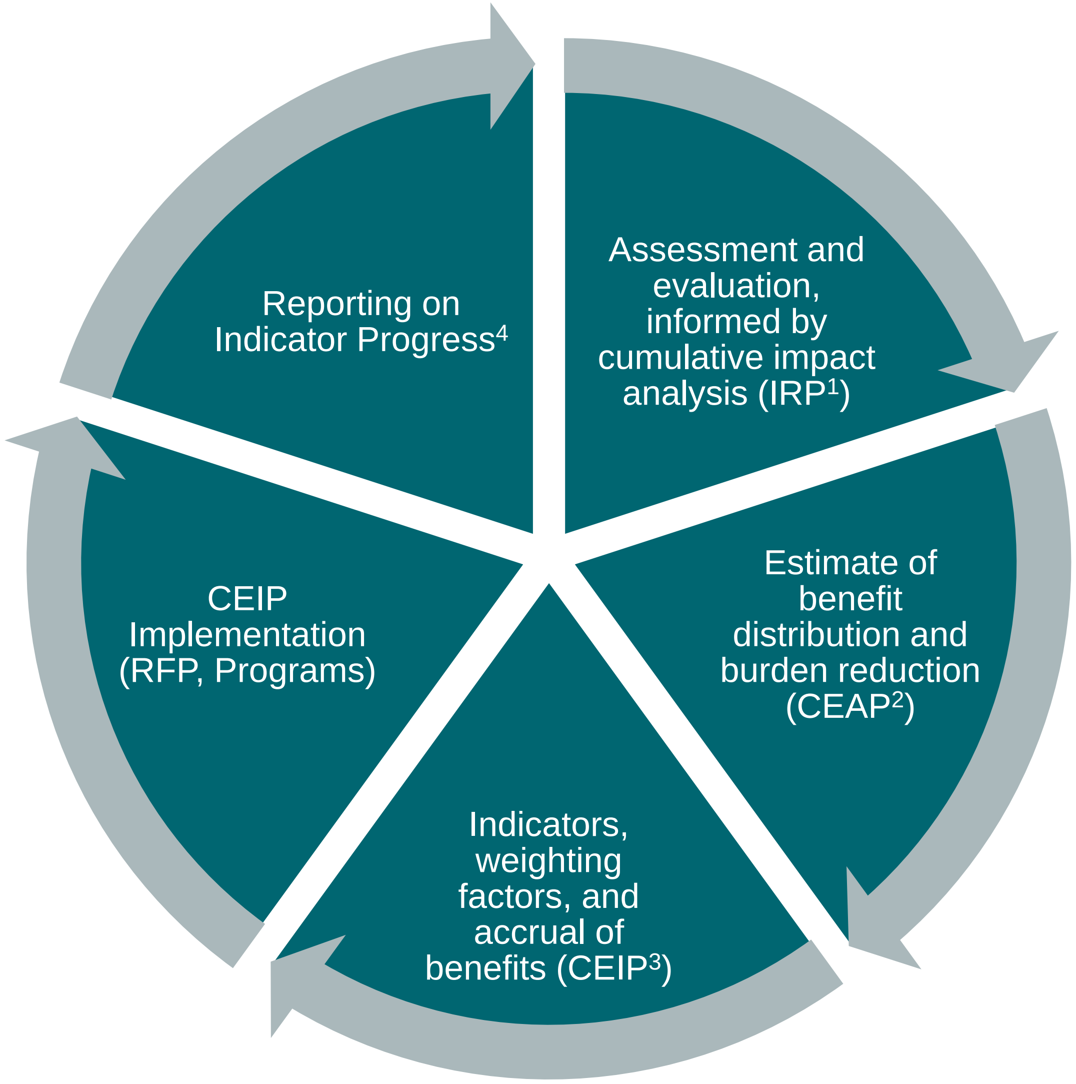
Draft WAC 480-100-610 (4) (c) : "Ensure that all customers are benefitting from the transition to clean energy through:
(i) The equitable distribution of energy and non-energy benefits and reduction of burdens to vulnerable populations and highly impacted communities;
(ii) Long-term and short-term public health and environmental benefits and reduction of costs and risks; and
(iii) Energy security and resiliency."

Draft WAC 480-100-610 (4): "In making progress toward and meeting subsections (2) and (3) of this section, each utility must: (a) Pursue all cost-effective, reliable, and feasible conservation and efficiency resources, and demand response;"

Draft WAC 480-100-610 (4) (b): "Maintain and protect the safety, reliable operation, and balancing of the electric system;"

PUGET SOUND ENERGY

CETA Equitable Distribution of Benefits Lifecycle



[1] IRP Assessment and Evaluation: Draft WAC 480-100-620(9) and (11)(g)

[2] CEAP Estimates: Draft WAC 480-100-620(12)(c)(ii)

[3] CEIP Indicators and Weighting Factors: Draft WAC 480-100-640(4) and (5)(a)

[4] Reporting on indicator progress: Draft WAC 480-100-650(1)(d)

New IRP Requirement: Economic, Health and Environmental Benefits Assessment

WAC 480-100-620 Content of an Integrated Resource Plan

(9) Economic, health, and environmental burdens and benefits.

The IRP must include an assessment of

energy and non-energy benefits and reductions of burdens to vulnerable populations and highly impacted communities;

long-term and short-term public health and environmental benefits, costs, and risks; and

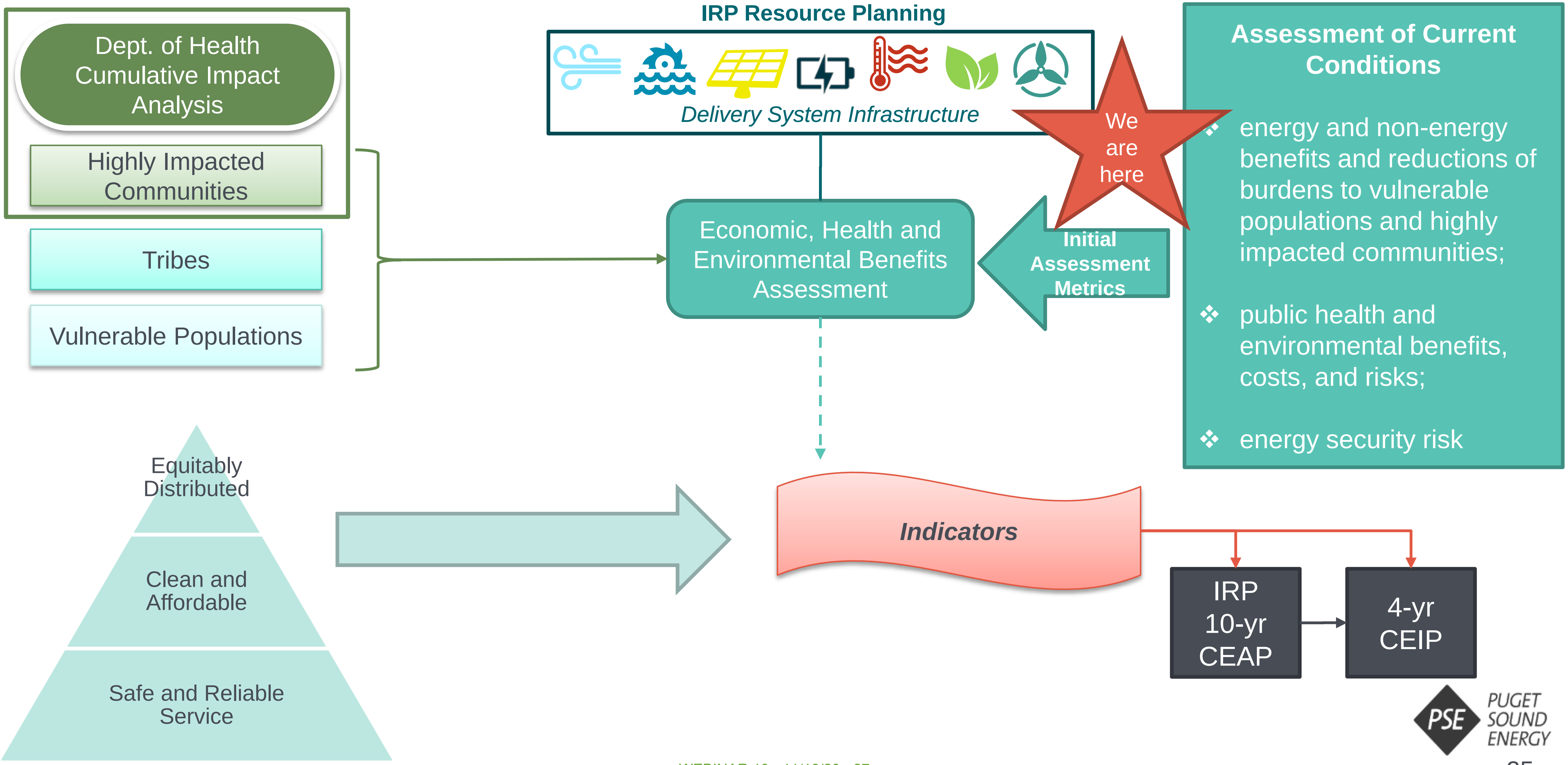
energy security risk.

The assessment should be informed by the cumulative impact analysis conducted by the department of health.

RCW 19.405.140 (Section 24 of E2SSB 5116, 2019 CETA)

"By December 31, 2020, the department of health must develop a cumulative impact analysis to designate the communities highly impacted by fossil fuel pollution and climate change in Washington. The cumulative impact analysis may integrate with and build upon other concurrent cross-agency efforts in developing a cumulative impact analysis and population tracking resources used by the department of health and analysis performed by the University of Washington department of environmental and occupational health sciences."

Incorporating the Assessment into the IRP



PUGET SOUND ENERGY

Stakeholders input on initial assessment metrics

Filed jointly as the IRP

IRP | **Clean Energy Action Plan** | **Clean Energy Implementation Plan** | **Reporting**

The IRP identifies PSE's energy, capacity, and renewable energy need ***through 2045***, potential options to meet those needs, and models the energy, capacity, and cost of meeting those needs.

The CEAP identifies the lowest reasonable cost resource plan PSE will pursue over the next ***10 years*** to meet the energy capacity, and renewable energy needs, considering risk and equity.

The CEIP identifies the specific and interim targets consistent with the plan in the CEAP, and the actions the company will take over the next ***4 years*** to achieve the specific and interim targets.

Reporting identifies the actual progress the company makes and the cost incurred over the past year.

Assessment of Current Conditions

- energy and non-energy benefits and reductions of burdens to vulnerable populations and highly impacted communities;
- public health and environmental benefits, costs, and risks;
- energy security risk

Questions for Stakeholders

1. How do we measure disparities affecting highly impacted communities and vulnerable populations?
2. Are there quantifiable public health and environmental benefits and reductions of costs and risks?
3. Are there other quantifiable economic or equity measures that should be included?
4. What other metrics should be applied?
5. Are there other quantifiable reliability, energy security and resiliency measures that can be included in the assessment?

PSE PUGET SOUND ENERGY

Economic, Health and Environmental Benefits Assessment

Assessment Objectives

- **WAC 480-100-620 (9) Economic, health, and environmental burdens and benefits.**

  The IRP must include an assessment of energy and non-energy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks; and energy security risk.

  The assessment should be informed by the cumulative impact analysis conducted by the department of health.

Existing IRP Models

Portfolio Model (AURORA)

Power Price Model (AURORA)

Flexibility Model (PLEXOS)

Resource Adequacy Model (Python)

Data Types
Dollars
MW, MWh
Resource Adequacy metrics
Emissions

WAC 480-100-620 (9)

Economic, Health and Environmental Benefit Assessment

Data Types
Dollars
MW, MWh
Resource Adequacy metrics
Emissions
Geography
Health
Security

Proposed Assessment Methodology for Current Conditions

Identify Highly Impacted Communities and Vulnerable Populations (HIC/VP)

Measure/track initial metrics on economic, health and environmental benefits and burdens

Understand how HIC/VP may be burdened or experience impacts differently

Identifying populations of interest

RCW 19.405.140 (Section 24 of E2SSB 5116, 2019 CETA)

> "By December 31, 2020, the department of health must develop a cumulative impact analysis to designate the communities highly impacted by fossil fuel pollution and climate change in Washington. **The cumulative impact analysis may integrate with and build upon other concurrent cross-agency efforts in developing a cumulative impact analysis and population tracking resources used by the department of health and analysis performed by the University of Washington department of environmental and occupational health sciences."**

Washington Environmental Health Disparities Map

ENVIRONMENTAL & OCCUPATIONAL HEALTH SCIENCES
SCHOOL OF PUBLIC HEALTH
UNIVERSITY of WASHINGTON

FRONT AND CENTERED

Washington State Department of Health

ENVIRONMENTAL PUBLIC HEALTH TRACKING

pscleanair.org
Puget Sound Clean Air Agency

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Washington Environmental Health Disparities Map

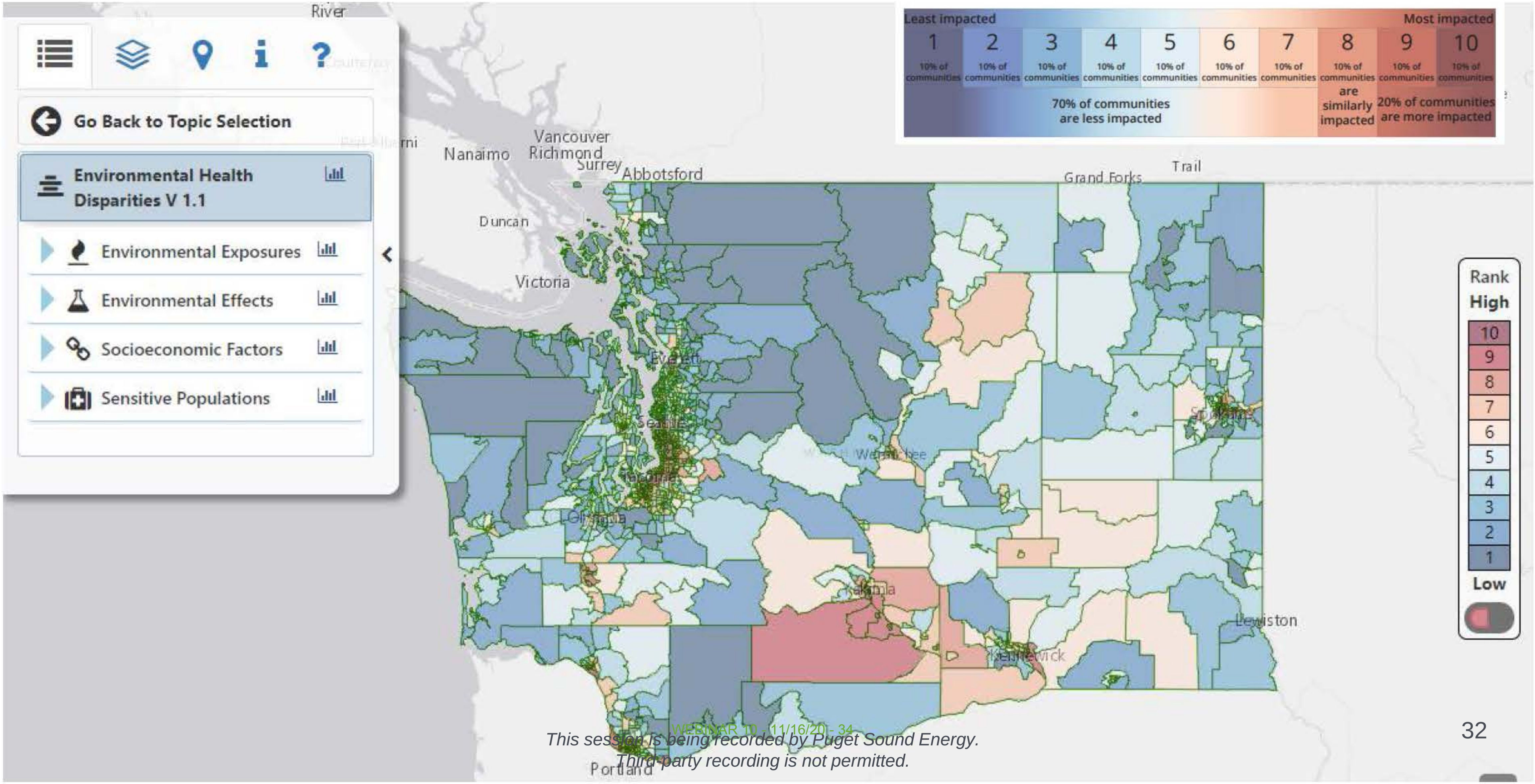
- Interactive tool to map 19 indicators of community health, including traffic density, proximity to hazardous waste facilities, income and race.

- Combines data into a cumulative score reflecting environmental and socioeconomic risk factors

- Results in a statewide view of cumulative risks each neighborhood in WA state face from environmental burdens that contribute to inequitable health outcomes and unequal access to healthy communities

- Report: https://deohs.washington.edu/sites/default/files/images/Washington_Environmental_Health_Disparities_Map.pdf

Mapping Tool: https://fortress.wa.gov/doh/wtn/WTNIBL



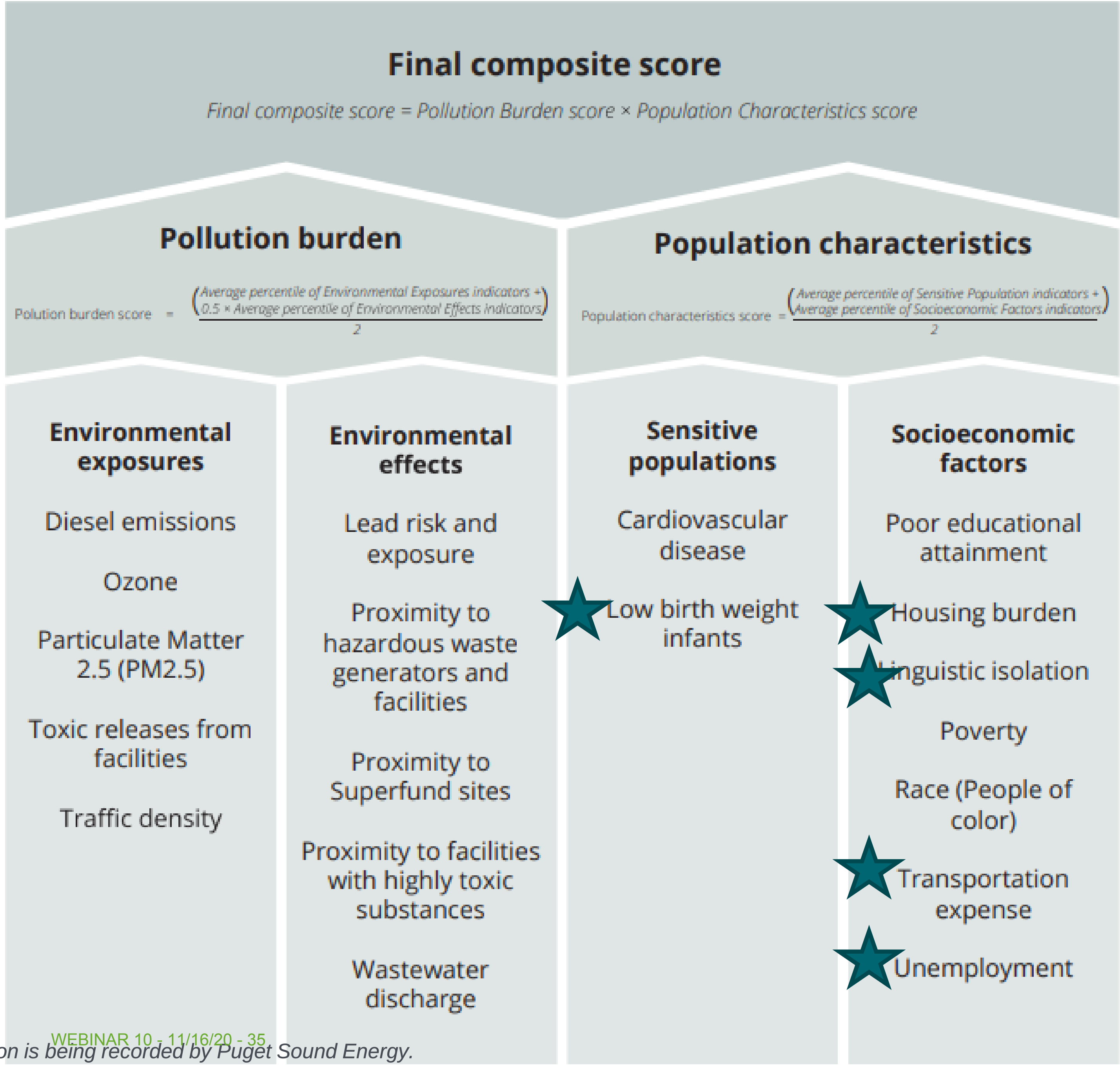
This session is being recorded by Puget Sound Energy.
Third party recording is not permitted.

Characteristics

- Source: https://deohs.washington.edu/sites/default/files/images/Washington_Environmental_Health_Disparities_Map.pdf

  page 17

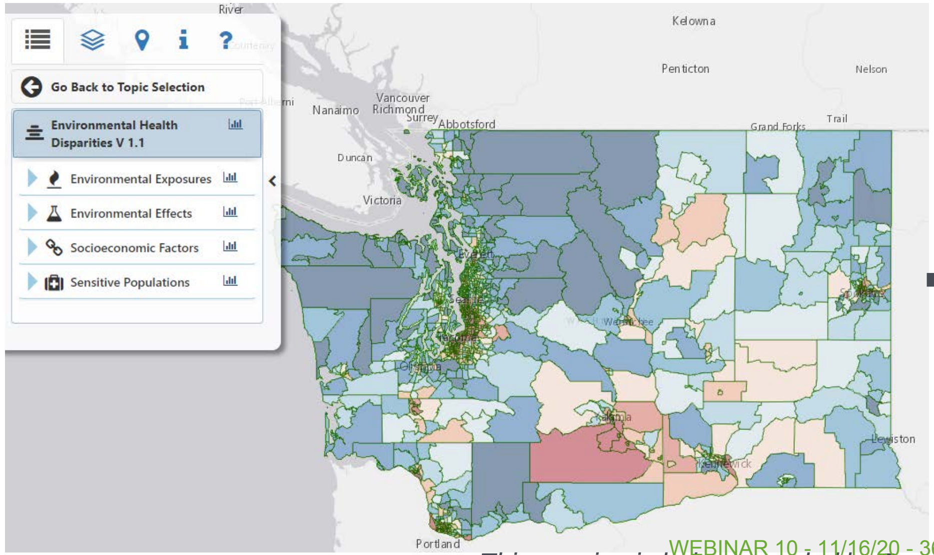
Characteristics identified in CETA



Assessment of disparities in current conditions

- The IRP team is gathering data and tools to conduct a **geospatial analysis** on the cost, reliability and environmental statistics as they relate to the HIC/VP on the DOH Environmental Disparities map

- The modeling approach will overlay the PSE service territory on top of the DOH Disparities map to identify two groups – HIC/VP PSE communities and “typical” PSE communities (the control group)



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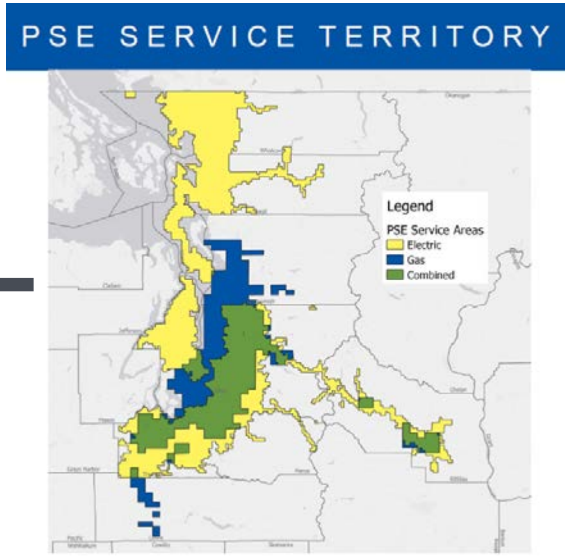
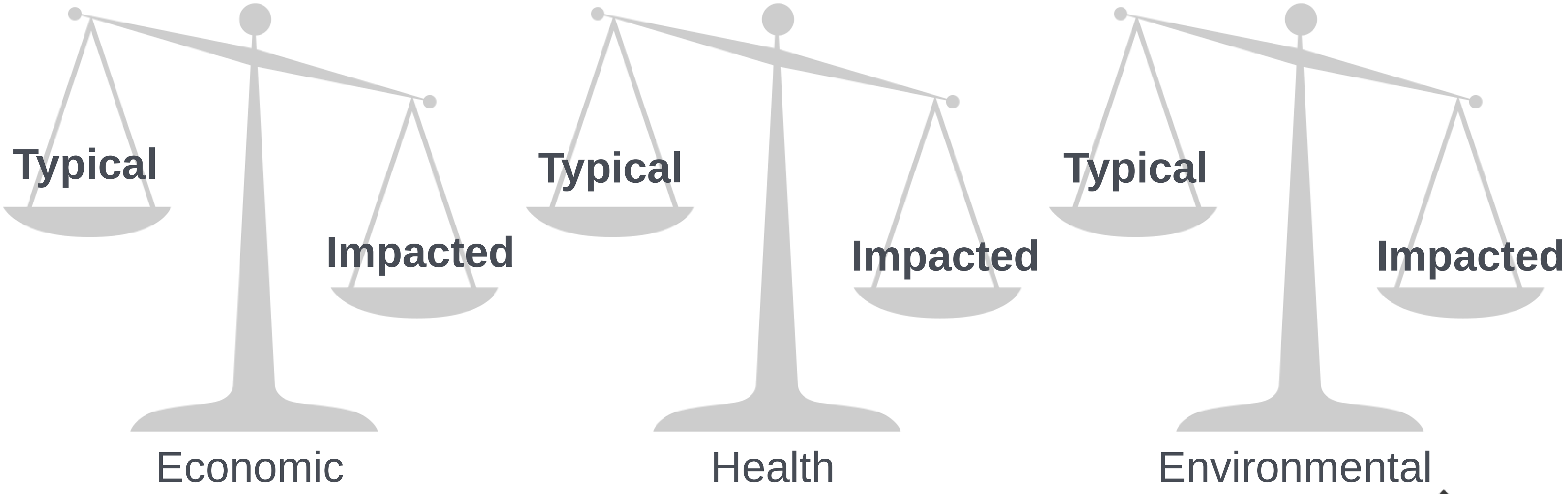


How to measure disparities to inform assessment

- Measure how highly impacted communities compare to a typical PSE community on a number of metrics



Potential IRP Assessment Metrics for PSE Service Territory

Categories	Initial Assessment Metrics	Questions for Stakeholders
Health	Environmental Health Disparities (aggregate or separate statistics)	**1. How do we measure disparities affecting highly impacted communities and vulnerable populations?** **2. Are there quantifiable public health and environmental benefits and reductions of costs and risks?** **3. Are there other quantifiable economic or equity measures that should be included?** **4. What other metrics should be applied?**
Environmental	Plant specific emissions Societal impacts from emissions (SCGHG emissions)	
Economic (Lowest reasonable cost)	Cost to average customer Energy burden	
Reliability, Energy Security & Resiliency	Resource adequacy metrics Energy use per household size System Average Interruption Frequency Index (SAIFI) System Average Interruption Duration Index (SAIDI) Customer Average Interruption Duration Index (CAIDI)	**5. Are there other quantifiable energy security and resiliency measures that can be included in the assessment?**

Are these metrics appropriate?
How do these metrics impact CETA targets?

5-minute break

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Delivery System and Grid Modernization Needs

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Participation Objectives

- PSE will inform stakeholders about the delivery system and grid modernization needs for the 10-year transmission and distribution plan

IAP2 level of participation: INFORM

Overview

- CETA and DER planning rules
- Delivery System Planning (DSP) process
- Non-wire alternative progress
- Planned project/growth area needs
- DER planning, integration & tool needs
- DSP capability evolution
- Delivery system investment in the IRP

Delivery system investments are integrated in the IRP draft rules*

WAC 480-100-605 Definitions “Lowest reasonable cost” means “……The analysis of the lowest reasonable cost must describe the utility's combination of planned resources and **related delivery system infrastructure** and show consistency with chapters 19.280, 19.285, and 19.405 RCW."

WAC 480-100-620 Content of an integrated resource plan. (1) Purpose. Consistent with chapters 80.28, 19.280, and 19.405 RCW, each electric utility has the responsibility to identify and meet its resource needs with the lowest reasonable cost mix of conservation and efficiency, generation, distributed energy resources, and **delivery system investments** to ensure the utility provides energy to its customers that is clean, affordable, **reliable**, and equitably distributed.

WAC 480-100-620 Content of an integrated resource plan. (3) Distributed energy resources.(a) The IRP must include assessments of a variety of distributed energy resources. These assessments must incorporate non-energy costs and benefits not fully valued elsewhere within any integrated resource plan model. Utilities must assess the effect of distributed energy resources on the utility's load and operations under RCW 19.280.030 (1)(h). The commission strongly encourages utilities to **engage in a distributed energy resource planning process as described in RCW 19.280.100.** If the utility elects to use a distributed energy resource planning process, the IRP should include a summary of the results.

WAC 480-100-620 Content of an integrated resource plan. (12) CEAP must …g) **Identify any need to develop new, or to expand or upgrade existing, bulk transmission and distribution facilities;**

….c) Include proposed or updated indicators and associated weighting factors related to WAC 480-100-610 (4)(c) including, at a minimum, one or more indicators associated with energy benefits, non-energy benefits, reduction of burdens, public health, environment, reduction in cost, **energy security, and resiliency**.

**Excerpts from draft rules in UTC Dockets UE-191023 and UE-190698*

DER planning process per RCW 19.280.100

Provide a 10 year distribution plan that includes:

- Non-wire alternative analysis
- Cost benefit analysis with pessimistic and optimistic scenarios

Identify data gaps and upgrades that impeded a robust planning process

Proposed monitoring, control, and metering upgrades that provide net benefits for customers

Identify potential programs and tariffs to compensate customers for value of their DERs

Perform forecast of DER growth

Include DERs identified it the 10 year distribution plan in the IRP

"The goal of the plan should be to provide the most affordable investments for all customers and avoid reactive expenditures to accommodate unanticipated growth in distributed energy resources."

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PSE is working to incorporate new DSP and IRP process to meet the expectations of the new IRP rules

- Delivery system investments include tools, monitoring, controls, metering, DERs, and expansions or upgrades to existing bulk transmission and distribution facilities.

- To understand what specific delivery system investments should be included in the IRP, CEAP or CEIP, we need to review the delivery system needs.

The energy delivery system is the network of wires and pipelines, both distribution and transmission, that deliver power and natural gas from where energy enters PSE's system to a customer meter.

Delivery System Planning process*

Planning Triggers
- Safety
- Customer requests
- Population and load growth
- Grid modernization
- Gas modernization
- Asset health management
- Asset reliability and integrity
- Compliance with regulation
- Resource integration

The delivery system planning process requires many robust capabilities across PSE from the beginning of the process such as gathering customer, load, and distributed energy resources information and forecasts to beyond the planning process ending with the testing of results and benefit delivery.

Assumptions, performance targets and modeling input → Establish Grid Needs → Alternative choices and assumptions → Screen and analyze alternatives → Analyze and optimize solution → Initiate project feasibility and planning

*https://pse-irp.participate.online/delivery-system-planning

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Delivery System Planning process

Assumptions, performance targets and modeling input → Establish Grid Needs → Alternative choices and assumptions → Screen and analyze alternatives → Analyze and optimize solution → Initiate project feasibility and planning

Key Capabilities

- Granular (feeder-level) load forecasting
- Powerflow evaluation across multiple peak and off-peak time periods (summer, winter, light loading, etc.)

Key metrics set the stage for these needs:

- Reliability - SAIDI, SAIFI, CEMI
- Equipment Loading
- Transmission Resiliency Index (TRI)
- Substation Resiliency Index (SRI)
- System stability - voltage

Delivery System Planning process

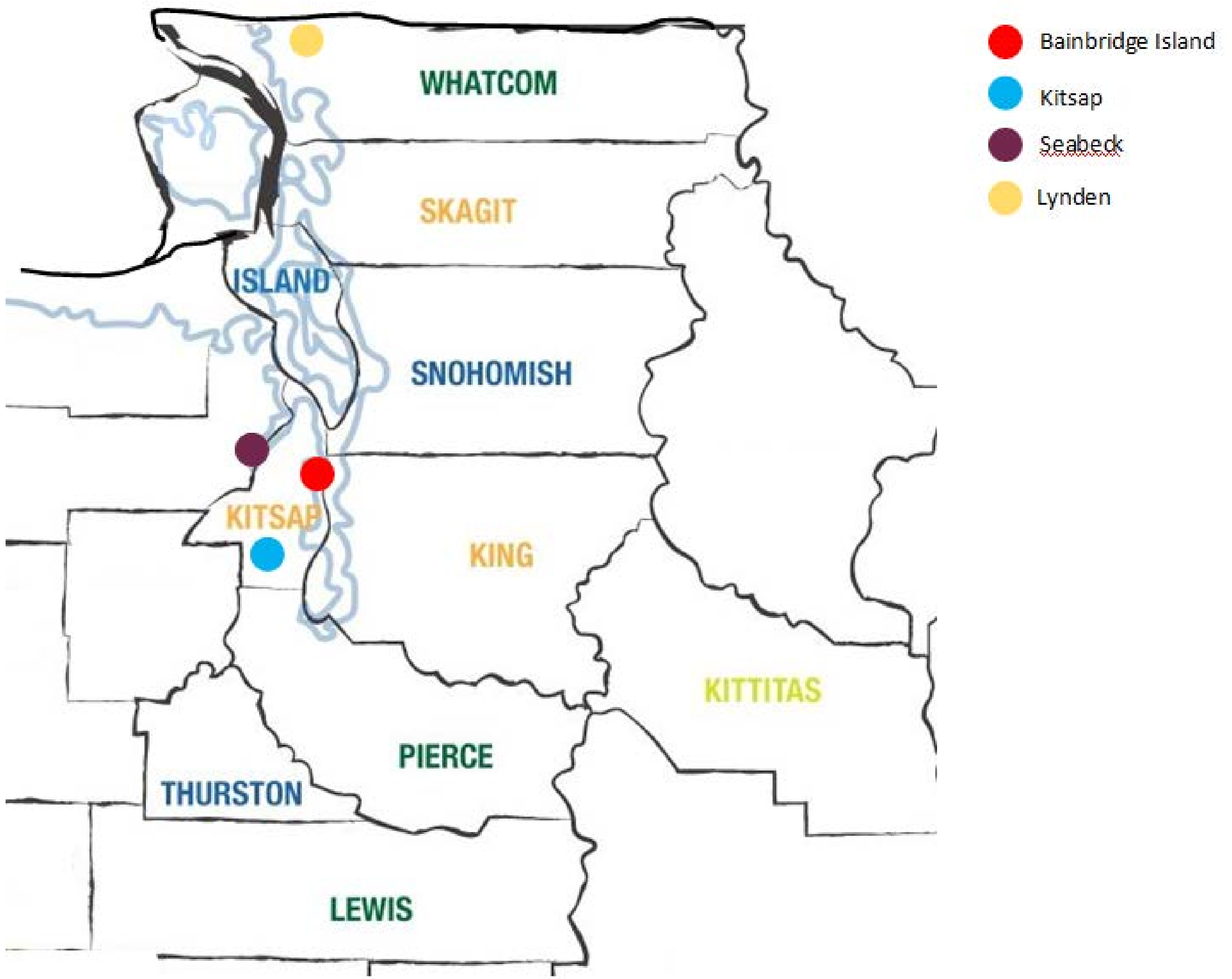
Assumptions, performance targets and modeling input → Establish Grid Needs → Alternative choices and assumptions → Screen and analyze alternatives → Analyze and optimize solution → Initiate project feasibility and planning

Key Capabilities

- Evaluation of wired, non-wired and hybrid solutions
- Inclusion of customer partnership opportunities
- Benefit valuation for non-wire alternatives
- Robust project optimization which maximize benefits to cost for investments

Non-wire alternative progress

- 2018 commitment to completing NWA on four focus areas
    - Chosen for their diverse drivers
- Work completed on 4 projects areas
- Fully included wired, non-wired and hybrid alternatives
- Deep dive on projects at a future IRP meeting



Delivery System Planning electric needs

Distribution Needs - (12.47 & 34.5 kV)

Evaluates the following system deficiencies at a Substation, Feeder or Lateral level:

- Capacity (Equipment loading)
- Voltage
- Reliability
    - SAIDI, SAIFI, CEMI
- Aging Infrastructure
- Operational Concerns

Transmission Needs - (115 & 230 kV)

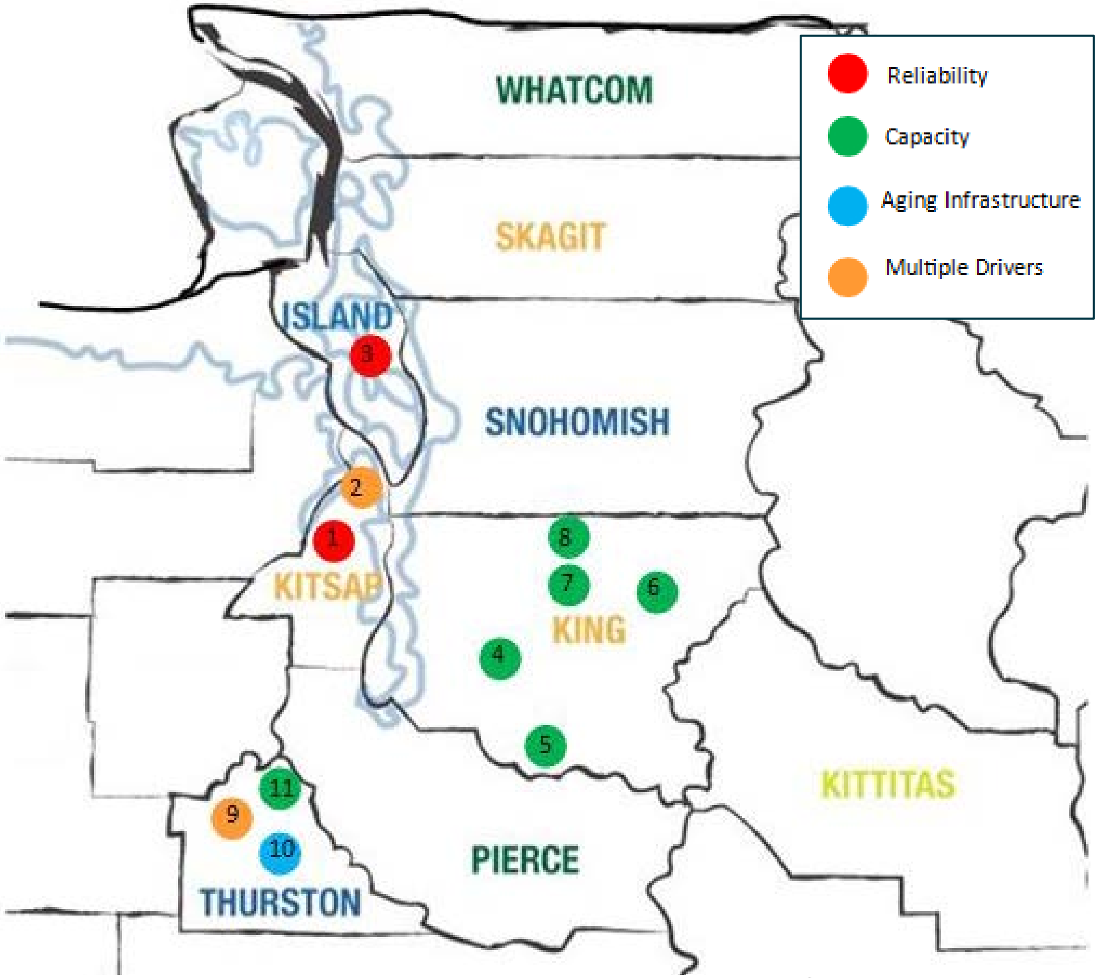
Evaluates the transmission system in accordance with the transmission planning requirements per the NERC standards.

Typical need drivers include:

- Capacity (Equipment Loading)
- Reliability
    - Transmission/Substation Resilience Index
    - CMI
- Aging Infrastructure
- Operational Concerns
- Dynamic Stability – Voltage
- Generation ramp rate

Electric planned growth/project areas

SUMMARY OF ELECTRIC PLANNED PROJECTS IN PLANNING PHASE	DATE NEEDED	NEED DRIVER
1. Seabeck (NWA Pilot)	Existing	Reliability
2. West Kitsap Transmission Project (NWA Pilot)	Existing	Stability, Transmission Capacity & Aging Infrastructure
3. Whidbey Island Transmission Improvements	Existing	Reliability
4. Kent / Tukwila New Substation	2020	Capacity
5. Black Diamond Area New Substation	2020	Capacity
6. Issaquah Area New Substation	Existing	Capacity
7. Bellevue Area New Substation	2021	Capacity
8. Inglewood – Juanita Capacity Project	2024	Capacity
9. Spurgeon Creek Transmission Substation Development (Phase 2)	Existing	Stability & Capacity
10. Electron Heights - Yelm Transmission Project	2024	Aging Infrastructure
11. Lacey Hawks Prairie	2021	Capacity



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Needs in DER planning, integration, and optimization

Data Gaps and Upgrades	•Customer and operational analytics using Advanced Metering Infrastructure (AMI) •IT Architecture and integration to connect enterprise systems, particularly GIS
Monitoring, Control, and Metering	•Applications enabled by AMI including the Advanced Distribution Management System (ADMS) •Volt-Var Optimization; Fault Location, Isolation, Service Restoration (FLISR); Distributed Energy Resource Management System (DERMS)
Customer Programs and Tariffs	•Time of Use (TOU) rates to incent beneficial customer usage patterns •Alternative pricing structures to enable DER/renewables integration
DER Growth Forecast	•Enabled by Geospatial Load Forecasting Tool •Key input for locational valuation of DERs

Need: Enabling tools

Customer/Utility Interface

1) Enhanced Meter Data Visibility

2) Hosting Capacity Map

3) Enhanced Interconnection Portal

Future State

Increased Utility and Customer Sited DERs

Alternative Rates and Pricing Programs

Operational Platforms

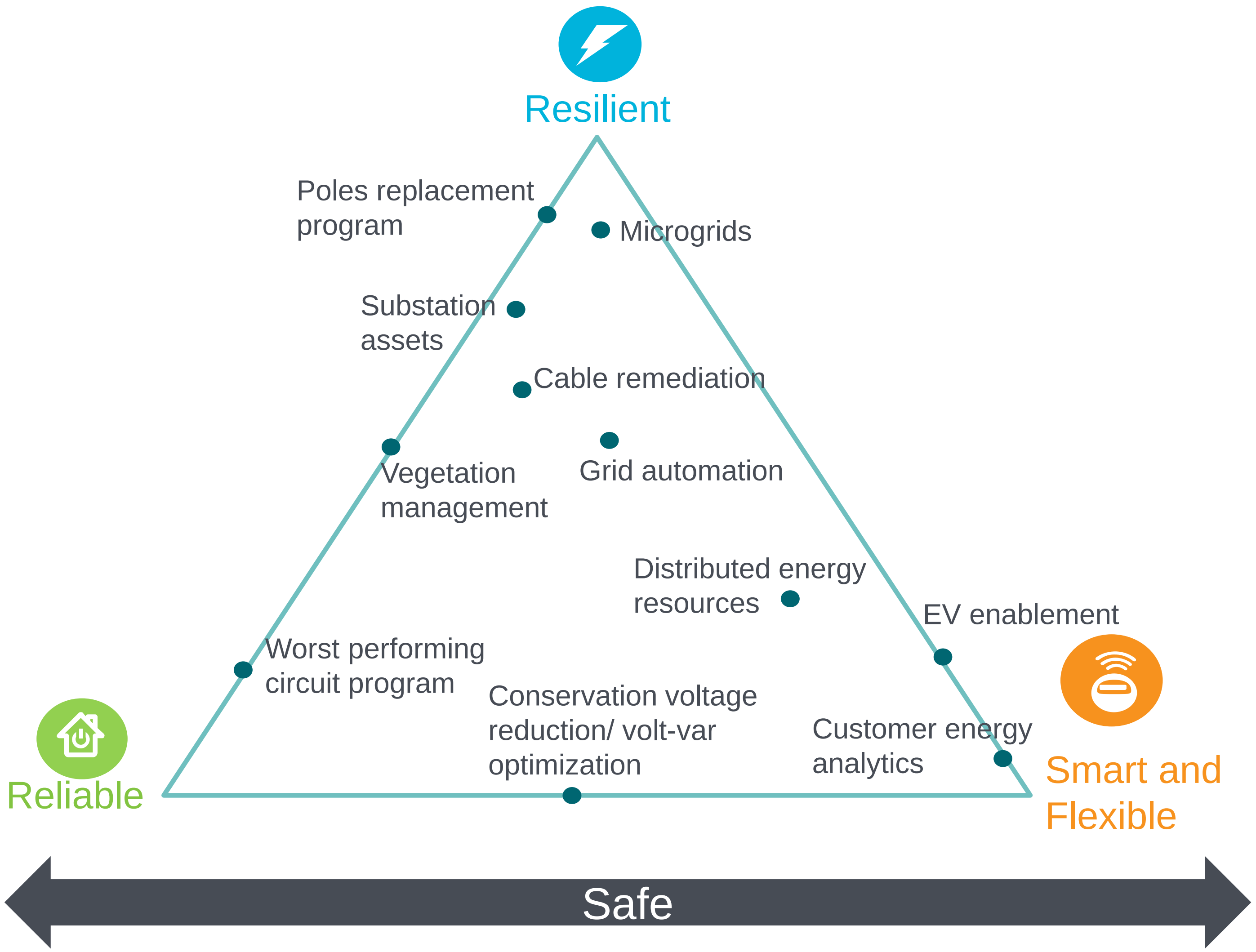
1) Advanced Distribution Management System (ADMS)

2) Distributed Energy Resource Management System (DERMS)

3) Transactive Energy + Distributed Market Operations

- PSE and customers have greater access to data and insights
- Infrastructure investments are optimized Interconnection is more transparent and streamlined
- Resources are dispatched safely to meet the need

Grid Modernization Key Programs



Key programs

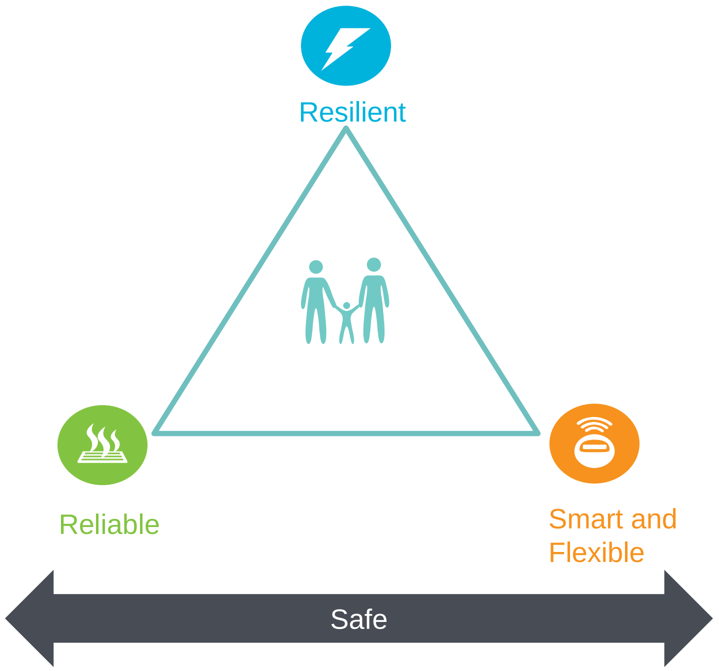
- Pole replacement program
- Substation assets
- Cable remediation
- Vegetation management
- Electric system upgrade - Worst performing circuits (WPC)
- Grid automation
- Electric vehicle (EV) enablement
- Distributed energy resources (DER)
- Microgrids
- Customer energy analytics
- Conservation voltage reduction/volt-var optimization

Delivery System Planning capability evolution

Enhancing our DSP capabilities across people, process, and technology

- Necessary to meet CETA and DER planning requirements
- Necessary to meet customer needs

The goal of the plan should be to provide the most affordable investments for all customers and <u>avoid reactive expenditures</u> to accommodate unanticipated growth in distributed energy resources.



Mindful of lessons learned from other utilities case study examples dealing with rapid DER demand:

- DER ramp rate
- DER Saturation
- Interconnection bottleneck

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Delivery System Investment in the IRP

- Accelerated installation of DER's will likely accelerate our grid modernization investments.
  - Highly dependent on the specific amount, location, type and concentration of the specific DER's

For 2021 IRP:

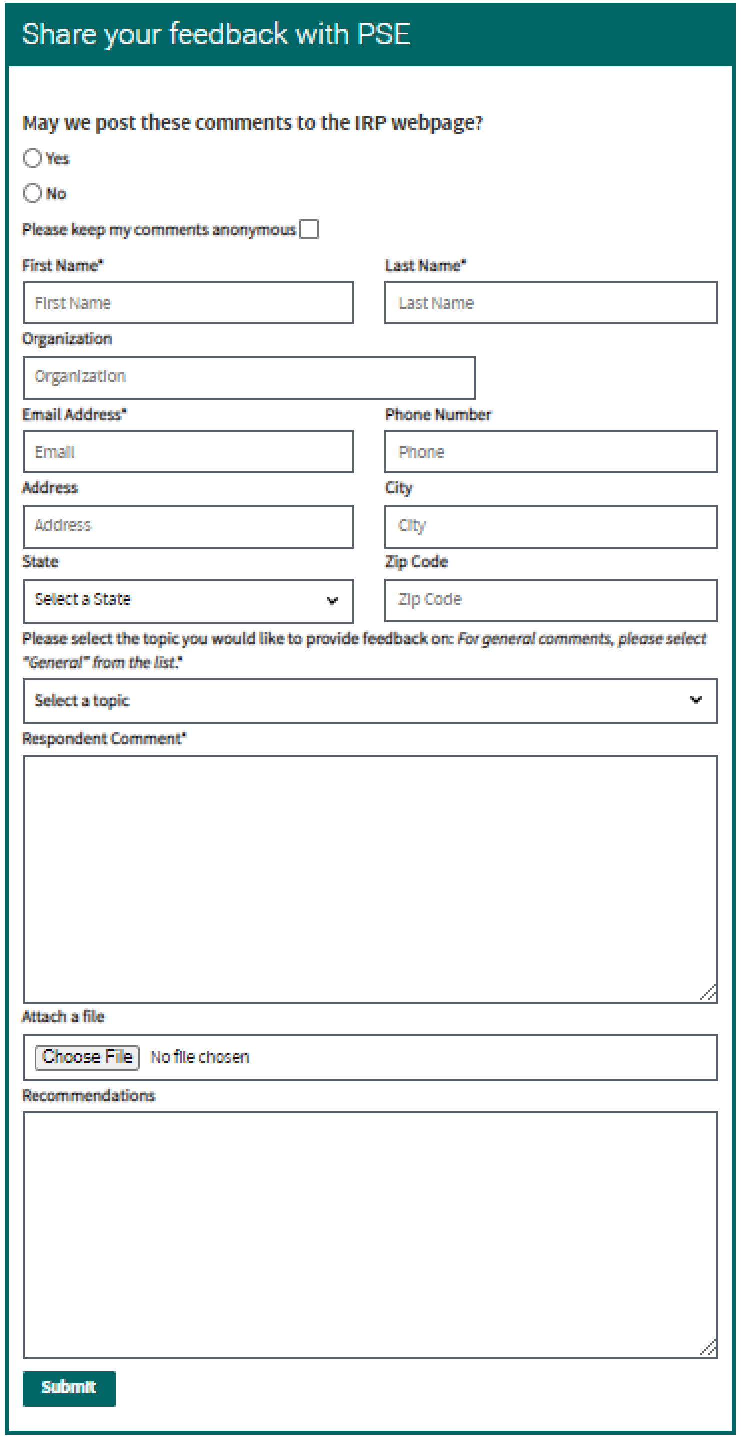
- Including a range for local DER interconnection costs to account for the grid modernization costs.
  - Part of the existing must-take sensitivity:
    #10 "Distributed" Transmission/build constraints - Tier 2
  - The cost range will consider both a pessimistic and optimistic perspective.

Questions & Answers

Feedback Form

- An important way to share your input
- Available on the website 24/7
- Comments, questions and data can be submitted throughout the year, but timely feedback supports the technical process
- Please submit your Feedback Form <u>within a week of the meeting topic</u>

Feedback Form → **Feedback Report** → **Consultation Update**



Share your feedback with PSE

May we post these comments to the IRP webpage?

( ) Yes

( ) No

Please keep my comments anonymous [ ]

First Name* [First Name] Last Name* [Last Name]

Organization [Organization]

Email Address* [Email] Phone Number [Phone]

Address [Address] City [City]

State [Select a State] Zip Code [Zip Code]

Please select the topic you would like to provide feedback on: *For general comments, please select "General" from the list.**

[Select a topic]

Respondent Comment*

Attach a file

[Choose File] No file chosen

Recommendations

[Submit]

Feedback Form

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- Available on the website 24/7
- Comments, questions and data can be submitted throughout the year, but timely feedback supports the technical process
- Please submit your Feedback Form within a week of the meeting topic

Feedback Form | **Feedback Report** | **Consultation Update**

Next steps

- Submit Feedback Form to PSE by **November 30, 2020**
- A recording and the chat from today's webinar will be posted to the website **tomorrow**
- PSE will compile all the feedback in the Feedback Report and post all the questions by **December 7, 2020**
- The Consultation Update will be shared on **December 14, 2020**

Upcoming meetings and key dates

Date	Topic
December 15, 1:00 – 5:00 pm	Portfolio draft results Flexibility analysis
Additional 2021 meetings will be scheduled soon.	
January 4, 2021	DRAFT 2021 Electric and Natural Gas IRP published
April 1, 2021	FINAL 2021 Electric and Natural Gas IRP filed with the WUTC

Details of upcoming meetings can be found at pse.com/irp

Thank you for your attention and input.

Please complete your Feedback Form by November 30, 2020

We look forward to your attendance at PSE's next public participation webinar on December 15, 2020

PUGET SOUND ENERGY

Webinar #10: Clean Energy Action Plan and Clean Energy Implementation Plan, Economic, Health and Environmental Benefits Assessment of Current Conditions and delivery system and grid modernization needs

11/17/2020

Overview

On November 16, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss the Clean Energy Action Plan and Clean Energy Implementation Plan, Economic, Health and Environmental Benefits Assessment of Current Conditions and delivery system and grid modernization needs. Additionally, participants were able to ask questions and make comments using a chat box provided by the Go2Meeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 75 stakeholders and PSE staff attended the webinar, plus another 6 attendees who called into the meeting and did not identify themselves (81 people total).

Attendees included: Allison Jacobs, Andrew Wood, Anne Newcomb, Anthony O'Rourke, Ben Farrow, Bill Pascoe, Bill Westre, Bob Stolaski, Brett Rendina, Brian Tyson, Brian Grunkemeyer, Chad Ihrig, Charlie Black, Charlie Inman, Cindy Song, Colin Crowley, Cress Wakefield, Cuong Nguyen, David Meyer, Diann Strom, Don Marsh, Doug Howell, Elaine Markham, Elyette Weinstein, Eric Kang, Fred Heutte, Gurvinder Singh, James Adcock, Jennifer Snyder, Jens Nedrud, Jon Piliaris, Joni Bosh, Kara Durbin, Kathi Scanlan, Katie Ware, Kendra White, Kevin Jones, Kristina Kelly, Kyle Frankiewich, Leslie Almond, Lori Elworth, Marcus Sellers-Vaughn, Mariel Thuraisngham, Norm Hansen, Warren Halverson, Peter Brown, Rahul Venkatesh, Scott Williams, Shay Bauman, Sheri Maynard, Stephanie Chase, Ted Drennan, Thad Curtz, Therese Miranda-Blackney, Tom Eckman, Tyler Tobin, Vlad Gutman-Britten, Virginia Lohr, Wendy Gerlitz, and Wiemin Dang.

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 1:00 PM PDT and ended at 3:48 PM PDT.

Name	Time Sent	Comment
James Adcock	**1:11 PM**	Comment: I express concerns about the big elements which will not be ready in time for the Draft IRP, which I believe will keep participants from commenting in an informed manner on that Draft.
Don Marsh	**1:13 PM**	The Draft IRP should contain all the parts that stakeholders would want to participate and comment on. If the analysis is not available, the Draft IRP should be delayed until they are.
Kevin Jones	**1:14 PM**	The current CETA Rules call for UTC review only of DRAFT IRP's, which PSE is now telling us will be incomplete on their filing date. Will PSE be addressing this issue with the UTC so that a complete PSE DRAFT IRP will be available for review?
Kevin Jones	**1:17 PM**	James - I believe you filed a technical input (vice a comment)...
Doug Howell	**1:26 PM**	Raised hand. slide 19
Brian Grunkemeyer	**1:29 PM**	I strongly encourage PSE to invite land use planners throughout your service area to participate in the IRP Advisory Group.
Brian Grunkemeyer	**1:30 PM**	we have data on WA avoided tailpipe emissions from some EV's.
Don Marsh	**1:32 PM**	Are there any situations where a person would be excluded from the IRP Advisory Group? I ask because PSE once told me that I did not meet the qualifications for participating in the Technical Advisory Group. I hope that isn't happening any more.
Doug Howell	**1:33 PM**	Raised hand, follow up question on Slide 19?
Don Marsh	**1:34 PM**	Thanks for the answer, Irena. I am encouraged by PSE's increasing openness in that regard.
Elise Johnson	**1:42 PM**	A reminder to please mute your phone or computer mic to prevent feedback when speakers are presenting.
Michele Kvam	**1:43 PM**	Caller 04, please mute. Thank you.
Thad Curtz via Alexandra Streamer	**1:47 PM**	Reposting a question Thad Curtz posed to Organizers: Re Slide 22 - Is your view that any action which doesn't meet all of these criteria should be excluded from the plan, or is it that the suite of actions as a whole should meet these criteria?
James Adcock	**1:49 PM**	Slide 26: How do you want us to best send you our inputs requested on this slide?
Kyle Frankiewich	**1:54 PM**	Q on slide 29
James Adcock	**1:58 PM**	Comment: I would ask that for all PSE beneficially programs, such as weatherization, energy efficiency, etc. that PSE report on these programs divided into two groups -- the first section being ratepayers in the group "highly impacted communities and vulnerable populations" vs. the second group being ratepayers not in that group, and report actual financial spending normalized on a per ratepayer basis for the 1st group vs. the 2nd group -- such that we can see overall which PSE beneficially programs are equitably meeting the actual needs of each set of groups -- or not. For example I would be concerned that many PSE beneficially programs might be in practice inaccessible by the 1st group, either due to lack of funds, or because of the "split incentives" problem -- i.e. landlords vs. renters, or even just from a lack of understanding. If PSE beneficially programs for whatever reason are not reaching the 1st group, then that is an equity problem which needs to be actually fixed.

Don Marsh	**2:01 PM**	The Health Disparities Map is a very useful place to start. It shows that the census tract nearest PSE's Tacoma LNG facility is very highly impacted, vulnerable, and has a high percentage of residents from tribes. It would be useful to understand how PSE would change its approach under this policy. Would you find a better place for the plant? Would you seek higher participation from residents who have many difficult challenges they are facing? How are these policies implemented in practice?
Joni Bosh	**2:02 PM**	Will you be capturing downwind impacts in any of these initial metrics? Or just generation point impacts?
Michele Kvam	**2:03 PM**	Warren HALVERSON has some questions submitted in the IRP mailbox; he is on the phone
Fred Huette	**2:04 PM**	Has PSE reviewed the Avista assessment of Vulnerable Populations & Highly Impacted Communities? While this is an initial effort and can be enhanced and improved, this shows the promise of combining disparate data sources to provide important insights relevant to CETA and other planning contexts, and we recommend PSE and stakeholders take a look. Here's the most recent presentation (starting on slide 85): **https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/2021-irp-tac-2-presentations.pdf?la=en**
James Adcock	**2:05 PM**	Comment re slide 35 "Environmental Impacts." I am concerned that PSE has not been responsive to date to the issue of the environmental impact of new Transmission Lines, and how needless oppressive to the perceived environmental quality of the communities where a new transmission line is pushed though. For example PSE just cut down a huge number of beautiful trees along 148th in Bellevue, replacing those trees with gigantic creosote glue-lam poles -- some about 6 feet wide, and placed in the business property of a minority owner. PSE needs to honestly consider all the environmental impacts of their new transmission lines and make meaningful design choices to minimize the needless and excessive environmental damages and environmental ugliness of those transmission lines. Rather than just doing what is quickest and cheapest.
Bill Westre	**2:09 PM**	Raise Hand
Bill Westre	**2:09 PM**	James, that is a very good point. Transmission lines are often placed in impacted communities, because they are not seen as desirable in nicer parts of our community or business districts.
Warren Halverson via Michele Kvam	**2:09 PM**	From Warren Halverson: How does PSE map communities and/or customers to DOH maps? If the community can be defined down to the customer level, are you concerned at privacy issues?
Brian Grunkemeyer	**2:09 PM**	Raise hand
Charlie Black	**2:10 PM**	Kyle Frankiewich had a question on Slide 29 - has that been addressed?
Fred Huette	**2:12 PM**	raise hand for a follow-up
Joni Bosh	**2:14 PM**	Agree with Kyle's interpretation of slide 29

James Adcock	**2:16 PM**	Comment: The Slide 24 RCW quote makes it clear for the purposes of this section of environmental impact we are only considering the impacts on Washington State residents.
James Adcock	**2:18 PM**	Comment: +1 Brian -- avoided tailpipe emissions -- or the lack of avoided tailpipe emissions (where PSE's EV programs "fail") should be part of the consideration and evaluation.
James Adcock	**2:19 PM**	Comment: For example PSE support of electric busses might be a way to extend tailpipe reduction efforts to more communities.
Brian Grunkemeyer	**2:26 PM**	Great idea, Jim. Another idea would be looking at the Mileage Purchase Agreement as a financing mechanism to make EV's more affordable. This works out well for high-mileage drivers, including potentially transportation network company drivers. Adrian at Flux Auto is commercializing the MPA idea. **https://www.fluxauto.co/**
Brian Grunkemeyer	**2:29 PM**	(Sorry, it's Andrew, not Adrian)
James Adcock	**2:32 PM**	Slide 41: Does "Lowest reasonable cost" as related to "delivery system infrastructure" mean that PSE needs to implement transmission lines in a way that leads to needless and excess local environmental destruction?
Kevin Jones	**2:34 PM**	Slide 41: Given the new rules inclusion of electricity delivery systems in power planning, does PSE believe this applies to ALL transmission systems even if they were proposed prior to these new rules?
James Adcock	**2:38 PM**	Thank you I think you just did so.
Doug Howell	**2:38 PM**	Is PSE now assuming its full transmission capacity on the Colstrip Transmission System?
James Adcock	**2:39 PM**	Slide 44: How many times a year does my Bellevue neighborhood have to lose power before PSE considers that they are NOT delivering power "safely and reliably?"
Kevin Jones	**2:49 PM**	Follow-up to my earlier question: Does PSE believe that ALL transmission projects will be discussed in IRP and CEIP planning meetings even if those projects were proposed prior to these new rules?
Doug Howell	**2:49 PM**	Okay. Thank you
James Adcock	**2:51 PM**	Follow-up: We lose power all the time. Meanwhile PSE is arguing how many peakers do they need to avoid a system-wide outage every 20 years, or every 40 years, and "reach back in time" 100 years to find weather conditions which can no longer possibly exist -- and while ignoring that in practice our neighborhood loses it's power All The Time, because tree maintenance is not being done.
Charlie Black	**2:53 PM**	Regarding previously-planned transmission projects, can you clarify what 'included' means? Does that mean those projects will be evaluated, or will they be assumed to be built?
James Adcock	**3:00 PM**	Slide 48: Question: What does it take to actually get neighborhood tree maintenance so that we can actually experience the kind of safety and reliability which PSE claims it is designing it's power system to? We lose power all the time. Multiple times a year. Meanwhile PSE is arguing how many peakers do they need to avoid a system-wide outage every 20 years, or every 40 years, and is "reaching back in time" 100 years to find weather conditions which can no longer possibly exist -- and while ignoring that in practice our neighborhood loses it's power All The Time, because tree maintenance is not being done. What does it take so that we can actually in practice experience safe and reliable power delivery?

Charlie Black	**3:00 PM**	I do not see Energy Eastside listed on Slide 49. Does that imply the delivery system plan is assuming it will be built and therefore not evaluated in the delivery system plan?
Kevin Jones	**3:00 PM**	Slide 49: Which of these projects are associated with Energize Eastside?
Kyle Frankiewich	**3:01 PM**	Q on slide 43: Does PSE propose a threshold for what kinds or sizes of delivery system projects will be "included in the IRP"?
Warren Halverson via Michele Kvam	**3:04 PM**	Questions from the IRP mailbox from Warren: Two questions: 1. Is item 7 the Richards Road substation? 2. PSE did not submit a formal IRP this last year and, in fact, abruptly canceled a long awaited discussion of transmission and distribution activities. Now, with some details about CETA we can understand why😀 2. Please provide the current status and update where PSE is concerning Energize Eastside? Include, does PSE stand by their forecast of 2.4 per cent peak growth? If not what is the current peak demand forecast for the Eastside? Finally, Energize Eastside forecasts that took place 5-7 years ago showed we would basically be in deep trouble in 2019. That has not happened either winter or summer. We request you provide a 10 year Update to that forecast? Thank you, Warren Halverson
Kyle Frankiewich	**3:04 PM**	Q on slide 49: I see that these 11 projects are "in planning phase". Can PSE describe the various phases of the delivery system planning and implementation process, and detail how the handoff occurs from planning to implementation?
Joni Bosh	**3:07 PM**	Slide 49 - it looks like all of these projects would be pursued even if CETA didn't exist, correct?
Joni Bosh	**3:11 PM**	Thanks
Bill Westre	**3:16 PM**	When will DERMS and TOU be ready?
James Adcock	**3:18 PM**	Slide 51: In regards to "Enhanced Meter Data Visibility" will customers have the same access to their meter data that PSE has? If not why not -- why shouldn't we be allowed to have the same access to our own usage data as PSE has? Continued: For example is PSE has access to hourly meter data, can the customer have access to hourly meter data? If not why not?

Tom Eckman	**3:22 PM**	Slide 51 - Does PSE anticipate that it will ultimately have DER potential assessments by feeder (or substation) that is linked to its load forecast for that feeder/substation? Does PSE anticipate including DERs as resource options in its capacity expansion modeling? If so, does PSE anticipate initiating DER acquisition programs, similar to its EE programs, in addition to providing TOU or other rate design signals for DER development?
Lori Elworth	**3:23 PM**	Transmission line planning data should be updated prior to building if the data is not current. Customers are paying a huge price for old technology of Energize Eastside. There are better solutions today. Can this be addressed? Warren had some good questions that were not answered.
Joni Bosh	**3:23 PM**	Do you have an existing analysis/report on what PSE needs/is evaluating for Grid modernization? Slide 51, I think? My mistake, might be slide 52?
James Adcock	**3:30 PM**	Comment: Just to give one "Reality check point" I just checked what is available to me in terms of meter data, and I can still only access meter data on a daily-cumulative basis, not on an hourly basis. Having access to hourly-usage data would allow customers to begin to understand where their electrical and/or natural gas usage is going to -- allow them to actually target conservation and efficiency efforts.
Joni Bosh	**3:31 PM**	Thanks
James Adcock	**3:39 PM**	Raise hand
Cress Wakefield	**3:39 PM**	How are you currently working with commercial customers and large companies that are driving net positive energy goals on their sites?
Kyle Frankiewich	**3:41 PM**	Q on Jens's response: what litigation is pending regarding Energize Eastside, and why would that prevent conversation in the context of this public meeting?
Anne Newcomb	**3:43 PM**	Is PSE considering burying wires? If not why? With all of the trees and wind in this area I have always thought it makes sense.
Kyle Frankiewich	**3:45 PM**	follow-up: I can understand that there might be some hesitance to discuss issues under litigation right now. Could you provide more background for the legal dispute or a reference to it?
Bill Westre	**3:45 PM**	Thanks to all the presenters
Anne Newcomb	**3:46 PM**	Thanks!
Kyle Frankiewich	**3:47 PM**	Thank you for offering stakeholders additional time!

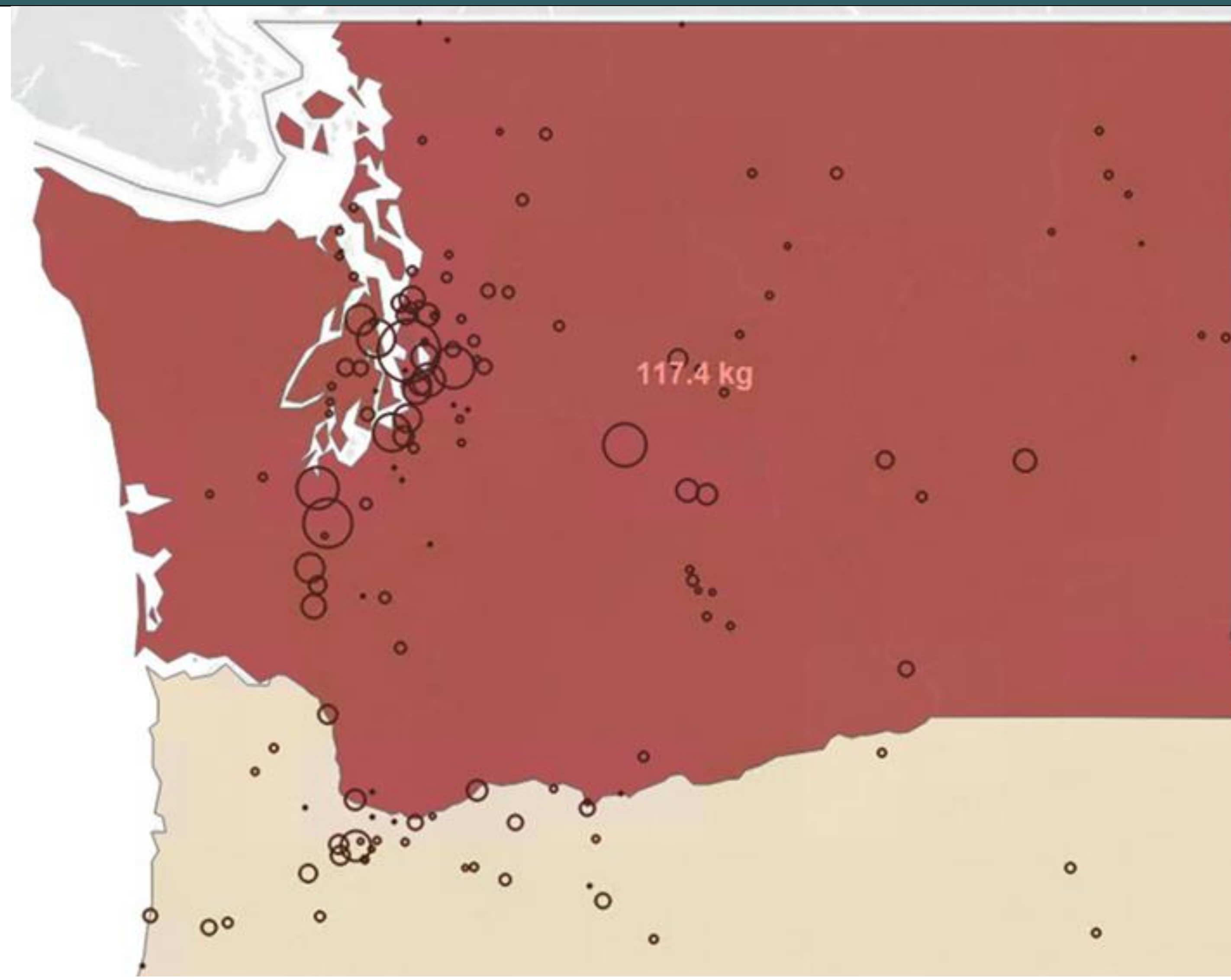
PSE IRP Feedback Report
Webinar 10: Clean Energy Action Plan (CEAP) and Clean Energy Implementation Plan, Economic, Health and Environmental Benefit Assessment of Current Conditions and Delivery System and Grid Modernization Needs
November 16, 2020

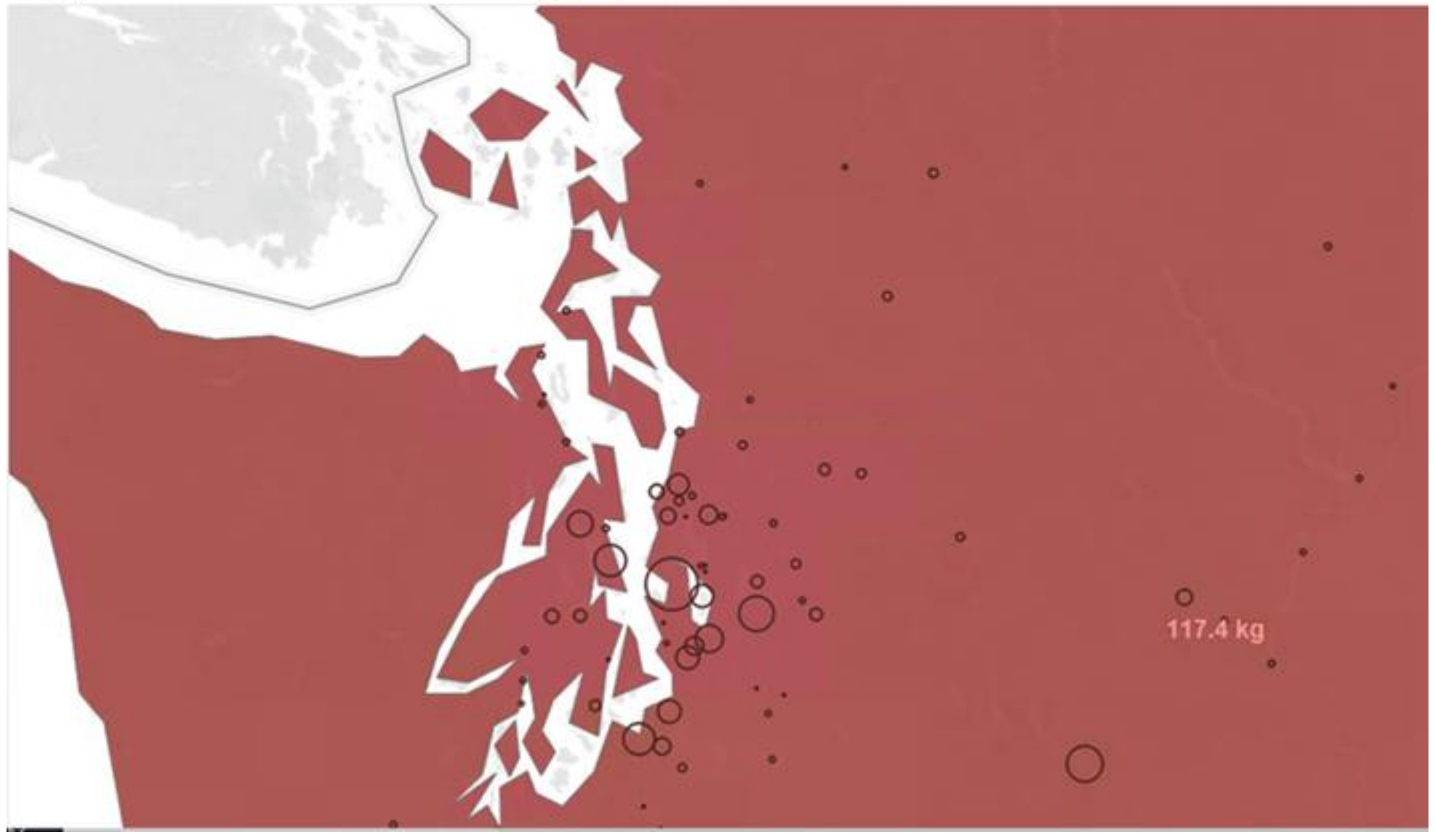
12/07/2020

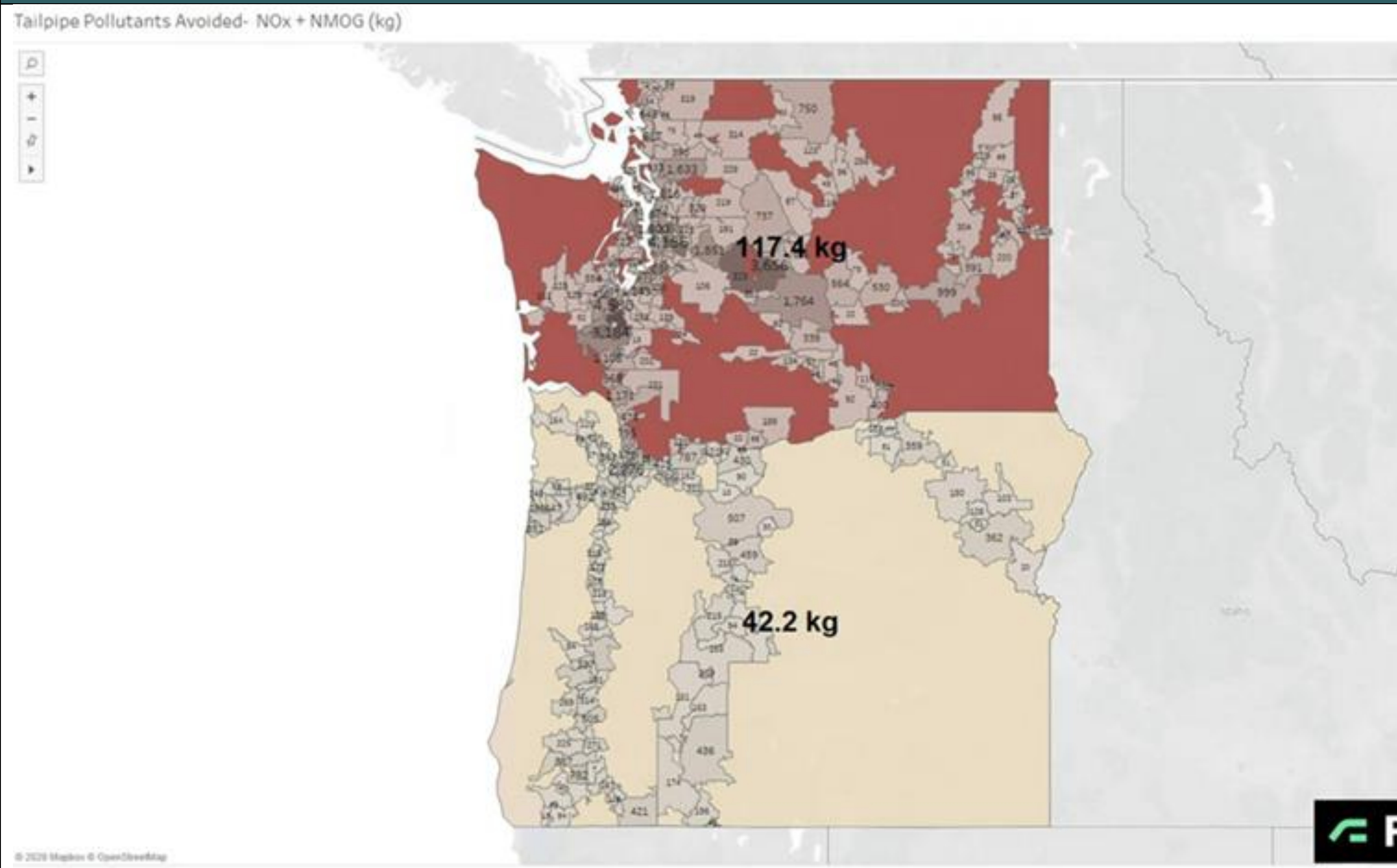
The following stakeholder input was gathered through the online Feedback Form, from November 9 through November 30, 2020. PSE's response to the feedback can be found in the far-right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on December 14, 2020.

Feedback Form Date	Stakeholder	Comment	PSE Response
11/13/2020	Don Marsh, CENSE	Dear PSE IRP Team, Thank you for the slides for the November 20 IRP webinar posted at https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/Nov_16_Webinar/Webinar%2010%20-%20Presentation.pdf. We would like to comment on the section titled “Highly Impacted Communities and Vulnerable Populations Assessment” (beginning at slide 27). In this section, PSE describes how the company will *measure* population disparities, but it is not clear what the company will *do differently* after it has collected this information. An example would be helpful for stakeholders to understand how PSE has fulfilled this responsibility in the past, how effective these efforts have been, and what PSE will change in the future to meet CETA requirements. For example, district 53053940005 in Tacoma is located approximately 1.25 miles from PSE's new Tacoma LNG facility. By our calculations, this district scores 54 points out of a maximum of 75 using the “Final composite score” formula on slide 33. By any measure, this is a “highly impacted community.” Accordingly, it would be helpful for stakeholders to know: • What extra efforts did PSE make to engage a community that endures challenging socioeconomic factors such as Limited English (rank 8), People of Color (rank 9), and unemployment (rank 8)? • This community suffers the second-highest rank in overall Environmental Exposures and Environmental Effects categories. What steps did PSE take to assure the community that the LNG plant would not further impact the health and well-being of its residents? • What percentage of this community was fully engaged in the process? What percentage submitted written and oral and written comments in public meetings regarding the facility? Was this response proportional to the proximity of the community to the project? • In the future, what steps could PSE take to better engage a community that is disadvantaged by language, culture, and employment conditions? PSE's answers to these questions have relevance to the question posed on page 37: “Who do we need to involve to improve the analysis?” In addition to our concerns about representation and treatment of vulnerable populations, we would like to comment on slide 45 regarding the Delivery System Planning process. The first box lists “Assumptions, performance targets and modeling input” as a primary step to establishing grid needs. However, these assumptions and performance targets are not available to the public for comment and review. In various forums, PSE has claimed this information is restricted by federal laws that protect the energy grid from malicious attacks by terrorists. We support reasonable restrictions on information to inhibit terrorist attacks. However, PSE has also prevented individuals and experts with appropriate security clearance from seeing these assumptions and performance targets. In the case of Energize Eastside, PSE has not updated its forecasts or analysis that justify the project since 2015. However, PSE acknowledges that demand forecasts and energy technologies have changed significantly during the last five years. State legislation has also changed in important ways. Questions about Energize Eastside are relevant to Monday's webinar because PSE lists a “Bellevue Area New Substation” on slide 50 without explanation of the capacity need it is addressing. This substation is an integral part of the Energize Eastside	Thank you for your comments on the Economic, Health and Environmental Benefits Assessment of Current Conditions and feedback on equity. As discussed during the webinar, PSE is at the beginning of the evaluation and the purpose of the webinar was to solicit input from stakeholders to help inform the assessment. The assessment will inform the outcome of the final IRP. Concerning PSE's efforts to broaden public engagement, efforts were made in early 2020 to broaden the 2021 IRP participation and an email list of more than 1,500 people was developed with input from regulators, stakeholders, and community outreach specialists. Personal phone calls were made to invite targeted individuals representing various communities and populations to participate. There is more work to be done concerning outreach and inclusion. There have been challenges with all meetings of the 2021 IRP process conducted remotely because of COVID-19 restrictions and PSE welcomes input concerning outreach and solutions for inclusion. The need for the Energize Eastside project has been firmly established going back to 2013; information regarding the need for the project can be found on their website at www.energizeeastside.com. Any further questions should be directed to the energize eastside team via their dedicated e-mail, energizeeastside@pse.com.

Feedback Form Date	Stakeholder	Comment	PSE Response
		project. PSE claims that it has verified the need for this project with supplemental studies in 2016, 2017, 2018, and 2019. However, the company has not shared the results of these studies with the public or consultants hired to represent the public. We would like to verify that PSE has appropriately updated its assumptions and forecasts that underlie these studies. Such disclosures are important to set the stage for increased transparency and accountability – key elements for a just and equitable Clean Energy Transformation. Sincerely, Don Marsh, President CENSE.org	
11/16/2020	James Adcock	I express concerns about the big elements which will not be ready in time for the Draft IRP -- including that which has been most controversial over the last 12 years, namely the stochastic modeling -- which I believe will keep participants from commenting in an informed manner on that Draft. I recommend that PSE and UTC figure out some way to get substantially complete modeling efforts, including the stochastic modeling, in the "Draft" IRP time frame, so that the IRP participates can meaningfully comment on elements of that draft which they believe are in error. Otherwise it becomes an invitatation for PSE to slip-stream the more controversial aspects into just the final IRP document, such that no timely feedback can be given, and PSE, after continually blocking meaningful conversations with participants during the IRP meetings, now creates a fait accompli -- where participants are effectively frozen out of the entire IRP process up through the final IRP documentation being published.	PSE acknowledges your concerns and is working to include all the analysis conducted to date in the draft IRP, due January 4, 2021. PSE looks forward to stakeholder feedback on the draft. PSE will host two more public participation meetings in 2021 before the final IRP to review the remaining analysis and obtain stakeholder feedback.
11/16/2020	Cress Wakefield, ARUP	Recommend including timelines as part of the IRP on delivery system planning for DERMS and TOU, as the carbon initiatives of large commercial companies and cities seem to be outpacing the readiness of the utilities. Even if the incentives/pricing were unclear, it would help with planning.	Thank you for your suggestions. The timeline for TOU pilot activity will be included in the IRP. The timeline for DERMS implementation is in development, but will be discussed in the IRP.
11/16/2020	Brian Grunkemeyer Founder & CEO FlexCharging, Inc.	I wanted to follow up with Tyler Tobin and Ben Farrow about tailpipe emissions from gasoline cars. We can use that to justify accelerating EV adoption. We have a deep but not broad data set. I suggest we could work together to collect more data to better make a compelling case for additional spending on increasing EV adoption. In terms of indicators of equity, I suggest you include air pollution. Specifically, EV investments that speed up adoption will avoid tailpipe emissions from gasoline vehicles, *in specific communities*. We all know air pollution impacts human health, through asthma attacks and shortened lifespans. But programs increasing EV adoption can help avoid air pollution, and therefore avoid these health impacts and costs. For the vehicles signed up with FlexCharging, my team has analyzed the avoided NOx + NMOG tailpipe pollution, grouped by city. There are also avoided pollution from particulate matter, formaldehyde, and carbon monoxide, all informed by EPA estimates. Note most of the drivers live in the Seattle & Eastside area (and some in Portland), but the avoided tailpipe emissions impact is statewide. This data of course requires tracking cars & where they drive, instead of focusing on smart plugs.	Thank you for input and suggestions. This is interesting work, which may hold value during the development of PSE's Clean Energy Action Plan (CEAP) and Clean Energy Implementation Plan (CEIP). PSE will follow up outside of this Feedback Report to learn more about FlexCharging, Inc.'s data set and its applicability to PSE's models.

Feedback Form Date	Stakeholder	Comment	PSE Response
		 Zooming in, you can see more details about affected communities:	

Feedback Form Date	Stakeholder	Comment	PSE Response
		Tailpipe Pollutants Avoided- NOx + NMOG (kg)  We get this data by polling vehicle status regularly when driving. We have high resolution GPS data, which we can then map to zip codes, or with a little work, down to the census tract. Here's our data broken down by zip code. State level numbers are in kg, and each zip code is in g.	

Feedback Form Date	Stakeholder	Comment	PSE Response
		 Our data shows a statewide benefit to many communities, to augment the equity benefits from accelerating EV adoption. FlexCharging can provide a data gathering piece for your measurement & verification needs, to demonstrate this benefit. There are two very clear answers for policy makers: 1) WA air pollution exposure is highest in the Puget Sound region, heavily overlapping with your service territory. 2) Benefits from EV's in Bellevue extend to air quality improvements statewide, in addition to just the owner's territory. We additionally support managed charging to optimize around dynamic prices from a utility, and we're working on optimizing around minimizing marginal CO_2 emissions, using an emissions forecast from WattTime. The money aspect impacts all ratepayers by affecting your costs, while the carbon emissions impact is global, though quantifying it can help the US as we establish national goals under the Paris Climate Accord. At some point, national goals need to translate into per-state and per-utility level commitments. We can support your efforts with our data set, and perhaps we could collaborate on expanding this data set.	
11/24/2020	Don Marsh, CENSE	Dear PSE IRP Team, I seek further details regarding a statement by Jens Nedrud in IRP Webinar #9 at timestamp 02:10:35 (see the recording at https://transcripts.gotomeeting.com/#/s/74f800380e1968d7d6749493e6c8287fbf835cb8af1a8321f59b6590ed2a5e0c). Mr. Nedrud said: "*I will say that we have experienced significant summer peaking events that have caused our operators a little bit of challenges in operating the grid that Energize Eastside would have addressed. So again, you can find more information on the project website.*"	The need for the Energize Eastside project has been firmly established going back to 2013; information regarding the need for the project can be found on their website at www.energizeeastside.com. Any further questions should be directed to the energize eastside team via their dedicated e-mail, energizeeastside@pse.com.

Feedback Form Date	Stakeholder	Comment	PSE Response
		Checking the website (https://energizeeastside.com), I find no details about summer peaking events that strained the transformers and transmission lines that PSE proposes to upgrade. Answers to the following questions would help us understand the situation Mr. Nedrud alluded to. 1. On what dates and hours did the challenges occur that Mr. Nedrud mentioned? 2. What was the peak load (in MW) that was being consumed by Eastside customers at the time? 3. What percentage of their peak capacity was experienced by the four Eastside transformers and two transmission lines that would be relieved by Energize Eastside upgrades? 4. How long did the stress conditions last? 5. What actions did operators take to alleviate the problem? 6. Approximately how many customers would have lost power if the operators had not acted? 7. How many times have similar conditions occurred during the past decade? Thank you for providing these clarifying details to help the public understand the need for Energize Eastside.	
11/30/2020	Don Marsh, CENSE	Dear PSE IRP Team, The attached letter contains questions regarding Jens Nedrud's presentation in IRP Webinar #9 regarding disclosure of information on major projects (including Energize Eastside, which has never been discussed in an IRP Advisory Group meeting). I hope PSE will answer these questions to avoid possible denial of rate increases for projects that have not been transparently presented to the public or land use examiners. That unfortunate outcome would harm not only PSE and its investors, but also ratepayers who need a financially healthy utility to make critical investments expected by CETA. Sincerely, Don Marsh	As discussed at the IRP meeting, the portion of the IRP pertaining to the "Delivery System and Grid Modernization Needs" specifically discussed the planning process to evaluate needs on PSE's delivery system. PSE also discussed the future planned growth/project areas currently in the planning phase. These include all major projects that require substantial transmission and/or distribution infrastructure. Each of the projects has an identified need and alternatives are being analyzed. As highlighted at the meeting, projects in the implementation phase, which are those in permitting, construction or energization, will be discussed at a future IRP webinar, currently scheduled for February. These projects alternatives have already been evaluated and their recommended solution selected. Specific to the question posed related to Energize Eastside discussion in prior IRP processes, the need for that project has been discussed in multiple prior IRP processes and included in those plans. Each of those processes has allowed for and included public engagement including stakeholder presentations as well as incorporated public comments. The Energize Eastside project is in the implementation phase and there have been no significant changes in either the need for the project or the solution evaluation which warrant a change to the recommended solution. Therefore, the Energize Eastside project will not be discussed at any upcoming 2021 IRP webinars. For the specific questions related to the project status and need for the Energize Eastside project, please refer those questions to the project e-mail at energizeeastside@pse.com.
11/30/2020	Scott Thomas, Town of La Conner	Affordability challenges may lead to shutoffs or disconnections due to non-payment. PSE should report out which and how many households are shut off on an annual basis, and make the data publicly available. The data should be analyzed to ascertain the prevalence of disconnection notices and service disconnections served on low-income households, African-American and Latino households, households with children, renters, and people living in older and poorly insulated homes. Further, there is a need to explore the coping strategies that families resort to to keep their homes warm and lit, such as forgoing food and medicine and keeping homes at an unhealthy temperature.	PSE recognizes this is a difficult time for many customers and has voluntarily suspended disconnections due to non-payment since early March of this year. Such disconnections will not resume before May 1, 2021, consistent with recent direction from the Utilities and Transportation Commission (UTC) related to COVID-19 relief. Additionally, PSE will be providing additional COVID-19 related energy assistance funds to low-income households needing help paying their energy bills during this time. PSE is already reporting data by zip code regarding prior disconnections, past due balances, and related data points to the UTC in Docket UE-200281.

Feedback Form Date	Stakeholder	Comment	PSE Response
11/30/2020	David Perk, 350 Seattle	Irena Netik, Director, Resource Planning & Analytics Ben Farrow, Director, Clean Energy Strategy, PSE Tyler Tobin, Resource Planning Analyst, PSE Thank you for your presentation on November 16 covering Highly Impacted Communities & Vulnerable Populations Assessment. 350 Seattle is glad to see that lawmakers have compelled Puget Sound Energy to take equity into account. Unfortunately, we're not surprised that it would require legislation, given PSE's history. Environmental racism has been a hallmark of the Tacoma LNG project. With insufficient consultation with the Puyallup Tribe (1), failure to acknowledge health and safety risks to the highly vulnerable populations around the facility (2), and construction before all permits were secured, PSE's relentless pursuit of the project has been a tremendous stress to vulnerable communities in Tacoma. Given this negative track record, PSE is going to have to dramatically improve its outreach and consultation with affected communities, and especially tribes, when undertaking future facilities and infrastructure projects. The choice of fracked gas as a replacement maritime fuel is itself deeply problematic. Fracked gas has profound social and health impacts at the site of extraction, and its global climate impacts can no longer be denied. Man camps used during the construction and extraction of fossil fuels have been linked to spikes in the epidemic of missing and murdered indigenous women and hardships to indigenous communities (3). Fracking produces large quantities of toxic water, poisoned wells and water tables, earthquakes, habitat and biodiversity loss (4). Young people locally and across the world recognize they face a bleak and uncertain future as a result of the climate crisis caused by fossil fuel use (5). By seeking to preserve and expand its gas business, PSE denies those impacts and works to ensure they continue by cynically targeting children who have already lost the prospect of a stable climate in their future (6). Our advice: reach out to local members of the Sunrise Movement for inclusion in the equity advisory group and end your relationship with the Partnership for Energy Progress. In our view, your equity advisors can't start soon enough. During the Covid-19 pandemic PSE has put profits over people, seeking to have ratepayers cover all additional costs incurred during the pandemic. To do this while your top executives, in the top 1% of state salaries, take no reductions in pay, is simply callous (7). Our advice: increase assistance to economically challenged ratepayers and consult with members of the utility justice movement, if they're willing to meet with you, like Puget Sound Sage. The recommended health disparities map is a good start (8) and we encourage you to continue your outreach for additional datasets. We urge you to implement a scope of action beyond the direct effects of PSE facility, infrastructure and fleet emissions. Equity efforts should include addressing air quality, both indoor (gas appliances) and out (tailpipe emissions). PSE is uniquely positioned to contribute to regional air quality solutions by supporting electric trucking in the Puget Sound freight corridor, and faster, wider electric vehicle adoption, including in low income areas. By contributing more air monitoring to regional data sets, PSE could help better identify point-sources and help verify future improvements. PSE should help build resilient communities by dramatically increasing your weatherization and community solar programs, and start implementing local storage and micro-grids (9). Finally, PSE needs to recognize the hard truth that your fossil gas business has no place in a decarbonized future (10). We urge you to start planning a path to get there. Sincerely, David Perk	Thank you for your input and suggestions. PSE appreciates the recommendations to contact Partnership for Energy Progress and Puget Sound Sage as an Equity Advisory Group is established. Public health will be key component of the Economic, Health and Environmental Benefits Assessment, as such, air quality will certainly be included in the assessment.

Feedback Form Date	Stakeholder	Comment	PSE Response
		350 Seattle 5031 University Way NE Seattle, WA 98105 References (1) Washington Tribes stand with the Puyallup Tribe, http://news.puyalluptribe-nsn.gov/washington-tribes-stand-with-the-puyallup-tribe/ (2) Tacoma Human Rights Commission, http://news.puyalluptribe-nsn.gov/wp-content/uploads/2019/04/THRC-LNG-rec-ltr-for-4.18.19-mtg-1.pdf (3) Man Camps Fact Sheet, http://www.honorearth.org/man_camps_fact_sheet (4) Environmental Health Concerns From Unconventional Natural Gas Development, https://oxfordre.com/publichealth/view/10.1093/acrefore/9780190632366.001.0001/acrefore-9780190632366-e-44 (5) Global Climate Strike, https://globalclimatestrike.net/ (6) Puget Sound Energy Wants Your Kids to Love Natural Gas, https://www.thestranger.com/slog/2020/06/26/43974948/puget-sound-energy-wants-your-kids-to-love-natural-gas (7) AG Ferguson calls on UTC to protect Washingtonians from utility shut-offs amid COVID-19 pandemic, https://www.atg.wa.gov/news/news-releases/ag-ferguson-calls-utc-protect-washingtonians-utility-shut-offs-amid-covid-19 (8) Washington Tracking Network (WTN), https://fortress.wa.gov/doh/wtn/WTNIBL (9) Building Back Better: Investing in a Resilient Recovery for Washington State, https://climate-xchange.org/2020/06/30/building-back-better-investing-in-a-resilient-recovery-for-washington-state/ (10) Draft 2021 State Energy Strategy, https://www.commerce.wa.gov/wp-content/uploads/2020/11/WA-2021-State-Energy-Strategy-FIRST-DRAFT-2.pdf	
11/30/2020	Nathan Sandvig	Please see attached. Thank you.	Thank you for all your suggestions and for the Navigant white paper reference. PSE has done a lot of work for the externality costs and decommissioning costs associated with combustion turbines and have not seen a lot of information around the costs associated for battery energy storage systems. PSE will continue to monitor the costs and externalities associated with battery storage.
11/30/2020	Norman Hansen	FYI. PSE feedback form submitted concerning an IRP discussion on Energize Eastside Transmission line proposed North Segment. Submitted comment and request: " Energize Eastside Transmission line North Segment has not yet been permitted. Consequently, it is not yet in the implementation phase and should be discussed at the next IRP meeting. Please advise your concurrence to discuss to meet the intent of the Washington Administrative Code."	As highlighted at the meeting, projects in the implementation phase, which are those in permitting, construction or energization, will be discussed at a future IRP advisory group meeting, currently scheduled for February.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Questions and recommendations from presentation:	Thank you for your questions and recommendations. PSE inserted each item below along with PSE's responses.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 16: The slide include equity considerations as part of the CEAP, but not the IRP. RCW 19.280.030(1)(j) requires that the IRP implement RCW 19.405.030 through 19.405.050, which includes the customer benefit provisions in 19.405.040(8).	Thank you for your feedback and code references concerning "the new planning cycle."
11/30/2020	Kyle Frankiewich, Washington	Slide 17: As in slide 16, staff notes that the statute has equity requirements for the IRP specifically. We hope PSE will reconcile its economically optimized portfolio and all equity requirements within its IRP broadly, and not just within the CEAP.	Thank you for your feedback. The portfolio optimization model is a computer mathematical model that needs defined inputs and equations. Given that the assessment is new for the IRP, PSE will be looking at it outside the computer model and adjusting the portfolio.

Feedback Form Date	Stakeholder	Comment	PSE Response
	Utilities and Transportation Commission		
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 19: During the meeting, PSE verbally acknowledged that highly impacted communities and vulnerable populations are relevant customer groups. Staff agrees that these groups should be specific, intentional customer groups that are specifically engaged.	Thank you for your feedback and support that highly impacted communities and vulnerable populations are relevant customer groups who should be engaged. Efforts were made in early 2020 to broaden the 2021 IRP participation and an email list of more than 1,500 people was developed with input from regulators, stakeholders, and community outreach specialists. Personal phone calls were made to invite targeted individuals representing highly impacted communities and vulnerable populations to participate. PSE agrees with you that there is more work to be done concerning outreach and inclusion. There have been challenges with all meetings of the 2021 IRP process conducted remotely because of COVID-19 restrictions and PSE welcomes input concerning outreach and solutions for inclusion.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 20: During the meeting, PSE verbally acknowledged that customer input is relevant for indicator development. Staff agrees that customer input is necessary for indicator development. Proposed CR-102 rules at WAC 480-100-655(2)(a) require customer input to develop indicators. Additionally, the Equity Advisory Group should be involved in the Company's CEIP in addition to the Low Income Advisory Group and Conservation Resources Advisory Group.	Thank you for your feedback. PSE is actively working toward establishing an Equity Advisory Group to help develop indicators and the broader CEIP. PSE also looks forward to continued engagement with stakeholders and customers including the IRP public participation process, Equity Advisory Group, Low Income Advisory group and Conservation Resources Advisory group.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 22: The slide uses the term "equitably distributed" in the triangle graphic. Staff recommends using the term "customer benefit" to refer to the full set of requirements in 19.405.040(8) and included in proposed CR-102 rules at WAC 480-100-610(4)(c), including the elements required by -4(c)(ii) related to public health, environment, and reductions and costs and risks as well as those required by -4(c)(iii) related to energy security and resilience. The term "equitably distributed" may unintentionally be seen to only refer to the requirements in -4(c)(i) related to the equitable distribution of benefits and reduction of burdens to vulnerable populations and highly impacted communities.	Thank you for your feedback concerning the word selection on slide 22: Meeting CETA goals. In future presentations, PSE will better clarify that all aspects of WAC 480-100-610(4) are clearly indicated. It was not PSE's intention to limit focus to -4(c)(i).
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 25: This is a good slide! It is busy, but that is appropriate given the myriad considerations and concepts being represented.	Thank you for your feedback concerning slide 25: Incorporating the Assessment into the IRP.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 26: Staff understands these questions to be the start to a productive conversation. Staff's initial responses are in the next section.	Thank you for your feedback.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 28: Staff understands this slide to help stakeholders parse energy and non-energy benefits might be assessed through this analysis.	The intention of slide 28: Assessment Objectives is to introduce stakeholders to the concept of the Economic, Health and Environmental Benefits Assessment. Then to provide some context as to the different data types necessary to complete such an assessment. Finally, how those data types do not necessarily align with existing IRP model framework and illustrate the effort needed to incorporate this new modeling framework into existing IRP models.
11/30/2020	Kyle Frankiewich, Washington	Slide 28. During the meeting, PSE verbally references the assessment as a quantitative assessment. Staff recommends that the Company consider qualitative input as well as qualitative information can inform the Company's judgement and discretionary decisions when developing its preferred portfolio.	Thank you for your suggestion to consider qualitative information in addition to quantitative information in the Economic, Health and Environmental Benefits Assessment. PSE acknowledges WAC 480-100-605 defines an indicator as an either qualitative or

Feedback Form Date	Stakeholder	Comment	PSE Response
	Utilities and Transportation Commission		quantitative attribute. PSE looks forward to developing a robust set of indicators with stakeholders, which will inform the assessment.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 29: This process map seems unnecessarily linear. We envision steps 1 and 2 to happen in parallel. As mentioned during the meeting, Staff notes that the identification of highly impacted communities and vulnerable populations should not be depicted as a precursor to developing the current conditions assessment pursuant to RCW 19.280.030(1)(k) as these are distinct work products. ○ The designation of highly impacted communities is outlined in statute in RCW 19.405.020(23). Specifically, highly impacted communities must be based on the Department of Health's Cumulative Impact assessment, which will identify impacts based on climate change and fossil fuels, and census tracts that are at least partially in Indian Country. The process for designating vulnerable populations is described in proposed CR-102 rules at WAC 480-100-640(4)(b). ○ The assessment described in RCW 19.280.030(1)(k) should capture energy and nonenergy benefits and burdens from utility programs and infrastructure, as well as general public health, environment, costs, risks, and energy security for all customers. ○ After completion, these two work products should help to determine disparities in current condition for highly impacted communities and vulnerable populations compared to all other utility customers. The degree of disparity will guide the proportion of benefits, including the reduction of burdens, should be directed to highly impacted communities and vulnerable populations during the transition to clean energy to ensure an equitable distribution.	Thank you for sharing the WUTC's perspective on the expected workflow and work products of the Economic, Health and Environmental Benefits Assessment. Upon reflection, PSE would agree that most of the work and results of steps 1 and 2 could be completed in parallel and will endeavor to do so during the assessment. PSE also agrees with the Staff's interpretation of determining the disparities based on the two work products.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 33: This is useful, and it is clear that the company's initial approach to the equity assessment has benefited from the IRP team's thoughtfulness. However, we worry that a purely quantitative approach will not capture the benefits of a qualitative review as well.	Thank you for your feedback concerning PSE's first approach concerning identifying the characteristics of the Economic, Health and Environmental Benefits Assessment. PSE acknowledges WAC 480-100-605 defines an "indicator" as an either qualitative or quantitative attribute. PSE looks forward to developing a robust set of indicators with stakeholders, which will inform to the assessment.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 33: The process for identifying vulnerable pops is codified in draft rule. How does PSE's approach align with that guidance?	WAC 480-100-605 defines a vulnerable population as "communities that experience a disproportionate cumulative risk from environmental burdens due to: Adverse socioeconomic factors, including unemployment, high housing and transportation costs relative to income, access to food and health care, and linguistic isolation; and sensitivity factors, such as low birth weight and higher rates of hospitalization." For the 2021 IRP, PSE intends to rely on the DOH Environmental Health Disparities Map, which includes many of these factors (as indicated by the stars on the slide), among others, in its composite score, to help identify vulnerable populations. However, as an Equity Advisory Group is established and further opportunities for public participation are made available, PSE intends to evolve its methodology and criteria for identifying vulnerable populations.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 35: Staff notes that the economic, health, and environment graphics on this slide should be considered as a subset of the disparities PSE considered. We hope this slide is illustrative rather than comprehensive. The assessment described in RCW 19.280.030(1)(k) must include data on energy and nonenergy benefits, costs and risks, as well as energy security. Therefore, the measurement of disparities should also reflect these categories. Related to our comments regarding slide 20, Staff recommends that the Company consider the disparities assessment an overlay to the Economic, health, and environmental burdens and benefits where the assessment itself focuses on understanding current conditions for all PSE customers.	Slide 35 was intended to illustrate, in broad strokes, the aims and methods of the assessment. PSE's Economic, Health and Environmental Benefits Assessment will fulfill all requirements of RCW 19.280.030(1)(k).

Feedback Form Date	Stakeholder	Comment	PSE Response
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 36: The company's methodology sketched out here implies that draft rules under draft WAC 480-100-610(4)(c) describes three separate customer benefit requirements. This is not staff's current understanding of the draft rule, though ideally this will get clarified in rule or in the adoption order	PSE believes this comment may be in reference to slide 35, in which case, PSE would reiterate the response above, "Slide 35 was intended to illustrate, in broad strokes, the aims and methods of the assessment. PSE's Economic, Health and Environmental Benefits Assessment will fulfill all requirements of RCW 19.280.030(1)(k)."
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 36: Staff notes that qualitative measures are also called out in statute, and may inform the CEIP. Also, the definition of vulnerable populations (VPs) is different from HICs. The attributes that make a PSE customer a member of a VP might not inherently or per-se be geographically clustered, and may not map obviously onto a geospatial analysis.	Thank you for pointing out the distinction between the disparate definitions of vulnerable populations and highly impacted communities. PSE has lumped these terms together for the purposes of this presentation, as we are still waiting on the results of the DOH cumulative impact study to identify highly impacted communities. PSE intends to incorporate qualitative metrics as the CEIP process progresses. An initial assessment, relying on quantitative metrics, will be conducted as a stepping stone to a more robust assessment following input from an Equity Advisory Group and further public participation. PSE acknowledges that a geospatial analysis may not account for each individual customer within a given geographic region. PSE is working to identify methods to limit the influence of these shortfalls and will incorporate new methods as they are established.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 36: To clarify, in staff's view, PSE does not have to show progress in the assessment metrics; the company should demonstrate progress in the indicators. The indicators don't necessarily map 1:1 to assessment metrics. Tailpipe emissions may be a good example in this regard, in that EV adoption may ameliorate air quality but air quality is not only correlated to ICE vehicles.	Thank you for providing improved clarity the relationship between assessment metrics and indicators.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 43: The public meeting chat discussion at ~2:50pm focused on applicability of CETA planning requirements to Tx projects currently being pursued by PSE. Participant Black asked about which projects are being assumed as built within the IRP. PSE's Nedrud clarified that projects such as Energize Eastside are in the implementation phase. What are the phases that were referenced? What types of investments follow this phased development approach? What phases will PSE include as a part of decisions made and supported within the IRP, and in what phases are projects included as finished projects? Has PSE typically included capital-intensive projects in the company's IRPs at a certain phase (perhaps a planning phase?), but not at others (like an implementation phase)?	All projects have a lifecycle including planning and implementation (consisting of permitting, construction and energization). Large projects specifically follow this development approach. Project needs are identified and alternatives are analyzed during the planning phase. Feedback and input on those will be sought as part of this IRP process and also through PSE's attachment K stakeholder process in accordance with PSE's FERC requirements. The solution is then selected based on that alternative analysis as well as feedback. Once a solution is identified and the project moves to the implementation phase, stakeholder engagement transitions to the local outreach and the jurisdiction governing permitting requirements. After identifying the recommended solution, PSE does not use the IRP process to continue to evaluate a solution unless there are significant changes that warrant revisiting. Specific to Energize Eastside, this project is in the implementation phase and there have been no significant changes in either the need for the project or the solution evaluation which warrant a change to the recommend solution. The typical types of investments for major projects include solutions to address needs identified to meet NERC compliance requirements on the transmission system, new distribution substations to meet local capacity needs or other projects which would reconfigure the topology or modify transmission system ratings.

Feedback Form Date	Stakeholder	Comment	PSE Response
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 51: Does PSE anticipate that it will ultimately have DER potential assessments by feeder (or substation) that are linked to the company's load forecast for that feeder or substation? Does PSE anticipate including DERs as resource options in its capacity expansion modeling? If so, does PSE anticipate initiating DER acquisition programs, similar to its EE programs, in addition to providing TOU or other rate design signals for DER development? Participant Eckman asked questions along these lines verbally, and staff includes them here with the hope of a written response.	At this time, PSE is not planning to produce DER potential assessments akin to the conservation potential assessment at the feeder or substation level. However, hosting capacity analysis will allow PSE to understand where DERs can be sited without significant additional investment in the electric system. As verbally stated, PSE is including DERs as resource options in the capacity expansion model. Regarding DER acquisition programs, PSE anticipates defining the acquisition process as appropriate in the Clean Energy Implementation Plan.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Feedback and recommendations separate from slides: Note: Many recommendations for this meeting are included in the slide-specific comments above.	Thank you for your feedback and recommendations separate from the slides. PSE inserted each item below along with PSE's responses.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	**Responses to PSE's questions re: equity assessment** a. How do we measure disparities affecting highly impacted communities and vulnerable populations? i. Surveys and advisory groups are also a good way to understand these disparities. ii. The metrics themselves are explored more in the second question, but some other views into these disparities could come from PSE's customer data. For example, historical usage data could help the company identify disparities in weatherization within a neighborhood's housing stock. If an address's load is substantially more temperature-dependent, that home would likely be a good candidate for efficiency measures. b. Are there quantifiable public health and environmental benefits and reductions of costs and risks? i. The metrics on slide 33 are a great start. 1. Transportation issues are represented fairly by "transportation expense." This topic could also include average commute time, as well as access to transportation alternatives like bike routes or employer-organized transportation (vanpools, shuttles). 2. "Cardiovascular disease" is broad and well-tracked, but other health-related metrics could draw a fuller picture. Asthma correlates strongly to air quality, and would definitely be appropriate for this list. Reduction of asthma rates would link directly to quantifiable benefits. 3. Related to health and quality of life, food access and diet concerns – proximity to full-service grocers, cost of food relative to average income, obesity as a health risk – could also be added. ii. Historical inequities and patterns of institutional action to the detriment of vulnerable populations persist, and are visible quantitatively in many of the metrics floated by the company. Practices such as redlining may be visible in housing burden data, for example. From a qualitative perspective, the unique history of PSE's service territory could inform the unique types of equity concerns PSE could ameliorate through its CETA-prompted actions, or inform the specific actions themselves. c. Are there other quantifiable economic or equity measures that should be included? i. Other than factoring cost-of-living at as granular a level as is practicable, the economic metrics the company has proposed seems like a good place to start. d. What other metrics should be applied? i. No other considerations at this time. e. Are there other quantifiable reliability, energy security and resiliency measures that can be included in the assessment? i. The proliferation of distributed energy resources around PSE's service area will have an impact on reliability. It is likely that DERs which enhance reliability will be adopted by more affluent customers – resources that may not be nearly as accessible to HICs and VPs. To the extent PSE can include some aggregate measure of technologies like PV, EVs, and small-scale battery storage, the company will be	Thank you for providing thoughtful answers to the presentation prompts. PSE will take these suggestions under advisement as we continue to develop and refine the Economic, Health and Environmental Benefits Assessment and progress the CEAP and CEIP.

Feedback Form Date	Stakeholder	Comment	PSE Response
		able to see the inequitable distribution of these resources. This should be easy, too, as DER assessments are also required under CETA.	
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	**Content of the draft IRP**: While staff supports the continued engagement of the IRP advisory group after the IRP draft is filed, staff shares the concerns of other stakeholders that key parts of the IRP analysis may not be finished in time for inclusion in the draft IRP. Specifically, the broader exploration of flexibility and stochastic risk analysis of the company's (draft) preferred portfolio may not be available for thorough review by stakeholders prior to its completion in the IRP due in April. The IRP must evaluate changes to achieve, among many other constraints, the requirements of CETA at least reasonable cost, considering risk. The risk component implies some stochastic analysis of the preferred portfolio.	PSE acknowledges your concerns and is working to include all the analysis conducted to date in the draft IRP, due January 4, 2021. PSE looks forward to stakeholder feedback on the draft. PSE will host two more public participation meetings in 2021 before the final IRP to review the remaining analysis and obtain stakeholder feedback.
11/30/2020	Virginia Lohr, Vashon Climate Action Group	On Slide 19, I want to address Irena Netik's oral comments regarding public participation in the IRP Advisory Group (on the Nov. 16, 2020 Webinar recording from 29:38 to 31:41). My understanding of what she said is that PSE decided to have a very open process for the 2021 IRP and considered anyone who attended one of the IRP webinars to be part of the 2021 IRP Advisory Group. I have really appreciated this openness and the broad acceptance of who may participate. She also mentioned that this process was selected because it appeared to be where the rules for future IRPs were headed. She suggested that there was not full clarity in what the final rules will ultimately say. I want to express my hope that PSE will continue with this broad understanding of who may participate on the IRP Advisory Group in the future, regardless of what the rules say, assuming the rules are setting minimum requirements that PSE could exceed. The 2021 IRP process has been much more welcoming of participation than the 2019 IRP, which felt more exclusionary. I assume it was not intended, but the closed nature of 2019 IRP process contributed to some people's impressions that PSE was trying to hide information from the public.	Thank you for your feedback and sharing your support of the inclusive nature of the 2021 IRP public participation process. Thank you for your suggestions concerning public participation in PSE's future IRPs.
11/30/2020	Virginia Lohr, Vashon Climate Action Group	Please continue your inclusion of all interested people as participants in future IRP Advisory Groups.	PSE welcomes all interested people as participants in the 2021 IRP process. Thank you for your continued participation!

PSE IRP Consultation Update

Webinar 10: Clean Energy Action Plan (CEAP) and Clean Energy Implementation Plan, Economic, Health and Environmental Benefit Assessment of Current Conditions and Delivery System and Grid Modernization Needs

November 16, 2020

12/14/2020

The following consultation update is the result of stakeholder suggestions gathered through an online Feedback Form, collected between November 9 and November 30, 2020 and summarized in the December 7 Feedback Report. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

Economic, Health and Environmental Benefits Assessment

PSE received feedback from Don Marsh (CENSE), Brian Grunkemeyer (FlexCharging), David Perk (350 Seattle) and Kyle Frankiewich (WUTC Staff) regarding PSE's intial approach for the Economic, Health and Environmental Benefits Assessment.

PSE has reached out to Brian Grunkemeyer to discuss some of the details of the avoided tailpipe emissions dataset and some intitial information was exchanged on December 8. A meeting will be arranged for later in December or early January to learn more.

PSE thanks stakeholders for their thoughtful review and suggestions and will endeavor to adopt the following suggestions in development of the Economic, Health and Evironmental Benefits Assessment:

1. Coordination with local advocacy groups
2. Inclusion of air quality metrics in the assessment
3. Parallel assessment of named communities and metric evaluation
4. Continued evaluation and refinement of assessment metrics and metholologies to best capture distributions of named communities

Scope of PSE's Draft IRP

James Adock and Kyle Frankiewich (WUTC Staff) provided feedback of concerns regarding the scope of PSE's 2021 Draft IRP, due January 4, 2021. While not all the analysis will be completed for the draft IRP, PSE is confident that stakeholders will have meaningful content for review and feedback. PSE fully intends to incorporate stakeholder feedback on the draft IRP received during the WUTC comment period that is expected to begin in early January. In addition, PSE will continue with its public participation process and stakeholders will have opportunity to provide feedback on analysis that is completed after the draft IRP is filed. PSE is committed to documenting stakeholder feedback and demonstrating its application in the IRP analyses.

Summary of all updates

PSE appreciates the feedback provided by stakeholders. In summary, the following changes will be implemented:

- PSE will work to adopt the four stakeholder suggestions above in the Economic, Health and Evironmental Benefits Assessment as practical.
- PSE will work to develop a draft IRP with key analyses, scenarios and sensitivies completed for stakeholder review and feedback. The draft IRP will be available at www.pse.com/irp on January 4, 2021.

Webinar 11, December 15, 2020

Flexibility Analysis, Portfolio Draft Results (electric & natural gas)

Webinar #11: Flexibility Analysis and Portfolio Draft Results
December 15, 2020 from 1:00 p.m. to 5:00 p.m. PST

Virtual webinar link: https://global.gotomeeting.com/join/255497885
Access code: 255-497-885
Call-in telephone number (audio only): +1 (408) 650-3123

Topic	Lead*
Welcome • Agenda review • Safety moment • How to participate • Speaker introductions	EnviroIssues
Draft Conservation Results (Electric & Gas)	Gurvinder Singh, Sr. Energy Resource Planning Analyst, PSE
5-minute break	
Draft Electric Results • Draft Mid Portfolio Results • Draft Sensitivity Results	Elizabeth Hossner, Manager Resource Planning & Analysis, PSE Jennifer Magat, Sr. Energy Resource Planning Analyst, PSE
5-minute break	
Flexibility Analysis	Zhi Chen Sr. Energy Resource Planning Analyst, PSE Elizabeth Hossner, Manager Resource Planning & Analysis, PSE
Draft Gas Results • Draft Mid Portfolio Results • Draft Sensitivity Results	Gurvinder Singh, Sr. Energy Resource Planning Analyst, PSE
Wrap up and next steps • Next steps • Upcoming meeting schedule • Thank you's	EnviroIssues

**speakers may change the day of the meeting*

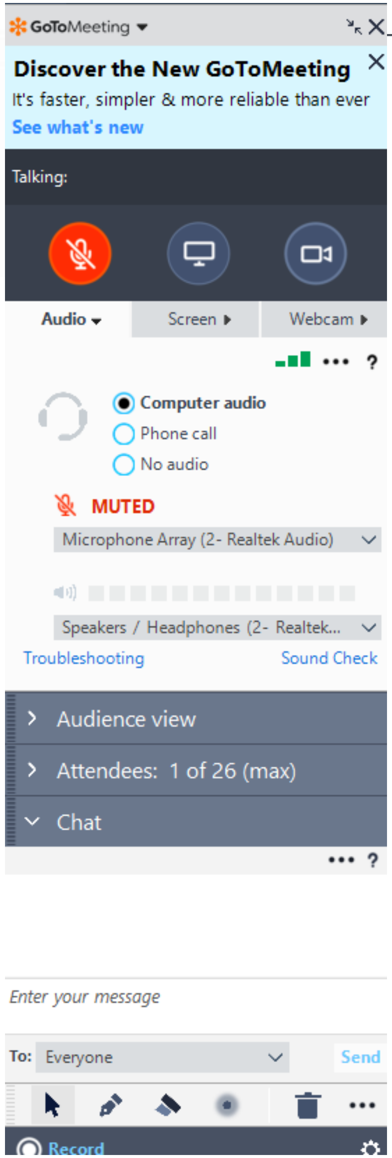
2021 IRP Webinar #11: Draft IRP Results

Electric & Gas Portfolio Model Results
Flexibility Analysis

December 15, 2020

Welcome to the webinar and thank you for participating!

GoToMeeting



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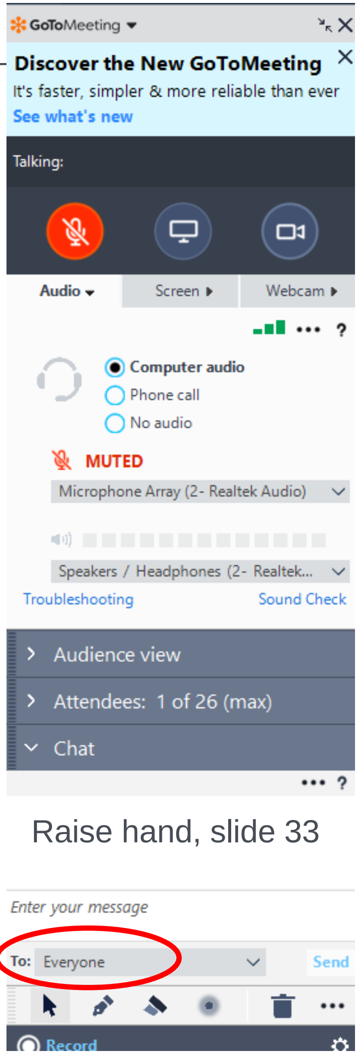


Presentation Do's

- Mute your mic during the presentation
- You can participate in writing or verbally using the chat window
  - **In writing:** your question will be read
  - **Verbally:** type "Raise hand" and slide #, share with "Everyone"; please wait to be called on to ask your question
- Be considerate of others waiting to participate
- We will try to get to all questions

PUGET SOUND ENERGY

Agenda


- Safety Moment
- Draft Electric Results
    - Draft Mid Portfolio Results
    - Draft Sensitivity Results
- Flexibility Analysis
- Draft Gas Results
    - Draft Mid Portfolio Results
    - Draft Sensitivity Results

Safety Moment: Accident prevention at home

With many of us working from home and with other adults, children and pets in close proximity, keeping out of the ER or vet clinic is a high priority. Consider these tips to help keep yourself and others in the household and pets safe:

- Keep your first-aid kit well stocked; you may be able to administer aid with a consult with a first responder/911 instead of going to the ER
- Do a self assessment to make sure your home environment is safe (hanging cords, trip hazards like rugs and cleaning supplies should be stored carefully)
- Anchor furniture
- Move medication out of kids’ and pets’ reach

Today's Speakers

Jennifer Magat
Senior Resource Planning Analyst, PSE

Tyler Tobin
Resource Planning Analyst, PSE

Charlie Inman
Associate Resource Planning Analyst, PSE

2021 IRP modeling process

The 2021 IRP will follow a 6-step process for analysis:

1. Analyze and establish resource need
2. Determine planning assumptions and identify resource alternatives
3. Analyze scenarios and sensitivities using deterministic and stochastic risk analysis
4. Analyze results
5. Develop resource plan
6. 10-year Clean Energy Action Plan

2021 IRP
Electric Mid Portfolio Draft Results

PUGET SOUND ENERGY

Participation Objectives

- PSE will inform stakeholders of the draft electric portfolio results.

  IAP2 level of participation: INFORM

- PSE will consult with stakeholder in identifying the key elements of the resource plan.

  IAP2 level of participation: CONSULT

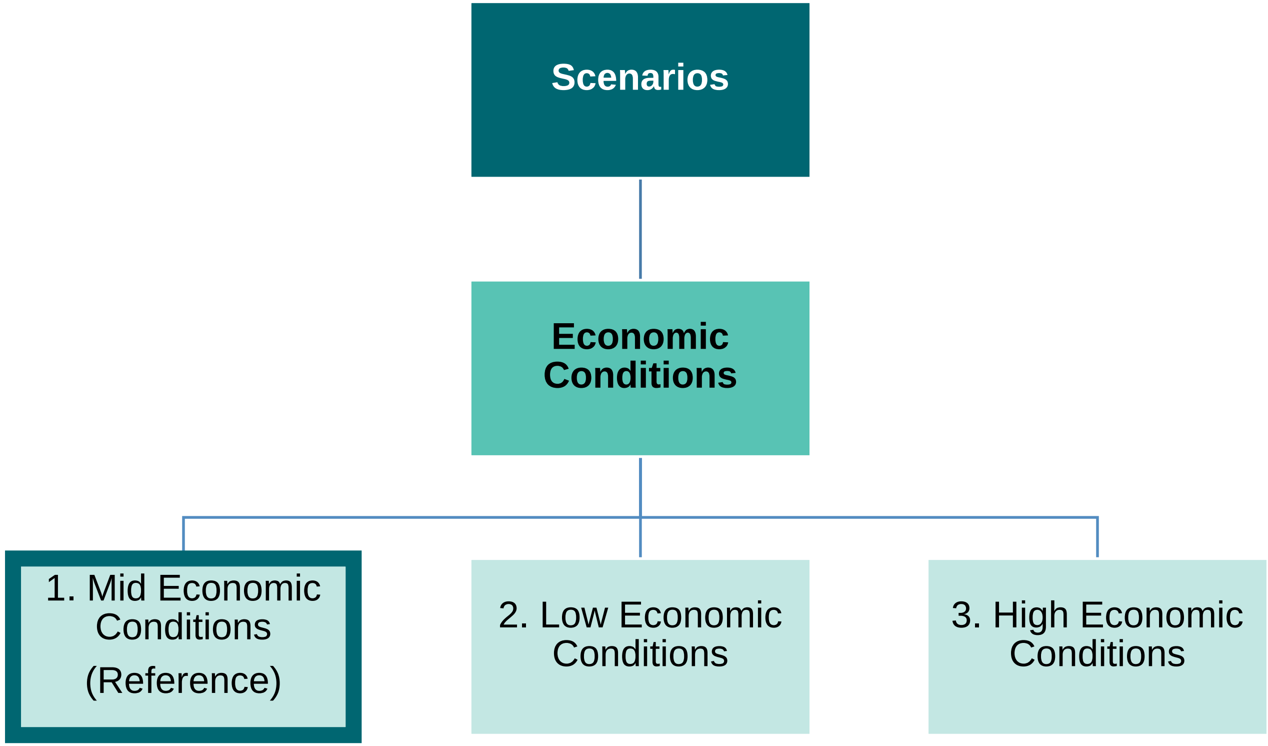
PUGET SOUND ENERGY

2021 IRP draft mid portfolio

- The draft mid portfolio meets the Clean Energy Transformation Act:
  - Coal free by 2025
  - Carbon neutral by 2030
  - 100% carbon free by 2045

- The results are the output from the portfolio optimization model of the least cost set of resources.

- **<u>This is NOT PSE's preferred portfolio or the final resource plan</u>**.



Model Assumptions

Inputs	Assumptions
CETA Constraint	At least 80% of delivered load must be met with renewable or non-emitting resources by 2030 and 100% by 2045. Colstrip units 3 and 4 retire by 12/31/2025.
SCGHG	Modeled as a cost adder.
Demand	The 2020 IRP Base (Mid) Demand Forecast is applied for PSE in the portfolio model.
Economic Retirement	The portfolio model allows for economic retirement of existing resources.
Natural gas price	Mid gas prices are applied, levelized 20-yr Sumas gas price is $3.39/MMBtu.
Power price	Mid electric prices are applied, levelized 20-yr Mid C power price is $24.19/MWh.
Time horizon	2022 – 2045
Transmission	Transmission constraints to resources in eastern Washington unconstrained. Transmission connections to ID, WY, and MT are included. MT limited to 750 MW, ID/WY limited to 400 MW.
Upstream emissions	Upstream CO_2 emissions are added to the emission rate of natural gas plants in PSE's portfolio model.

25 unique supply-side resource alternatives and numerous demand-side resource options were evaluated

Resource alternatives:

Renewable Resources

- Solar (utility scale)
  - WA West
  - WA East
  - Idaho
  - WY East
  - WY West
- Solar (Distributed)
- Wind – onshore
  - WA East
  - Idaho
  - WY East
  - WY West
  - MT Central
  - MT East
- Offshore Wind
- Biomass

Energy Storage

- Battery storage
  - 2-hr Lithium Ion
  - 4-hr Lithium Ion
  - 4-hr Flow
  - 6-hr Flow
- Pumped Storage Hydro (PSH)

Combined Resources

- WA Solar + battery
- WA Wind + battery
- MT wind + PSH

Combustion Turbine Resources

- Combined cycle combustion turbines baseload gas plant (CCCT)
- Simple cycle combustion turbine peaking plant (frame peaker)
- Reciprocating internal combustion engines peaking plant (recip peaker)

Note: renewable fuel options are evaluated through the sensitivity analysis

Demand Side Resources

- Energy Efficiency
- Demand Response
- Distribution Efficiency
- Codes and Standards
- Distributed Solar PV (customer)

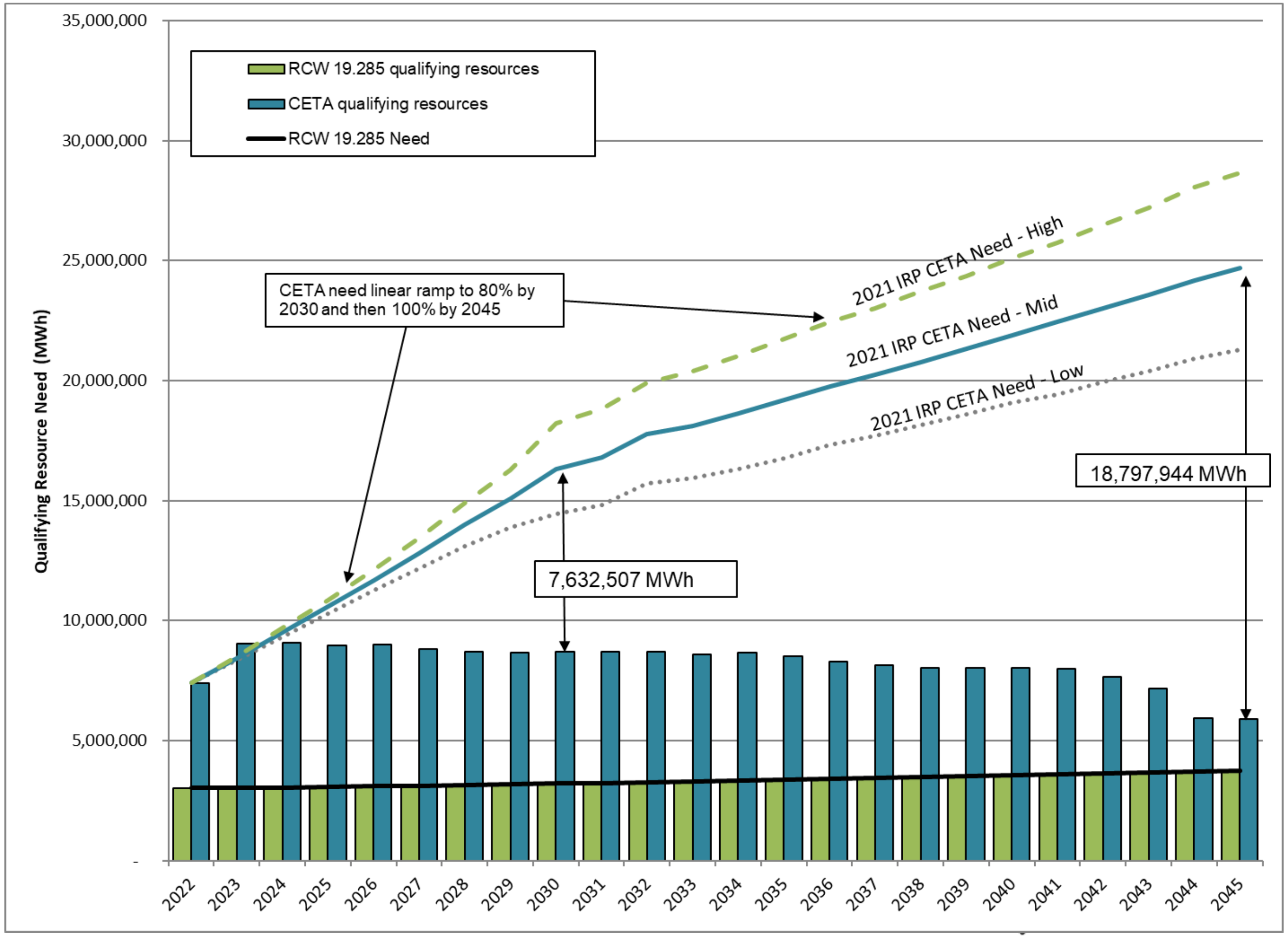
Note: Supply-side resources were discussed at the May 28, 2020 webinar. Demand-side resources were discussed at the July 14, 2020 webinar. Modeling assumptions include stakeholder feedback documented through the Feedback Reports and Consultation Updates.

Existing Portfolio and Renewable Need, before demand-side resources

- PSE's current portfolio faces shortfalls of:
  - **7.6 million MWh** of renewable generation in 2030
  - **18.8 million MWh** of renewable generation in 2045

- CETA renewable need is added to the portfolio model as a linear ramp rate to meet the 2030 and 2045 targets.

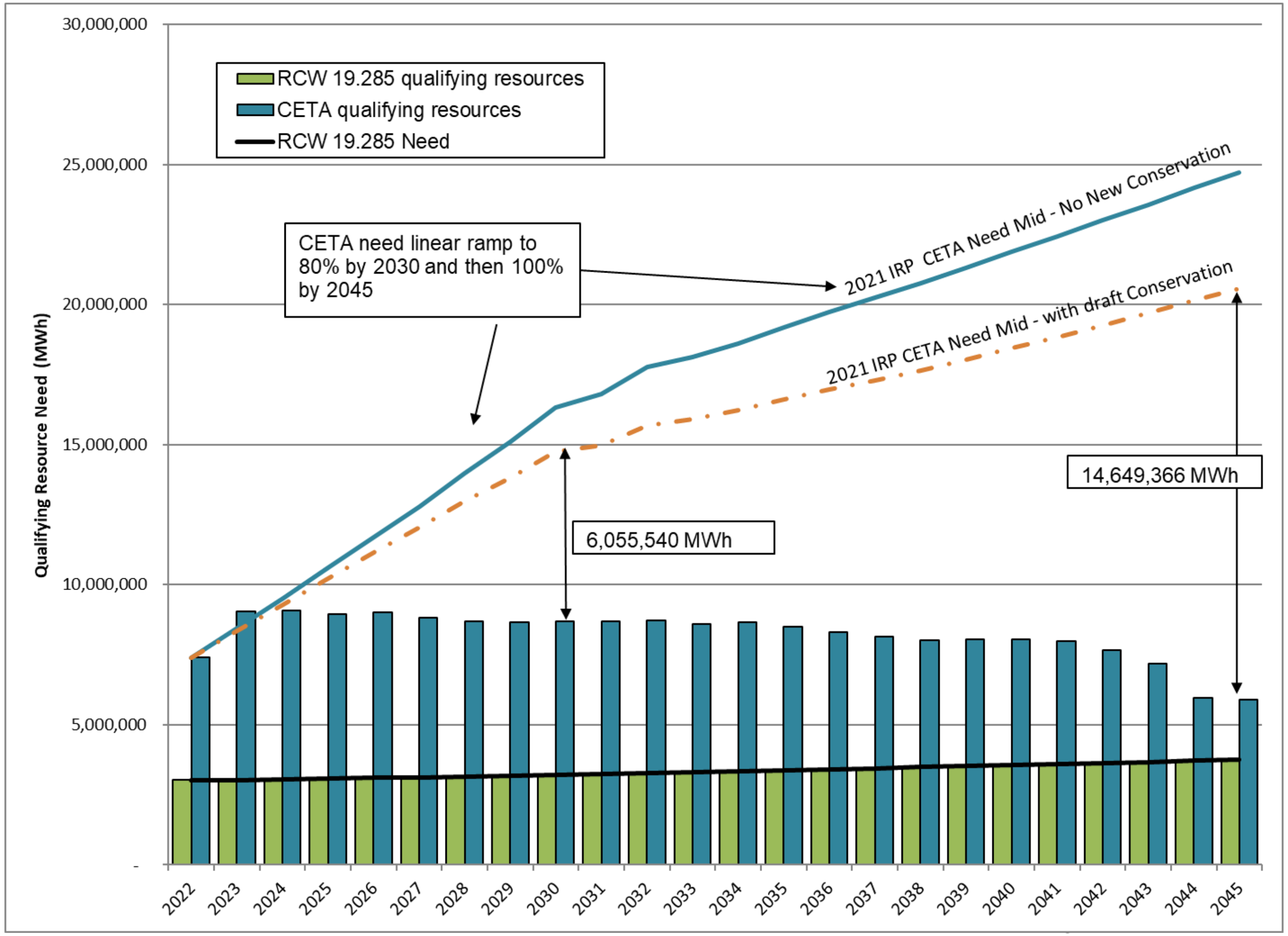
- The portfolio also meets the RPS requirement, RCW 19.285.



Existing Portfolio and Renewable Need, with cost-effective demand side resources

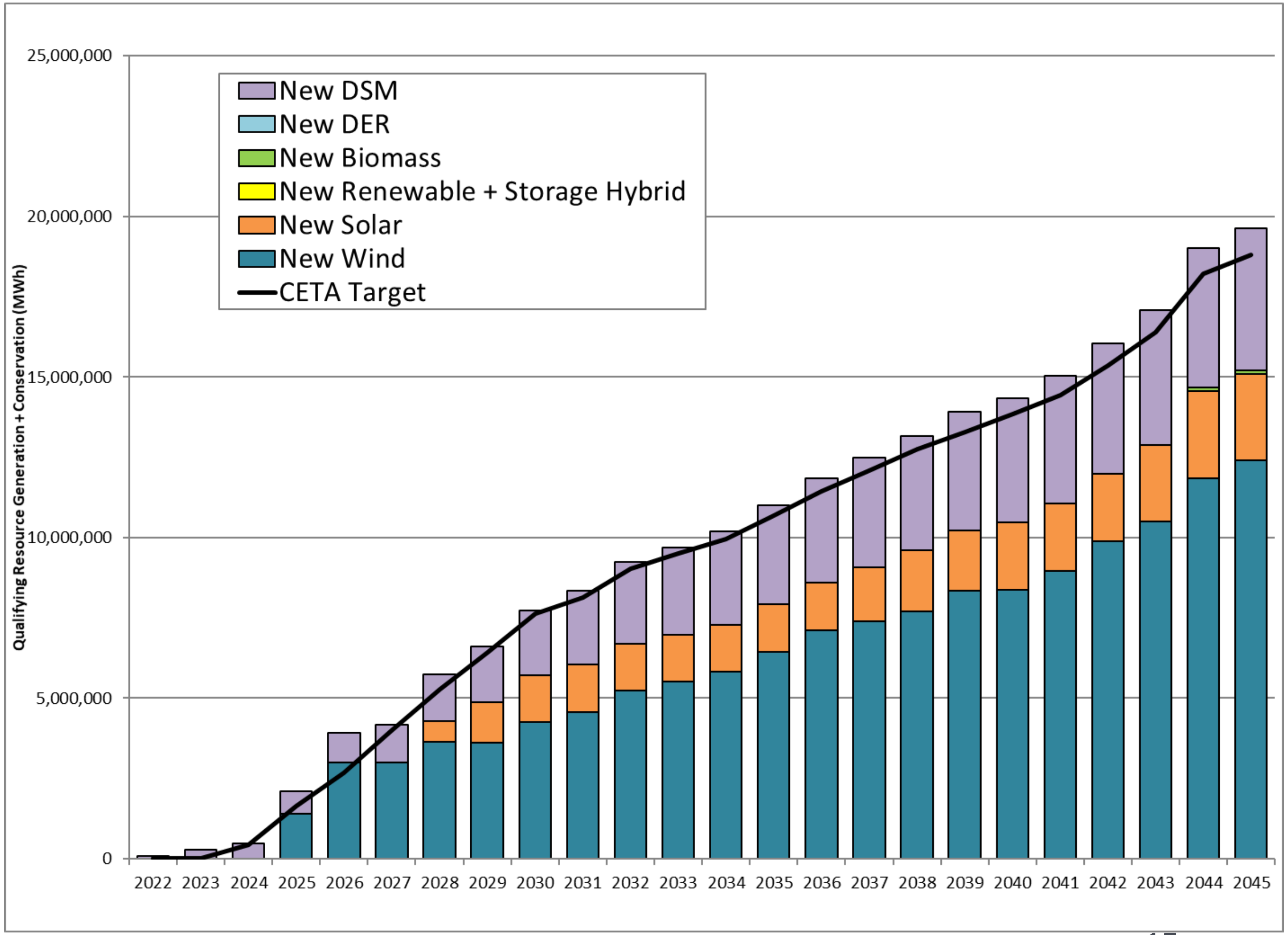
- Cost-effective demand side resources reduce the renewable need by:
  - **1.5 million MWh** of renewable generation in 2030
  - **4.1 million MWh** of renewable generation in 2045

- Electric draft demand side resources include:
  - Conservation savings up to bundle 10 ($175/MWh)
  - Codes and Standards
  - Solar PV BAU
  - Distribution efficiency

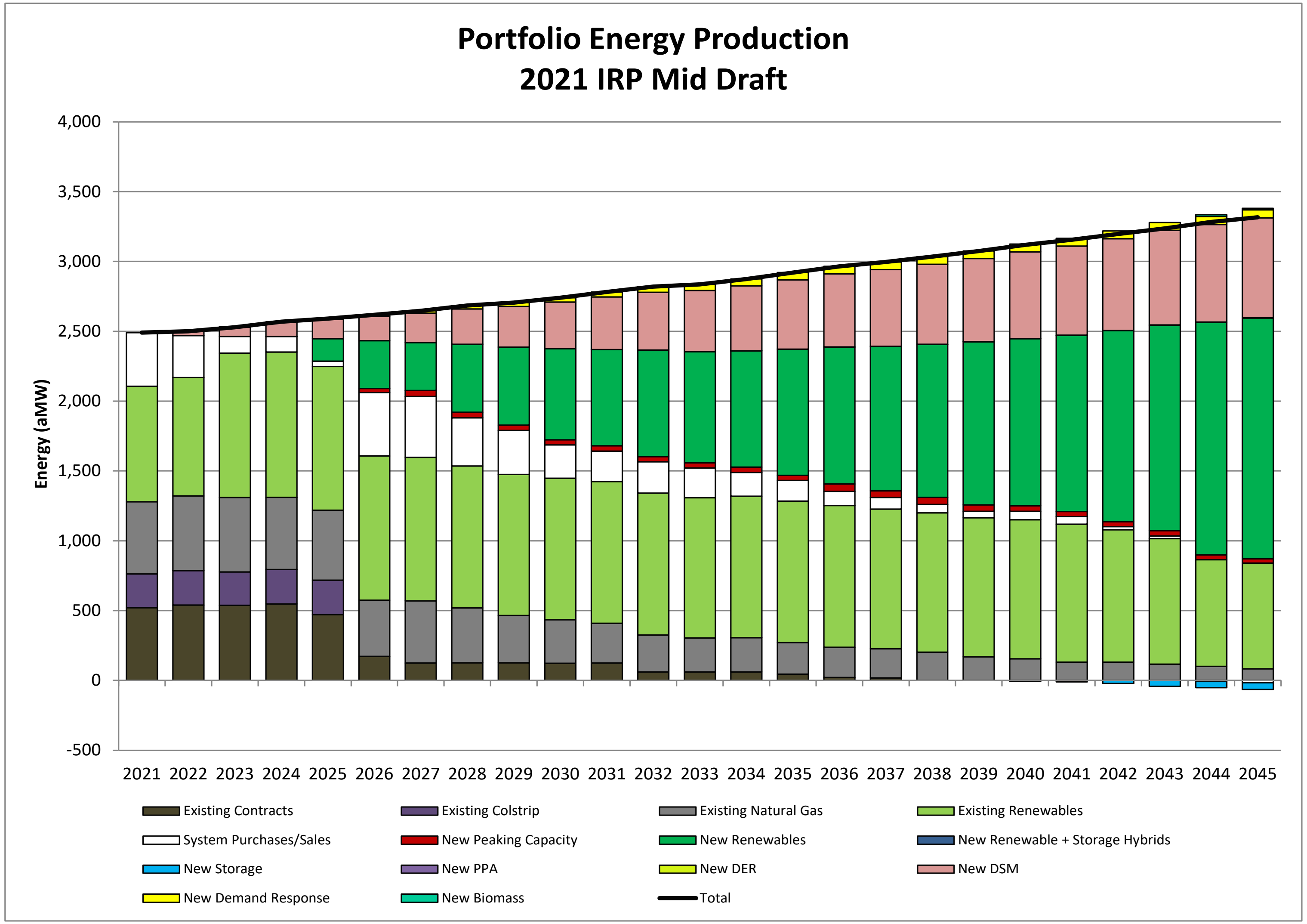


Renewable energy need is met annually across the planning horizon

- Wind is the primary renewable resource added to the portfolio, followed by solar starting in 2028.
- 15 MW of biomass capacity is added in 2044.
- WY and MT wind are the first wind resources added in 2025 and 2026, because their generation profile is well-matched to PSE's load profile but they are limited by transmission.
- Without transmission constraints, WA wind is added consistently through the planning time horizon starting in 2028.



Hourly energy need is met in mid portfolio

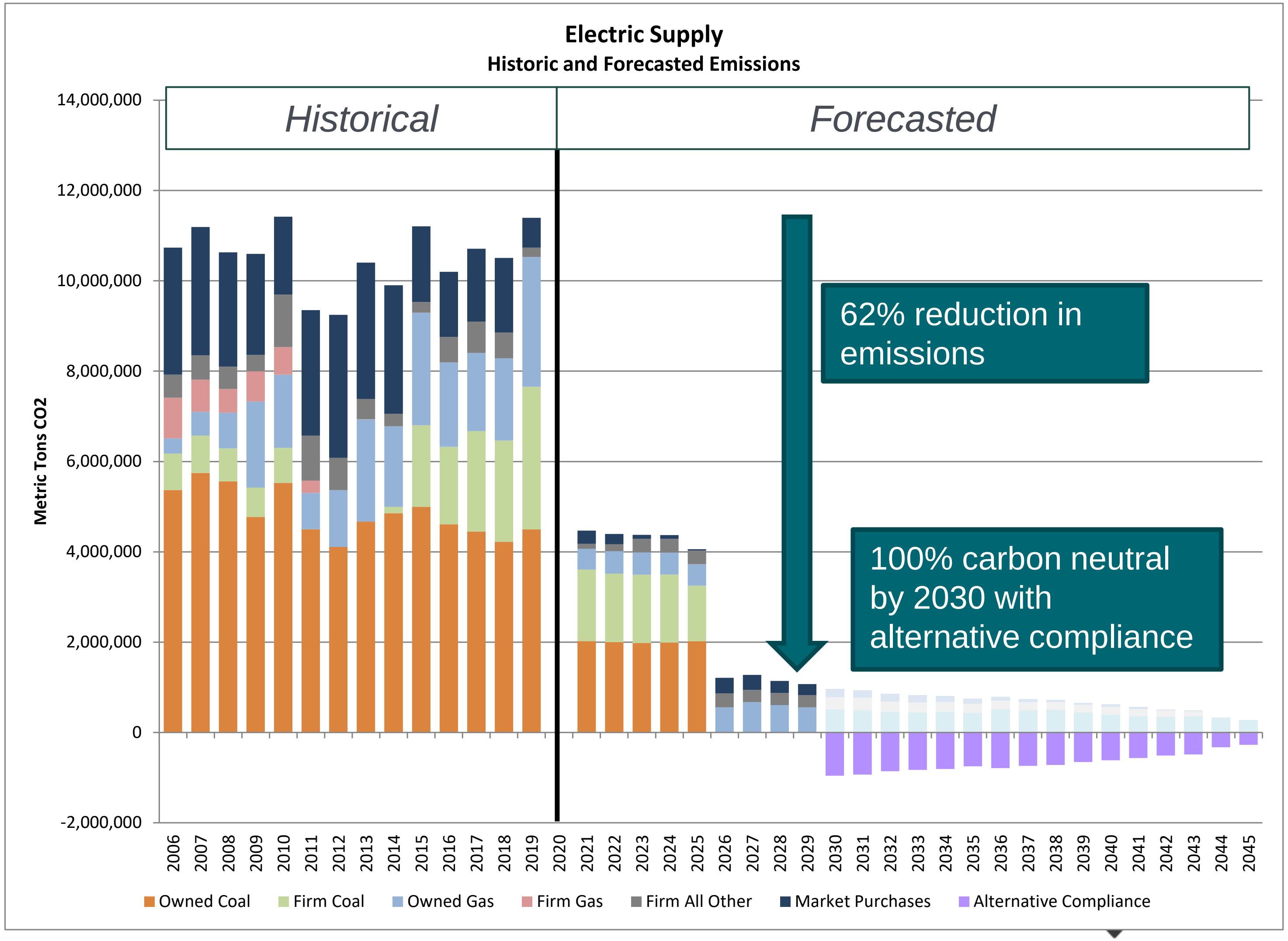


- Model is constrained to meet hourly energy need. This chart shows the sum for each year.
- Energy is provided by conservation and new and existing renewable resources.
- The use of existing non-renewable resources decreases significantly over planning horizon.
- Under normal hydro conditions, the capacity factor of existing CCCT plants drops from 70% in 2022 to 5% by 2045.

Significant emission reductions are achieved

- 62% reduction in emissions is achieved by 2029 from the retirement of Colstrip and Centralia and reduced dispatch of existing resources.

- PSE is 100% carbon neutral by 2030 with the combination of renewable resources and alternative compliance.

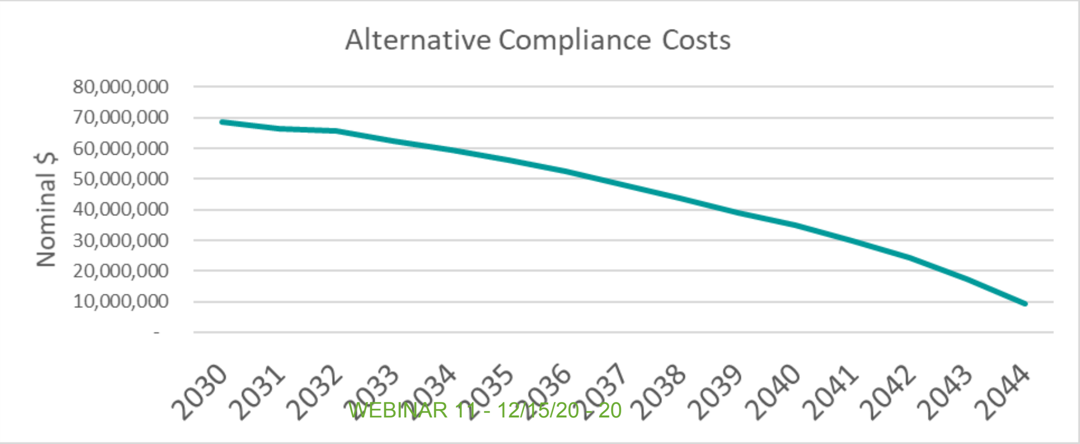


Alternative compliance is used to achieve carbon neutral starting in 2030

- Alternative compliance is represented through renewable energy credits.
  - Actual compliance of the 2030 carbon neutral standard may be met through renewable resources, energy efficiency, unbundled RECs or energy transformation projects.
- In 2030, 20% of load may be met through alternative compliance. 20% decreases linearly to zero in 2045.
- Example calculation:
  - In 2030, the expected load is 20,406,699 MWh
  - 80% of this load, the CETA requirement, is 16,325,360 MWh
  - For the remaining 4,081,340 MWh:

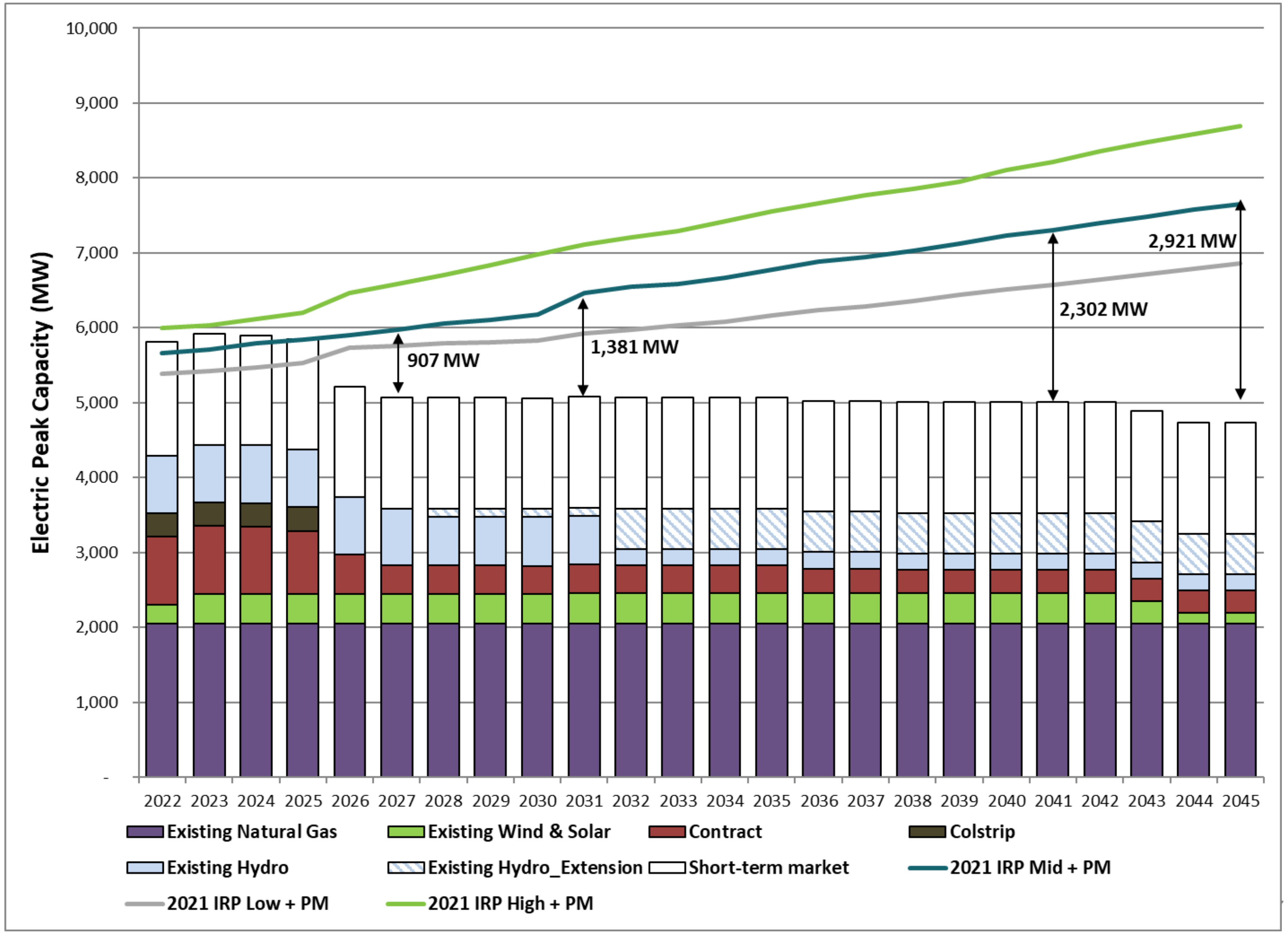
4,081,340 MWh X 0.481709 short ton/MWh X $34.87/short ton = $68,562,923

Remaining energy		CETA market purchase emission rate		CA Carbon Price, Nominal $



Existing Portfolio and Peak Capacity Need, before demand-side resources

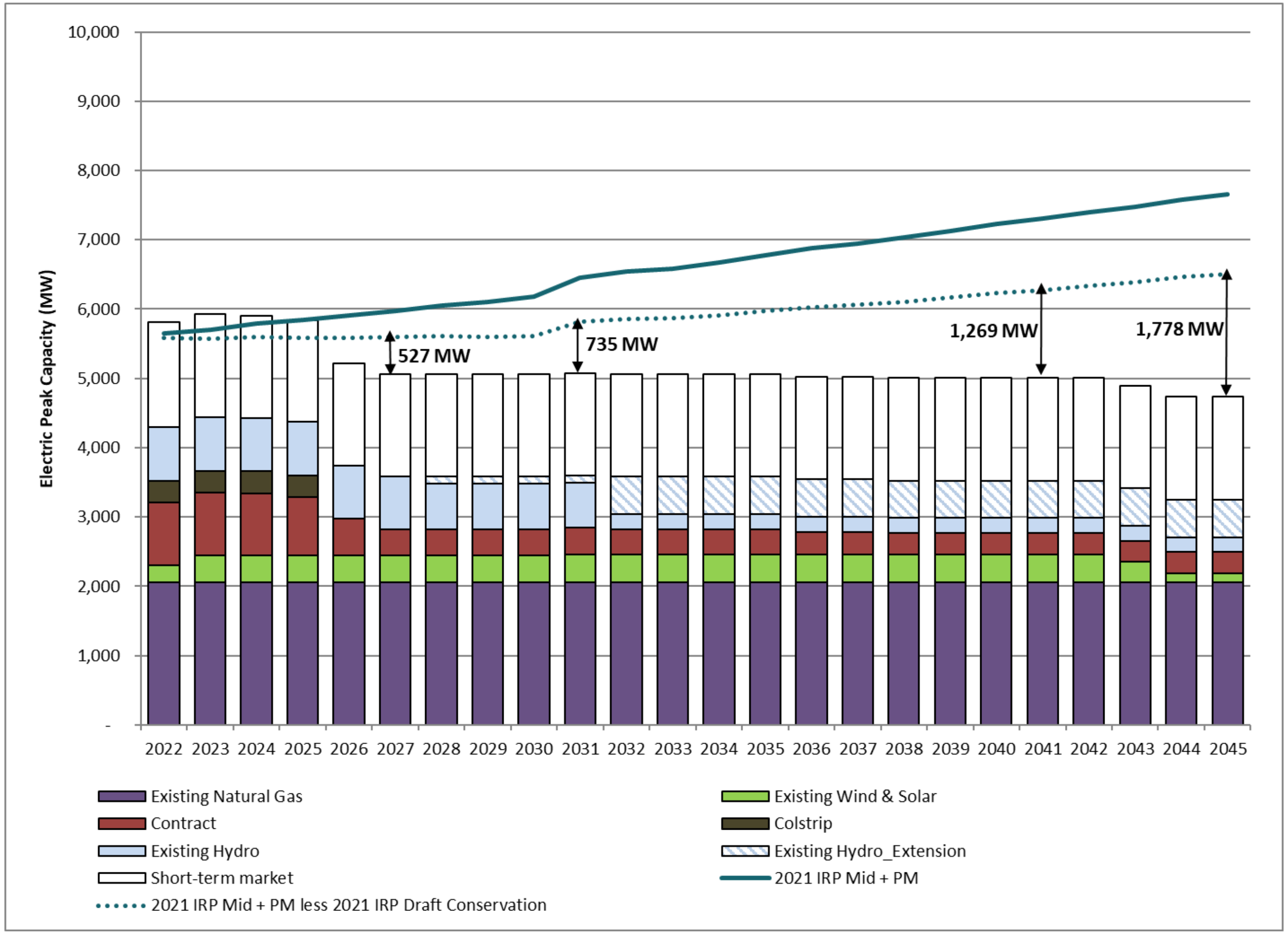
- Peak capacity need is the one-hour winter peak needed to meet load plus planning margin.
  - The planning margin is 20.7% in 2027 and 24.2% in 2031.
- PSE’s current portfolio is projected to provide sufficient peak capacity until the year 2025.
- In 2025, Centralia and Colstrip 3 & 4 are removed from PSE’s portfolio.



Existing Portfolio and Peak Capacity Need, with cost-effective demand side resources

- In 2027, cost-effective demand side resources reduce the peak capacity need by 380 MW.

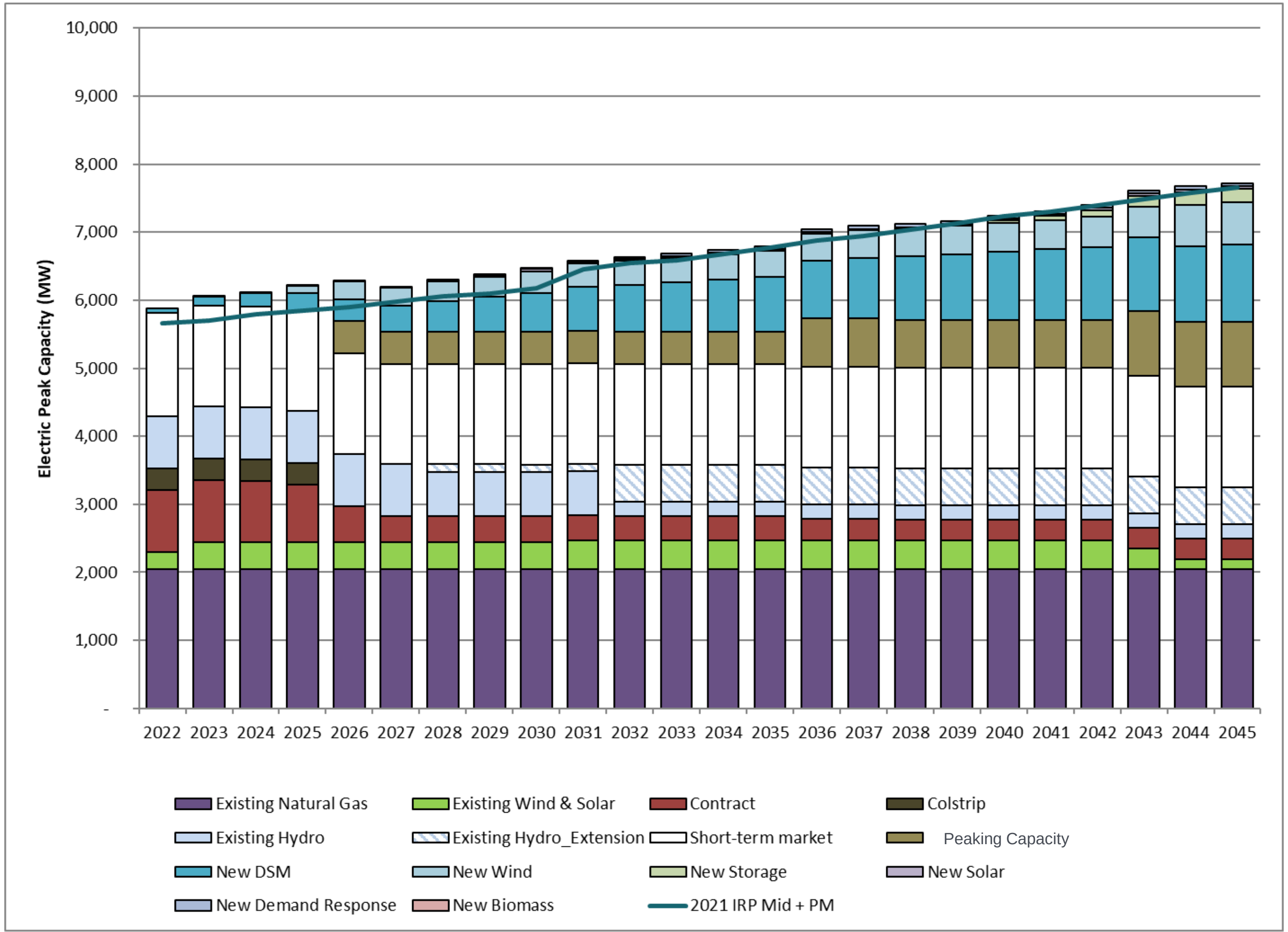
- Total peak capacity contribution of electric draft demand side resources is provided by:
  - Codes & Standards
  - Conservation savings up to bundle 10 ($175/MWh)
  - Distribution Efficiency
  - Demand Response



Annual resource additions for mid portfolio

Incremental Resource Additions		DSM Bundles	DSM C&S + PV	Total DSM	DER Solar	DER Storage	Total DER	Demand Response		Biomass		Wind		Solar		Storage		Peaking Capacity	
2022 - 2025 Colstrip and Centralia Retire in 2025	**2022**	37	37	**256**	-	3	**16**	-	**5**	-	**-**	-	**400**	-	**-**	-	**-**	-	**-**
	2023	39	25		3	3		1		-		-		-		-		-	
	2024	42	19		3	6		1		-		-		-		-		-	
	2025	44	13		-	4		3		-		400		-		-		-	
2026 - 2030 CETA 80% Renewable Requirement in 2030	**2026**	47	16	**344**	-	3	**19**	5	**46**	-	**-**	400	**800**	-	**697**	-	**-**	474	**474**
	2027	49	16		-	5		6		-		-		-		-		-	
	2028	52	28		3	3		13		-		200		299		-		-	
	2029	52	18		2	3		9		-		-		299		-		-	
	2030	56	11		-	4		14		-		200		100		-		-	
2031-2045 CETA 100% Renewable Requirement in 2045	**2031**	58	14	**907**	1	3	**55**	14	**69**	-	**15**	100	**2,550**	-	**699**	-	**600**	-	**474**
	2032	28	21		1	4		15		-		200		-		-		-	
	2033	29	29		1	3		15		-		100		-		-		-	
	2034	32	35		1	3		5		-		100		-		-		-	
	2035	29	28		1	4		5		-		200		-		-		-	
	2036	29	3		1	4		2		-		200		-		-		237	
	2037	28	30		1	3		1		-		100		100		-		-	
	2038	27	31		1	3		1		-		100		100		-		-	
	2039	27	45		1	3		1		-		200		-		-		-	
	2040	24	49		1	3		1		-		-		100		150		-	
	2041	21	24		1	4		1		-		200		-		75		-	
	2042	19	27		1	4		1		-		300		-		100		-	
	2043	16	45		1	4		1		-		200		200		175		237	
	2044	17	60		1	4		1		15		350		200		75		-	
	2045	15	68		1	4		1		-		200		-		25		-	
Grand Total		**817**	**690**	**1,507**	**28**	**89**	**118**	**121**		**15**		**3,750**		**1,396**		**600**		**948**	

Flexible, peaking capacity is needed to meet peak capacity need



- Flexible peaking capacity is needed to replace Colstrip 3 & 4 and Centralia in 2026.
- Alternative renewable fuels, such as hydrogen, will be analyzed in the sensitivities.
- The resources shown are the least-cost optimization results and should not be used as an indication of PSE's future acquisitions.
- Includes 1500 MW of available Mid-C transmission to market.

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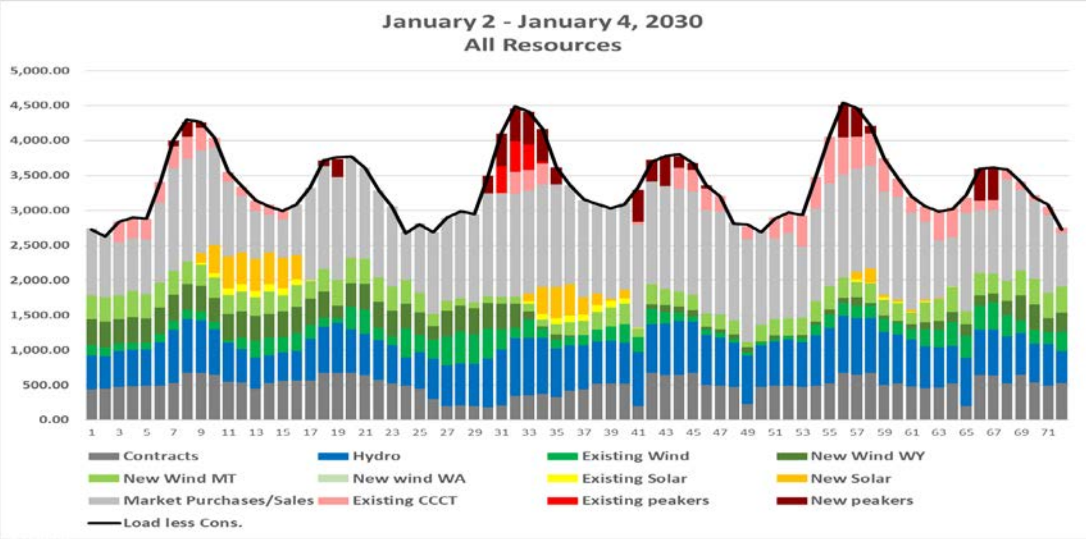
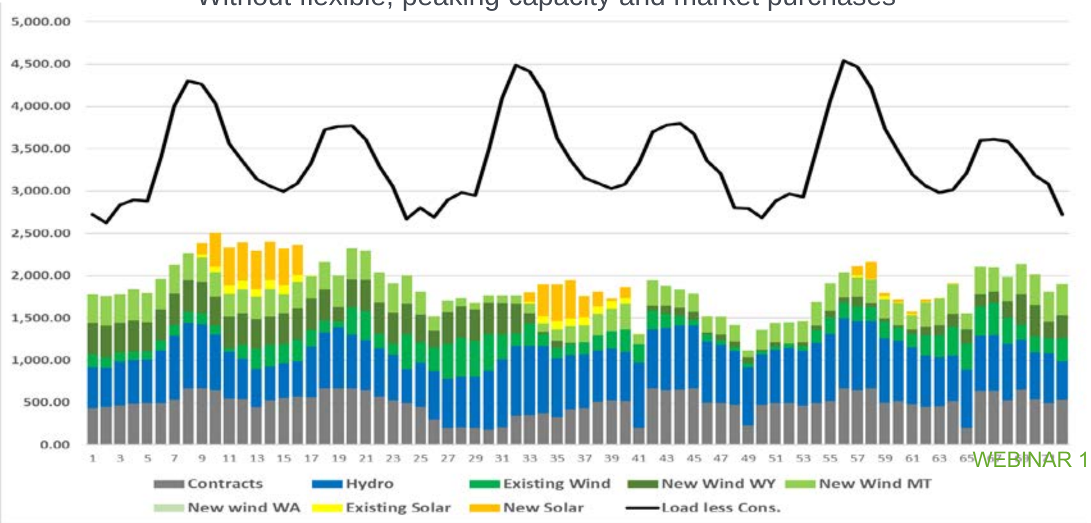
Flexible, peaking capacity is needed during periods of peak load and limited renewable generation



January 2 – January 4, 2030
Without flexible, peaking capacity and market purchases



- Flexible, peaking capacity is needed during extended periods of limited wind and solar supply.
- Results show large amounts of market reliance during a peak event based on economic dispatch. Market reliance will be further evaluated through sensitivity analysis.
- The modeled energy storage resources provide limited capacity contributions during periods of resource shortfall such as the 72-hour period shown.

Resource	Discharge Time
Batteries	2-6 hours
Pumped Hydro Storage	8-10 hours

2021 IRP draft mid portfolio observations

- ✓ CETA targets are met in 2025, 2030 and 2045.
- ✓ Emissions are reduced by 62% by 2029 and 100% carbon neutral by 2030.
- ✓ Conservation is a key resource contributing to meeting CETA targets.
- ✓ Utility-scale renewable resources are added to meet the renewable requirements.
  - Transmission constraints are not included but may be present and are further analyzed in the sensitivities.
- ✓ Flexible, peaking capacity is needed to meet the capacity shortfall starting in 2026 and to reliably meet load during periods of peak load events.
- ✓ There is no early retirement of any existing resources, including Colstrip 3 & 4, even though the portfolio model is allowed economic retirement.
- ✓ Increased amounts of demand response are selected in the least cost portfolio.
- ✓ Capacity factors of existing CCCT drops from 70% in 2022 to 5% by 2045.

Note: Any observations made from the least-cost optimized portfolio only apply to this specific portfolio model results and are not representative of PSE's preferred portfolio or final resource plan.

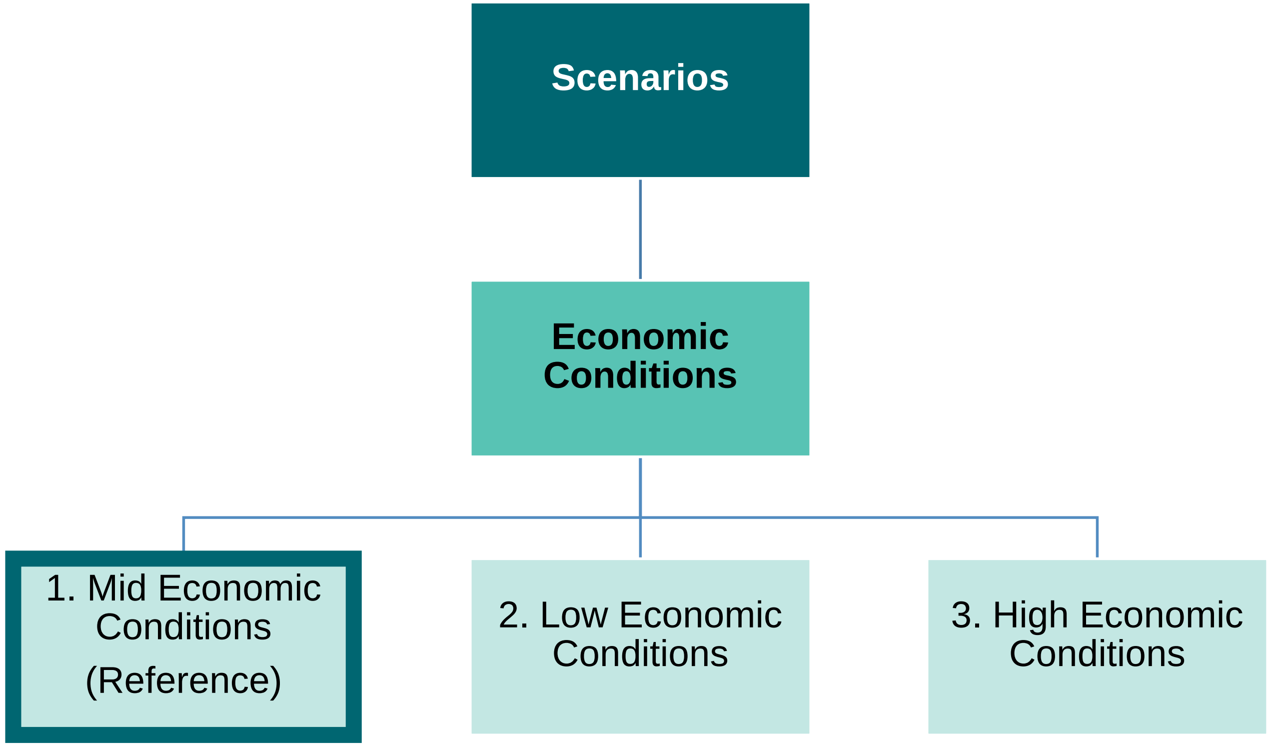
2021 IRP Electric Portfolio Sensitivity Draft Results

Mid, low and high plus results for 6 sensitivities are included in this presentation

- **1. Mid Economic Conditions (reference)**
  - **Future Market Availability**
    - A. Renewable Over-generation Test
  - **Transmission Constraints and Build Limitations**
    - C. Distributed Transmission (Tier 2)
    - D. Transmission as a % of Nameplate
  - **Social Cost of Greenhouse Gases**
    - I. SCGHG as “Externality Cost” in LTCE Model Only
  - **Emissions Reduction**
    - N. 100% renewable generation by 2030
    - O. Gas Generation Out by 2045
    - P. Must-Take DR and Battery Storage
  - CETA Costs
    - S. SCGHG only, no CETA
    - T. No CETA or SCGHG

This is the list of the sensitivities that will be included in the draft IRP. Additional sensitivities will be modeled for the final IRP.

Economic Conditions – mid, low, and high



Economic Conditions:

Mid –

- Mid gas price
- Mid demand forecast
- Mid power price

Low –

- Low gas price
- Low demand forecast
- Low power price

High –

- High gas price
- High demand forecast
- High power price

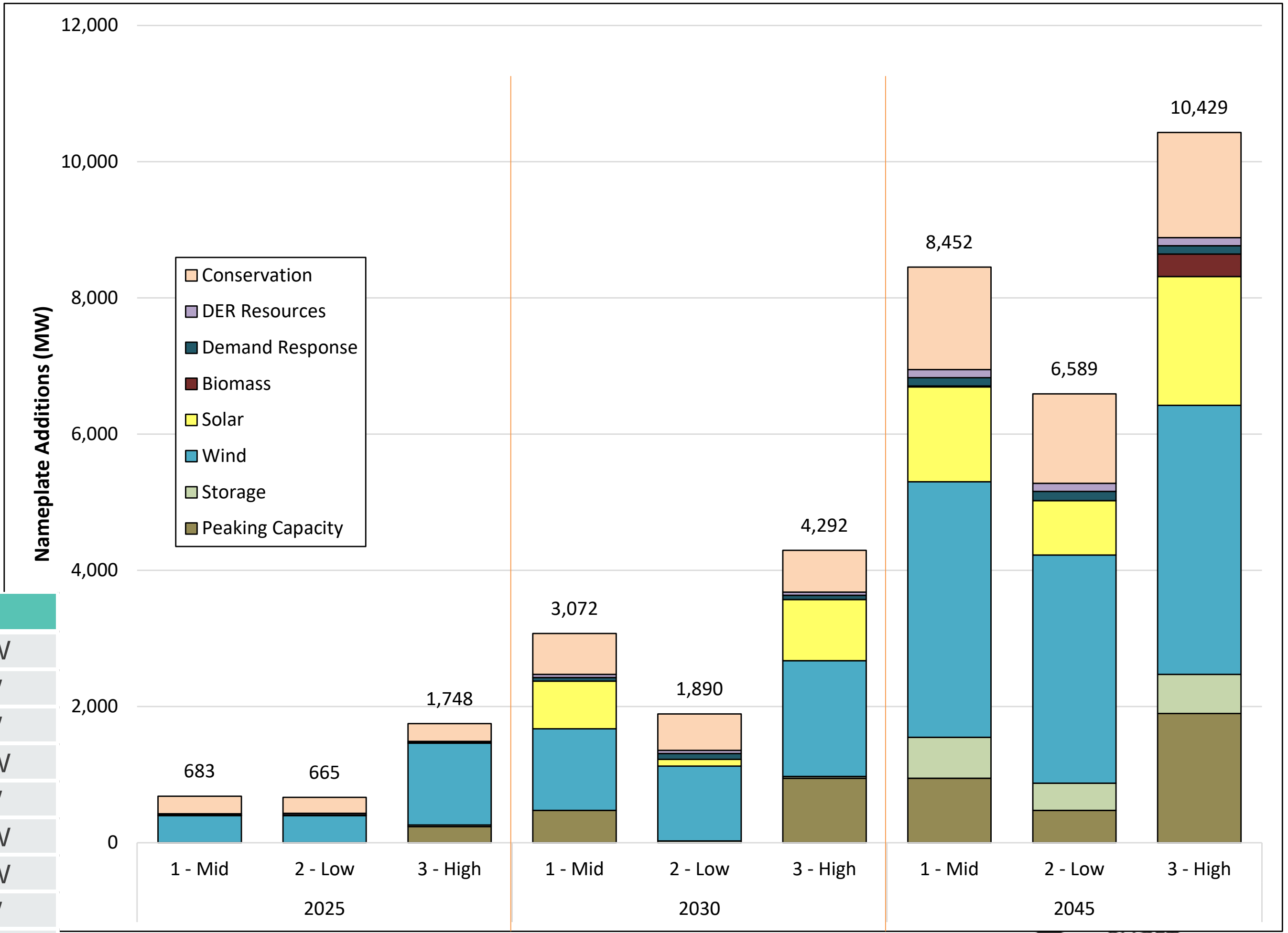
Economic Conditions - results

Low

- ➢ Less resources added because of lower peak capacity and renewable energy need
- ➢ Conservation savings up to bundle 8
- ➢ No economic retirements of existing resources

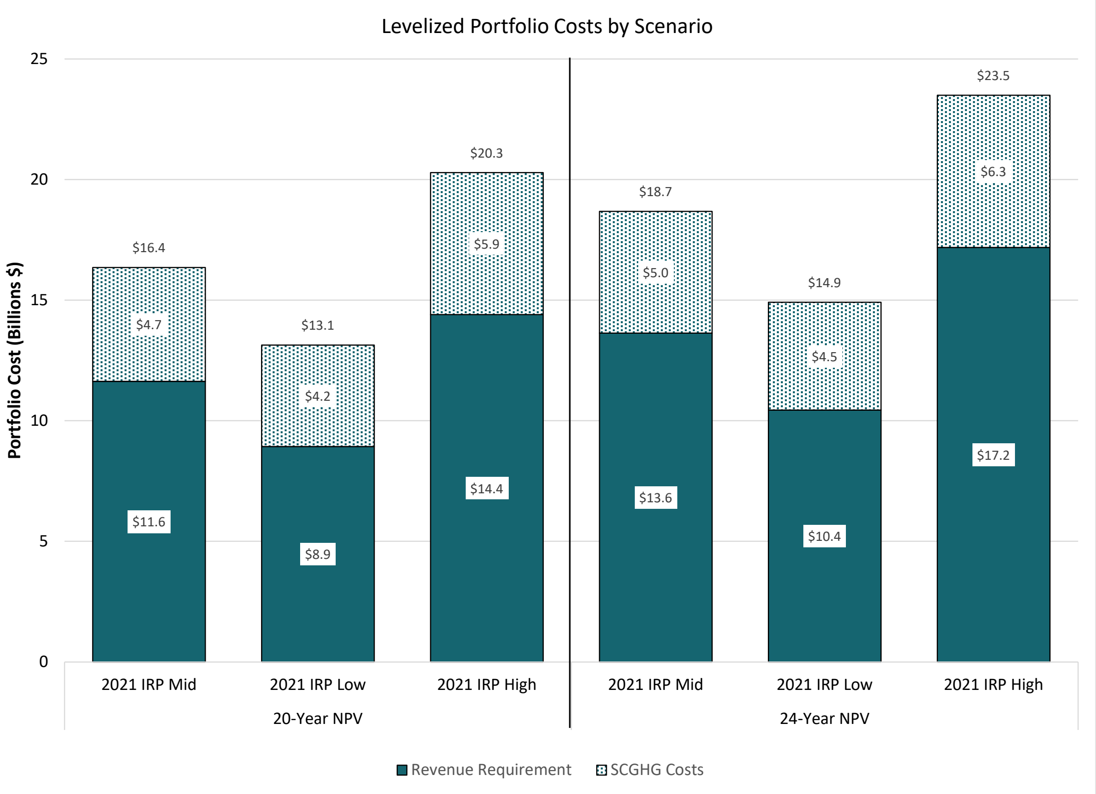
High

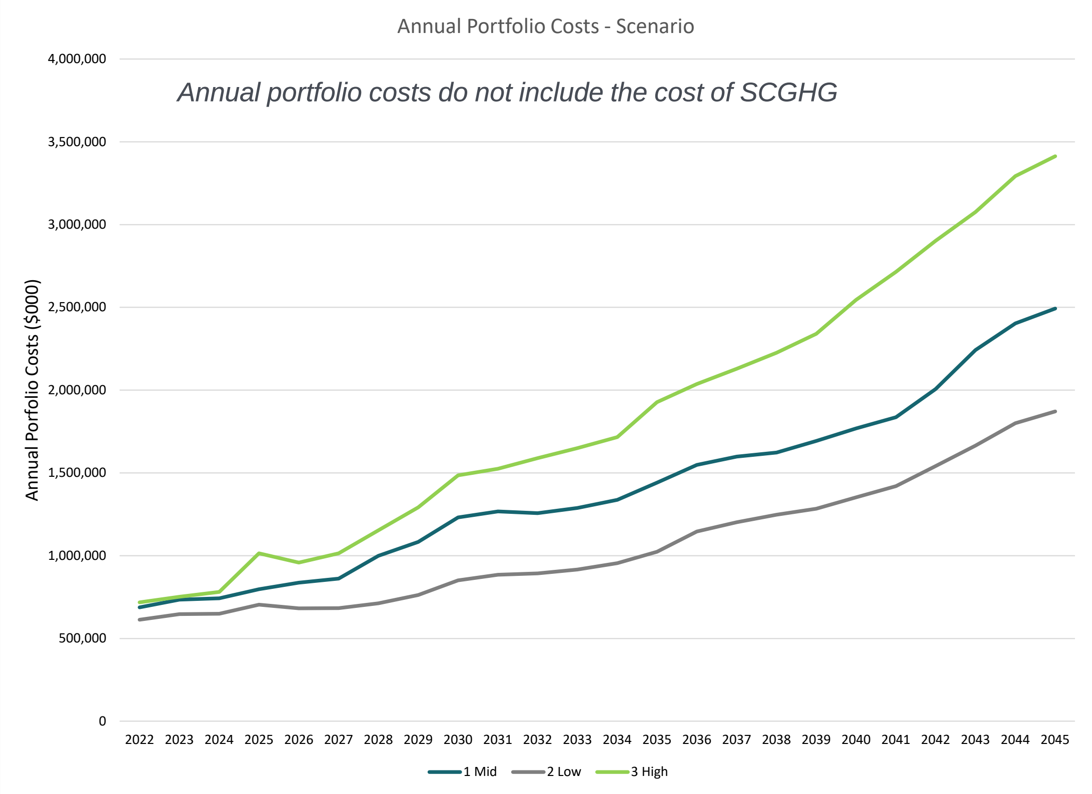
- ➢ More resources added because of higher peak capacity and renewable energy need
- ➢ Conservation savings up to bundle 11
- ➢ No economic retirements of existing resources



Resource Additions by 2045	Mid	Low	High
Conservation	1507 MW	1313 MW	1547 MW
DER Resources	118 MW	118 MW	118 MW
Demand Response	121 MW	137 MW	122 MW
Renewable Resources	5158 MW	4147 MW	6171 MW
Biomass	15 MW	0 MW	330 MW
Solar	1393 MW	797 MW	1891 MW
Wind	3750 MW	3350 MW	3950 MW
Storage	600 MW	400 MW	575 MW
Peaking Capacity	948 MW	474 MW	1896 MW

Economic Conditions – portfolio costs





Portfolio Costs	Mid	Low	High
Total Portfolio Costs 24 Yr Levelized	$18.7	$14.9	$23.5
Revenue Requirement	$13.6	$10.4	$17.2
SCGHG Costs	$5.0	$4.5	$6.3
Total Portfolio Costs 20 Yr Levelized	$16.4	$13.1	$20.3
Revenue Requirement	$11.6	$8.9	$14.4
SCGHG Costs	$4.7	$4.2	$5.9

A

Market Sensitivities – renewable over-generation test

1. Mid Economic Conditions

(reference)

Future Market Availability

A. Renewable Over-generation Test

A. Renewable Over-generation test

- The model currently counts any energy that is generated and sold to the Mid-C market towards meeting PSE's CETA targets.
- This sensitivity forces the curtailment of any energy sold to the Mid-C market instead and the model has to meet the CETA requirements strictly by serving load.
- **In short, this sensitivity allows PSE to purchase from the Mid-C market, but not to sell to the Mid-C market.**

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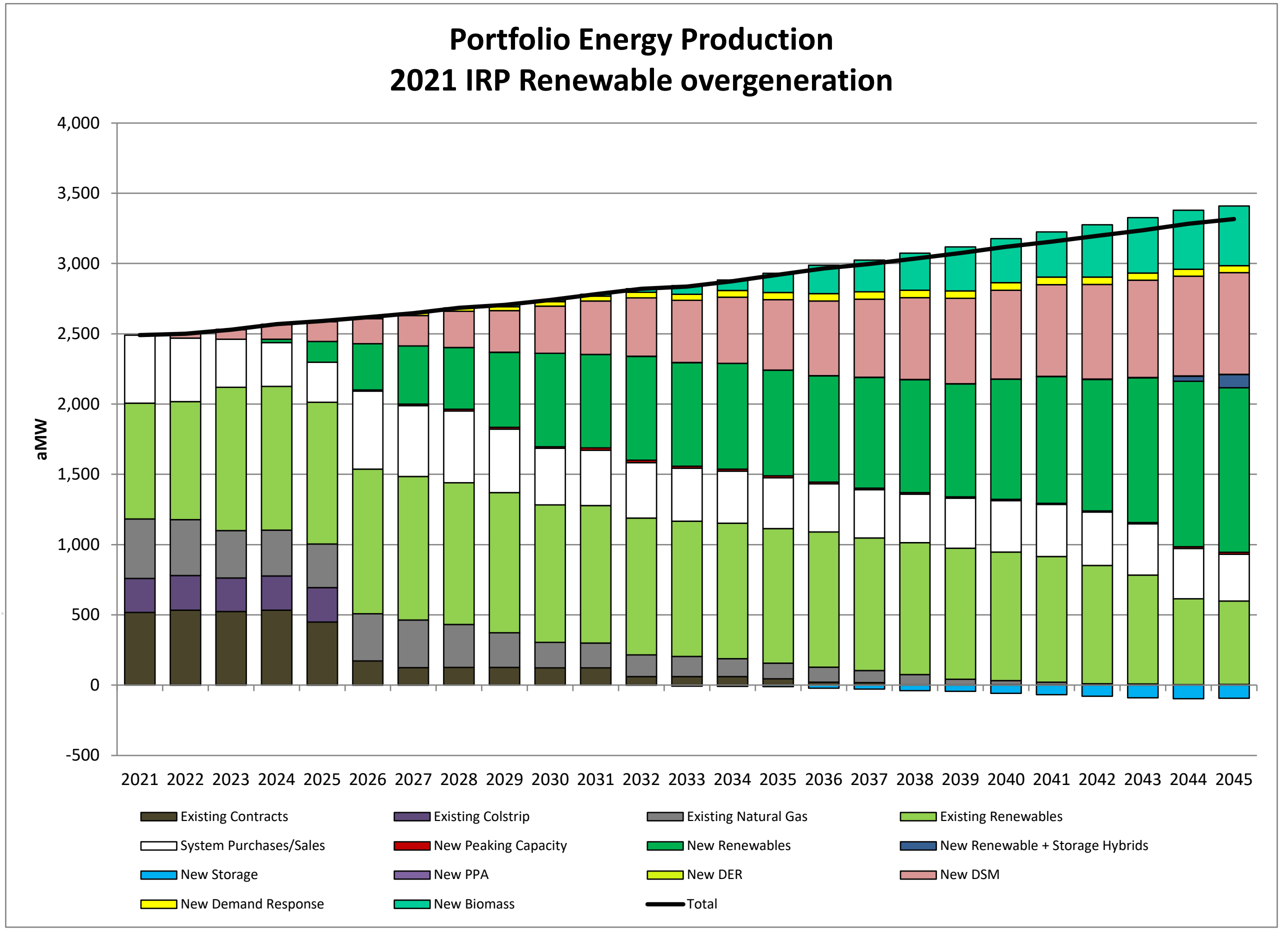
A

Market Sensitivity – renewable over-generation test - results

- Increased energy storage and lowered peaking capacity
- Lack of sales and overbuilding leads the portfolio to a greater reliance on market at peak hours and higher cost
- Less solar wind, and peaking capacity built
- More biomass added
- Constant, though reduced, market purchases
- Conservation savings up to bundle 12
- No economic retirements of existing resources
- Further analysis is needed to assess the effect of eliminating market purchases

Resource Additions by 2045	Mid	A - Renewable Overgeneration
Conservation	1507 MW	1554 MW
DER Resources	118 MW	118 MW
Demand Response	121 MW	183 MW
Renewable Resources - Biomass Excluded	5143 MW	3640 MW
Biomass	15 MW	525 MW
Storage	600 MW	1125 MW
Peaking Capacity	948 MW	692 MW



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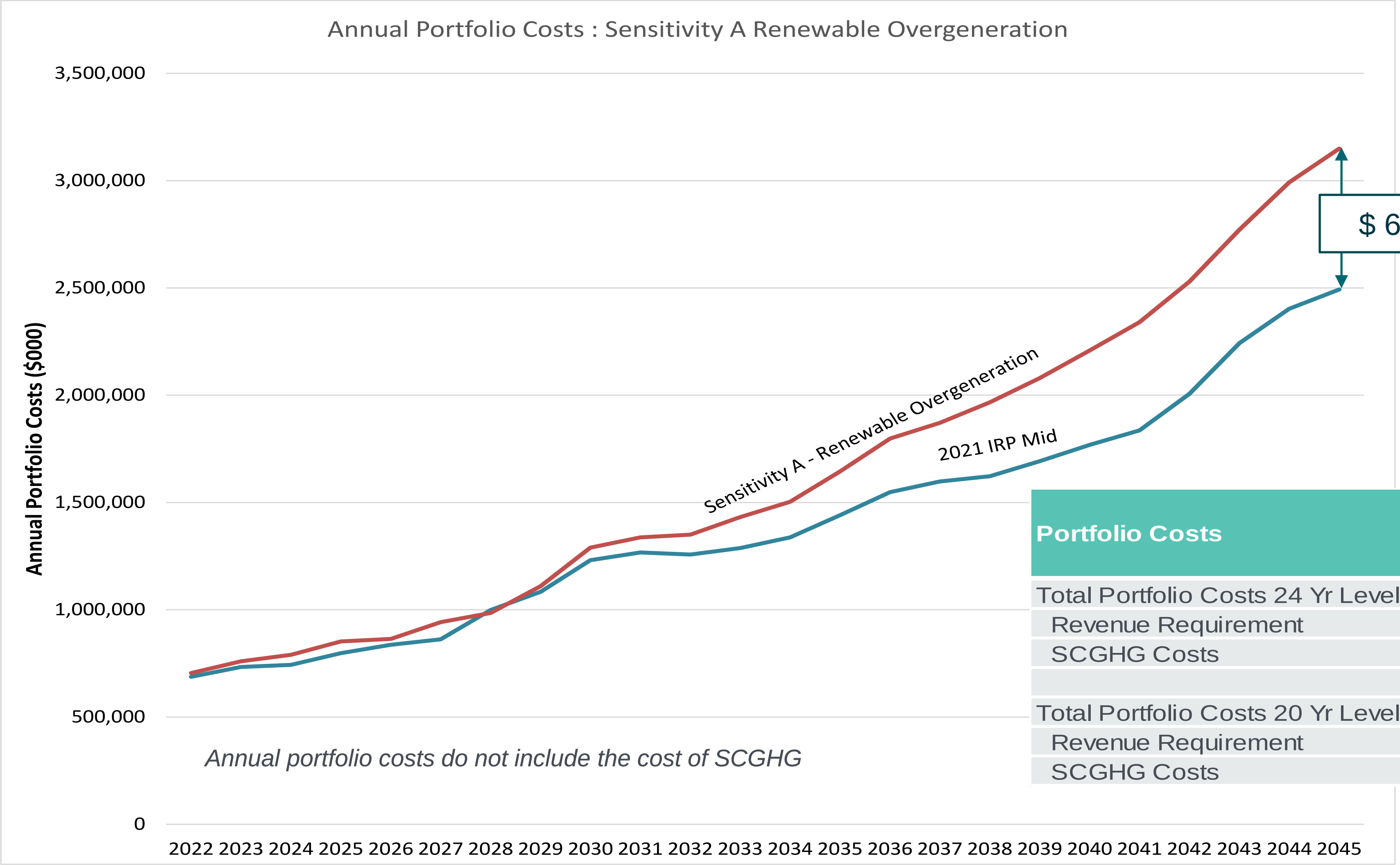
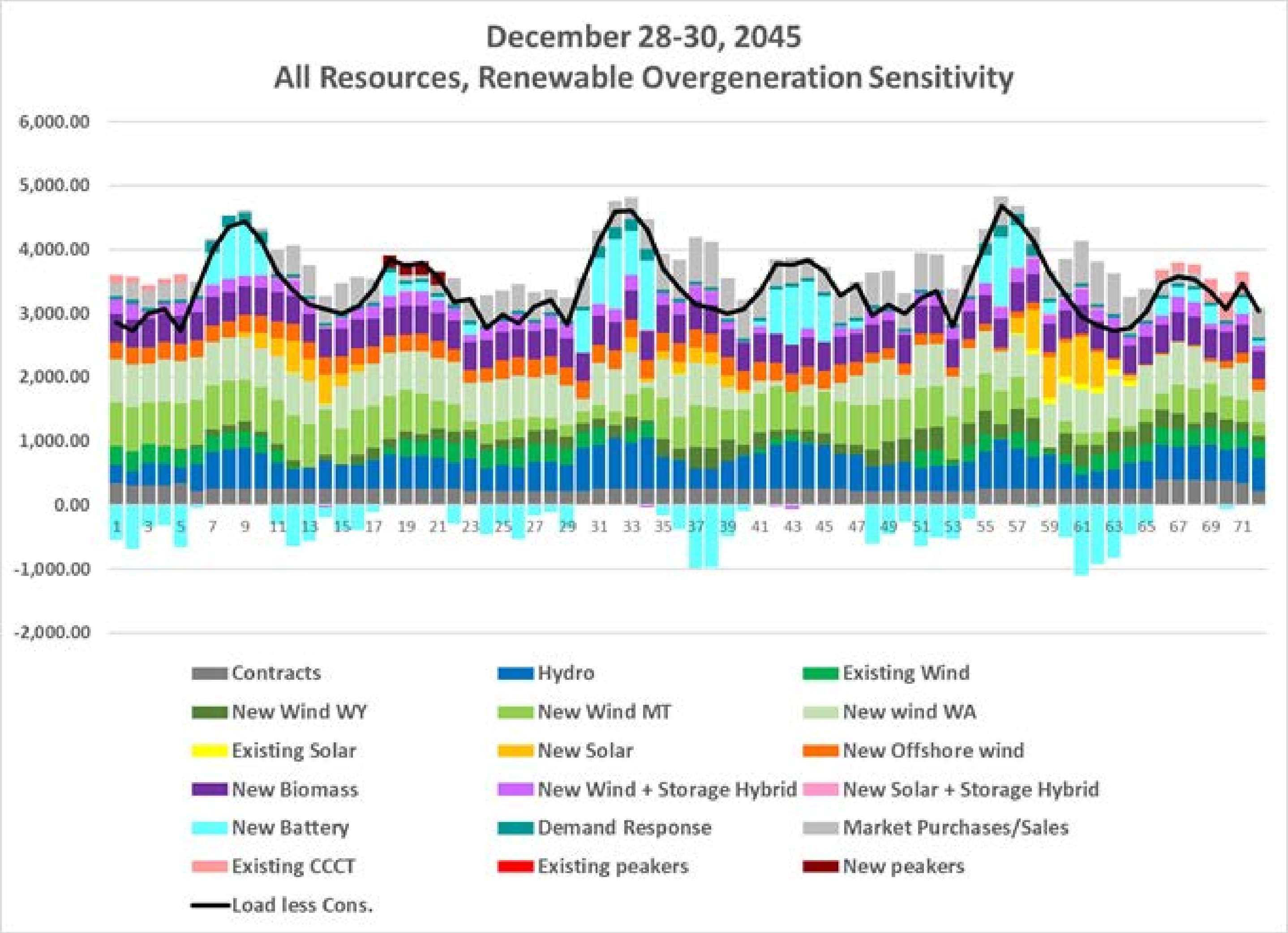
A Market Sensitivity – renewable over-generation test – portfolio costs



Portfolio Costs	Mid	A - Renewable Overgeneration
Total Portfolio Costs 24 Yr Levelized	$18.7	$19.6
Revenue Requirement	$13.6	$15.3
SCGHG Costs	$5.0	$4.2
Total Portfolio Costs 20 Yr Levelized	$16.4	$16.8
Revenue Requirement	$11.6	$12.8
SCGHG Costs	$4.7	$4.0

Market Sensitivity – renewable over-generation test – generation during peak load hours



- **The portfolio is relying heavily on market purchase availability to charge the batteries.** There is no oversupply of resources from PSE's portfolio to charge the batteries.
- Nearly twice the storage capacity of the Mid Portfolio is added by 2045.
- The batteries charge in the lower load hours using market purchases in excess of load and discharge during high load hours.
- Further sensitivity analysis is needed to assess the effect of eliminating market purchases.
- Increased biomass generation tads baseload capacity and helps meet CETA targets.

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Market Sensitivity – renewable over-generation test - hourly generation of renewable resources in 2030

Mid Portfolio - 2030

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0:00	564	655	480	344	49	(11)	334	500	707	474	456	423
1:00	518	620	464	340	(1)	(69)	274	426	662	422	419	337
2:00	551	640	452	285	(112)	(142)	234	381	662	384	423	367
3:00	597	709	508	327	(59)	(125)	232	412	685	420	468	391
4:00	556	633	583	410	32	(79)	311	462	768	489	327	333
5:00	944	873	719	354	(56)	(127)	214	437	714	496	528	680
6:00	1283	1152	1044	486	60	(10)	368	572	826	734	774	1091
7:00	1421	1130	971	416	(41)	(87)	291	514	670	695	812	1259
8:00	1375	1041	884	272	(107)	(106)	298	534	609	565	735	1235
9:00	1180	953	742	245	(64)	(71)	379	585	660	569	674	1163
10:00	1110	897	626	182	(123)	(92)	392	591	661	492	682	1136
11:00	980	842	507	111	(147)	(90)	386	606	643	464	633	954
12:00	856	751	351	38	(189)	(143)	326	591	620	429	567	807
13:00	761	670	291	22	(209)	(143)	318	565	643	405	515	787
14:00	684	621	222	50	(177)	(187)	294	568	620	355	503	758
15:00	684	693	343	79	(167)	(127)	299	581	653	415	590	883
16:00	998	789	530	163	(142)	(138)	325	629	693	608	875	1306
17:00	1253	1042	879	408	(9)	42	437	787	992	809	949	1393
18:00	1338	1137	1169	694	303	284	605	935	1126	858	900	1308
19:00	1323	1149	1166	646	297	282	618	904	1077	801	841	1304
20:00	1196	987	1118	636	352	345	712	900	1086	739	741	1105
21:00	1015	871	941	544	300	344	625	812	979	662	633	899
22:00	890	919	701	441	158	78	470	605	796	455	732	904
23:00	640	713	635	500	185	127	444	598	839	559	589	627

Renewable Over-generation Test- 2030

2030	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0:00	578	673	514	380	134	71	354	528	715	500	485	450
1:00	546	655	482	371	103	33	300	465	682	472	460	377
2:00	582	675	475	327	23	14	265	442	677	440	476	395
3:00	618	737	533	366	48	15	271	470	685	486	506	410
4:00	575	660	605	442	120	52	349	525	771	533	379	341
5:00	948	886	732	404	48	19	234	484	713	530	549	664
6:00	1255	1161	1054	511	107	76	350	558	803	733	778	1061
7:00	1388	1129	953	394	31	14	235	476	592	683	811	1205
8:00	1342	999	820	262	-11	-13	207	451	509	557	701	1175
9:00	1111	892	662	228	-1	3	271	467	543	533	619	1088
10:00	1056	828	569	170	-19	-12	271	462	527	447	634	1074
11:00	929	769	481	140	-16	-2	261	474	509	413	587	887
12:00	812	692	348	81	-20	-23	203	454	484	394	539	734
13:00	719	602	292	71	-7	-26	201	421	514	381	490	719
14:00	660	557	256	105	0	-33	185	413	500	351	474	712
15:00	655	641	326	146	26	-15	172	424	531	400	562	845
16:00	978	743	514	177	18	-35	193	481	588	574	865	1285
17:00	1253	1030	842	381	63	65	314	683	940	796	940	1366
18:00	1337	1135	1177	681	283	260	518	875	1109	855	891	1277
19:00	1312	1142	1176	648	301	264	577	880	1069	802	846	1276
20:00	1196	996	1134	636	367	342	689	891	1072	751	744	1080
21:00	1013	878	946	554	326	357	611	813	971	673	662	899
22:00	896	923	713	459	195	122	465	621	793	469	756	916
23:00	660	729	651	518	238	152	448	630	842	573	618	631

Positive Values = Renewable Undersupply

Negative Values = Renewable Oversupply

- Decreased renewable over-generation in this sensitivity, as PSE can only store or curtail this over-generation instead of selling to market.
- In the mid portfolio, 14% of hours had over-generation totaling 1.4% of 2030 load.
- In the sensitivity, 15% of hours had over-generation totaling 0.3% of load.

Transmission Sensitivities

1. Mid Economic Conditions

(reference)

Transmission Constraints and Build Limitations

C. Distributed Transmission (Tier 2)

D. Transmission as a % of Nameplate

C. "Distributed" Tier 2 Transmission Constraints

- Transmission constraints with "Tier 2" projects available, defined as projects that are available by 2030, with a moderate degree of confidence in their feasibility.
- Available projects in this category total 3,070 MW of available transmission.

D. Transmission as a % of nameplate

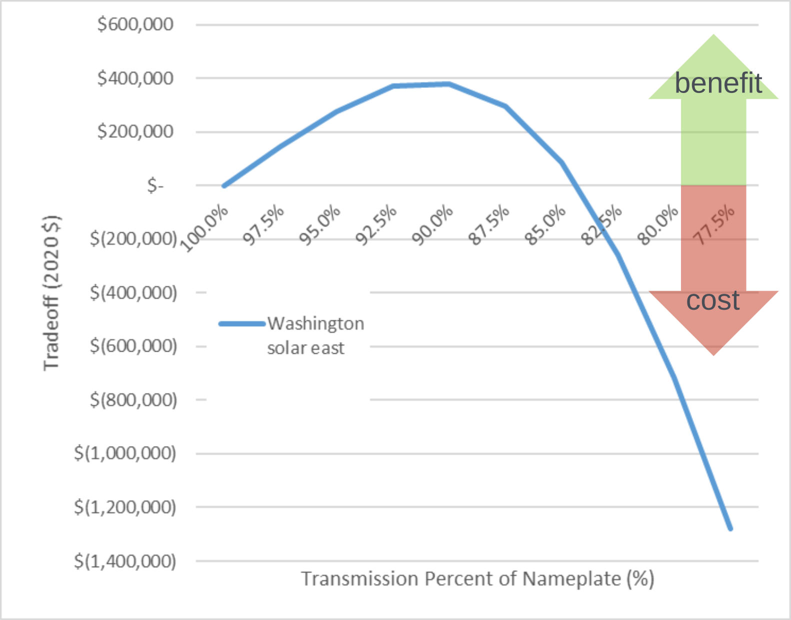
- Analyzed the level of firm transmission needed for wind and solar resources.

D Transmission Sensitivities – transmission as % nameplate – results

- Analysis performed outside of portfolio model
- Methodology summary:
  tradeoff = [reduced Tx incremental benefit] – [power replacement cost of Tx curtailments]

[fixed Tx cost] * [Tx increment]   [Tx curtailed production] * [levelized cost of power]

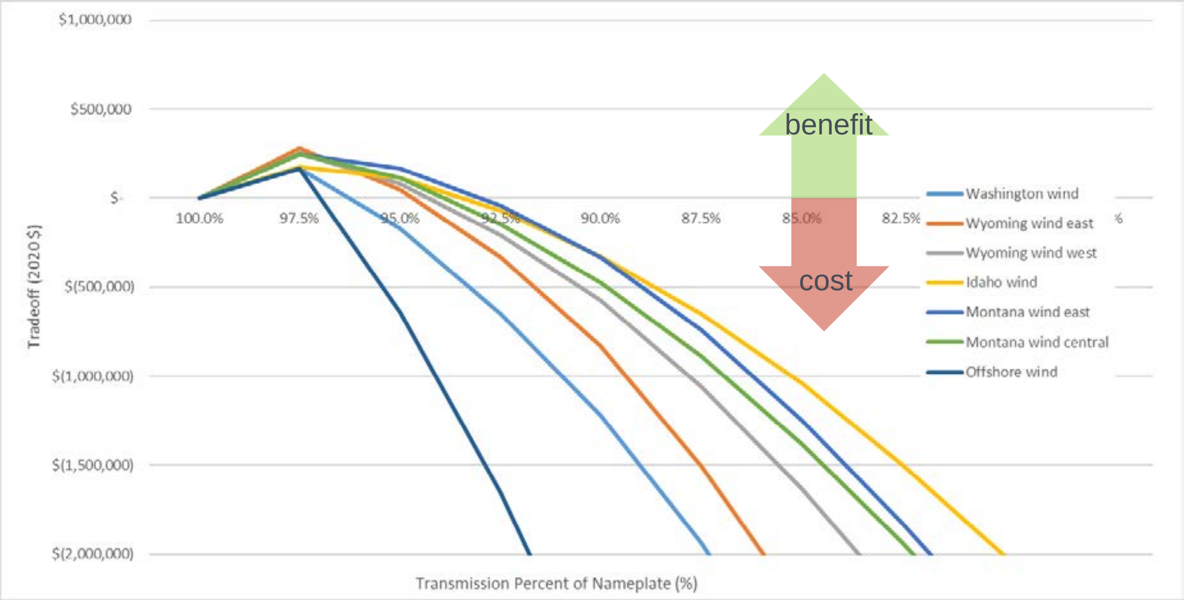
Tx percent of nameplate (%)	Tx limit (MW)	Tx curtailed production (MWh)	Delivered power (MWh)	Tx incr. (MW)	Tx incr. benefit ($)	Power replace. cost ($)	Tradeoff ($)
100.0%	200	0	427,800	0	0	0	0
97.5%	195	0	427,800	5	152,000	6,000	146,000
95.0%	190	200	427,600	10	305,000	27,000	277,000
92.5%	185	700	427,100	15	457,000	87,000	370,000
90.0%	180	1,800	426,000	20	610,000	229,000	380,000
87.5%	175	3,700	424,100	25	762,000	468,000	294,000
85.0%	170	6,600	421,300	30	914,000	829,000	85,000
82.5%	165	10,500	417,300	35	1,067,000	1,326,000	-259,000
80.0%	160	15,300	412,500	40	1,219,000	1,938,000	-719,000
77.5%	155	21,000	406,900	45	1,372,000	2,650,000	-1,279,000



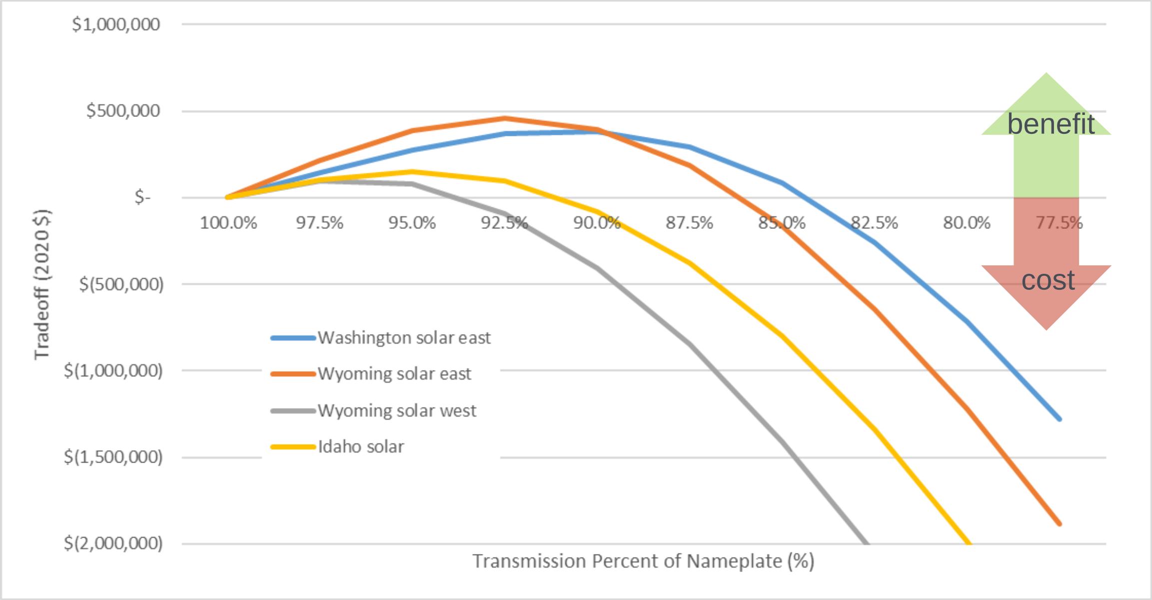
Tx = transmission

Transmission Sensitivities – transmission as % nameplate – results

Wind Tradeoff



Solar Tradeoff



- Tradeoff benefit is low as compared to annual revenue requirement of resources, therefore, not a viable means to reduce portfolio cost in IRP models
- Effective load carrying capability (ELCC) will be reduced, necessitating additional resource builds
- Assessment holds more value in resource acquisition and project development processes, instead of IRP long-term planning

SCGHG Sensitivities – SCGHG as an externality cost

1. Mid Economic Conditions

(reference)

Social Cost of Greenhouse Gases

I. SCGHG as an "Externality Cost" in LTCE Model Only

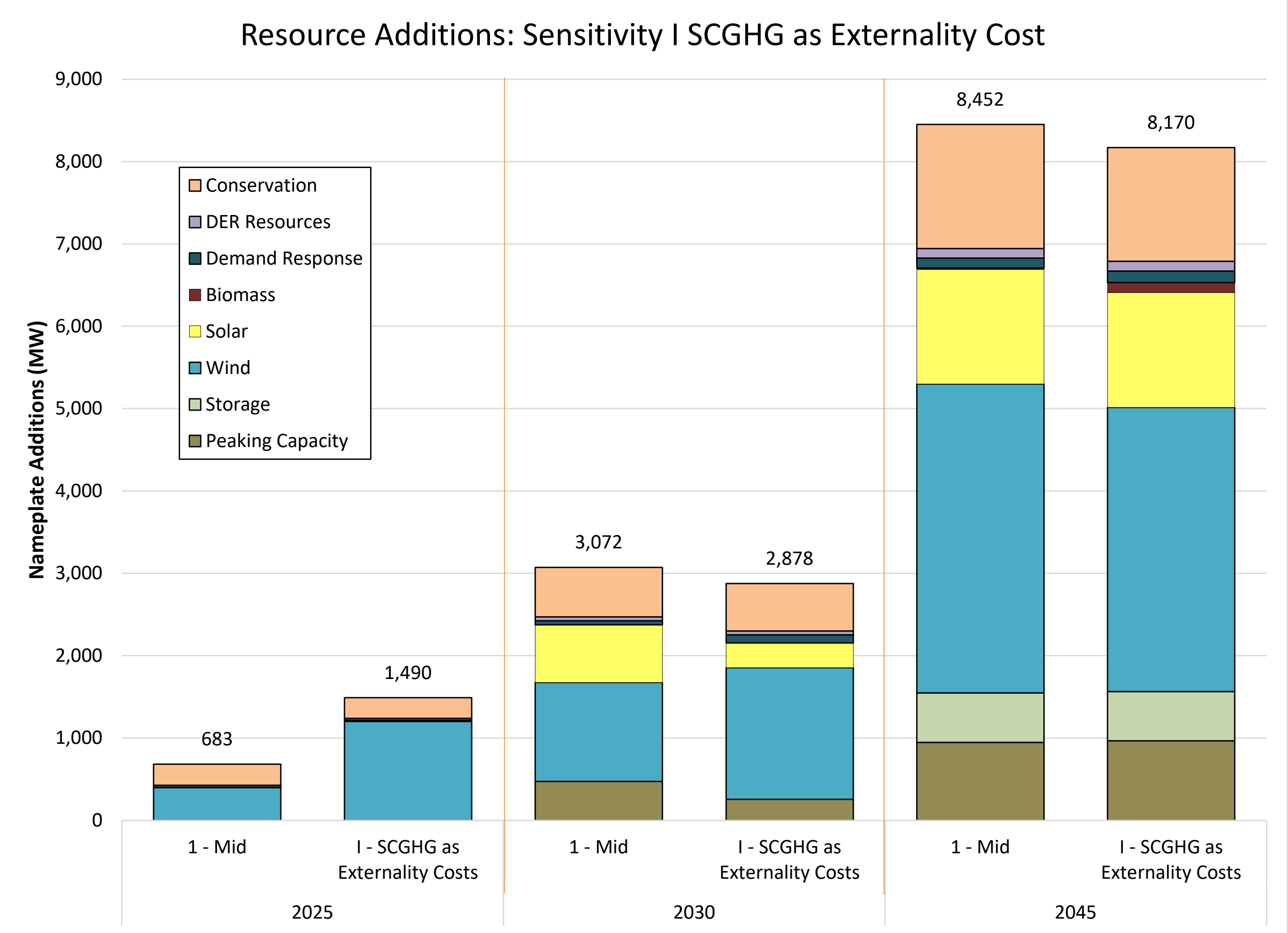
I. SCGHG as an "externality cost"

- The SCGHG is included as a dispatch cost in the LTCE model instead of a fixed cost adder.
- There is still no SCGHG applied in the hourly dispatch model.

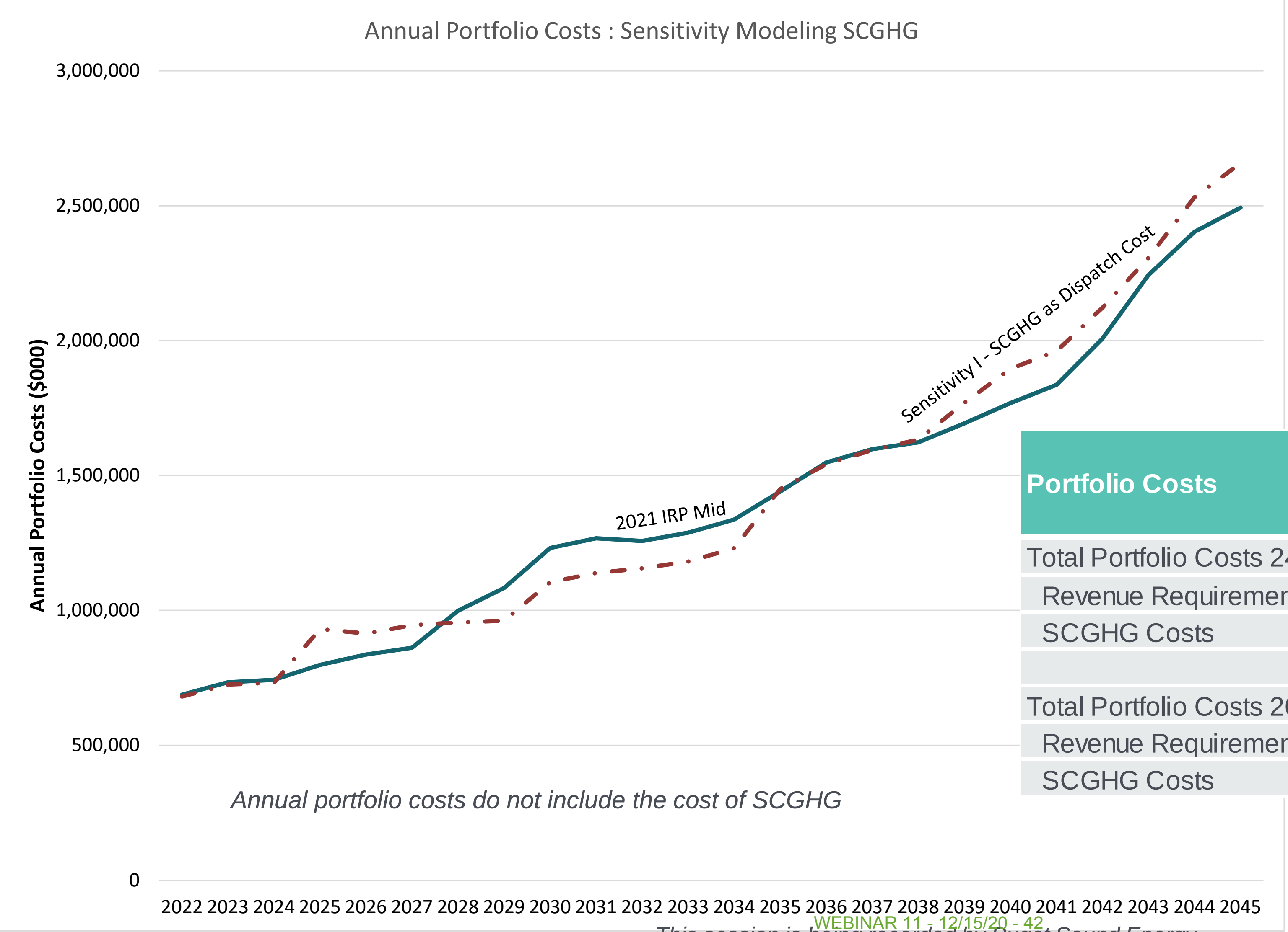
SCGHG Sensitivities – SCGHG as an externality costs – results

- Resource additions are very similar to the mid scenario
- Conservation savings are lower than mid portfolio (up to bundle 9)
- No economic retirements of existing resources

Resource Additions by 2045	Mid	I SCGHG as Externality Costs
Conservation	1507 MW	1381 MW
DER Resources	118 MW	118 MW
Demand Response	121 MW	141 MW
Renewable Resources	5158 MW	4964 MW
Biomass	15 MW	120 MW
Solar	1393 MW	1394 MW
Wind	3750 MW	3450 MW
Storage	600 MW	600 MW
Peaking Capacity	948 MW	966 MW



SCGHG Sensitivities – SCGHG as an externality cost – portfolio costs



- Lower dispatch of thermal plants leads to a lower avoided costs

Portfolio Costs	Mid	I SCGHG as Externality Costs
Total Portfolio Costs 24 Yr Levelized	$18.7	$18.4
Revenue Requirement	$13.6	$13.6
SCGHG Costs	$5.0	$4.8
Total Portfolio Costs 20 Yr Levelized	$16.4	$16.0
Revenue Requirement	$11.6	$11.5
SCGHG Costs	$4.7	$4.5

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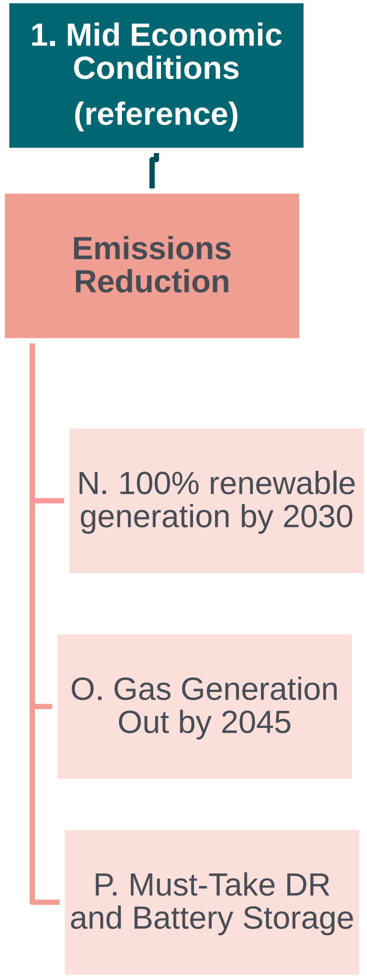
Emission Reduction Sensitivities



N. 100% renewable generation by 2030

- All existing natural gas plants are retired by the year 2030 regardless of their economic viability with CETA penalties.
- Not included in presentation, but will be in draft IRP

O. Gas Generation Out by 2045

- All existing natural gas plants are retired by the year 2045 regardless of their economic viability with CETA penalties.
- Not included in presentation, but will be in draft IRP

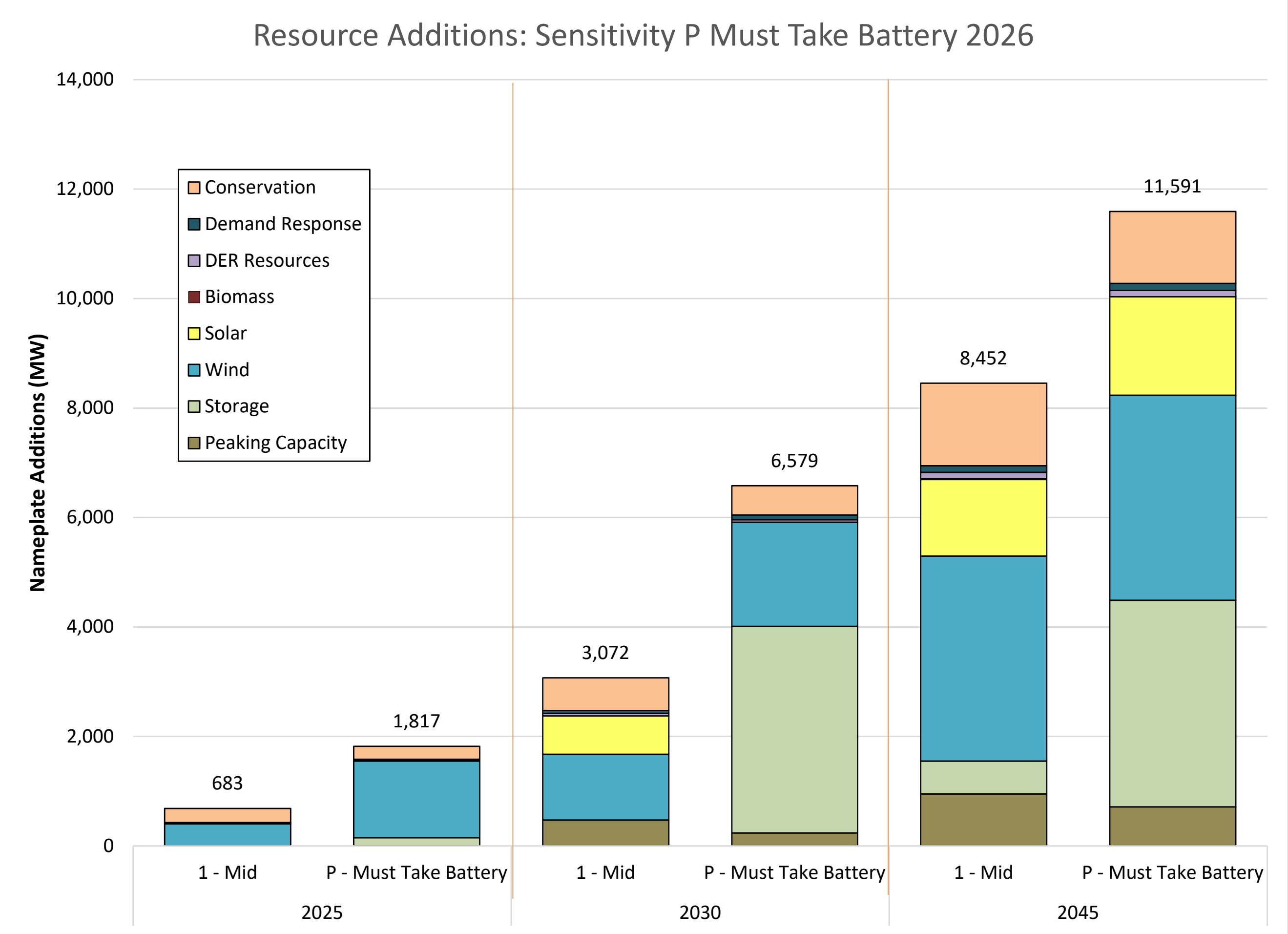
P. Must-Take Demand Response (DR) and Battery Storage

- Starting in 2026, the model is forced to reach the build limits of Demand Response and battery storage options before building any new peaking resources.

Emissions reduction sensitivities – must take DR & battery – results

- Instead of 474 MW of peaking capacity added in 2026, batteries are required to meet peak need.
  - 474 MW peaking capacity at 12.4% ELCC = 3,800 MW nameplate of batteries
- Lower cost-effective conservation in comparison to mid scenario (bundle 8)
- Colstrip 4 economic retirement in 2022

Resource Additions by 2045	Mid	P - Must Take Battery 2026
Conservation	1507 MW	1313 MW
DER Resources	118 MW	118 MW
Demand Response	121 MW	128 MW
Renewable Resources	5158 MW	5546 MW
Biomass	15 MW	0 MW
Solar	1393 MW	1796 MW
Wind	3750 MW	3750 MW
Storage	600 MW	3775 MW
Peaking Capacity	948 MW	711 MW



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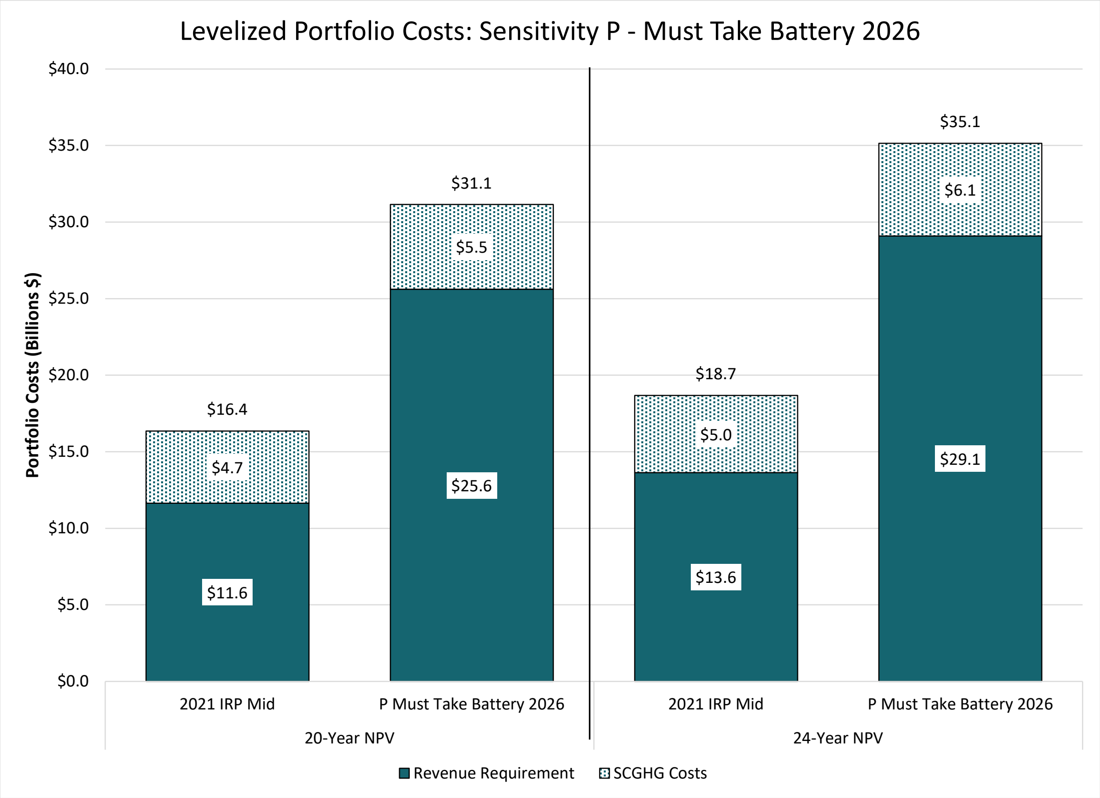
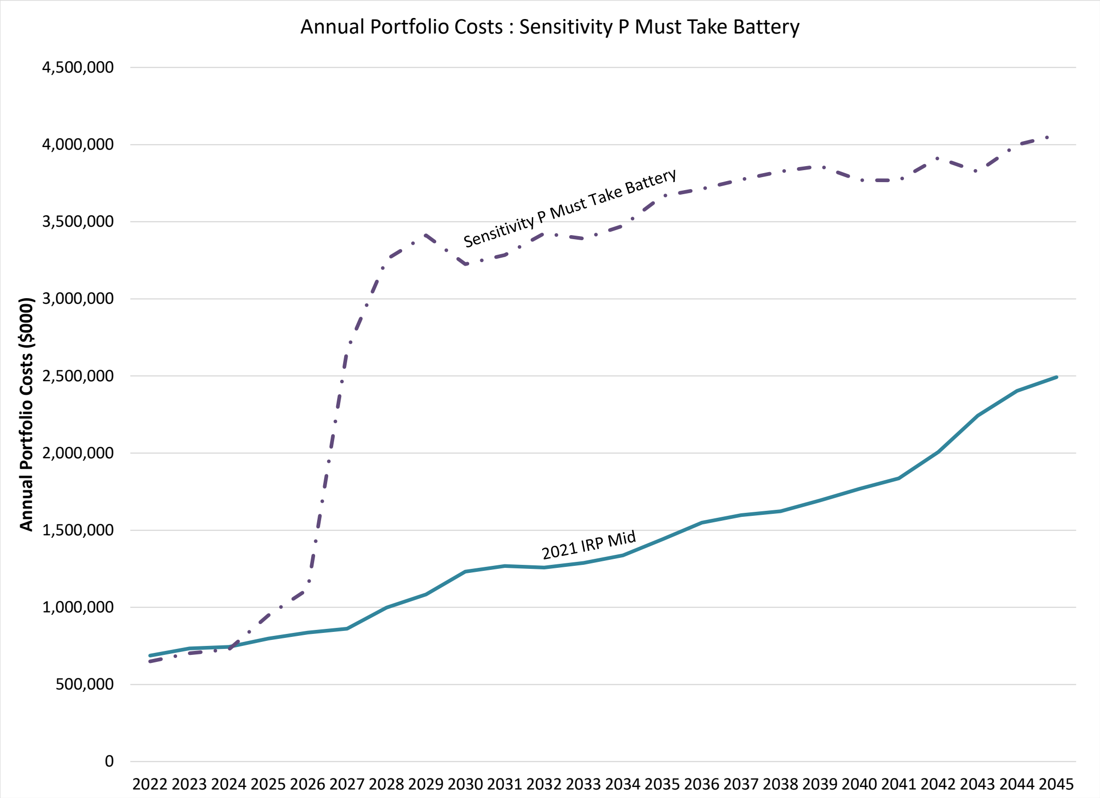
Emission reductions - must take DR & battery – portfolio costs





Portfolio Costs	Mid	P - Must Take Battery 2026
Total Portfolio Costs 24 Yr Levelized	$18.7	$35.1
Revenue Requirement	$13.6	$29.1
SCGHG Costs	$5.0	$6.1
Total Portfolio Costs 20 Yr Levelized	$16.4	$31.1
Revenue Requirement	$11.6	$25.6
SCGHG Costs	$4.7	$5.5

CETA Cost Sensitivities

1. Mid Economic Conditions (reference)

CETA Costs

- S. SCGHG only, no CETA
- T. No CETA or SCGHG

S. SCGHG Only, No CETA

- The SCGHG is modeled as a fixed cost adder
- CETA renewable requirements are not included
- 15% RPS requirement is still applied

T. No CETA or SCGHG

- SCGHG and CETA regulation are not included
- The 15% RPS requirement is still applied

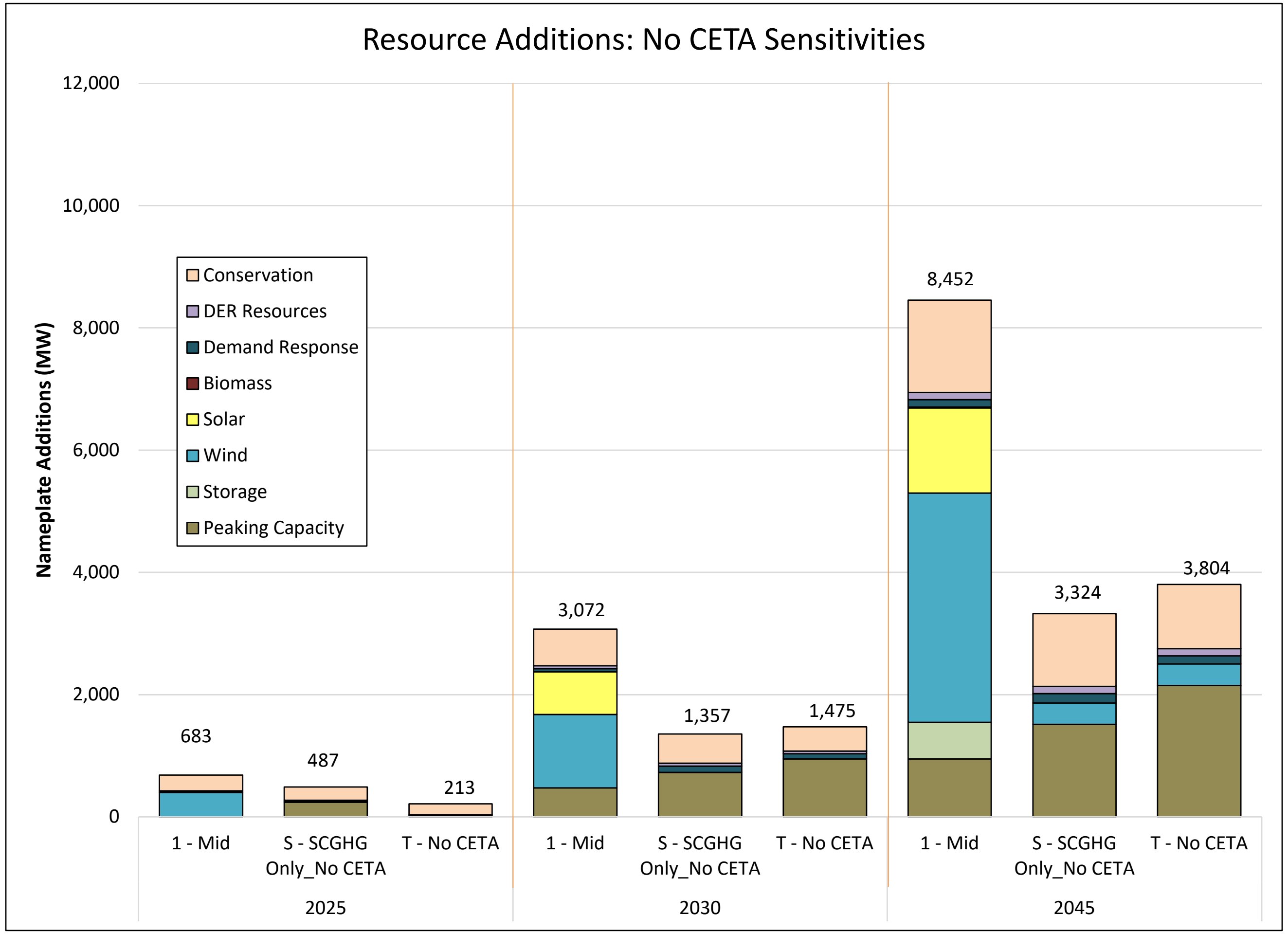
CETA cost sensitivities - results

SCGHG only

- ➢ One new renewable resource added in 2044 to maintain RPS
- ➢ Future capacity needs met with capacity resources and increased demand response
- ➢ Conservation savings up to bundle 6
- ➢ No economic retirements of existing resources

No CETA & No SCGHG

- ➢ One new renewable resource added in 2044 to maintain RPS compliance
- ➢ Future capacity needs met with peaking capacity resources and increased demand response
- ➢ Conservation savings up to bundle 2
- ➢ No economic retirements of existing resources



Resource Additions by 2045	Mid	S - SCGH Only No CETA	T - No CETA
Conservation	1507 MW	1188 MW	1052 MW
DER Resources	118 MW	118 MW	118 MW
Demand Response	121 MW	155 MW	133 MW
Renewable Resources	5158 MW	350 MW	350 MW
Biomass	15 MW	0 MW	0 MW
Solar	1393 MW	0 MW	0 MW
Wind	3750 MW	350 MW	350 MW
Storage	600 MW	0 MW	0 MW
Peaking Capacity	948 MW	1513 MW	2151 MW

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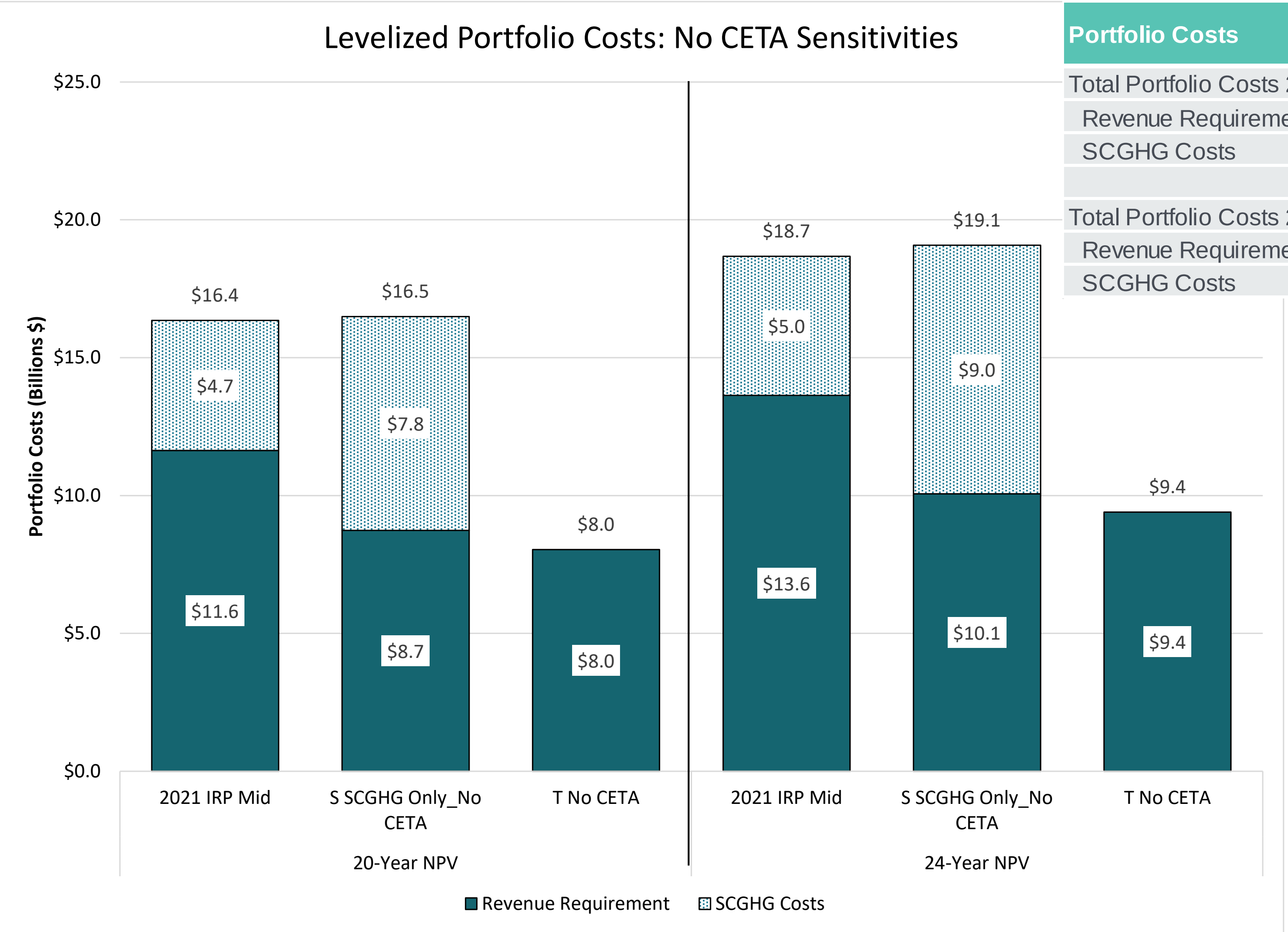
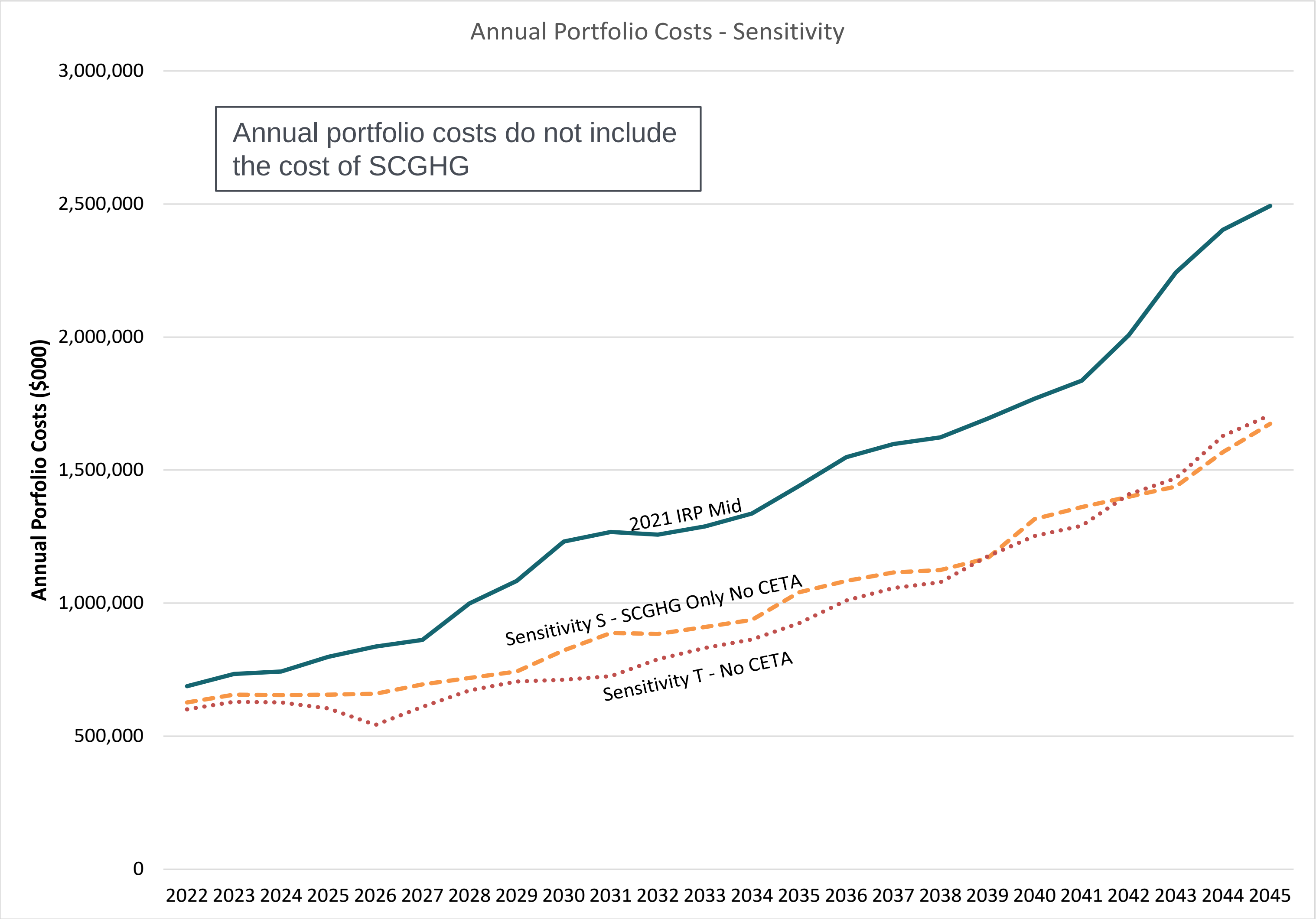
CETA Cost Sensitivities – total portfolio costs



Portfolio Costs	Mid	S - SCGHG Only No CETA	T - No CETA
Total Portfolio Costs 24 Yr Levelized	$18.7	$19.1	$9.4
Revenue Requirement	$13.6	$10.1	$9.4
SCGHG Costs	$5.0	$9.0	$0.0
Total Portfolio Costs 20 Yr Levelized	$16.4	$16.5	$8.0
Revenue Requirement	$11.6	$8.7	$8.0
SCGHG Costs	$4.7	$7.8	$0.0

CETA Cost Sensitivities – annual portfolio cost



- Mid scenario is the least cost optimized portfolio results and does not represent PSE's resource plan

- 2% annual increase for cost of compliance will be calculated based on the resource plan

Comparison of all the portfolios costs and renewable resource additions

Portfolio	24-yr Levelized Cost ($ Billions)			Renewable Additions by 2045 Nameplate (MW)			
	Revenue Requirement	SCHGH adder	Total	Biomass	Solar	Wind	Total
1. Mid	$13.6	$5.0	$18.7	15	1,393	3,750	5,158
2. Low	$10.4	$4.5	$14.9	-	797	3,350	4,147
3. High	$17.2	$6.3	$23.5	330	1,891	3,950	6,171
A. Renewable Over-generation	$15.3	$4.2	$19.6	525	1,490	2,150	4,165
I. SCGHG as Externality Cost	$13.6	$4.8	$18.4	120	1,394	3,450	4,964
P. Must take Battery	$29.1	$6.1	$35.1	-	1,796	3,750	5,546
S. SCGHG Only, No CETA	$10.1	$9.0	$19.1	-	-	350	350
T. No CETA	$9.4	$0.0	$9.4	-	-	350	350

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Consulting stakeholders

- Draft portfolio results help inform the draft resource plan

- PSE would like stakeholder feedback:
  - What conclusions are stakeholders making from the results?
  - Should these sensitivities be adjusted to better inform the resource plan? What adjustments should be made?
  - What other factors should PSE consider?

10-minute break

Flexibility Analysis

PUGET SOUND ENERGY

Participation Objectives

- PSE will review and solicit stakeholder feedback on flexibility analysis results

IAP2 level of participation: CONSULT

Sub-hourly flexibility analysis in Plexos

- PLEXOS is an hourly and sub-hourly chronological production simulation model that utilizes mixed-integer programming (MIP) to simulate unit commitment of resources at a day-ahead level, and then simulate the re-dispatch of these resources in real-time to match changes in supply and demand on a 15-minute basis.
- For the sub-hourly cost analysis using PLEXOS, PSE created a current portfolio case based on PSE's existing resources.
- Then tested each resource in the portfolio and calculated the cost difference in the real-time re-dispatch from the current portfolio case.
- The purpose of the flexibility analysis to explore the sub-hourly flexibility needs of the portfolio and determine how new resources can contribute to those needs.
- Flexibility benefit = day-ahead (DA) dispatch costs – Intra-hour (IH or "real-time") dispatch costs
- The flexibility benefit is then calculated as the total cost ($) / nameplate (MW) of resources as a fixed benefit per year ($/kw-year) and then added back to the resource in the capacity expansion model for making resource decisions.

Operating Reserves

Contingency reserves

- Bal-002-WECC-1 requires balancing authorities to carry reserves for every hour:
  - 3% of online generating resources
  - 3% of load to meet contingency obligations

Balancing reserves

- Utilities must also have sufficient reserves available to maintain system reliability within the operating hour; this includes frequency support, managing load and variable resource forecast error, and actual load and generation deviations.
- Balancing reserves do not provide the same kind of short-term, forced-outage reliability benefit as contingency reserves, which are triggered only when certain criteria are met.
- Balancing reserves are resources that have the ability to ramp up and down instantaneously as loads and resources fluctuate each hour.

Balancing reserve requirement

The balancing reserve requirements were assessed by E3 for two study years, using the CAISO flex ramp test. The results depend heavily on the Mean Average Percent Error (MAPE) of the hour-ahead forecasts vs real time values for load, wind and solar generation.

- 2025 case includes PSE's current portfolio
- 2030 case includes PSE's current portfolio, plus generic wind and solar resources to meet the 80% renewable requirement target

Case	Capacity of PSE balanced Wind (MW)	Capacity of PSE balanced solar (MW)	Average Annual Flex up (MW)	Average Annual Flex down (MW)	99th percentile of forecast error (flex up cap)	1st percentile of forecast error (flex down cap)
2025 case	875	-	141	146	190	196
2030 case	2,375	1,400	492	503	695	749

- When the model must flex generation down, it can turn off dispatchable plants, charge batteries, curtail renewable generation, or sell power to the market.
- When the model must flex generation up, it can turn on dispatchable plants, discharge batteries, or buy power from the market.

PLEXOS Simulation Phases

Inputs:
- Existing resources and contracts
- Natural gas price forecast
- Electric price forecast (from Aurora)
- Pond volumes daily max and min
- Hydro initial and end volume
- Inflow for baker
- **Reserve requirement**
- Demand forecast

PASA
- Simulates the scheduled maintenance
- Random outage simulation for forced outages

scheduled maintenance and forced outage

Mid-Term (MT)
- mid-term optimization run for the entire year with low resolution 3 steps/day
- utilize water for lower and upper baker over next 12 months

daily water storage target for Baker

Day Ahead (DA)
- Day ahead unit commitment for CCCT units
- 16-hour block trades with Mid-C for the next operating day

CCCT units commitment and block trade

Intra-day (ID)
- hourly trade with Mid-C for the balancing day
- Hourly dispatch

hourly market purchases and sales

Intra-hour (IH)
- CAISO EIM engine, optimize dispatch for slow start resources, quick-start resources, and fifteen minute market (FMM) real-time (RT) trade with EIM

Sub-hourly dispatch of flexible capacity and total portfolio cost

Generic resources providing flexibility

- The PLEXOS model performs flexibility tests on the base portfolio, and compares changes from the base portfolio with the new resource additions.

Resource	Capacity (MW)	Heat Rate (Btu/kWh)	Energy Storage (MWh)	Roundtrip Efficiency (%)
Frame Peaker	237	9,904	-	-
Recip Peaker	18.2	8,445	-	-
CCCT	355	6,624	-	-
Li-Ion Battery 2-hr	100	-	200	82
Li-Ion Battery 4-hr	100	-	400	87
Flow Battery 4-hr	100	-	400	73
Flow Battery 6-hr	100	-	600	73
Pumped Storage Hydro	100	-	800	80
Demand Response	100	40 hours/season, 1 call/day, max of 4 hours/day		

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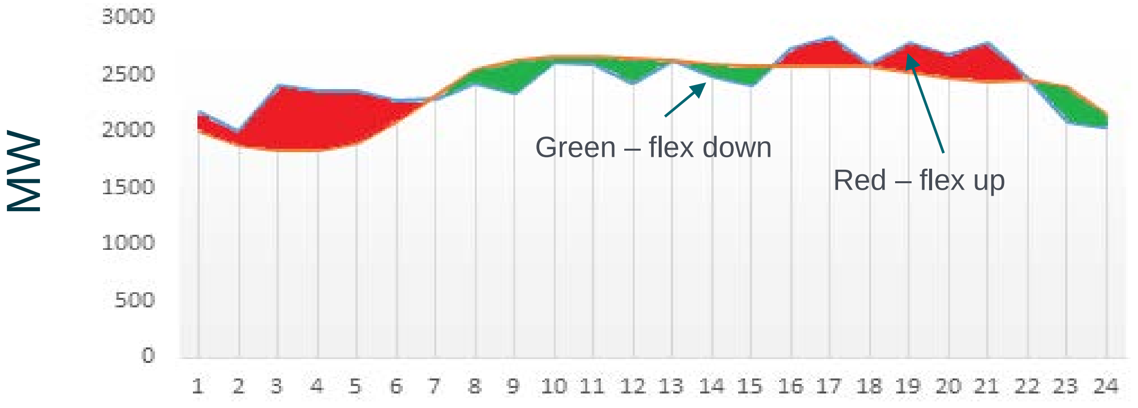
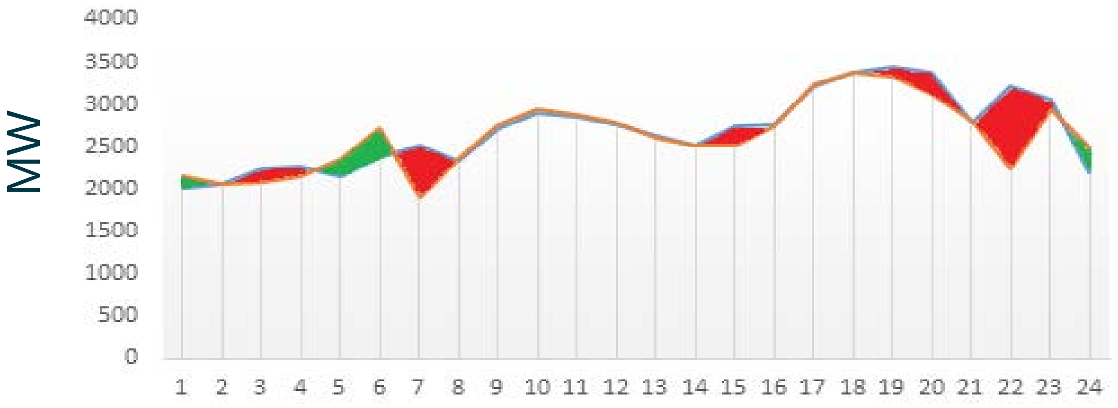
2025 case – adjustments to load day-ahead to hourly

- Differences between the Day-Ahead and hourly load for summer and winter months

June 13, 2025



December 30, 2025



- Green area is the flex down needed
- Red area is the flex up needed
- More flex up and flex down capacity is needed in summer because of more intermittent resources such as solar
- New resources will be tested to fill in the flex up and flex down need
- Expect that the flex up and flex down need will increase with 2030 case

2025 case – flex violations

DRAFT RESULTS

Number of hours of flex up/flex down violations and magnitude (MWh)

Month	Flex up (Hours)	Flex Down (Hours)	Flex up (MWh)	Flex Down (MWh)
January	16.5	8.75	374	615
February	20	10.75	452	497
March	45.25	21.5	1,666	704
April	18.5	14	658	402
May	35.75	41.25	970	1,160
June	28	6.75	721	221
July	46.5	3.75	1,297	168
August	54.5	5	1,413	151
September	36	11.75	921	286
October	28.25	10.75	735	300
November	30.75	14	850	511
December	23.75	15.75	879	625
Annual	383.75	164	10,934	5,639

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2025 case – draft portfolio results

DRAFT RESULTS

Dispatch cost increased by $0.6 Million in the intra-hour model run

Resource Type	2025 PSE System Costs ($MM)	2025 PSE System Energy (GWh)
Wind	23.0	3,456
Hydro	1.9	4,808
Thermal	143.2	4,614
Solar	13.5	343
Contracts	292.2	5,324
IRP Resource	-	-
Total Generation	*473.8*	*18,545*
Net Market Purchases/Sales	*97.0*	*4,512*
Total	**570.9**	**23,057**

−

Resource Type	2025 PSE System Costs ($MM)	2025 PSE System Energy (GWh)
Wind	22.8	3,523
Hydro	2.0	4,881
Thermal	153.8	4,681
Solar	13.5	343
Contracts	292.2	5,324
IRP Resource	-	-
Total Generation	*484.3*	*18,752*
Net Market Purchases/Sales	*87.2*	*4,235*
Total	**571.5**	**22,988**

=

Resource Type	2025 PSE System Costs ($MM)	2025 PSE System Energy (GWh)
Wind	0.2	(67)
Hydro	(0.1)	(72)
Thermal	(10.6)	(67)
Solar	-	(0)
Contracts		
IRP Resource	-	-
Total Generation	*(10.5)*	*(207)*
Net Market Purchases/Sales	*9.9*	*276.3*
Total	**(0.6)**	**69.3**

Day-Ahead dispatch cost − Intra-hour dispatch cost = change to portfolio for sub –hourly flexibility

PUGET SOUND ENERGY

2025 case – day-ahead system costs ($MM)

DRAFT RESULTS

2025 PSE System Costs ($MM)	Base Portfolio	CCCT	Frame Peaker	Recip Peaker	Li-Ion 2-hr	Li-Ion 4-hr	Flow 4-hr	Flow 6-hr	Pumped Hydro Storage	Demand Response
Wind	23	23	23	23	24	24	24	24		
Hydro	2	2	2	2	2	2	2	2		
Thermal	143	101	130	141	128	127	126	128		
Solar	14	14	14	14	14	14	14	14		
Contracts	292	292	292	292	292	292	292	292		
IRP Resource	-	47	11	-	-	-	-	-		
Total Generation	*474*	*478*	*471*	*472*	*460*	*458*	*458*	*459*	-	-
Net Market Purchases/Sales	*97*	*80*	*95*	*97*	*101*	*102*	*103*	*101*		
Total	**571**	**558**	**566**	**569**	**561**	**560**	**560**	**560**		
Change in Cost from Base		**(13)**	**(4)**	**(2)**	**(10)**	**(11)**	**(11)**	**(11)**		

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2025 case – intra-hour system costs ($MM) DRAFT RESULTS

2025 PSE System Costs ($MM)	Base Portfolio	CCCT	Frame Peaker	Recip Peaker	Li-Ion 2-hr	Li-Ion 4-hr	Flow 4-hr	Flow 6-hr	Pumped Hydro Storage	Demand Response
Wind	23	23	23	23	23	23	23	23		
Hydro	2	2	2	2	2	2	2	2		
Thermal	154	115	134	151	137	137	133	135		
Solar	14	14	14	14	14	14	14	14		
Contracts	292	292	292	292	292	292	292	292		
IRP Resource	-	46	11	0	0	-	-	-		
Total Generation	*484*	*491*	*474*	*482*	*469*	*467*	*464*	*466*	-	-
Net Market Purchases/Sales	*87*	*61*	*81*	*81*	*86*	*87*	*88*	*87*		
Total	**572**	**553**	**555**	**562**	**554**	**554**	**552**	**552**		
Change in Cost from Base		**(19)**	**(17)**	**(9)**	**(17)**	**(18)**	**(19)**	**(19)**		

2025 – draft flex benefit

DRAFT RESULTS

2025 PSE System Costs ($MM)	Base Portfolio	CCCT	Frame Peaker	Recip Peaker	Li-Ion 2-hr	Li-Ion 4-hr	Flow 4-hr	Flow 6-hr	Pumped Hydro Storage	Demand Response
Wind	0	0	1	0	1	1	1	1		
Hydro	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)		
Thermal	(11)	(14)	(4)	(9)	(9)	(10)	(7)	(7)		
Solar	-	-	-	-	-	-	-	-		
Contracts	0	0	0	0	0	0	0	0		
IRP Resource	-	1	1	(0)	(0)	-	-	-		
Total Generation	*(10)*	*(13)*	*(3)*	*(10)*	*(9)*	*(9)*	*(7)*	*(7)*	-	-
Net Market Purchases/Sales	*10*	*18*	*15*	*17*	*15*	*15*	*14*	*14*		
Total	**(1)**	**5**	**12**	**7**	**7**	**6**	**8**	**8**		
Change in Cost from Base		**6**	**12**	**8**	**7**	**7**	**9**	**8**		
Nameplate		355	237	18.2	100	100	100	100		
$/kw-yr		**16.79**	**51.32**	**417.25**	**71.51**	**66.52**	**85.17**	**84.26**		

- Significantly higher flexibility benefit than 2017 IRP analysis could be driven by higher flex violations

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Consulting Stakeholders

- PSE is soliciting feedback from stakeholders on how to make the best use of the Flexibility Analysis data.

- Questions:
  - What metrics are the most valuable in determining the flexibility benefit of a resource?
  - What aspects are at risk of being double-counted in the modeling process?
  - How do we determine flexibility need? Is it based on the flex violations size?
    - Should we create a placeholder resource similar to the resource adequacy model to come a certain level of flex violations?
    - What is the level?
  - What resources are there on other flexibility analysis studies to help benchmark results?

2021 IRP Draft Natural Gas Portfolio Results

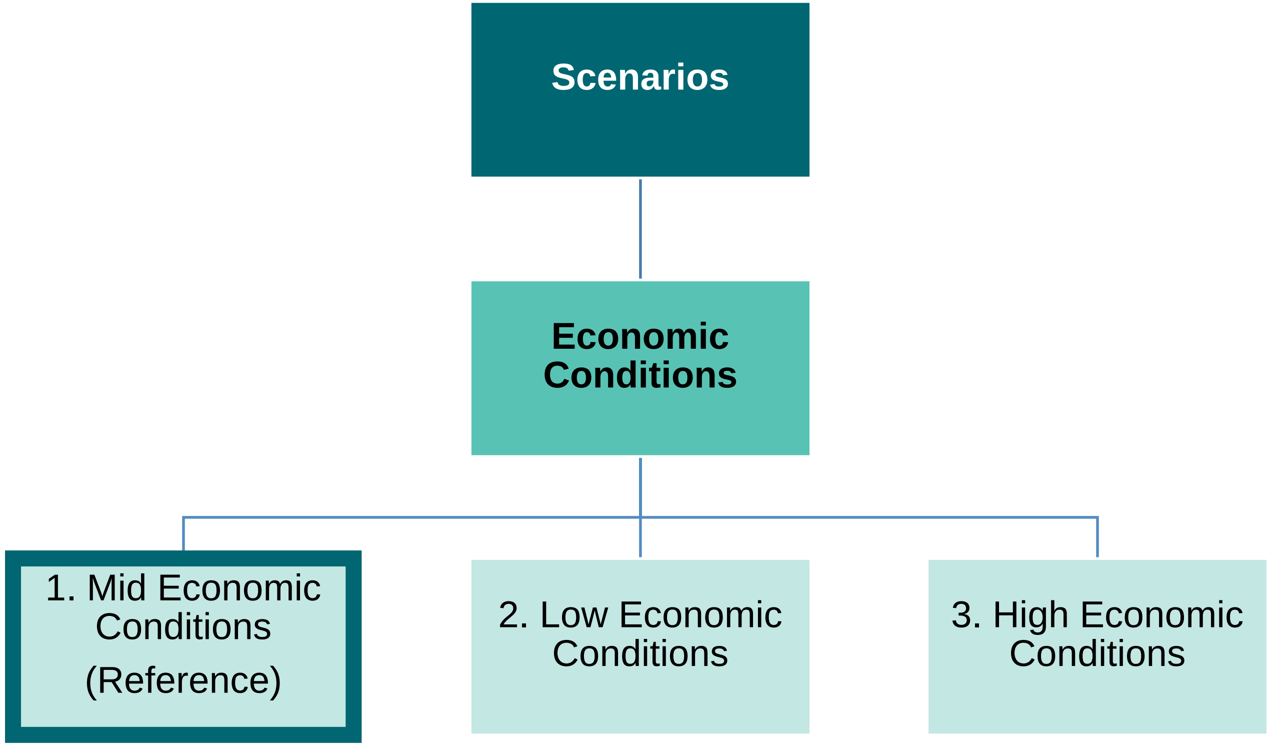
Participation Objectives

- PSE will inform stakeholders of the draft natural gas portfolio results.

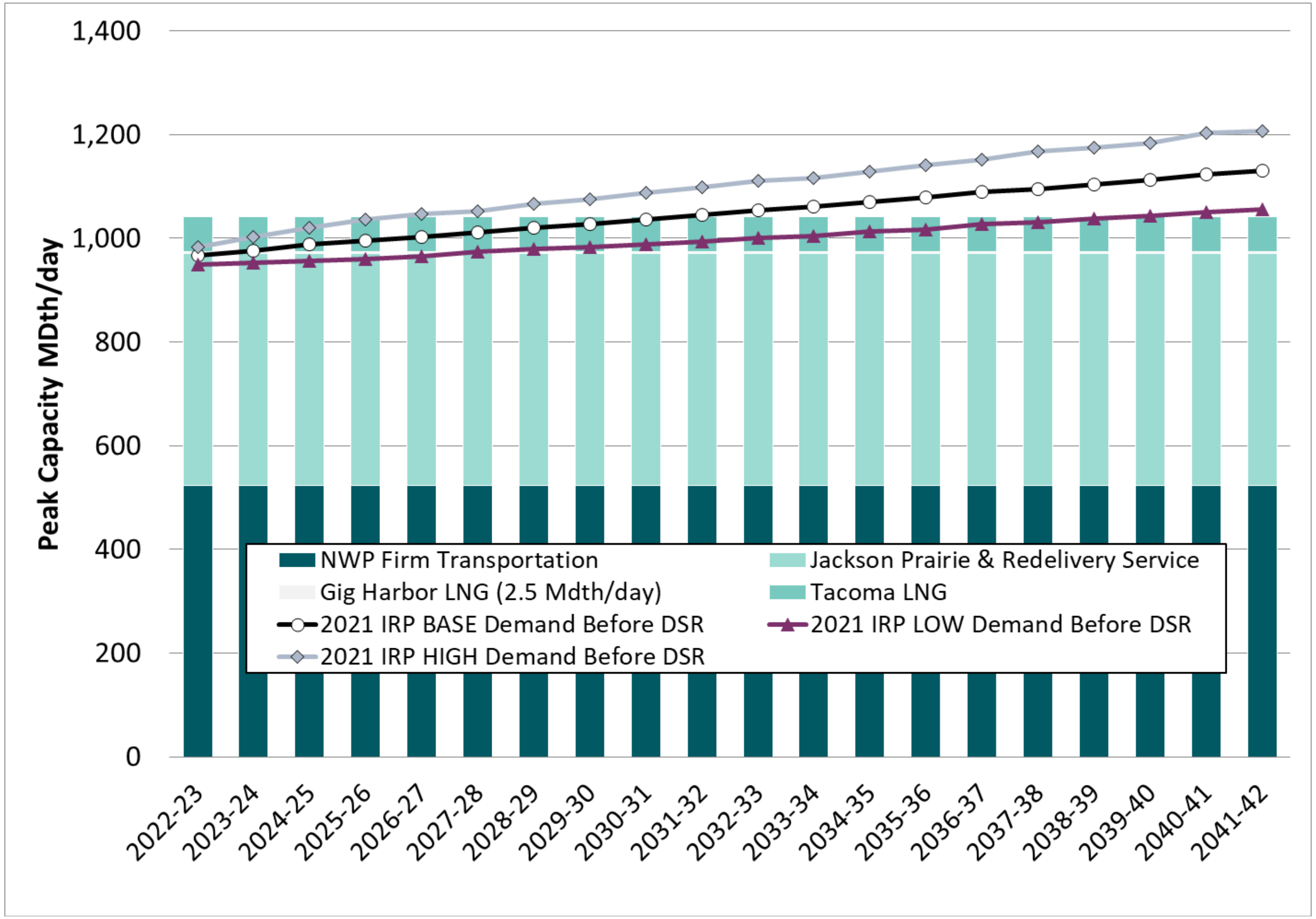
IAP2 level of participation: INFORM

Outline for Today

- Resource Need: Mid/Low/High
- Results
  - Mid/Low/High
  - Sensitivities:
    - 6 year Ramp
    - Upstream Emissions with AR5
    - Social Discount Rate (SDR)
- Conclusions



2021 IRP natural gas capacity need: mid, low and high



- The high and the low are modelled using 250 stochastic simulations.
- The peak simulations vary the economic and demographic conditions, such as population, employment, and income
- The high and low are the 90th percentile and 10th percentile of the 250 simulations, respectively.

Draft results – summary builds by scenario

- Cost-effective DSR did not vary by scenario – Bundle 9 ($0.85-$0.95/therm)
- In the mid and low scenario DSR is sufficient to fill resource need
- High scenario chooses supply side resources in PSE's control, some pipeline added starting in 2034.

Scenario	Resource Type	2022-2025	2026-2030	2031-2041
Mid	*DSR*	21	32	54
Low	*DSR*	21	32	54
High	*DSR*	21	32	54
	Plymouth LNG	15	15	15
	Swarr	0	0	30
	NWP + Westcoast	0	0	30

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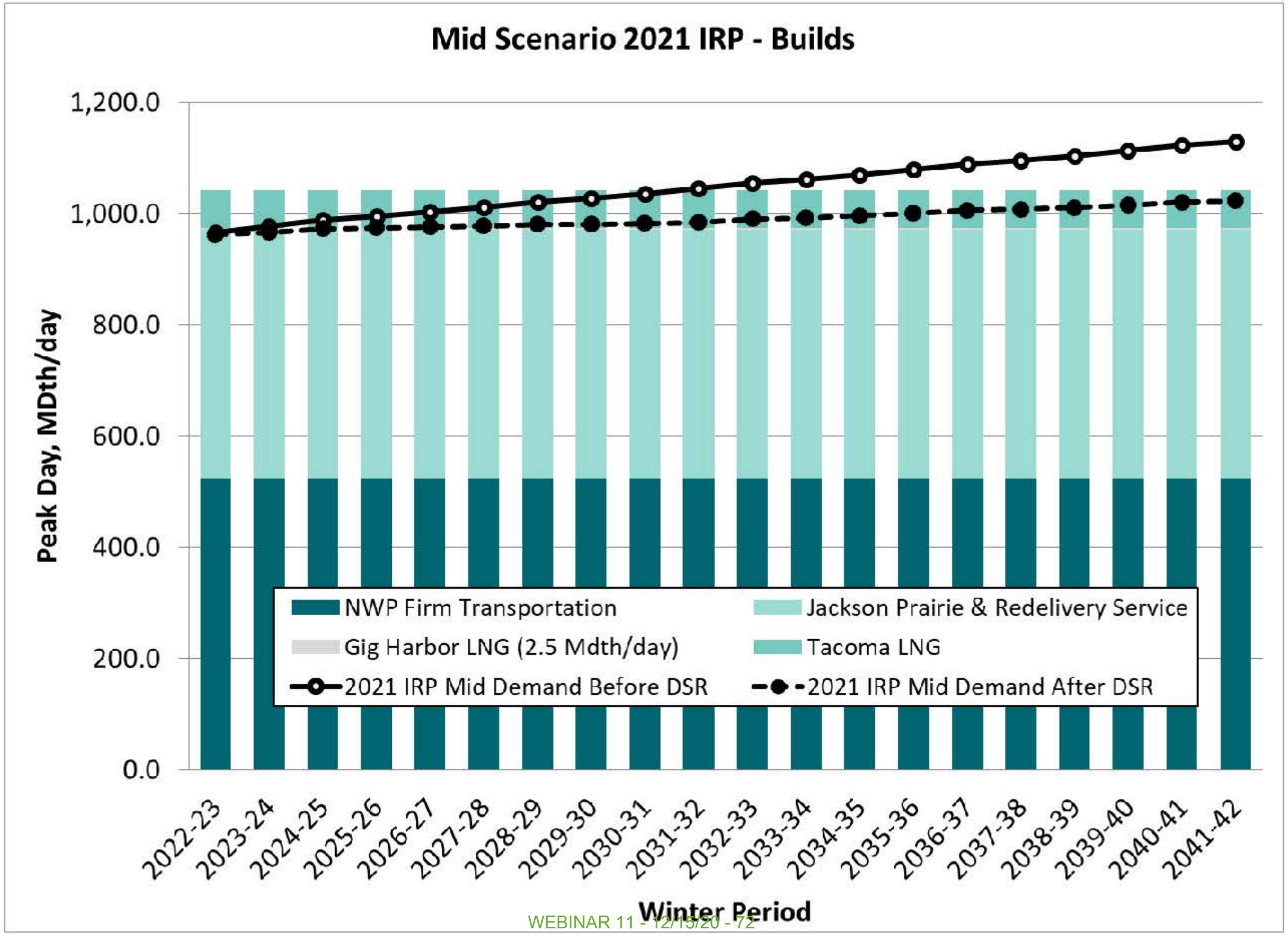
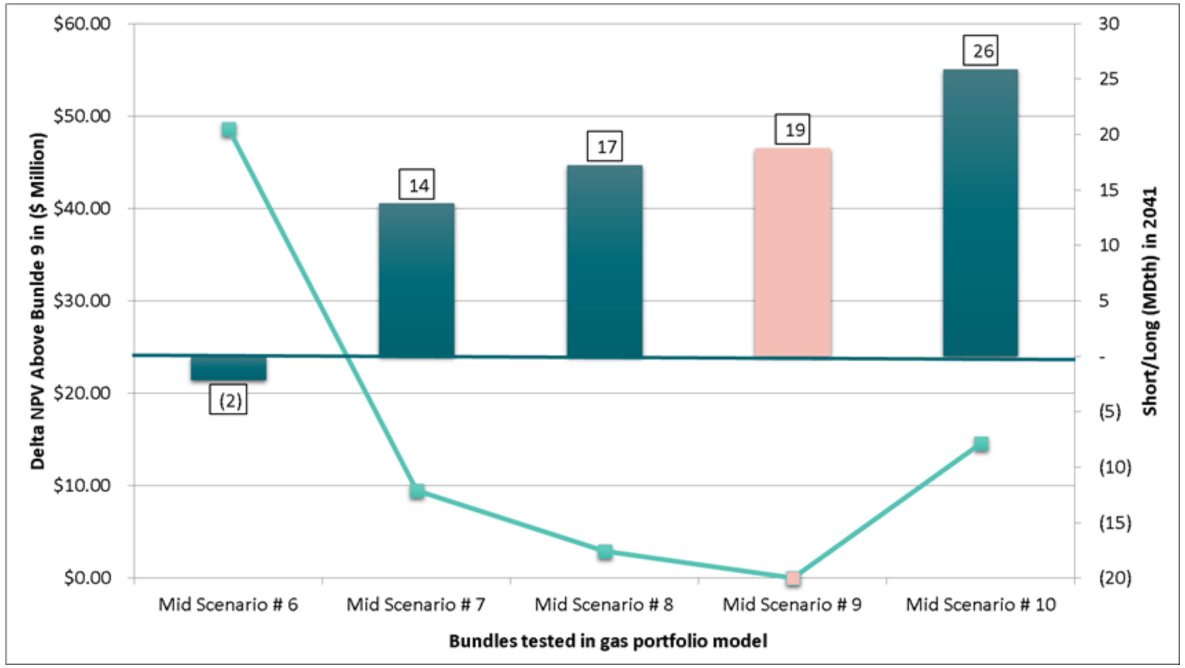
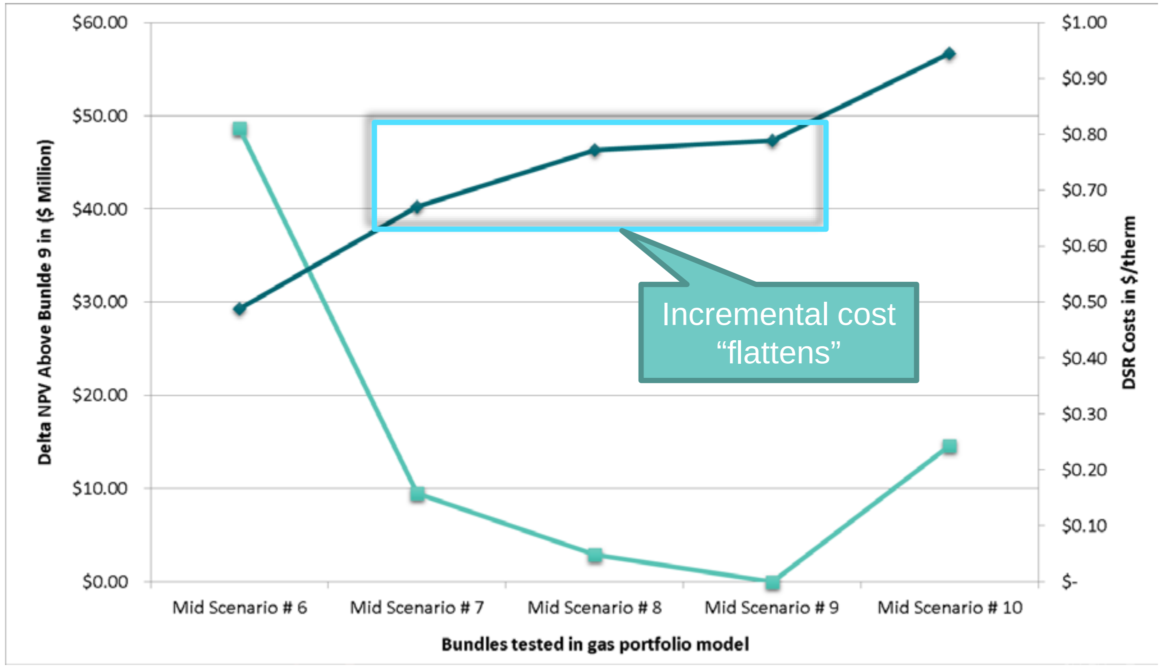
Draft mid scenario – DSR sufficient to meet future demand

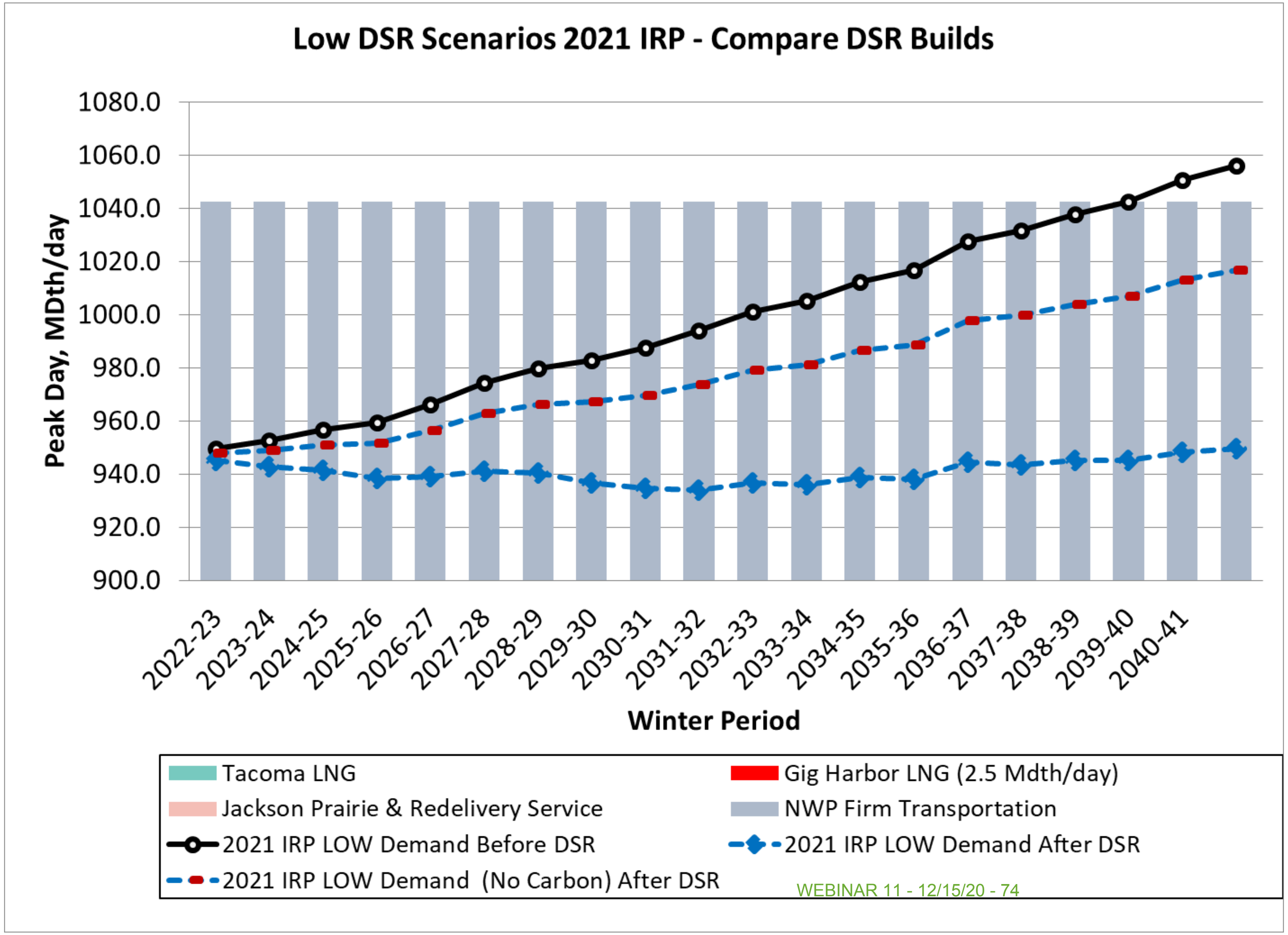


Draft mid scenario – Overbuilding DSR reduces portfolio cost



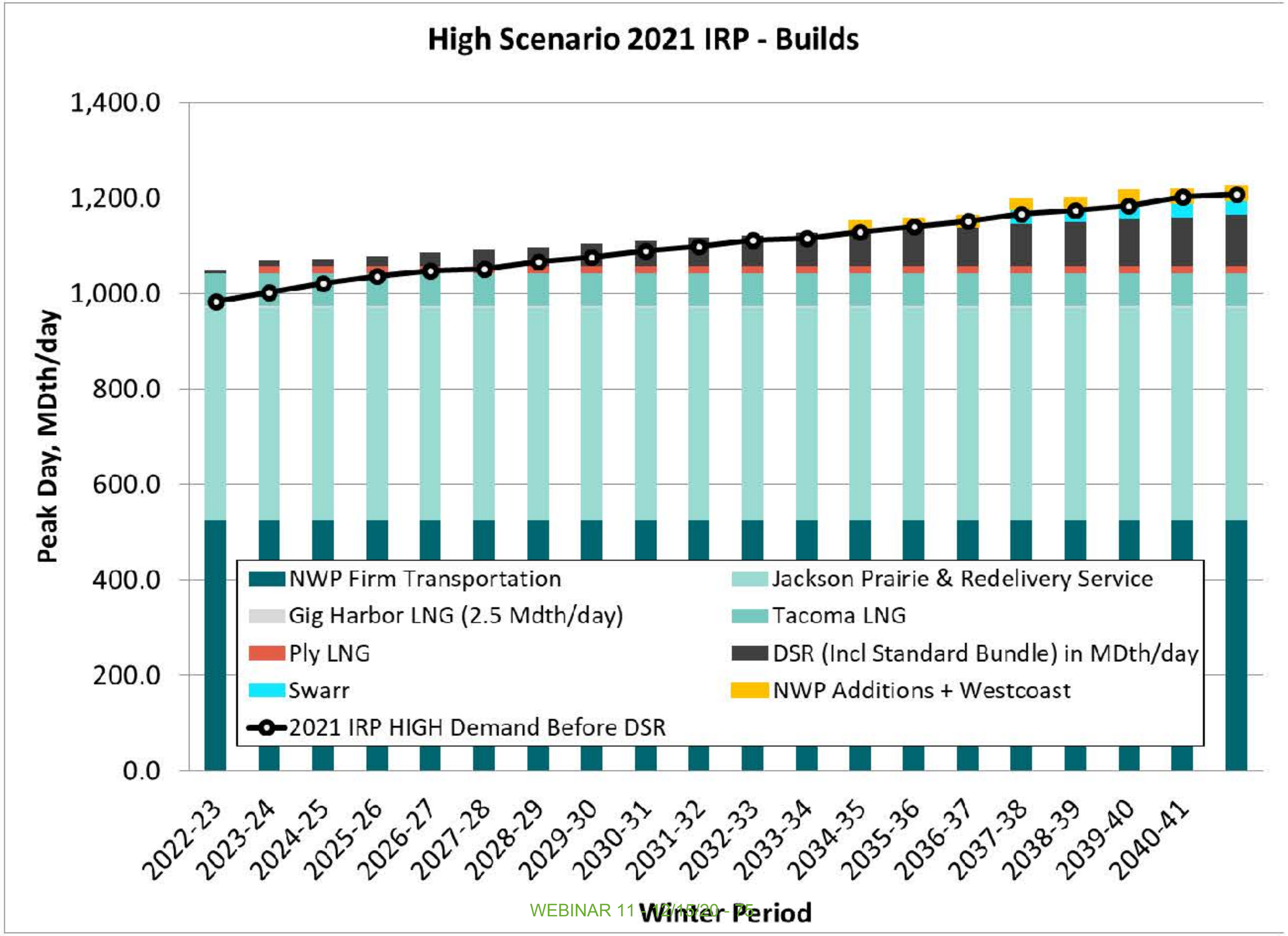


Draft Low scenario – Overbuilding DSR due to high carbon cost

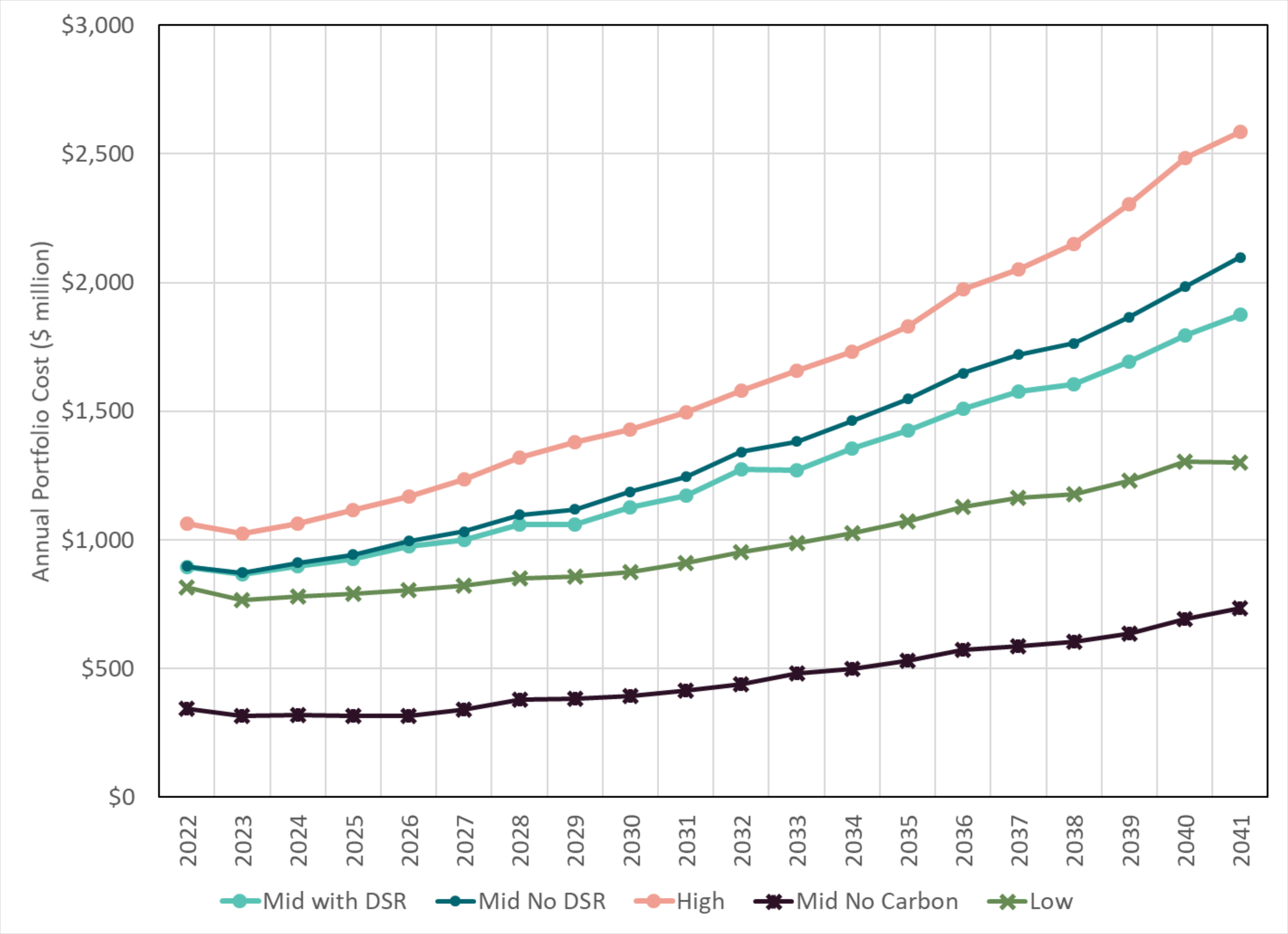


Scenario	Portfolio NPV, $ billion
Low	$9.899
Low No DSR	$10.327

Draft high scenario – Mostly DSR and PSE supply side resources



Draft results Mid/Low/High – portfolio costs



The mid scenario with cost effective DSR has an NPV about $500 million less than without: DSR reduces portfolio costs by $0.5 billion.

Carbon adders (SCGHG and Upstream emissions) add significant cost to the portfolio. Which drive more conservation.

Draft summary results – Sensitivities

Three sensitivities were run in the Mid Scenario:

- 6 Year Ramp vs 10 year ramp in the Mid
- AR5 on the upstream emissions vs AR4 in the Mid
- Social discount rate: 2.5% vs WACC 6.80% in the Mid

Results:

- 6 year ramp added the same bundle 9 as in Mid, but more savings early
- AR5 sensitivity had the same bundle as Mid Scenario
- Social discount rate sensitivity has more conservation than the Mid

Sensitivity	Resource Type	2022-2025	2026-2030	2031-2041
6 year ramp	*DSR*	29	27	51
AR5	*DSR*	21	32	54
Social Discount Rate	*DSR*	25	37	60

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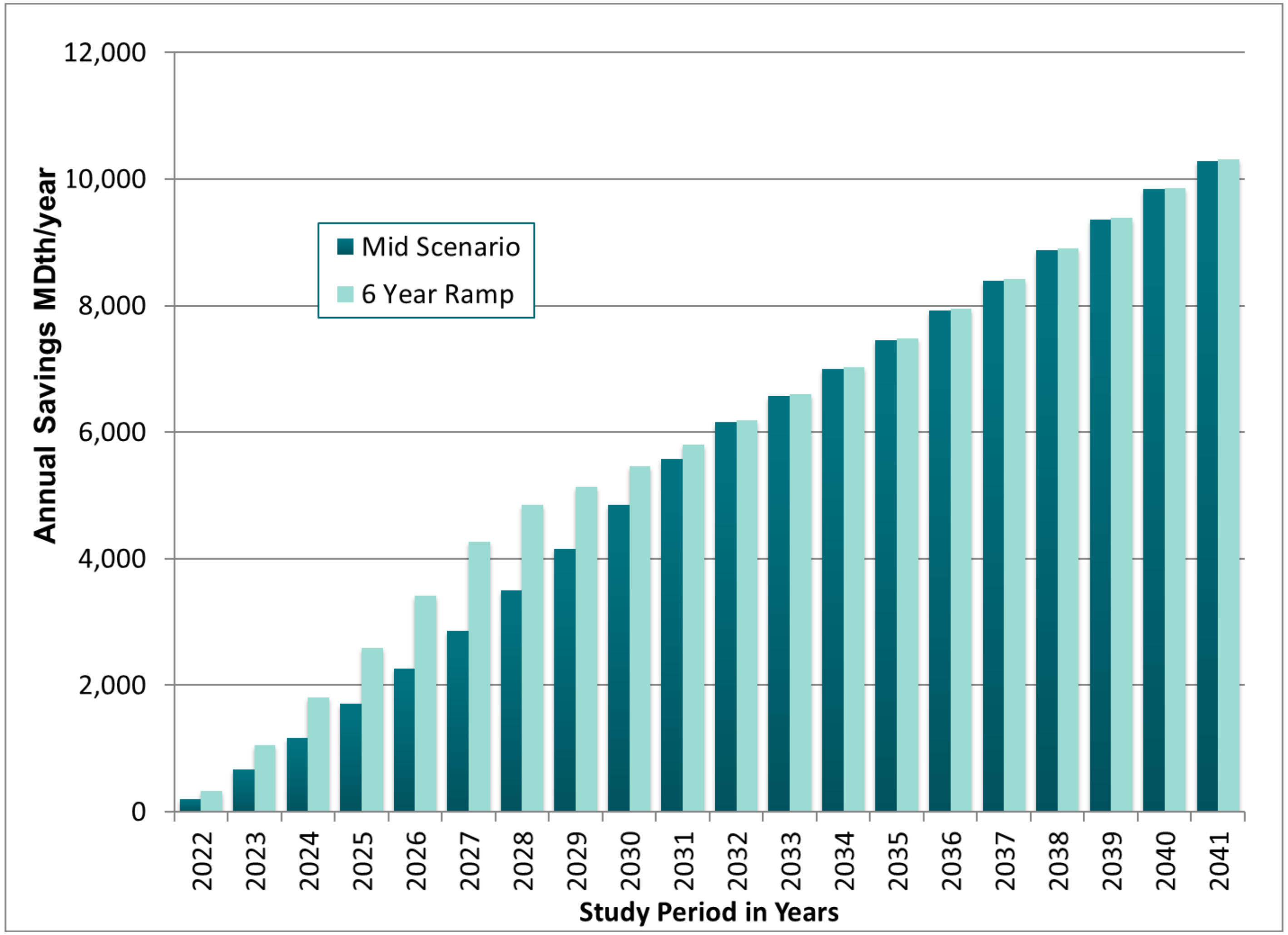
Draft sensitivity results – 6 year ramp

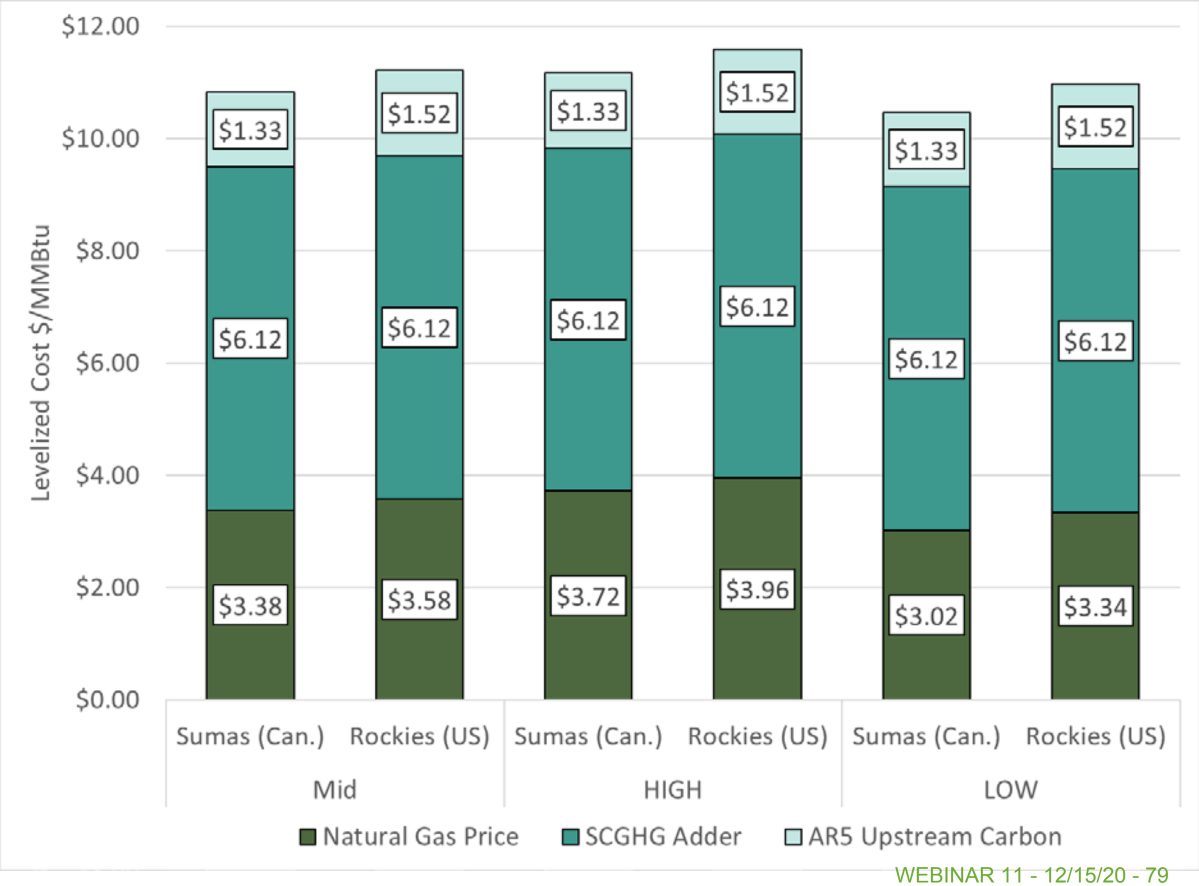


Result:

- Only chose DSR, no supply side resources
- Portfolio NPV was lower than Mid – due to earlier acquisition of DSR
- Same level of conservation as the Mid – Bundle 9 (Commercial Interruptible is 6)

Draft sensitivity results – AR5 upstream emissions

- Used AR5 data to update the upstream emissions
- Used the 10 year ramp same as Mid case DSR input
- Result: same amount of cost effective DSR as in Mid scenario



May 29, 2019 TAG#6	May 29, 2019 TAG#6
(Canadian Supply)	(Domestic Supply)
gCO2e/MMBtu	*gCO2e/MMBtu*
10,803	12,121

AR5	
Dec 15th, 2020	Dec 15th, 2020
(Canadian Supply)	(Domestic Supply)
gCO2e/MMBtu	*gCO2e/MMBtu*
11,564	13,180

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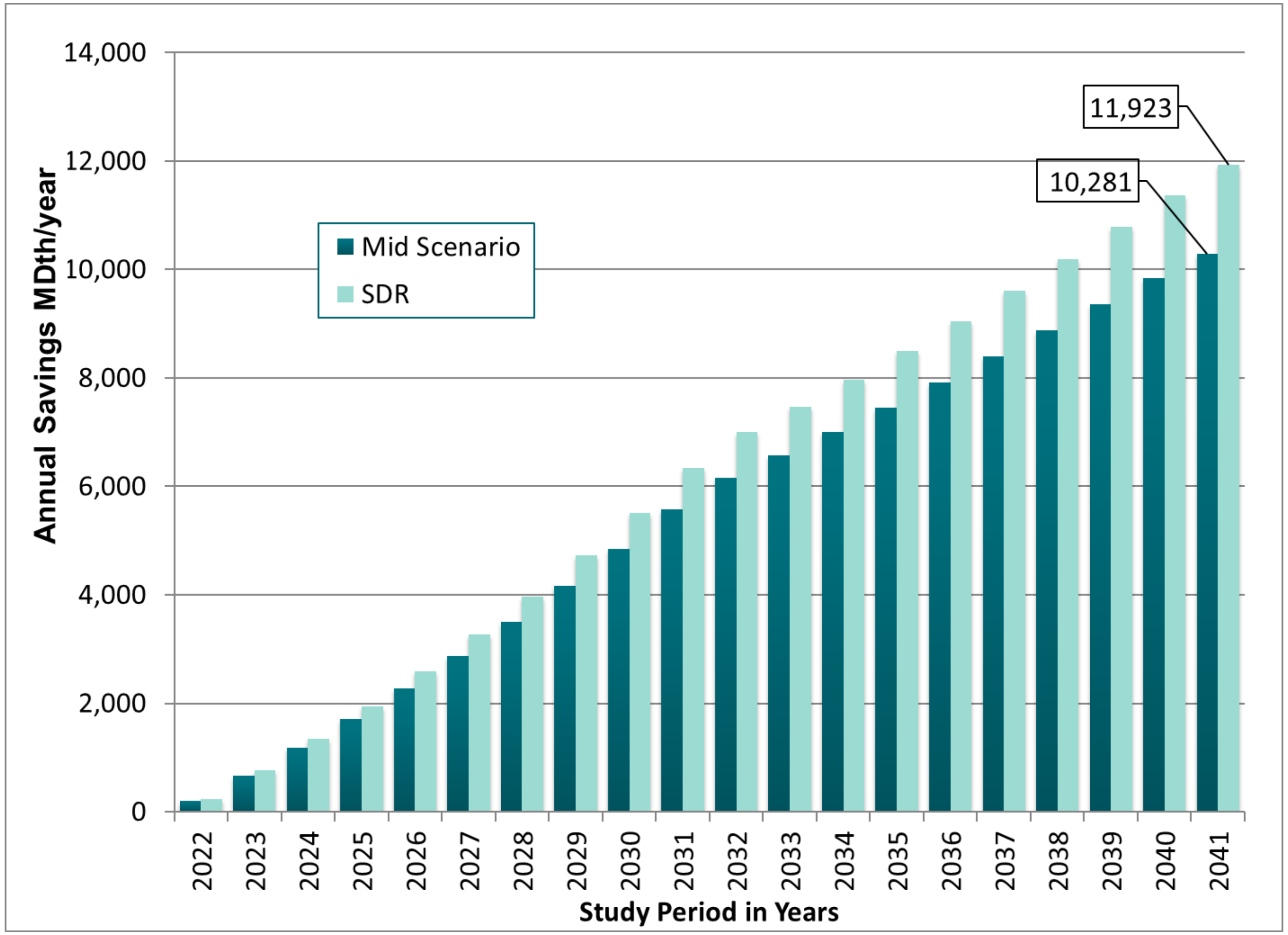
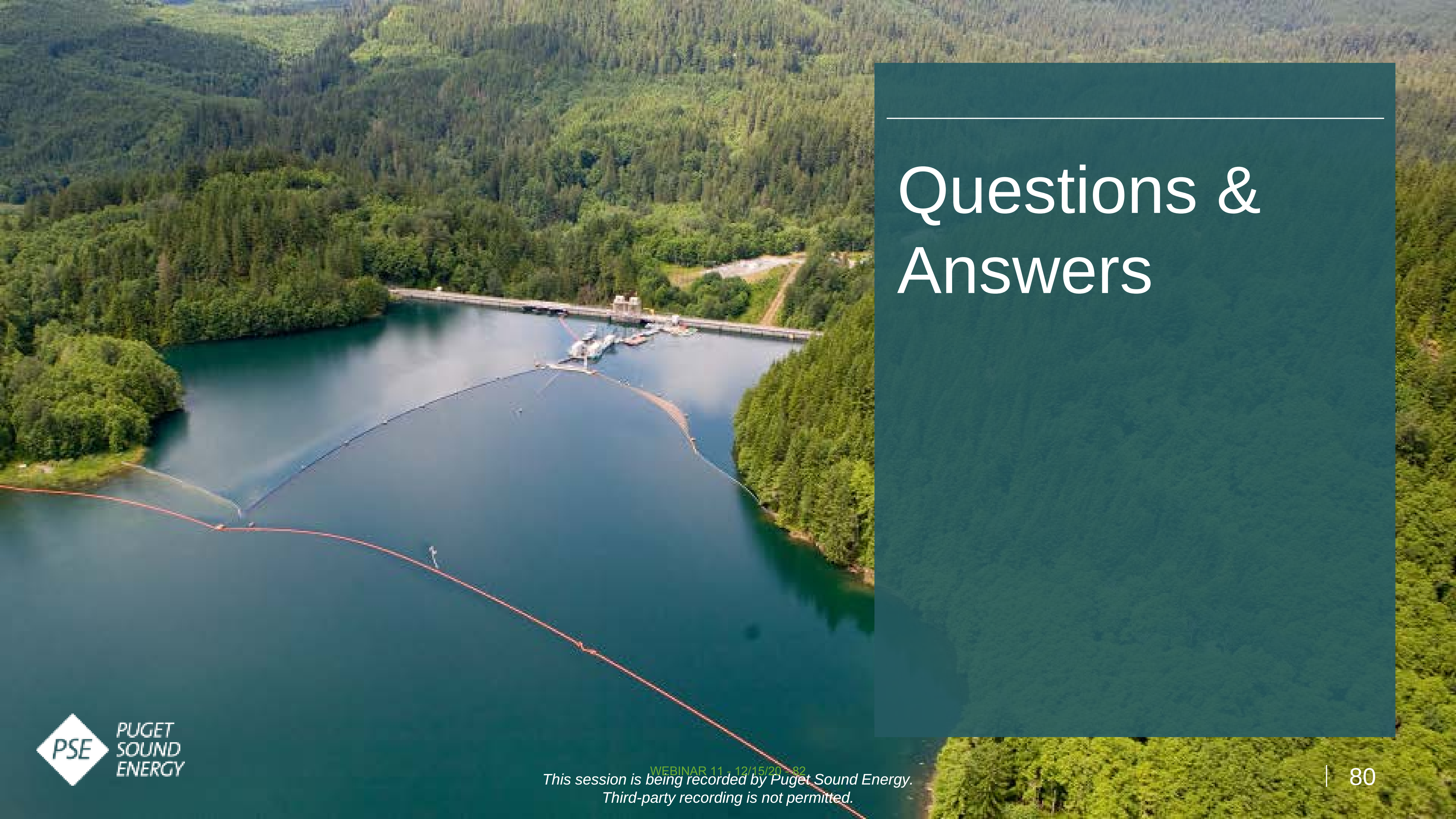
Draft sensitivity results – SDR



SDR was lower bundle 7 than Mid scenario bundle 9, but slightly higher savings.

Draft 2021 IRP gas portfolio - conclusions

- Cost effective conservation is “sticky” - same in the three scenarios
- Higher total gas costs are driving cost effective conservation higher on the conservation supply curve
- PSE is long and does not need incremental new supply side resources to meet resource need.

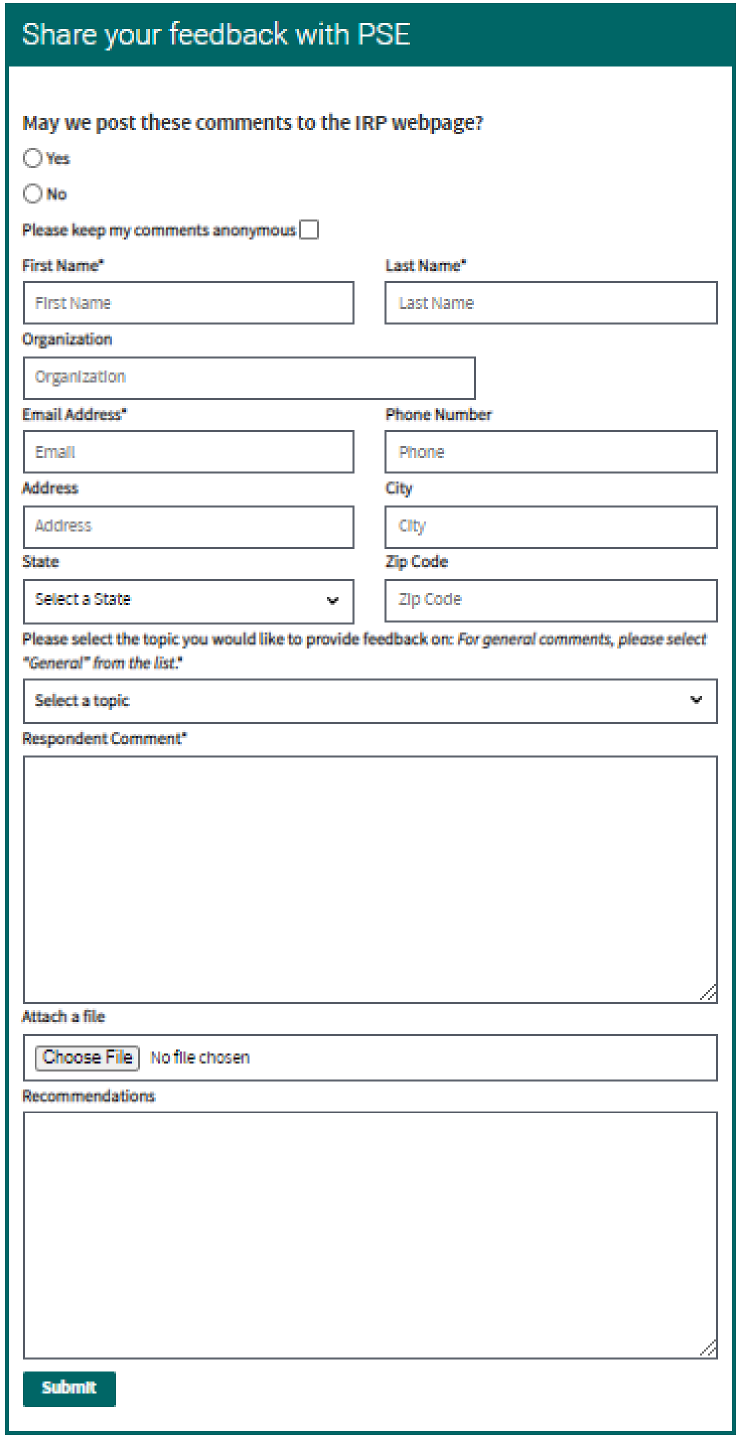


Questions & Answers

This session is being recorded by Puget Sound Energy.
Third-party recording is not permitted.

Feedback Form

- An important way to share your input
- Available on the website 24/7
- Comments, questions and data can be submitted throughout the year, but timely feedback supports the technical process
- Please submit your Feedback Form <u>within a week of the meeting topic.</u>



Share your feedback with PSE

May we post these comments to the IRP webpage?

- Yes
- No

Please keep my comments anonymous

First Name* — First Name
Last Name* — Last Name
Organization — Organization
Email Address* — Email
Phone Number — Phone
Address — Address
City — City
State — Select a State
Zip Code — Zip Code

Please select the topic you would like to provide feedback on: *For general comments, please select "General" from the list.**

Select a topic

Respondent Comment*

Attach a file — Choose File No file chosen

Recommendations

Submit

Feedback Form → **Feedback Report** → **Consultation Update**

Next steps

- Submit Feedback Form to PSE by **December 28, 2020.**
- A recording and the chat from today's webinar will be posted to the website **tomorrow**
- PSE will compile all the feedback in the Feedback Report and post all the questions by **January 11, 2021.**
- The Consultation Update will be shared on **January 19, 2021.**

Upcoming meetings and key dates

Date	Topic
January 4, 2021	DRAFT 2021 Electric and Natural Gas IRP filed with the WUTC
February 10, 2021 1:00 – 5:00 pm	Wholesale market risk Portfolio draft results Delivery System Planning: 10-year distribution & transmission plan solutions with non-wire alternatives
March 5, 2021 1:00 – 5:00 pm	Stochastic analysis Resource plan Clean Energy Action Plan
April 1, 2021	FINAL 2021 Electric and Natural Gas IRP filed with the WUTC

Details of upcoming meetings can be found at pse.com/irp

Thank you for your attention and input.

Please complete your Feedback Form by December 28, 2020

We look forward to your attendance at PSE’s next public participation webinar on February 10, 2020

Electric Appendix

Demand side resources total savings

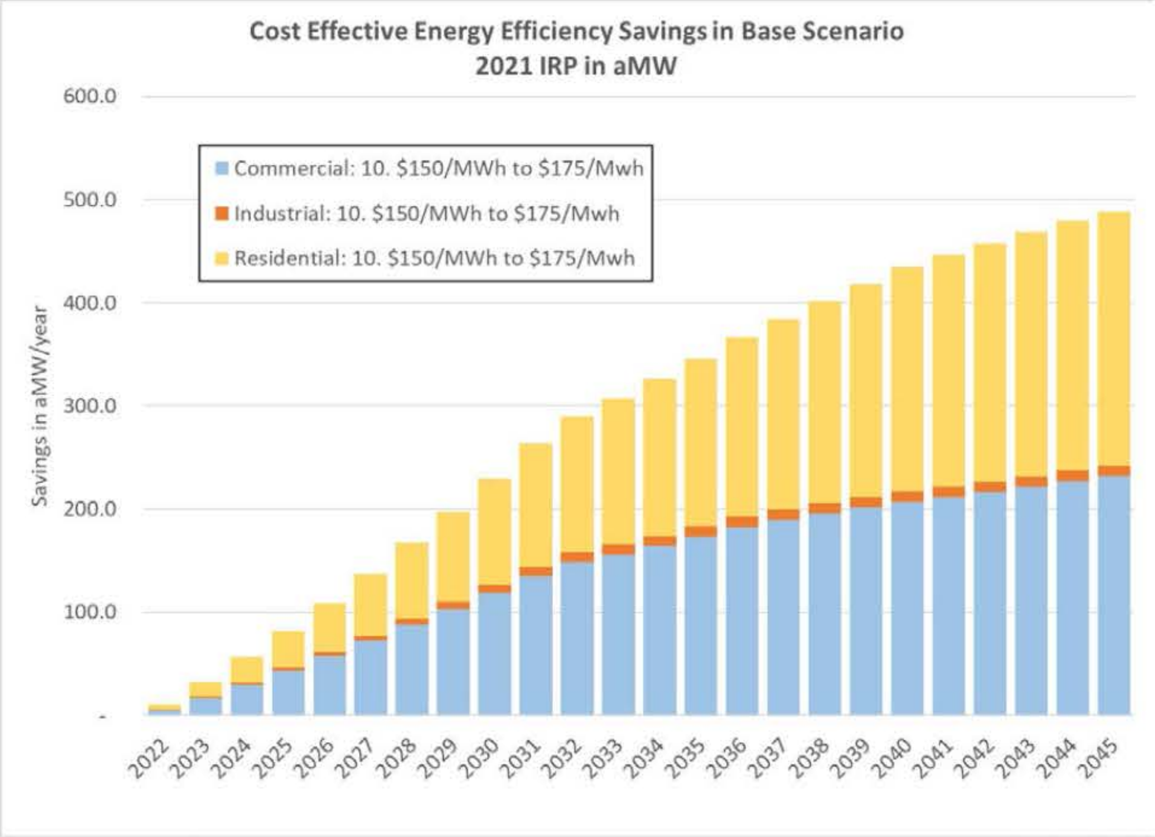
Electric draft demand side resources include:

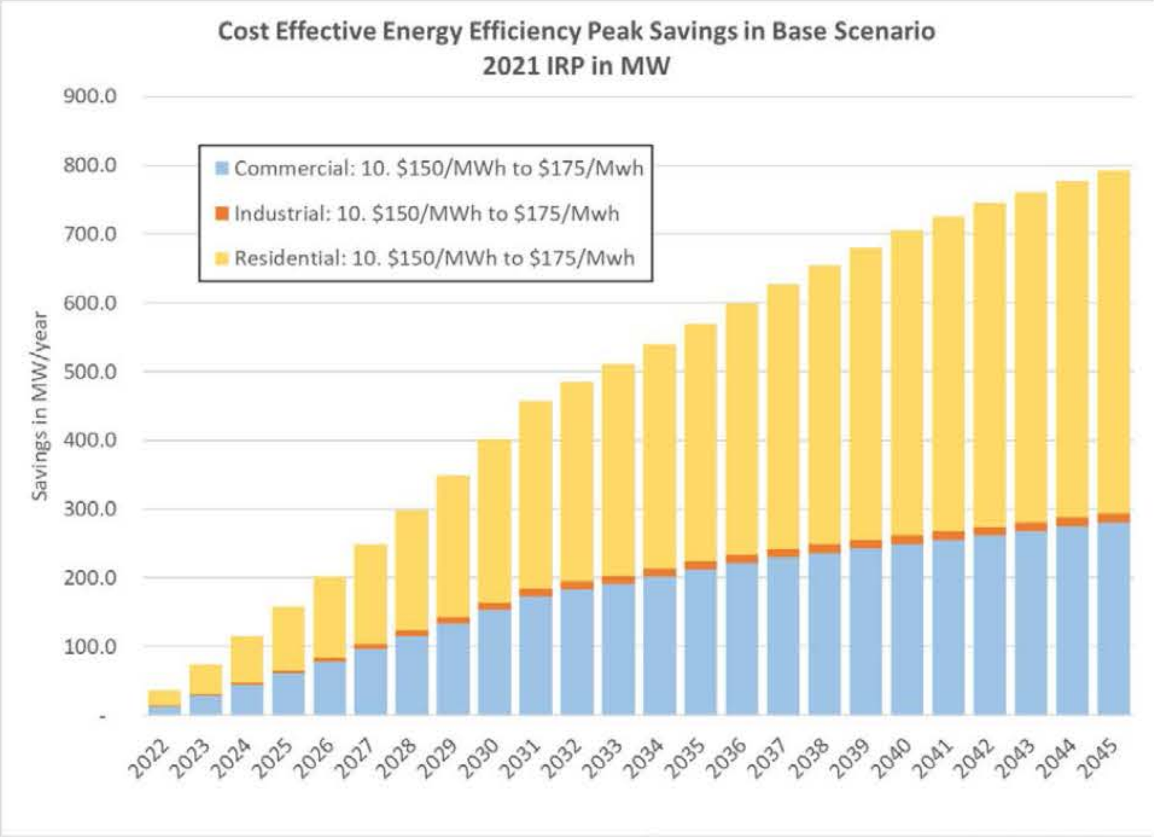
- Energy efficiency
- Conservation up to bundle 10 ($175/MWh)
- Distributed generation
- Distribution Efficiency

ELECTRIC	2017 IRP Electric CE Results			2021 IRP Electric DRAFT Mid Scenario Results		
Cost Effective DSR - Electric	**Total Energy (MWh)**	**Average Energy (aMW)**	**DR Capacity (MW)**	**Total Energy (MWh)**	**Average Energy (aMW)**	**DR Capacity (MW)**
20-Year Potential	2,336,387	267	114	4,080,018	466	111
10-Year Potential	1,799,149	205	107	2,423,908	277	36
2-Year Potential	358,547	41	25	293,248	33	0

PUGET SOUND ENERGY

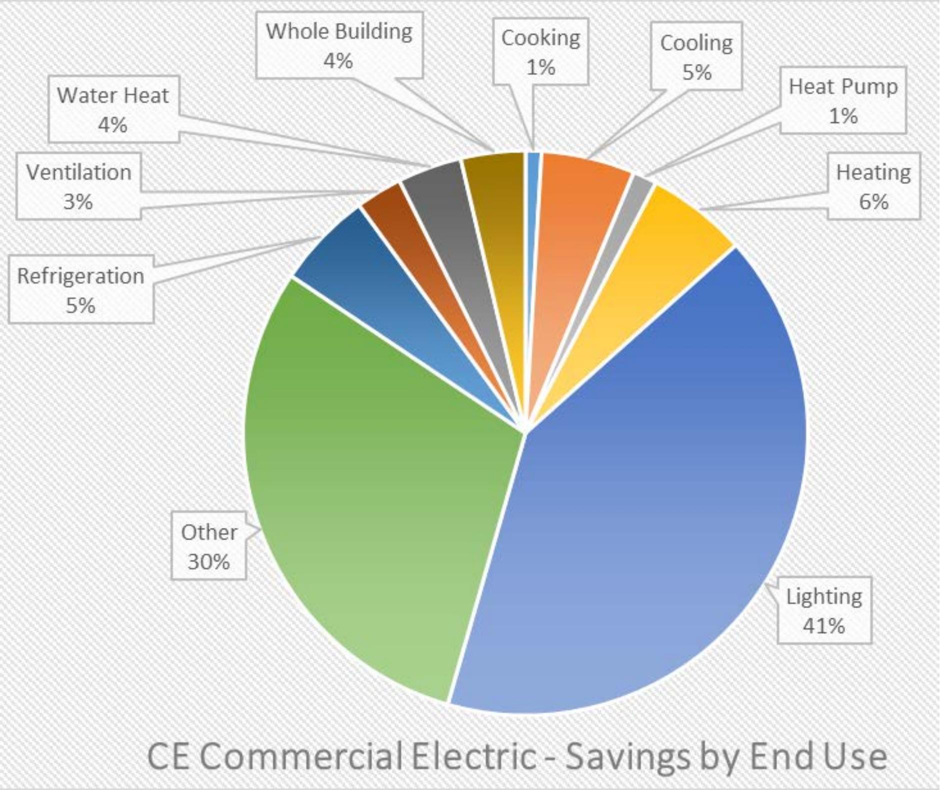
Cost effective energy efficiency savings by sector

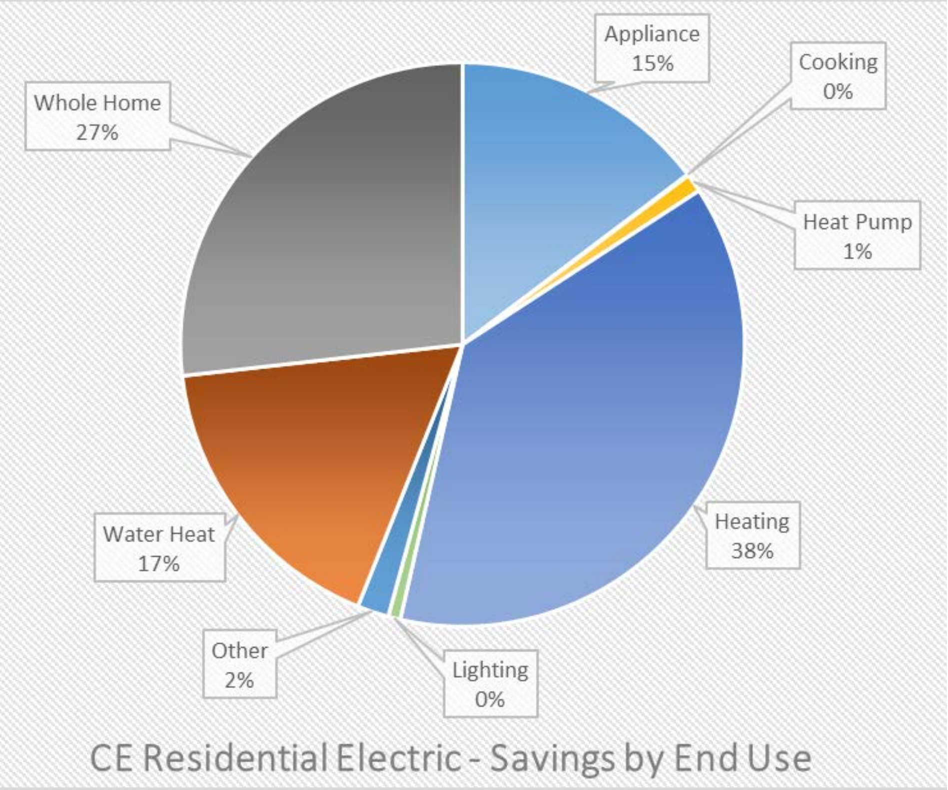




PUGET SOUND ENERGY

Cost effective conservation by end use



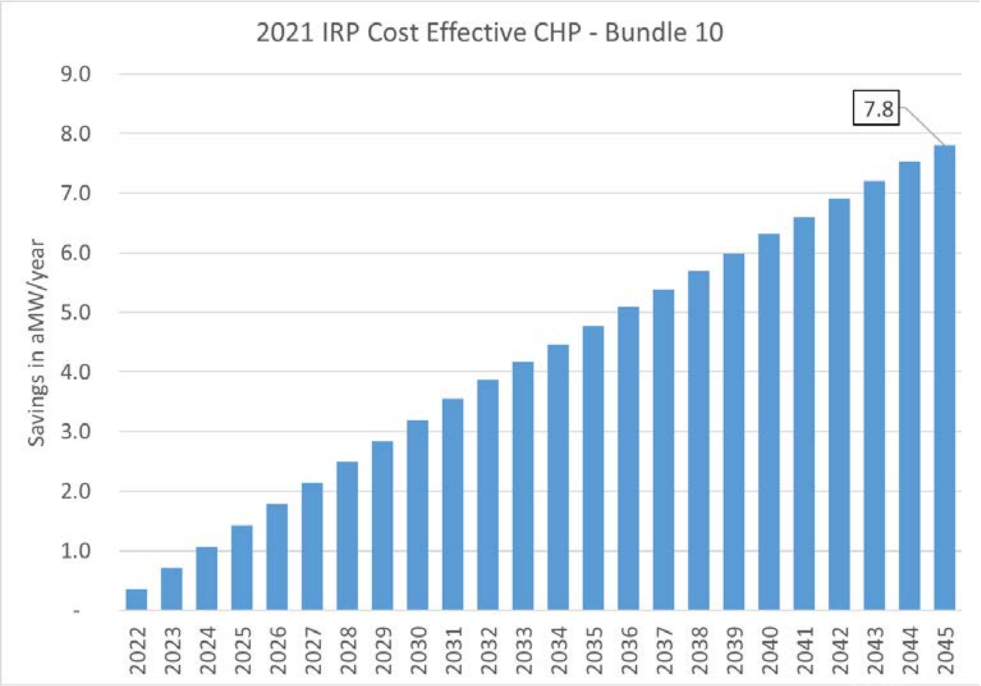


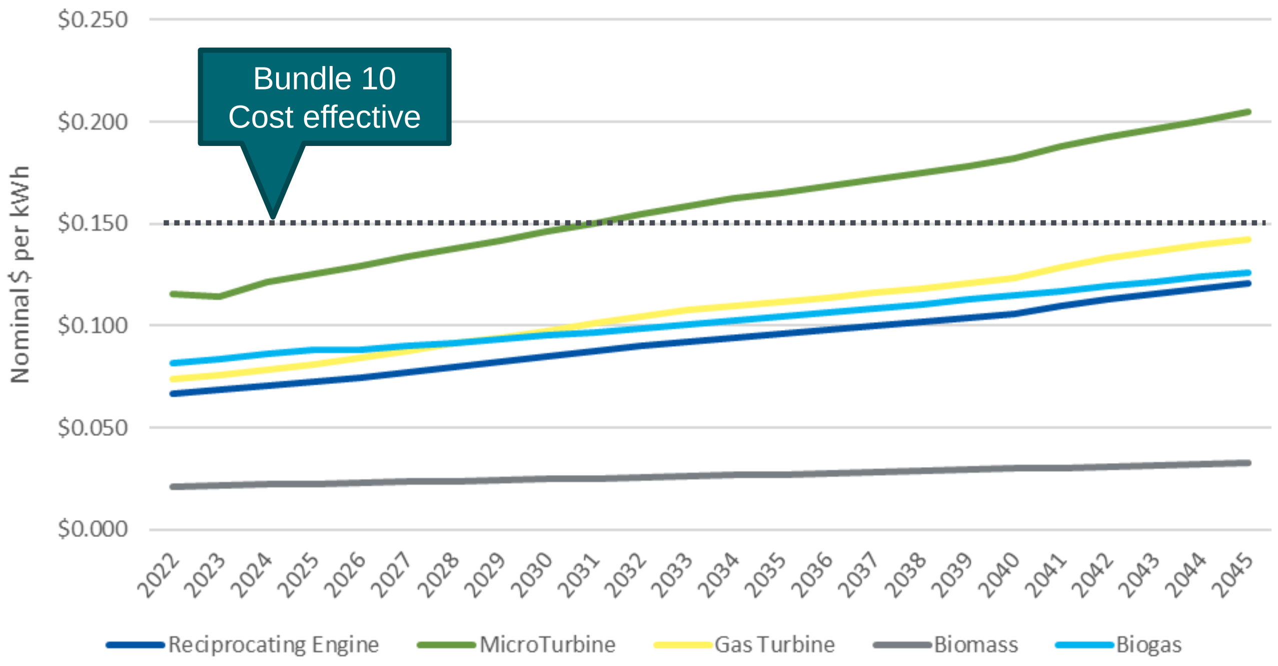
- Most savings are derived from lighting
- Space heating, water heating, and refrigeration make up an additional 15% of savings
- Other category includes: wastewater, pumps, and pool covers and pumps

- Heating, appliances, water heating and whole home in new construction are main areas for residential measures
- Lighting savings are small in comparison to the commercial sector

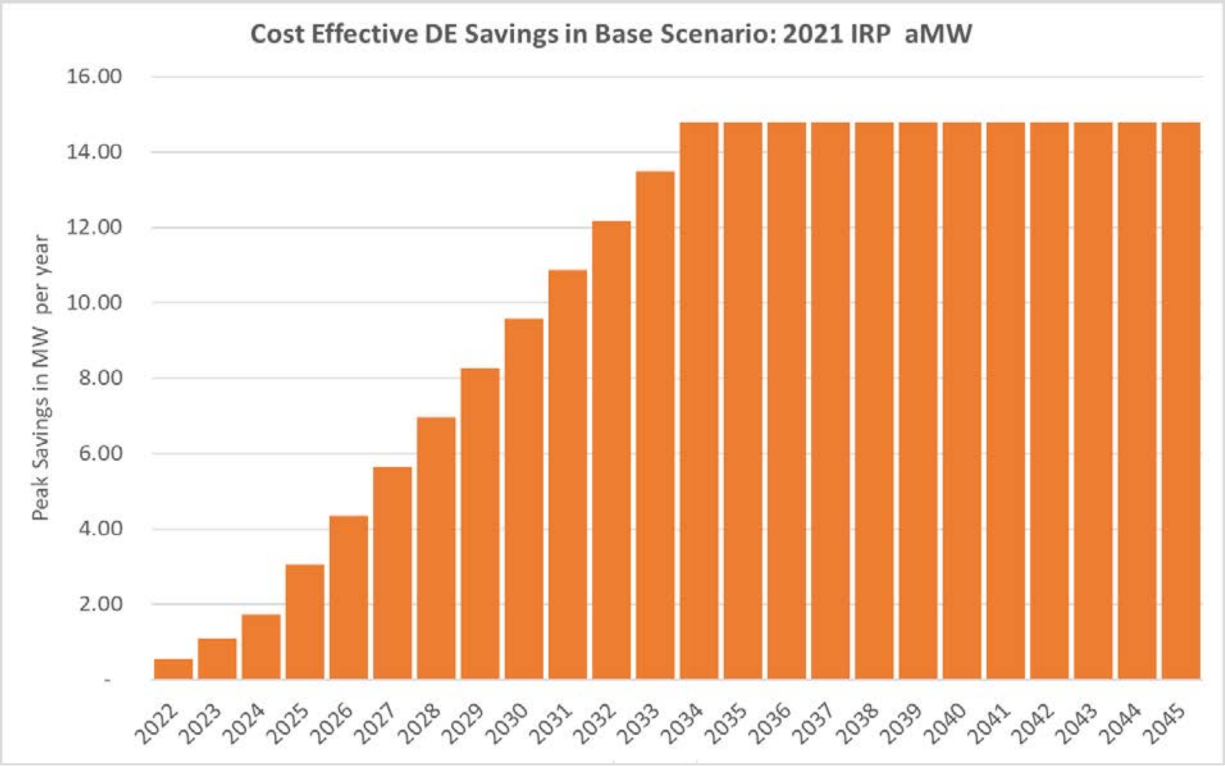
PSE PUGET SOUND ENERGY

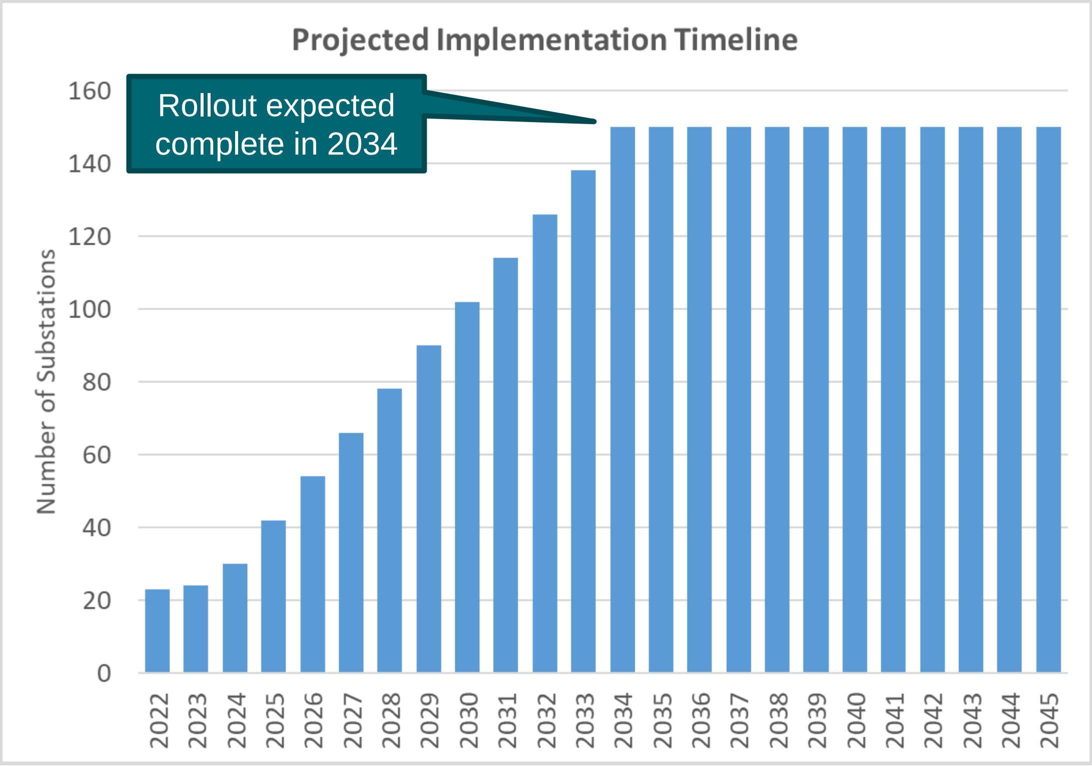
Combined Heat & Power (CHP) contributes to cost-effective DSR





Distribution Efficiency peak savings are realized by 2034





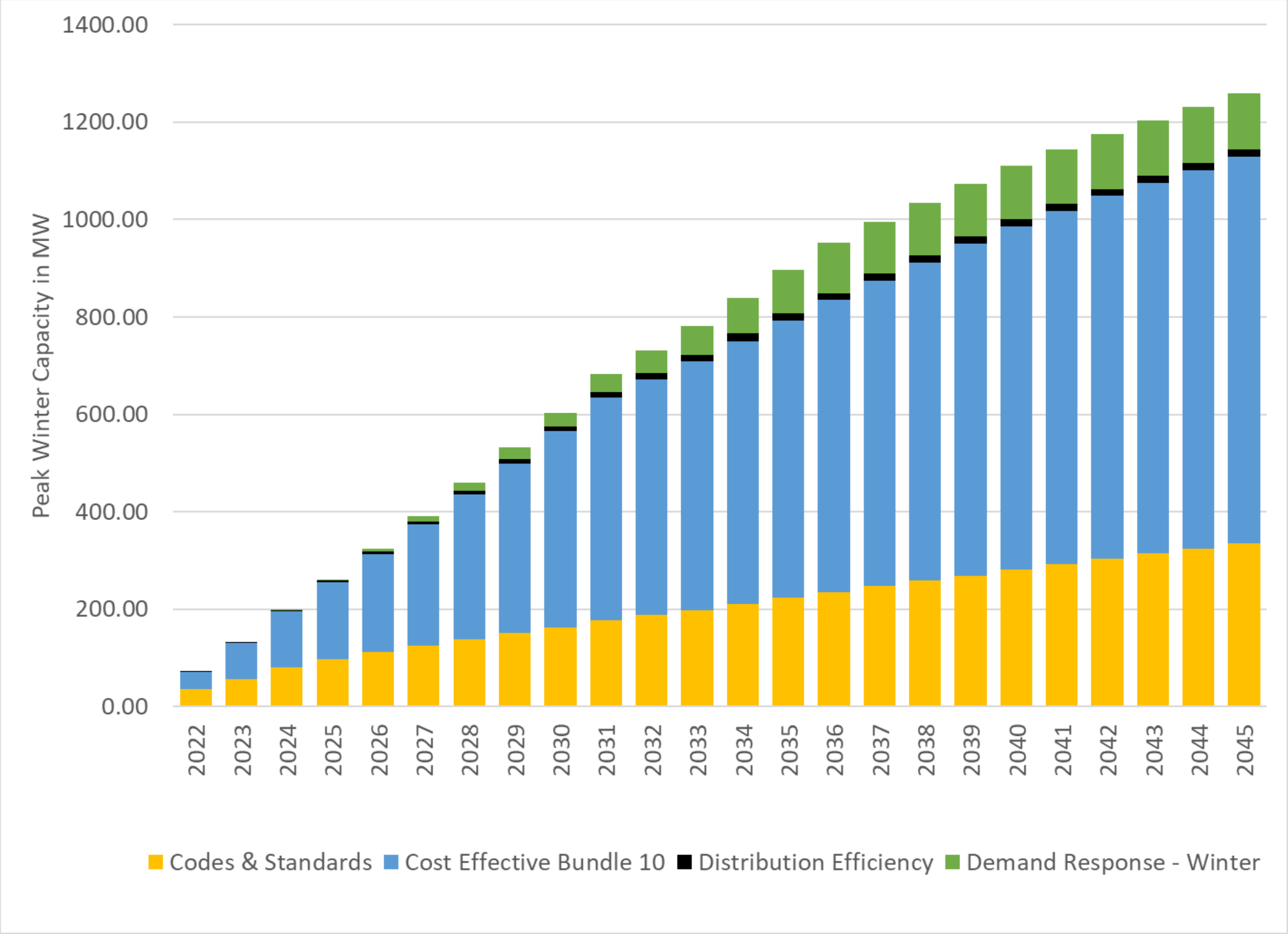
Distribution efficiency savings are based on Volt-Var optimization with Automated Distribution Management System (ADMS) and Advanced Metering Infrastructure (AMI)

Rollout schedule on substations, identified as eligible for CVR application, is expected to be complete in 2034

Annual renewable resource additions

Incremental Resource Additions		WA Wind	MT Wind East	MT Wind West	ID Wind	WY Wind East	WY Wind West	Offshore Wind	Total Wind	WA Solar East	WA Solar West	ID Solar	WY Solar Anticline	WY Solar West	Total Solar
2022 - 2025 Colstrip and Centralia Retire in 2025	**2022**	-	-	-	-	-	-	-		-	-	-	-	-	
	2023	-	-	-	-	-	-	-	**400**	-	-	-	-	-	**-**
	2024	-	-	-	-	-	-	-		-	-	-	-	-	
	2025	-	200	200	-	-	-	-		-	-	-	-	-	
2026 - 2030 CETA 80% Renewable Requirement in 2030	**2026**	-	-	-	-	400	-	-		-	-	-	-	-	
	2027	-	-	-	-	-	-	-		-	-	-	-	-	
	2028	200	-	-	-	-	-	-	**800**	299	-	-	-	-	**697**
	2029	-	-	-	-	-	-	-		299	-	-	-	-	
	2030	200	-	-	-	-	-	-		100	-	-	-	-	
2031-2045 CETA 100% Renewable Requirement in 2045	**2031**	100	-	-	-	-	-	-		-	-	-	-	-	
	2032	200	-	-	-	-	-	-		-	-	-	-	-	
	2033	100	-	-	-	-	-	-		-	-	-	-	-	
	2034	100	-	-	-	-	-	-		-	-	-	-	-	
	2035	200	-	-	-	-	-	-		-	-	-	-	-	
	2036	200	-	-	-	-	-	-		-	-	-	-	-	
	2037	100	-	-	-	-	-	-		100	-	-	-	-	
	2038	100	-	-	-	-	-	-	**2550**	100	-	-	-	-	**699**
	2039	200	-	-	-	-	-	-		-	-	-	-	-	
	2040	-	-	-	-	-	-	-		100	-	-	-	-	
	2041	200	-	-	-	-	-	-		-	-	-	-	-	
	2042	200	-	-	-	-	-	100		-	-	-	-	-	
	2043	100	-	-	-	-	-	100		-	200	-	-	-	
	2044	-	350	-	-	-	-	-		100	100	-	-	-	
	2045	100	-	-	-	-	-	100		-	-	-	-	-	
Grand Total		**2300**	**550**	**200**	**-**	**400**	**-**	**300**	**3750**	**1096**	**300**	**-**	**-**	**-**	**1396**

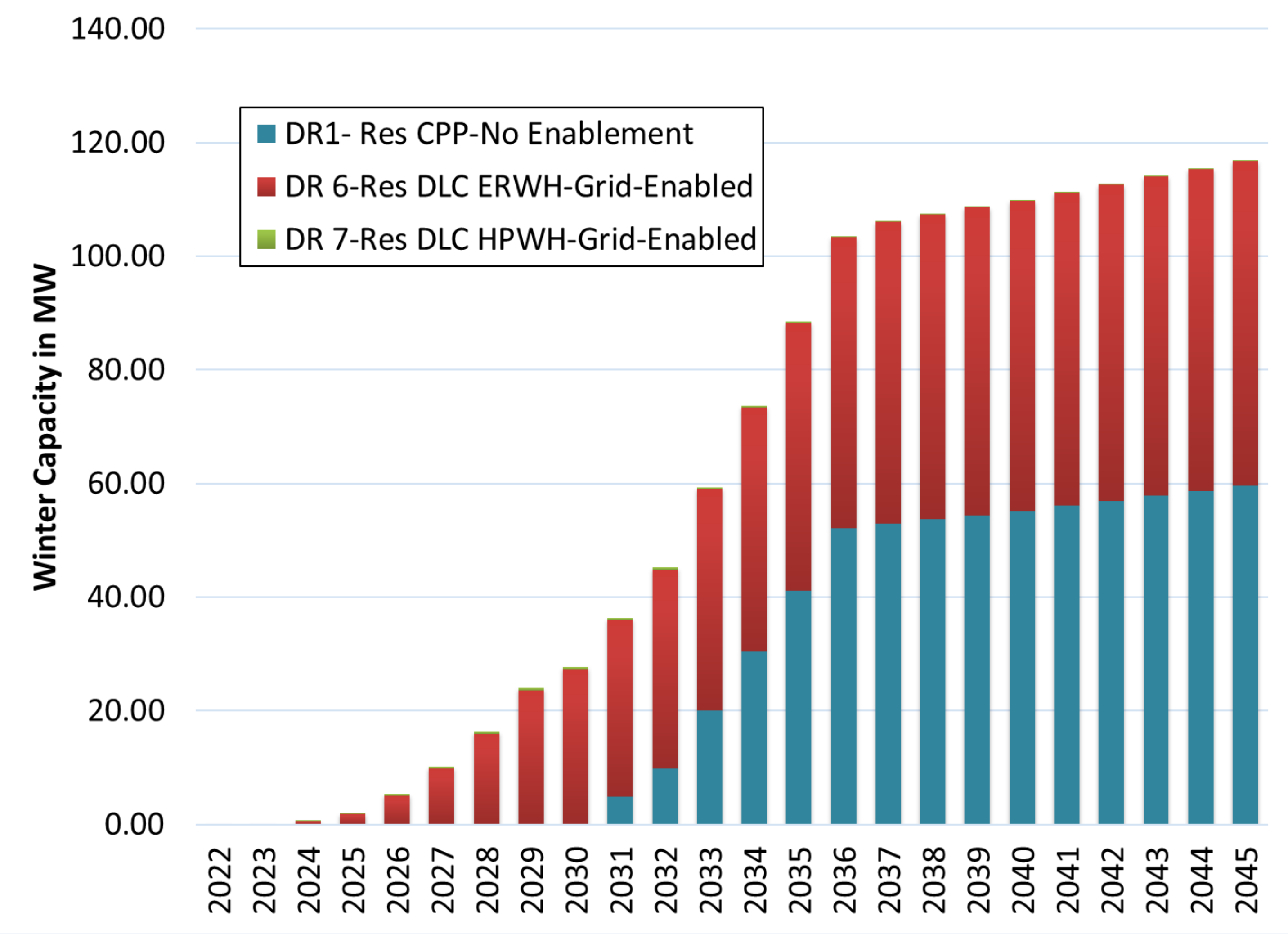
Demand-side resources total peak capacity savings



Electric draft demand-side resources include:

- Codes & Standards
- Conservation savings up to bundle 10 ($175/MWh)
- Distribution Efficiency
- Demand response

Three demand response programs were selected from the sixteen modeled



The portfolio optimization model selected 3 Demand Response programs in the mid portfolio:

- DR 1 Residential critical peak price
- DR 6 Residential direct load control (electric residence water heater)
- DR 7 Residential direct load control (heat pump water heater)

Grid-enabled refers to a two way communication with grid.

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Flexibility Analysis Appendix

PUGET SOUND ENERGY

Creating sub-hourly data inputs

Demand forecast

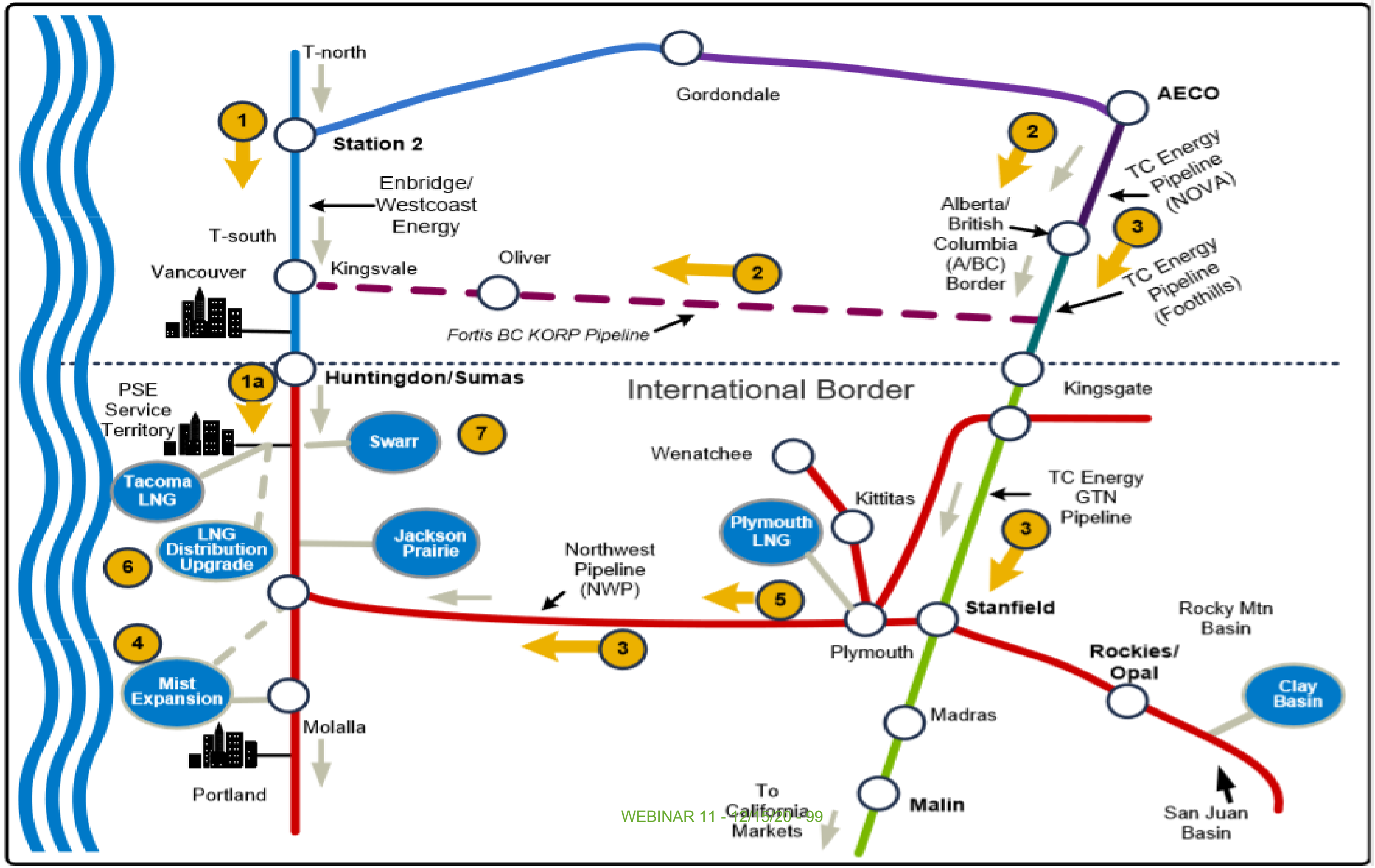
- Demand forecast was input into Plexos using the monthly energy need (MWh) and peak need (MW).
- Using the Boundary Interpolate method, Plexos extrapolated the hourly and 15-minute loads.
- PSE used the historical load shape from 2017 to create the 15-minute loads.

Power prices

- Aurora is run as an hourly model, so the hourly electric price forecast from the mid scenario as input into Plexos. This was used for the Mid-C day ahead and hourly market sales and purchases.
- Using the Step Method, Plexos extrapolated the 15-minute electric prices for the EIM market.

Natural Gas Appendix

Resource alternatives - schematic



2021 IRP CPA - low income customers

- The CPA identified Low Income customers from 2017 Residential Characteristics Survey (RCS) data and the qualifying income from PSE's Weatherization Assistance program.

Segment	Electric Low Income Customers as a Percent of Total Electric Housing Segment Customers
Single Family	9.1%
Multifamily	8.3%
Manufactured	11.3%

- Levelized cost for low income customers used a lower benefit cost ratio adjustment
- The achievable technical potential associated with Low Income customers:

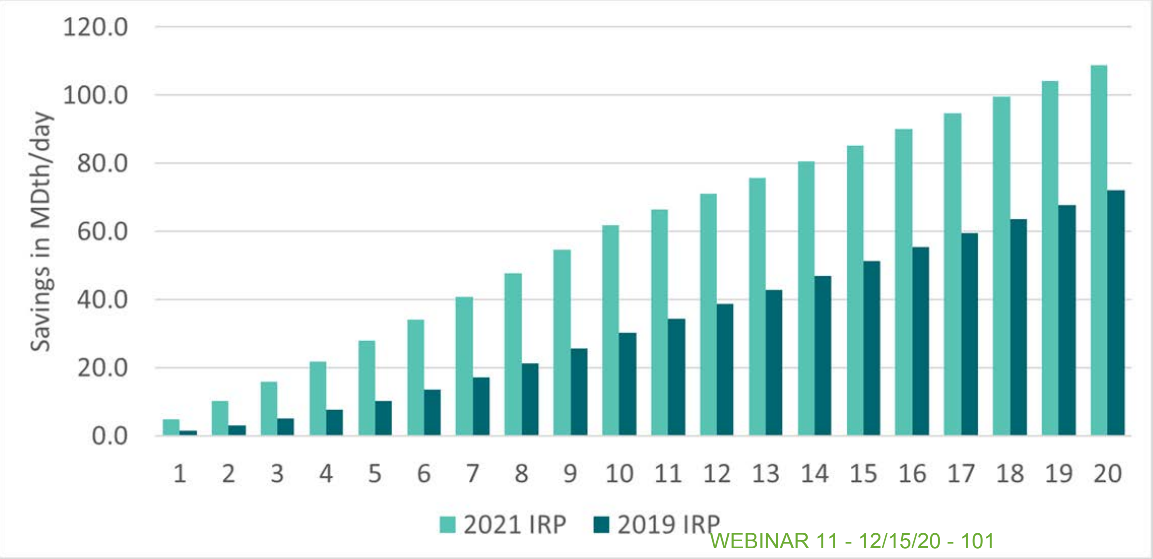
Segment	Cumulative 10-Year Achievable Technical Potential (MM Therms)	Cumulative 20-Year Achievable Technical Potential (MM Therms)
Single Family - Low Income	8.6	13.8
Multifamily - Low Income	2.7	5.0
Manufactured - Low Income	0.2	0.4
Total	**11.6**	**19.2**

Cost effective DSR results comparisons: 2017, 2019 vs 2021 IRP

- Cost effective DSR for gas: 2017 Base vs 2021 IRP draft Mid Scenario

Cost Effective DSR- GAS	2017 IRP	2021 IRP DRAFT - Mid Scenario
20-Year Potential	54,096,456	102,807,113
10-Year Potential	30,778,000	55,775,135
2-Year Potential	6,155,000	6,690,013

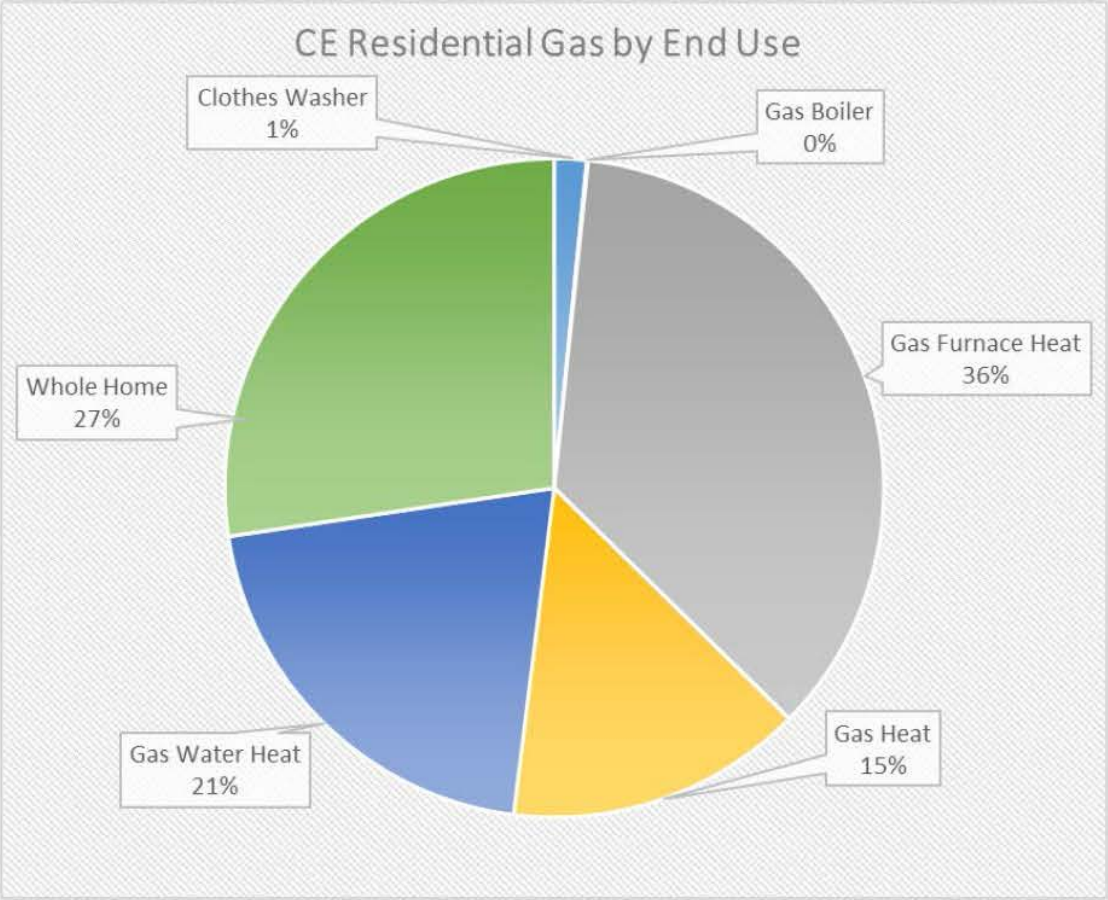
- Cost effective DSR for gas: 2019 IRP process vs 2021 IRP draft Mid Scenario

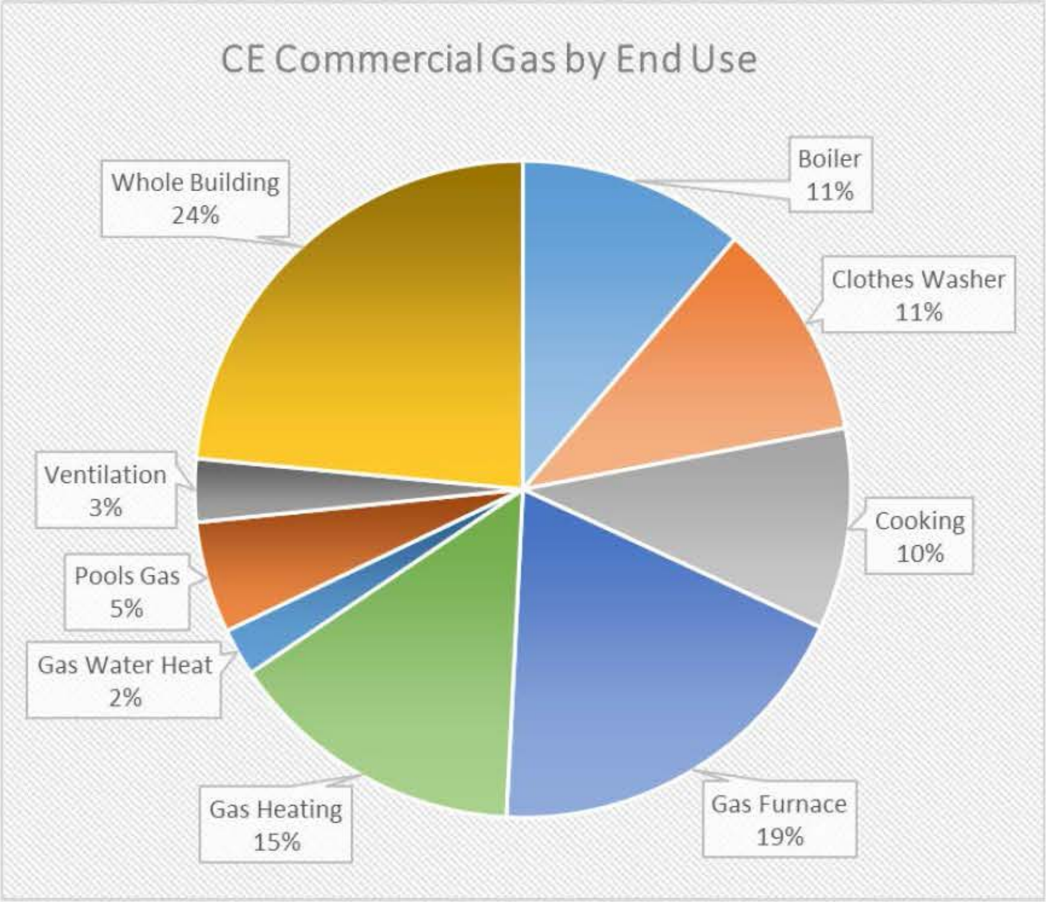


2017 IRP –
- Lower carbon adders
- Lower achievable technical potential
- Picked lower bundle

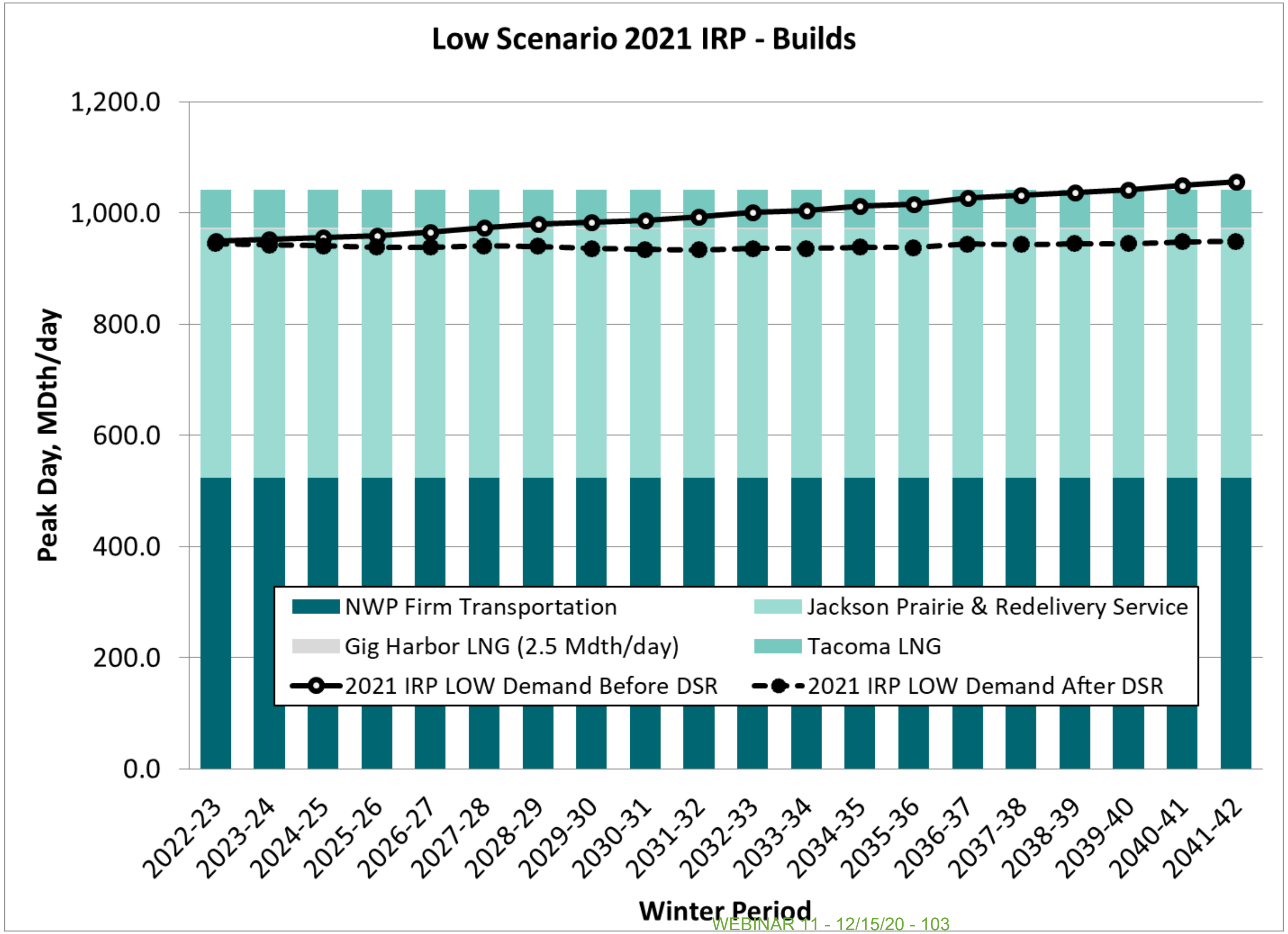
2019 IRP-
- Higher achievable technical potential
- Similar bundle cost point selected

Draft mid scenario – cost effective savings by end use





Draft Low scenario – DSR more than sufficient to meet need

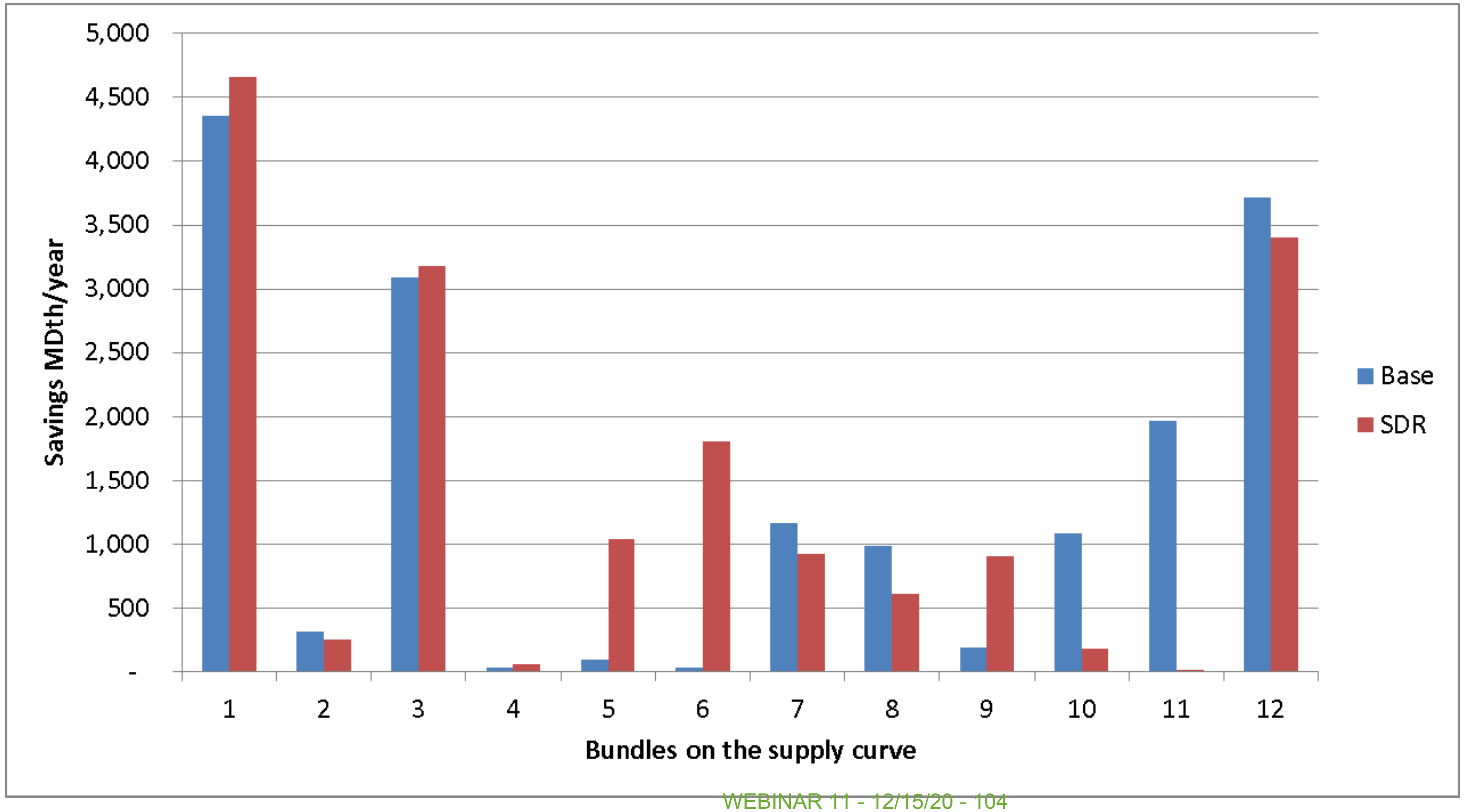


First resource need occurs in 2040-41 winter of 14 MDth/day

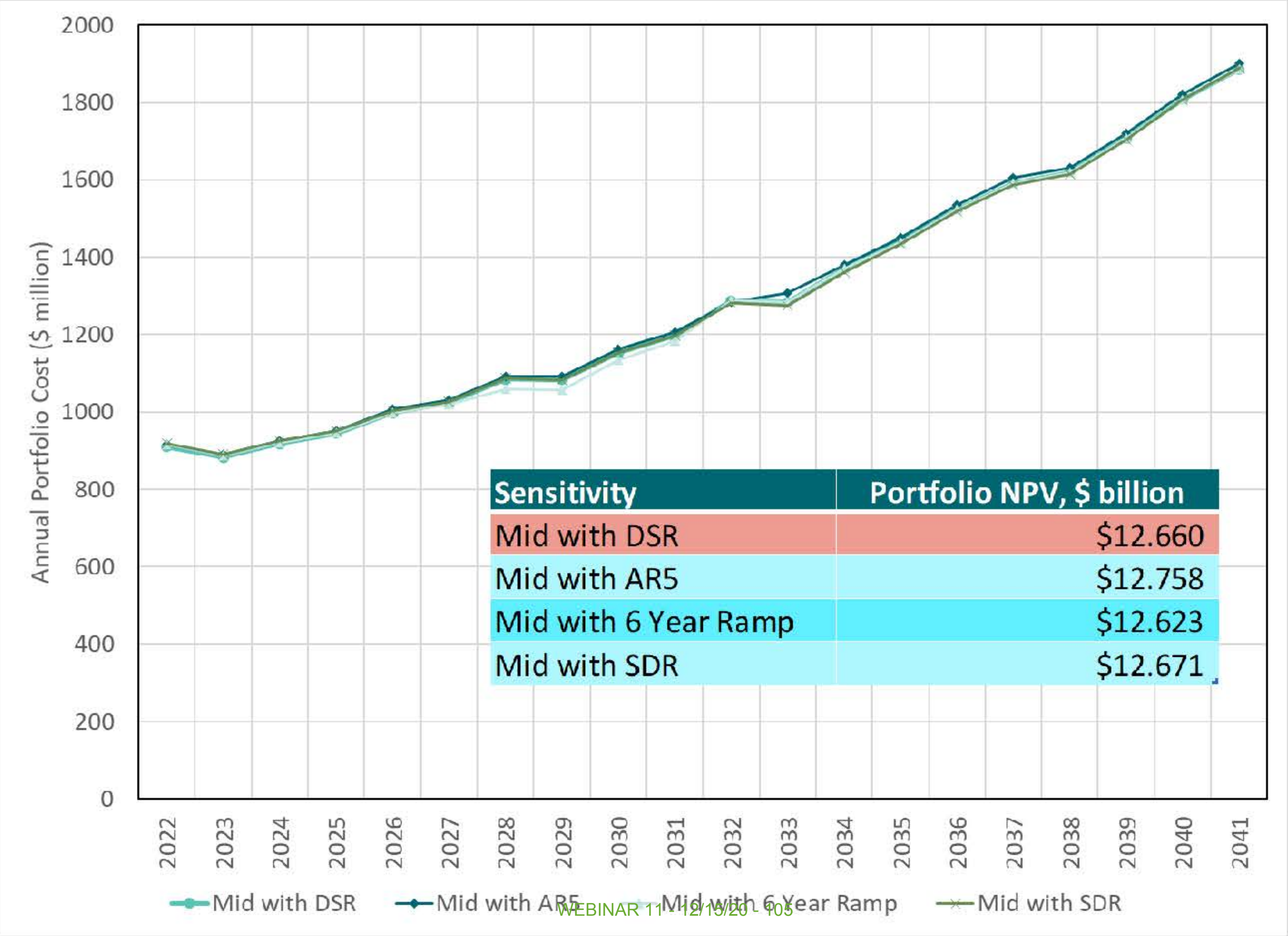
Same amount of cost effective DSR as in Mid scenario is selected by gas portfolio model

Draft sensitivity results – social discount rate (SDR)

- Inputs:
  - Used a SDR of 2.5%
  - Used the 10 year ramp
  - Measure shifted to lower cost bundles



Draft sensitivity results – portfolio costs



Sensitivity	Portfolio NPV, $ billion
Mid with DSR	$12.660
Mid with AR5	$12.758
Mid with 6 Year Ramp	$12.623
Mid with SDR	$12.671

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2021 IRP SENSITIVITY LIST

EXCEL SPREADSHEET

Click this link to download the spreadsheet:

https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/December_15_Webinar/Webinar%2011%20Updated%20Sensitivity%20List.xlsx

Webinar #11: Flexibility analysis & Portfolio draft results

12/16/2020

Overview

On December 15, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss the Flexibility analysis and Portfolio draft results. Additionally, participants were able to ask questions and make comments using a chat box provided by the Go2Meeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 79 stakeholders and PSE staff attended the webinar, plus another 9 attendees who called into the meeting and did not identify themselves (88 people total).

Attendees included: Alison Peters, Andrew Padula, Anne Newcomb, Barret Stambler, Bill Donahue, Bill Westre, Bob Stolaski, Bob Williams, Brett Rendina, Brian Tyson, Brian Grunkemeyer, Bruce Boram, C Bunch, Camerson Yourkowski, Cathy Koch, Charlie Black, Charlie Inman, Cody Duncan, Corey Kupersmith, Corina Pfeil, Court Olson, Cuong Nguyen, David Meyer, David Tomlinson, Diann Strom, Dillon Stambler, Don Marsh, Doug Howell, Elise Johnson, Elizabeth Hossner, Elyette Weinstein, Eric Markell, Fred Heutte, Gurvinder Singh, Horea Catanase, Irena Netik, James Adcock, Jennifer Magat, Jessica Raker, John Fazio, Jon Piliaris, Joni Bosh, Kara Durbin, Katherine Kissinger, Katie Ware, Kendra White, Kelly Xu, Kevin Jones, Kyle Frankiewich, Larry Becker, Leslie Carlson, Lori Elworth, Lorin Molander, Mark Lenssen, Matthew Shapiro, Michele Kvam, Nate Sandvig, Norm Hansen, Patrick Leslie, Rahul Venkatesh, Rob Briggs, Ron Roberts, Ryan Sherlock, Sarah Laycock, Scott Thomas, Scott Williams, Stephanie Chase, Steve Greenleaf, Therese Miranda-Blackney, Tom Eckman, Tracy Rolstad, Tyler Tobin, Virginia Lohr, Virginia Wiseman, Warren Halverson, Wendy Gerlitz, Wiemin Dang, Zac, and Zhi Chen

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 1:00 PM PDT and ended at 5:00 PM PDT.

Name	Time Sent	Comment
Don Marsh	**1:03 PM**	I'm aware of people waiting to get into the meeting.
Virginia Lohr	**1:03 PM**	The ink you sent out is not working!
Virginia Lohr	**1:04 PM**	The LINK does not work
Elise Johnson	**1:05 PM**	Hi Virginia! Is this the meeting link you're referring to?
Virginia Lohr	**1:05 PM**	The link sent out if your registered is wrong and says waiting for host to open. that is probably where people are waiting.
Don Marsh	**1:07 PM**	Court Olson and Fred Heutte have not been able to join.
Kyle Frankiewich	**1:07 PM**	the link on PSE's public-facing IRP website worked for me: **https://pse-irp.participate.online/get-involved**
Virginia Lohr	**1:07 PM**	https://global.gotomeeting.com/join/413142693. This is the bad link you sent out.
James Adcock	**1:08 PM**	How about this one: https://global.gotomeeting.com/join/255497885
Alison Peters	**1:09 PM**	Yes, James. That's the right link.
Michele Kvam	**1:09 PM**	Thank you, Jim! That is the correct link.
Elise Johnson	**1:09 PM**	Thanks for letting us know, all. We will send out an email with the correct link ASAP.
Doug Howell	**1:12 PM**	Would you please make note when there are changes in the slides that were release last week versus what is being used today?
James Adcock	**1:13 PM**	Whether or not I had a proper amount of time to develop my questions, I did ask a lot of question, because the slides for this meeting I found to be particularly confusing. I hope you will actually answer my questions so that we can all attempt to answer your slides.
Elise Johnson	**1:14 PM**	An email is now being sent with the correct link. Thank you, all!
James Adcock	**1:14 PM**	Sorry "so we call all attempt to *understand* your slides."
Elise Johnson	**1:18 PM**	Hi Doug! The slide deck being used today can now be found on the PSE IRP website at the following link: https://oohpseirp.blob.core.windows.net /media/Default/2021/meetings/December_15_Webinar/Webinar%2011 %20-%20Presentation.pdf
Kyle Frankiewich	**1:21 PM**	slide 15: I'm guessing that when the bars are higher than the CETA target, that represents overgeneration that comes with lots and lots of renewables. Is this correct?
Joni Bosh	**1:23 PM**	slide 16. Please repeat - does the red represent new peak gas plants?
Kyle Frankiewich	**1:23 PM**	slide 16: Is the NG in 2045 within line losses or why is there still NG in 2045?
Joni Bosh	**1:25 PM**	18 DOes the carbon price include the SCGHG?
Kyle Frankiewich	**1:26 PM**	slide 18: is this out-of-model or are RECs pinned to the CA market forecast selectable within the LTCE model?
James Adcock	**1:27 PM**	Slide 18 Question: Given that California is a "Double Counting" state that does not require the retirement of RECs used for "government mandates" -- unlike the definition of "RECs" used in CETA and by the EPA, why does it make sense to use Californian Carbon Prices? Shouldn't the use of Californian [fake] RECs be prohibited for CETA purposes? Shouldn't the price of "Real" RECs -- RECs meeting the definitional requirements of CETA and the EPA -- be higher in price?

James Adcock	**1:30 PM**	Slide 16 Question: Where do you think you can get that much Biomass ???
Fred Heutte	**1:30 PM**	On slide 16: what resources are included in "peaking capacity"
Kyle Frankiewich	**1:33 PM**	Elise, I think you may have missed Joni's and my Qs on slide 16
Kyle Frankiewich	**1:33 PM**	i’m comfortable coming back at the next pause
Charlie Black	**1:35 PM**	What price forecast for CARB GHG emissions allowances did PSE use?
Don Marsh	**1:35 PM**	Question on slide 21. Why are the numbers for DR and DER so tiny?
Don Marsh	**1:36 PM**	Those numbers seem very small compared to other utilities pursuing DR and DER.
Anne Newcomb	**1:37 PM**	Can more wind come online sooner? Before 2025?
Doug Howell	**1:37 PM**	How maximize existing gas instead of acquiring new?
R. C. Olson	**1:38 PM**	Are you assuming Market resources are fossil based?
James Adcock	**1:39 PM**	Slide 23 Question: You are showing a hypothetical future load "Jan 2 - Jan 4 2030" -- how exactly are you creating this future hypothetical load schenario?
Brian Grunkemeyer	**1:39 PM**	Slide 23: How can we be sure the market will be there if there is a substantial cold event affecting say most of the state? And would DR be your preferred option to meet peaking capacity?
Don Marsh	**1:40 PM**	I have a number of questions on slide 23. Best to ask them interactively I think.
Nate Sandvig	**1:40 PM**	How much of this market is out of region?
Bill Westre	**1:40 PM**	S-23 You currently have nearly 200MW of CCCT and peaker power. What justifies the new paekers?
Alison Peters	**1:40 PM**	Question from Nate S; how much of market is out of region?
Bill Westre	**1:41 PM**	S-24 I meant 2000MW
Nate Sandvig	**1:41 PM**	Is PG&E exchange agreement in these numbers?
Doug Howell	**1:41 PM**	Slide 24. If conservation does not assume a 6-year ramp verus a 10-year ramp rate, what is the additional contribution?
Doug Howell	**1:42 PM**	Now that PSE sale of Colstrip Unit 4 is happening, what does the new analysis say of Colstrip economics right now. The sale proceeding seem to reveal that Colstrip is not economic now.
Doug Howell	**1:43 PM**	* Colstrip sale NOT happening
Nate Sandvig	**1:45 PM**	based on PGE experience, given building new natural gas is extremely difficult if not impossible, what is scenario plan in the alternative?
Fred Heutte	**1:45 PM**	Slide 23: how frequent are extended duration events such as the one shown here happening in the modeling overall. Is it about 1 per year or something else?
Fred Heutte	**1:46 PM**	Slide 23: what is the cost of additional gas transportation and firm gas or other contractual provisions to provide gas to ride through long duration events?
Doug Howell	**1:48 PM**	Montana wind - you have about 350 MW of freed up Unit 1 and 2 so why couldn't you bring in Montana wind right now?
Doug Howell	**1:49 PM**	MW of transmission

Fred Heutte	**1:51 PM**	Just to note on market availability, PacifiCorp has documented that Mid-C transaction volume has fallen by about half since 2016, potentially related to the increase in EIM participation.
Fred Heutte	**1:56 PM**	my understanding is that gas can be held as spinning reserve if it's not being used for market dispatch
Brian Grunkemeyer	**1:56 PM**	Slide 23: Why is there no DR in this picture?
Fred Heutte	**1:56 PM**	correction, "market dispatch" better said as "dispatch to load" in the single-utility context
R. C. Olson	**1:59 PM**	Why did the model pick new peaker capacity and not add demand response capacity instead?
Alison Peters	**2:01 PM**	And we will move any leftover q's to the Feedback Report if we still have some at 5pm. Thank you.
James Adcock	**2:05 PM**	Slide 26 Question: I don't understand "I. SCGHG ..." -- can you please clarify what you are talking about here?
Kyle Frankiewich	**2:06 PM**	Slide 26: I understand that N, O, and one of the other ones are not actually included in this presentation. May want to correct the slide header
Alison Peters	**2:07 PM**	A friendly reminder to please stay on mute while speakers are presenting. Thank you.
Kevin Jones	**2:07 PM**	Slide 26 - Did PSE publish the results of the sensitivity voting? How many votes did sensitivity N receive?
Joni Bosh	**2:07 PM**	slide 27 - where are the actual values used for mid low and high found? Which previous presentation?
R. C. Olson	**2:09 PM**	How can PSE model conservation as a controlled variable? Conservation is happing outside of PSE control.
Elise Johnson	**2:10 PM**	Hi Kevin! Yes, this was published in Consultation Update #9: https://pse-irp.participate.online/consultation-updates
Tom Eckman	**2:10 PM**	Slide 28 - Was the amount of available conservation available less than the mid for the low forecast and more for the high forecast, given that you said there were lower and higher levels of population growth in thse forecast?
Eric Markell	**2:11 PM**	What project financing assumptions underlie assumed availability of MT and WY wind? Is assumed availability bi-lateral long term contracgts or merely Mid C spot purchases?
James Adcock	**2:12 PM**	Slide 29 Question: Can you define "Annual Portfolio Costs" -- is this really "Annual" costs or is "Cumulative" Portfolio costs?
Elyette Weinstein	**2:16 PM**	Please add the answer to Joni's question to slide 27. This will jelp your audience. We should not have to rifle through the October presentation, This should noyt be a challenge for you audience to make sense of the slides, especially since you have easiest and quickest access to this data.
Elise Johnson	**2:20 PM**	Hi Elyette! The October presentation can be found here: https://oohpseirp.blob.core.windows.net/media/Default/2021 /meetings/Oct_20_webinar/Webinar%209%20-%20Electric%20IRP%20Presentation.pdf
James Adcock	**2:26 PM**	Slide 31: I'm trying to understand battery storage being displayed as a negative number. I understand that when battery charges it represents a negative number, but when it discharges it represents a positive number, so shouldn't it also be displayed "above the line" -- above the zero mark?

Charlie Black	**2:29 PM**	Did I hear Elizabeth say today that all market power purchases are treated as unspecified energy? If so, does this mean that it is assumed PSE is only using owned and contracted renewables for CETA compliance?
Charlie Black	**2:29 PM**	This question is relevant for the overgeneration analysis.
Anne Newcomb	**2:30 PM**	Was a sensitivity run that uses excess energy to create Hydrogen?
Kyle Frankiewich	**2:30 PM**	oh, this is because the units are in aWM, and batteries don't 'make' MWhs.
Doug Howell	**2:32 PM**	Slide 35. Would you confirm that you currently have about 350 MW of TX capacity from the closure of Colstrip Units 1 and 2?
Eric Markell	**2:34 PM**	To All: What project financing assumptions underlie assumed availability of MT and WY wind? Is assumed availability bi-lateral long term contracgts or merely Mid C spot purchases?
Kyle Frankiewich	**2:37 PM**	slide 36: did PSE do this analysis for its rerouting of some Tx rights from PSE-owned wind projects to MidC?
Doug Howell	**2:37 PM**	So PSE could bring in some new Montana wind now.
James Adcock	**2:38**	Slide 37 Question: Can transmission still be "shared" when there is little conflict -- for example when Battery Storage and Wind are on the same Transmission "Stub Line" -- where battery will charge from Wind when Wind runs, and therefore actually represent a negative load on the Transmission stub line?
Kyle Frankiewich	**2:38 PM**	or, how does this analysis differ from that resource decision?
James Adcock	**2:44 PM**	Comment: The reason I asked was that PSE previously showed Battery costs (incorrectly I believe) including the costs of a 10 mile long dedicated stub line for that battery -- when that is NOT how your competitors are building Battery Storage -- rather they are building Battery Storage where additional new transmission line dedicated to that Battery Store *Is Not* needed.
Doug Howell	**2:46 PM**	Slide 38. Why isn't SCGHG when treated as an externality included in the dispatch model?
James Adcock	**2:48 PM**	Slide 39 Question: So am I understanding correctly, if PSE models SCGHG as a dispatch cost -- as many people have called for PSE to do -- then fewer new Natural Gas Peakers are required to be built?
James Adcock	**2:50 PM**	Does a phone user perhaps not have their phone on mute?
Eric Markell	**2:51 PM**	Slide 41 Does "retirement" mean deconstruction and site restoration? Are those entire costs included in your costing methodology?
Tom Eckman	**2:52 PM**	Slide 38 - Since the SCC is not applied to the hourly dispatch cost, this sensitivity appears to only impact resource selection, but not resource dispatch. Is that correct? If so, it doesn't seem to test whether including SCC in dispatch cost would futher reduce GHG emissions due to lower fossil resource utilization.
Don Marsh	**2:53 PM**	Slide 42. Can you remind us why batteries have only 12.4% ELCC?
Nate Sandvig	**2:53 PM**	slide 41, you say “batteries,” did you look at pumped storage?
Joni Bosh	**2:54 PM**	! to tom eckman's question.
Doug Howell	**2:58 PM**	Please respond to Tom Eckman's question about SCGHG and dispatch modeling.

James Adcock	**3:02 PM**	Slide 47 Question: My understanding is that the 2% cost cap limit "offramp" possibility does not exist prior to 2030 -- i.e. that PSE is strictly required to meet "80% in 2030." Is this PSE's understanding also, or does PSE believe that they can use the 2% 'offramp" prior to 2030?
Doug Howell	**3:04 PM**	Yes, it was understood that modeling needs to be in dispatch
Doug Howell	**3:04 PM**	When with the results of SCGHG in dispatch modeling be available?
James Adcock	**3:08 PM**	If PSE is going to answer questions in a future report, can PSE answer the questions *specifically* rather then lumping them all together and answering generically in a way that perhaps makes sense to PSE, but which doesn't make any sense to the people who actually asked the questions?
Joni Bosh	**3:09 PM**	No
James Adcock	**3:10 PM**	Riase hand
Brian Grunkemeyer	**3:11 PM**	raise hand
Kyle Frankiewich	**3:11 PM**	raised hand
Elise Johnson	**3:12 PM**	Hi James! Refering to your question on feedback reports - the feedback reports do answer the questions with line-by-line answers. For an example, you can refer to one of the reports: https://oohpseirp.blob.core.windows.net /media/Default/2021/meetings/Oct_20_webinar/Webinar%209%20-%20Electric%20IRP%20Feedback%20Report.pdf
James Adcock	**3:13 PM**	+1 “Smart Water Heaters.”
Eric Markell	**3:14 PM**	What is the general order of magnitude of increased credit that wil be required of PSE to proivide to market resources as purchased power to replace Colsgtrip and Centrailia and CCCTs
Kevin Jones	**3:16 PM**	Could you answer Kyle's question: Slide 48 - For the no CETA case, how is this cost not $0?
Charlie Black	**3:16 PM**	Agree with Kyle Frankiewich about showing the social costs of GHG emissions, valued at the SCGHG.
Kyle Frankiewich	**3:37 PM**	slide 56: what do the inputs look like for intermittent resources?
Kyle Frankiewich	**3:40 PM**	slide 56: relatedly, where does the variance to forecast occur for wind and solar? I would guess the last two steps, but some clarification would be helpful.
Brian Grunkemeyer	**3:41 PM**	Slide 57: The DR call restrictions are exactly why PSE should model Demand Flexibility resources as a new type of conservation measure.
James Adcock	**3:43 PM**	Slide 58 Question: Why are you seeing so much unexpected "Night Hour" variability in the Dec. 30 Example?
Kyle Frankiewich	**3:43 PM**	slide 57: do the attributes of DR align with CPP, or some other DR resource? I understand taht demand resources like water heaters can be callable multiple times a day without perceivable performance impacts to end users. These would presumably have a lot more value to this modeling goal than a lumpy DR program as shown.
Fred Heutte	**3:45 PM**	slide 55: "When the model must flex generation up, it can turn on dispatchable plants, discharge batteries, or buy power from the market." Can the model not also dispatch DR?

Zhi Chen	**3:45 PM**	PSE is using NREL data for wind and solar resources as the inputs in PLEXOS. Same input source as Aurora and the resource adequacy model.
James Adcock	**3:47 PM**	Slide 60 Question: Why wasn't Battery Storage included in this analysis?
Kyle Frankiewich	**3:47 PM**	slide 60: are the purchases and sales connected to the energy imbalance market? Seems like the EIM is a big intra-hour market that could lower costs or increases benefits for these types of problems
Tom Eckman	**3:51 PM**	Since it was stated earlier that conservation significantly reduced the amount of renewables needed to meet CETA, how is this benefit captured in the flexibility analysis, since it impacts the amount of balancing reserves needed?
Eric Markell	**3:51 PM**	Slide 62 Is the PSE staff aware of any specific site in the PNW where a utility scale pumped hydro project could be permitted, constructed and financed?
Zhi Chen	**3:51 PM**	The model has the CAISO EIM engine. But no EIM transactions so far. PSE could add the market players later on. All market purchases and sales (DA, ID, and IH) connected to the Mid C market so far.
James Adcock	**3:52 PM**	Slide 63 Question: Sorry I reallly don't understand what you are talking about in this slide. Can you go over it again in more detail to I can try to understand it?
Don Marsh	**3:53 PM**	Raise hand
Nate Sandvig	**3:53 PM**	lot of opportunities to comment with what you are asking from stakeholders due dec 28 over the Holidays. can we get a week extension at a minimum?
Nate Sandvig	**3:53 PM**	“heavy”
Charlie Black	**3:53 PM**	How do PSE's draft results on flexibility analysis compare with other utilities' IRP analyses?
Kyle Frankiewich	**3:54 PM**	re: other resources - PAC's 2019 IRP process explored a number of approaches to countenancing the value of dispatchable resources. Some were more palatable for stakeholders than others, but all were worth reviewing.
Tom Eckman	**3:54 PM**	PacifiCorp is using PLEXOS to evaluate the value of ancillary services, including balancing reserves.
Fred Heutte	**3:56 PM**	And in fact they are now using Plexos as their primary IRP model, replacing System Optimizer.
Fred Heutte	**3:56 PM**	These days Plexos is more of a model ecosystem than a core model.
Brian Grunkemeyer	**4:02 PM**	About your flexibility analysis, I thought your 2017 numbers were very low. But I had no comparison point to prove it, short of an anecdote from SRP saying they only had 150 MW of ramp capability.
Matthew Shapiro	**4:04 PM**	Also in pumped storage is the proposed Badger Mountain project in Douglas County, at the Mid-C hub. 500 MW.
Brian Grunkemeyer	**4:08 PM**	Elizabeth, on flexibility, SRP several years ago was considering a mix of demand response, demand flexibility (from electric vehicles), and maybe new generation to increase their ramp rate. Flexibility is cheap is you have it, but if you don't have it and need to build a new power plant, it's not free.
Brian Grunkemeyer	**4:09 PM**	This is made worse by CAISO market restrictions on DR. Basically, you need ramp to get ramp. It's a chicken and the egg problem.
Fred Heutte	**4:19 PM**	slide 70: it's a little hard to tell with the coloring, how much is JP & redelivery, and how much is Tacoma LNG

Don Marsh	**4:19 PM**	Slide 70: the relatively flat dashed line starts to increase in 2032. Is this because the 10-year ramp rate has expired?
C Bunch	**4:34 PM**	Like CA, many cities in WA are looking at gas expansion regulation. How is regulation factored into sensitivities analysis or demand?
Rob Briggs	**4:50 PM**	Would you please clarify Gurvinder's answer to the question on sensitivity analyses of new regulation of new gas hookups or the impact of electrification trends. Is there a sensitivity analysis coming as part of the 2021 IRP that will examine that potentially very significant trend?

The following stakeholder input was gathered through the online Feedback Form, from December 8 through December 28, 2020. PSE’s response to the feedback can be found in the far-right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on January 19, 2021, one day later than reported during the December 15 webinar due to a statutory holiday (Martin Luther King Day).

Many of PSE responses reference PSE’s draft 2021 IRP which is now available online.

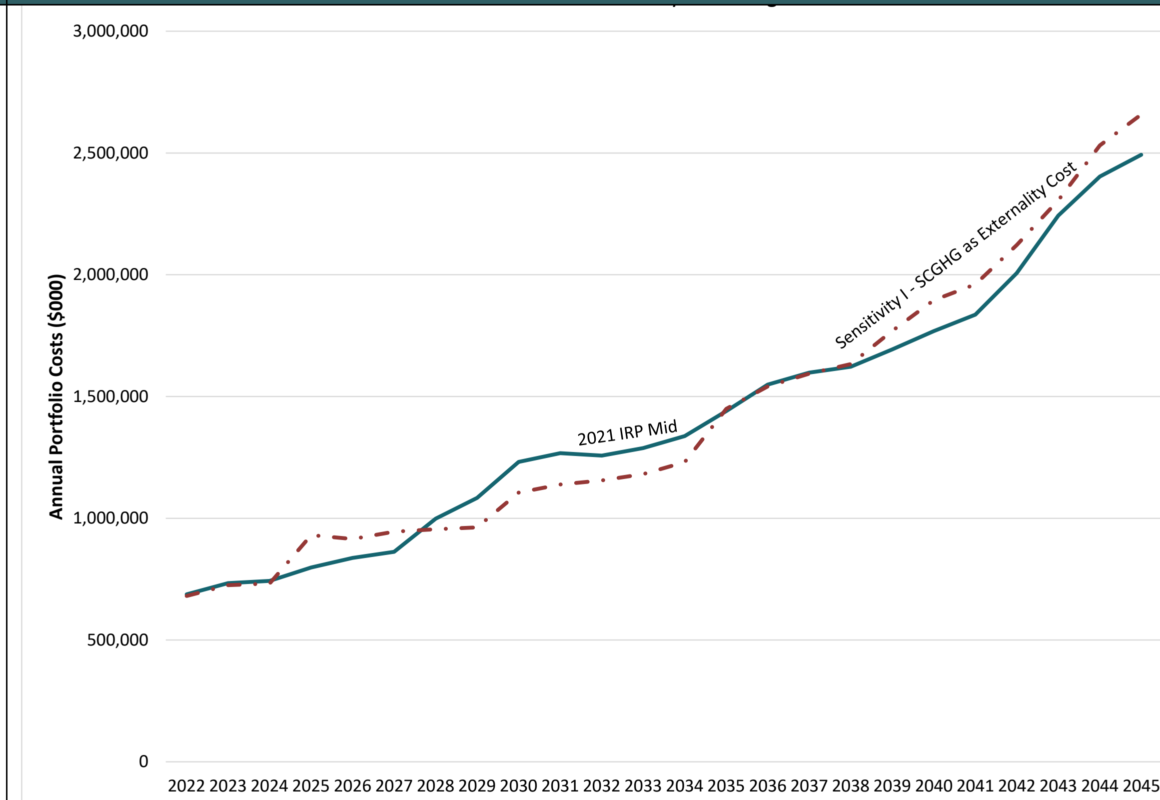
Feedback Form Date	Stakeholder	Comment	PSE Response
12/9/2020	James Adcock	Page 13 Question: I don't understand the statement "Levelized cost for low income customers used a lower benefit cost ratio adjustment" What does that mean, and why do low income customers have a "lower benefit cost ratio adjustment" ?	Please note this comment references a slide that was included in the draft slide deck distributed prior to the webinar, but was not included in the final slide deck. The lower benefit cost ratio means that low-income customers have a less stringent threshold to qualify a conservation measure. Even when a conservation measure is not cost effective with the standard benefit cost ratio, since the cost is higher than the benefit, it may still qualify under the lower benefit cost ratio for low-income customers. This resulted in shifting the measures to lower cost bundles in the supply curve and slightly more measures being included in the conservation supply curves overall. The result is the lower benefit cost ratio adjustment includes more measures that could be cost effective.
12/9/2020	James Adcock	Clarify the statement "Levelized cost for low income customers used a lower benefit cost ratio adjustment" and what it means, and show that it is not introducing an economic disparity in the treatment of PSE customers.	Please see response provided directly above.
12/9/2020	James Adcock	Page 22. Question: Is Page 22. Question: Is the winter peak "baseline system peak" a Morning Peak or an Afternoon Peak. What is the assumed winter "one-hour" temperature that corresponds to that Morning or Afternoon Peak? Please answer both for 2027 and for 2031.	The one-hour peak is a forecasted peak and can happen any time in the morning or evening. The temperature that corresponds to that peak is 23 degrees F.
12/9/2020	James Adcock	Please clarify whether the winter peak "baseline system peak" is a Morning Peak or an Afternoon Peak. And what is the assumed winter "one-hour" temperature that corresponds to that Morning or Afternoon Peak. Please answer both for 2027 and for 2031.	The one-hour peak is a forecasted peak and can happen any time in the morning or evening. The temperature that corresponds to that peak is 23 degrees F.
12/9/2020	James Adcock	Page 21. Question: What is meant by the three blue highlighted boxes? As opposed to the new acqusition which are not inside the three blue highlighted boxes?	The three blue highlighted boxes are intended to be a visual cue for the presentation. They highlight the resource additions related to the retirements of Colstrip and Centralia as well as the additional peaking capacity and storage resources discussed on slide 30.
12/9/2020	James Adcock	Please clarify what is meant by the three blue highlighted boxes? As opposed to the new acqusition which are not inside the three blue highlighted boxes?	Please see response provided directly above.
12/9/2020	James Adcock	Page 32. Question: When will the new Peakers that are being acquired planned to be retired? Do they continue to exist after 2045, or will they be retired prior to 2045? If they continue to exist after 2045 how will you use them? Will you just use them and then "pay the penalty" -- pay the "alternative compliance fee" ? Or how will you continue to use them after 2045?	The generic peaking capacity modeled in the AURORA model has an expected life of 30 years. The modeling horizon of the AURORA model does not extend past 2045. Any carbon-emitting thermal plants that are still in use after 2045 would be subject to CETA penalties, and the economic viability of those resources would be re-evaluated under those new conditions. The model currently uses peaking capacity only when necessary to meet peak demand. PSE is doing further analysis through sensitivities to understand the need for peaking capacity and evaluating the use of alternative fuels.
12/9/2020	James Adcock	Please answer these questions clearly and unambiguously. We ratepayers worry about paying for something just to see it be prematurely retired.	Please see response provided directly above.
12/9/2020	James Adcock	Page 34. Question: If, by implication, WA wind, in comparison to WY and MT wind, are not well-matched to PSE's load profile, then how do you actually "use" them under CETA requirements to serve PSE customers?	WA wind still provides energy and meets PSE’s loads in different seasons and times of day.

Feedback Form Date	Stakeholder	Comment	PSE Response
12/9/2020	James Adcock	Please clearly and unambiguously answer the question.	Please see response provided directly above.
12/9/2020	James Adcock	Page 34. Question: What is the actual value of the big red "X" on this page?	Please note this comment references a slide that was included in the draft slide deck, which was later updated. We apologize any confusion this may have caused.
12/9/2020	James Adcock	Please specify what the actual value is of the big red "X" on this page.	Please see response provided directly above.
12/9/2020	James Adcock	Page 38. Question: So when you say "By 2045, emissions are coming from market purchases and remaining peaker plants" is PSE saying that they are plannning to "pay the penalty" for these emissions -- i.e. PSE plans to pay the CETA "Alternative Compliance" costs?	PSE has factored the alternative compliance costs into the total portfolio costs. It starts at meeting 80% of the forecast in 2030 and reduces to zero by 2045 because all load is met with renewables. PSE is conducting additional sensitivities around retiring peakers before 2045 and moving to an alternative fuel for CETA compliance.
12/9/2020	James Adcock	Please clarify that when you say "By 2045, emissions are coming from market purchases and remaining peaker plants" whether or not PSE is saying that they are plannning to "pay the penalty" for these emissions -- i.e. that PSE plans to pay the CETA "Alternative Compliance" cost of $84 per megawatt hour.	Please see response provided directly above.
12/9/2020	James Adcock	Page 39. Question: I really don't understand this page. I am asking that can you spend additional time explaining it so that I and other can actually understand it? And/or plan to have time so that people can ask questions to understand it?	Please note that this response and the figures below are excerpts from Chapter 8 of PSE's 2021 IRP Draft, dated January 2021. Sensitivity I looks at adding the SCGHG as a variable dispatch cost instead of a fixed planning adder. The changes brought on by changing SCGHG to an externality cost are minor. The model optimizes dispatch of existing gas plants to minimize cost, while newly acquired peaking capacity is largely unused. The sensitivity resulted in more peaking capacity being built than the Mid Scenario, but the average capacity factors of the newly built plants averages to 0.3 percent by 2045. The costs of the portfolio remain similar throughout the time horizon. Sensitivity I reached a higher annual cost in 2045 as a result of increased biomass builds starting in 2036. Overall, the cost differences between these portfolios are minor, with Sensitivity I purchasing slightly more expensive resources in the later years.

Figure 8-35: 24-year Levelized Costs – Mid and Sensitivity I portfolios

		24-Yr Levelized Costs			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid Scenario	$13.63	$5.04	$18.68	
I	SCGHG as Externality Cost	$13.65	$4.78	$18.42	($0.25)

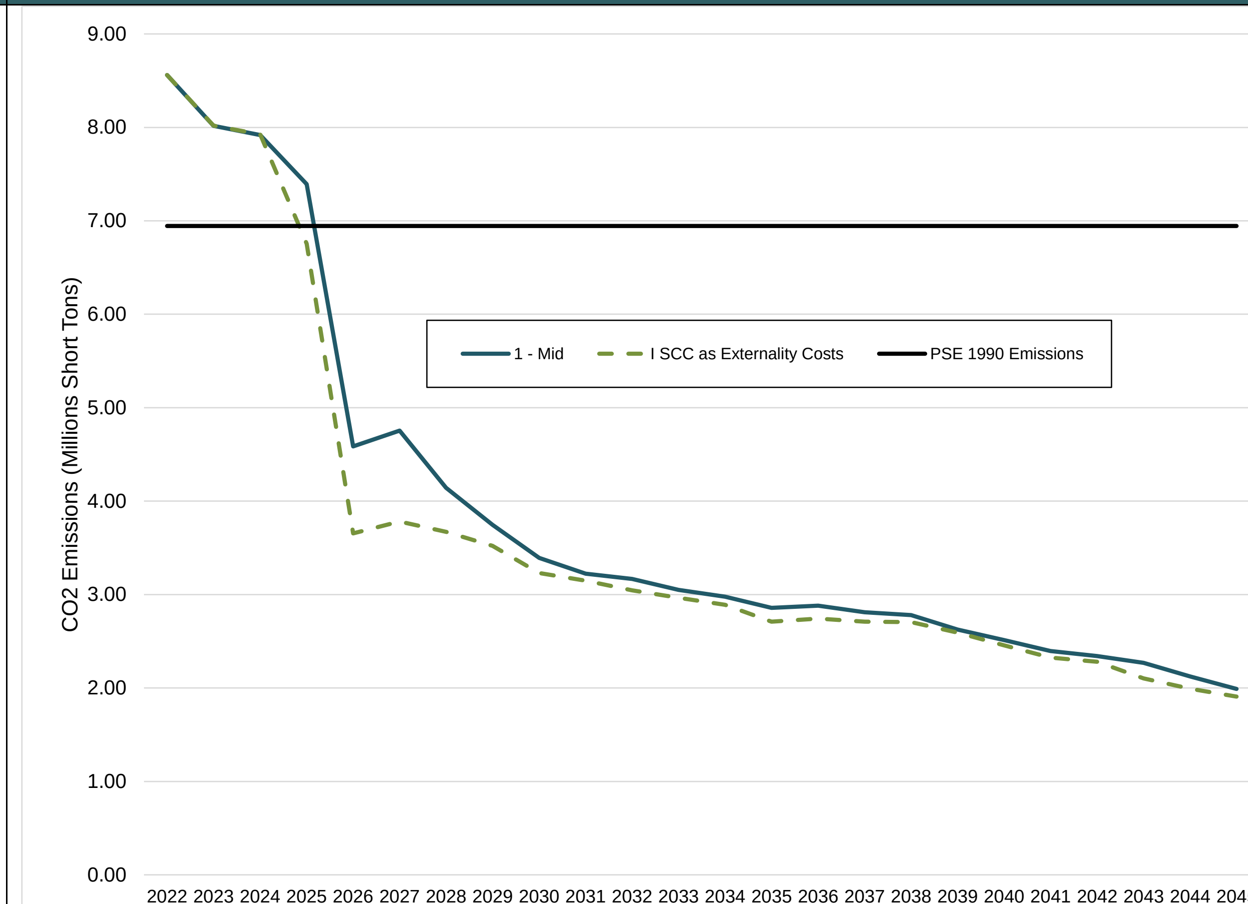
Figure 8-36: Annual Portfolio Costs – Mid Scenario and Sensitivity I

Feedback Form Date	Stakeholder	Comment	PSE Response
			 The model in Sensitivity I builds a large amount of Washington wind capacity in 2025 as Colstrip and Centralia are retired. However, the total Washington wind resources added to the Sensitivity I is lower by 300 MW nameplate capacity compared to the Mid Scenario. This can be seen as the costs increase in 2025. However, the sensitivity adds less conservation than the mid portfolio and slightly more peaking capacity.

	Portfolio	DSR	DER Resources	Demand Response	Biomass	Solar	Wind	Storage	Peaking Capacity	Total
1	Mid Scenario	1,497	118	121	15	1,393	3,750	600	948	8,442
I	Social Cost of Greenhouse Gases as an Externality Cost in the Portfolio Model	1,372	118	141	120	1,394	3,450	600	966	8,161

The reduced usage of new peaking capacity leads to an overall decrease in the emissions from resources in both portfolios. Sensitivity I has a lower emissions in the earlier years because of the additions of more renewable resources in years 2025 and 2026, but both portfolios converge back together by 2030 with the 80% renewable resources requirement. Figure 8-39 shows the emissions of the Sensitivity I portfolio, where PSE is producing below two million short tons of emissions in the year 2045. The portfolio does begin to lean more on market purchases, which have a CETA-specified emission rate of 0.437 metric tons of CO_2 per MWh.

Figure 8-39: Sensitivity I – Portfolio Emissions – Mid Scenario and Sensitivity I (includes calculated emissions on market purchases)

Feedback Form Date	Stakeholder	Comment	PSE Response
			
12/9/2020	James Adcock	Please can you spend additional time explaining it so that I and other can actually understand it? And/or plan to have time so that people can ask questions to understand it?	Please see response provided directly above.
12/9/2020	James Adcock	Page 40. Question: I'm trying to understand this page. What it seems to be saying is that it costs less to have PSE comply with the lower emissions requirements of CETA than when PSE had greater freedom to pollute just about as much as they wanted. Is that correct?	See reply above
12/9/2020	James Adcock	Please clarify whether or not it costs less to have PSE comply with the lower emissions requirements of CETA than when PSE had greater freedom to pollute just about as much as they wanted.	See reply above.

Feedback Form Date	Stakeholder	Comment	PSE Response
12/9/2020	James Adcock	Page 41. Question: I'm trying to understand this page. When I read the CETA law (section 9) it seems to state clearly that the alternative compliance costs (for Peakers) is $84 per megawatt hour. Why are you using a different calculation here that somehow relates to California, and not the $84 per megawatt hour required under Washington State Law?	PSE first discussed the alternative compliance costs and consulted with stakeholders at the September 1 webinar. PSE requested feedback from stakeholders regarding prioritization of the options for the 20% alternative compliance to reach carbon neutral target by 2030 in the 2021 IRP. PSE received one suggestion regarding this through the feedback forms. Feedback from Joni Bosch, NWEC: In response to the question posed on prioritizing options for the 20% alternative compliance actions that might be addressed in the 2021 IRP, NWEC would urge PSE to model an aggressive amount of conservation and demand response. Beyond the required conservation and demand response required in sections .040 and .050 of CETA, additional innovative conservation, efficiency, storage and demand response should be considered for Energy Transformation Projects. Exploring those has the double impact of further reducing/managing load and achieving additional GHG reductions. PSE created a portfolio that increased demand response, storage and distributed resources as Sensitivity V and W. For the baseline assumption and comparison, PSE wanted to use a price forecast for the alternative compliance costs. PSE feels that the California carbon price is a reasonable assumption, however we are open for discussion and can also evaluate other price forecasts to get a range of the alternative compliance costs. PSE also ran a sensitivity where the portfolio reaches 100% renewable resources in 2030 instead of relying on alternative compliance.
12/9/2020	James Adcock	Please clarify why are you using a different calculation here that somehow relates to California, and not the $84 per megawatt hour required under Washington State Law?	For the baseline assumption and comparison, PSE wanted to use a price forecast for the alternative compliance costs. PSE feels that the California carbon price is a reasonable assumption, however we are open for discussion and can also run another cost to get a range of the alternative compliance costs.
12/9/2020	James Adcock	Page 42. Question: I'm trying to understand this page. You state that CC Plants capacity factors are below 5%, but your Peaker capacity factors (at least in recent years) are also below 5%, so why wouldn't you just retain the CC Plants as "emergency use only" to run proactively when the local weather predictions are for unusually hot or cold weather? Are you stating that maintaining old CC Plants is more expensive than buying new Peaker Plants -- when the new Peaker Plants need to be retired in 15 years anyway?	Your statement to "just retain the CC Plants as "emergency use only" to run proactively when the local weather predictions are for unusually hot or cold weather" is correct. To keep the old CCCT plants to run for "emergency use only" is lower cost than buying new resources.
12/9/2020	James Adcock	Please clarify given that CC Plants capacity factors are below 5%, and your Peaker capacity factors (at least in recent years) are also below 5%, so why wouldn't you just retain the CC Plants as "emergency use only" to run proactively when the local weather predictions are for unusually hot or cold weather?	Please see response provided directly above.
12/9/2020	James Adcock	Page 54 Question: I don't understand the statement "Levelized cost for low income customers used a lower benefit cost ratio adjustment" What does that mean, and why do low income customers have a "lower benefit cost ratio adjustment" ?	Please note this comment references a slide that was included in the draft slide deck distributed prior to the webinar, but was not included in the final deck. The lower benefit cost ratio means that low-income customers have a less stringent threshold to qualify a conservation measure, so even when a measure is not cost effective with the standard benefit cost ratio since the cost is higher than the benefit, it may still qualify under the lower benefit cost ratio for low-income customers. This resulted in shifting the measures to lower cost bundles in the supply curve and slightly more measures being included in the conservation supply curves overall. The result is the lower benefit cost ratio adjustment includes more measures that could be cost effective.
12/9/2020	James Adock	Please clarify statement "Levelized cost for low income customers used a lower benefit cost ratio adjustment" and explain what does that mean, and why do low income customers have a "lower benefit cost ratio adjustment" ? Verify to participants that this does not mean that low income customers will receive less services in this area from PSE than for not-low-income customers.	Please see response provided directly above. See above.

Feedback Form Date	Stakeholder	Comment	PSE Response
12/17/2020	Christine Bunch, Seattle Office of Sustainability and Environment	PSE said on the call that the gas analysis is to support identifying the right amount of resources and to avoid overbuilding. It was noted that DSR would meet the needs except in the high demand case. To that end, I asked a question about how local and state regulation (ie. electrification) was factored into the analysis. The response from PSE was that it was feedback received earlier but that it was "not factored in at this point, but looking into it at a future date." No specifics were provided on the future date and whether it will be for sure included in the final IRP.	The gas to electricity conversion sensitivity will be included in the final IRP on April 1, 2021.
12/17/2020	Christine Bunch, Seattle Office of Sustainability and Environment	Please provide specific dates of when gas regulatory factors will be included in a sensitivity analysis and that it will be included in this round of the IRP.	The gas to electricity conversion sensitivity will be included in the final IRP on April 1, 2021.
12/21/2020	Katie Ware, Renewable Northwest	Please see Attachment 01. 2020-12-21 RNW Feedback re PSE Flexibility Analysis and Portfolio Draft Results.pdf for the complete submittal from Renewable Northwest. Key questions/suggestions have been paraphrased below by PSE for brevity.	Thank you for your thoughtful questions and comments.
12/21/2020	Katie Ware, Renewable Northwest	Flexibility Analysis: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest encourages PSE to incorporate four dimensions of flexibility (absolute power output capacity, speed of power output change, duration of energy levels and carbon intensity) into PSE's flexibility analysis.	Thank you for breaking down the key components of flexibility. PSE will keep these parameters in mind as we continue to refine our analysis.
12/21/2020	Katie Ware, Renewable Northwest	Flexibility Analysis: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest encourages PSE to examine specific dispatch characteristics of the sub-hourly PLEXOS model to pin point inconsistencies with previous flexibility assessments, particularly the flexibility benefit of reciprocating peaker plants of $417.25/kW-yr.	PSE has revised the nameplate capacity of the reciprocating peaker plant to 216 MW, which in turn reduced the calculated flexibility benefit to $35/kW-yr. Please note this revised flexibility value also incorporates some subtle revisions to the flexibility analysis methodology. PSE is continuing to refine its methodology and this value remains draft.
12/21/2020	Katie Ware, Renewable Northwest	Flexibility Analysis: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest encourages PSE to consider the value to 'controllable' solar and wind power plants.	PSE is aware of the growing interest and perceived value of controllable solar and wind resources. PSE will require time to understand how to best incorporate controllable solar and wind resources into its existing modelling frameworks and aims to include these resources in future IRP cycles.
12/21/2020	Katie Ware, Renewable Northwest	Flexibility Analysis: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest encourages PSE to consider incorporating a 6hr Li-Ion battery into the IRP.	Given the effort required to incorporate a new generic resource into the modeling environment, PSE is not able to incorporate a 6hr Li-Ion battery into the 2021 IRP. However, such a resource may be included in future IRP cycles.

Feedback Form Date	Stakeholder	Comment	PSE Response
12/21/2020	Katie Ware, Renewable Northwest	Flexibility Analysis: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest encourages PSE to provide a flexibility value of the 'diversity savings' from participation in the Energy Imbalance Market.	The EIM market is incorporated into the real time, fifteen-minute dispatch. The flexibility benefit then takes the change in dispatch from the day ahead and hourly dispatch to the real time dispatch and therefore the EIM benefits are incorporated into the flexibility benefit.
12/21/2020	Katie Ware, Renewable Northwest	Portfolio Draft Results: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest suggests that ELCC values for storage resources should be higher than described in the presentation, particularly pumped hydro storage.	Thank you for you feedback and concern for the ELCC analysis. In the draft 2021 IRP, Chapter 7, Resource Adequacy Analysis, PSE describes the analysis around energy storage ELCC. Below is an excerpt from Chapter 7, page 7-31: **STORAGE CAPACITY CREDIT.** The estimated peak contribution of two types of batteries were modelled in RAM as well as pumped hydro storage. The lithium-ion and flow batteries modeled can be charged or discharged at a maximum of 100 MW per hour up to two, four or six hours duration when the battery is fully charged. For example, a four-hour duration, 100 MW battery can produce 400 MWh of energy continuously over four hours. Thus, the battery is energy limited. The battery can be charged up to its maximum charge rate per hour only when there are no system outages. The battery can be discharged up to its maximum discharge rate or just the amount of system outage (adjusted for its round-trip [RT] efficiency rating) as long as there is a system outage and the battery is not empty. As stated previously, the LOLP is not able to distinguish the impacts of storage resources on system outages since it counts only draws with any outage event but not the magnitude, duration and frequency of events within each draw. Because of this, the capacity credit of batteries was estimated using expected unserved energy (EUE). The analysis starts from a portfolio of resources that achieves a 5 percent LOLP, then the EUE from that portfolio is calculated. Each of the storage resources is then added to the portfolio, which leads to lower EUE. The amount of perfect capacity taken out of the portfolio to achieve the EUE at 5 percent LOLP divided by the peak capacity of the storage resource added determines the peak capacity credit or ELCC of the storage resource. The estimated peak contribution of the storage resources is shown in Figure 7-19. The low peak capacity contribution for energy is because these are short duration resources. As shown in figures 7-8 and 7-12 above, loss of load events can have extended durations of 24 hours or more. Since energy storage resources have a short discharge period, they have little to contribute during extended duration events. *Figure 7-19: Peak Capacity Credit for Battery Storage Based on EUE at 5% LOLP*

BATTERY STORAGE	Capacity (MW)	2021 IRP Year 2027	2021 IRP Year 2031
Lithium-ion, 2 hr, 82% RT efficiency	100	12.4%	15.8%

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<tr><th>Feedback Form Date</th><th>Stakeholder</th><th>Comment</th><th>PSE Response</th></tr>
<tr><td></td><td></td><td></td><td>
<table>
<tr><td>Lithium-Iin, 4 hr, 87% RT efficiency</td><td>100</td><td>24.8%</td><td>29.8%</td></tr>
<tr><td>Flow, 4 hr, 73% RT efficiency</td><td>100</td><td>22.2%</td><td>27.4%</td></tr>
<tr><td>Flow, 6 hr, 73% RT efficiency</td><td>100</td><td>29.8%</td><td>35.6%</td></tr>
<tr><td>Pumped Storage, 8 hr, 80% RT efficiency</td><td>100</td><td>37.2%</td><td>43.8%</td></tr>
</table>
The below is an excerpt from Chapter 3, page 3-25:
Figure 3-14 is a 12x24 table that shows the loss of load hours prior to the addition of new resources. The plot represents a relative heat map of the number hours of lost load summed by month and hour of day. The majority of the lost load hours still occur in the winter months. From this chart, the large blocks of yellow, orange, and red in January and February illustrate long duration periods, 24 hours or more, with a loss of load event. The portfolio optimization model must meet these long duration capacity shortfall events using generic resources. Given current technologies, energy storage and demand response do not completely meet the peak capacity needs because of their short duration of availability.
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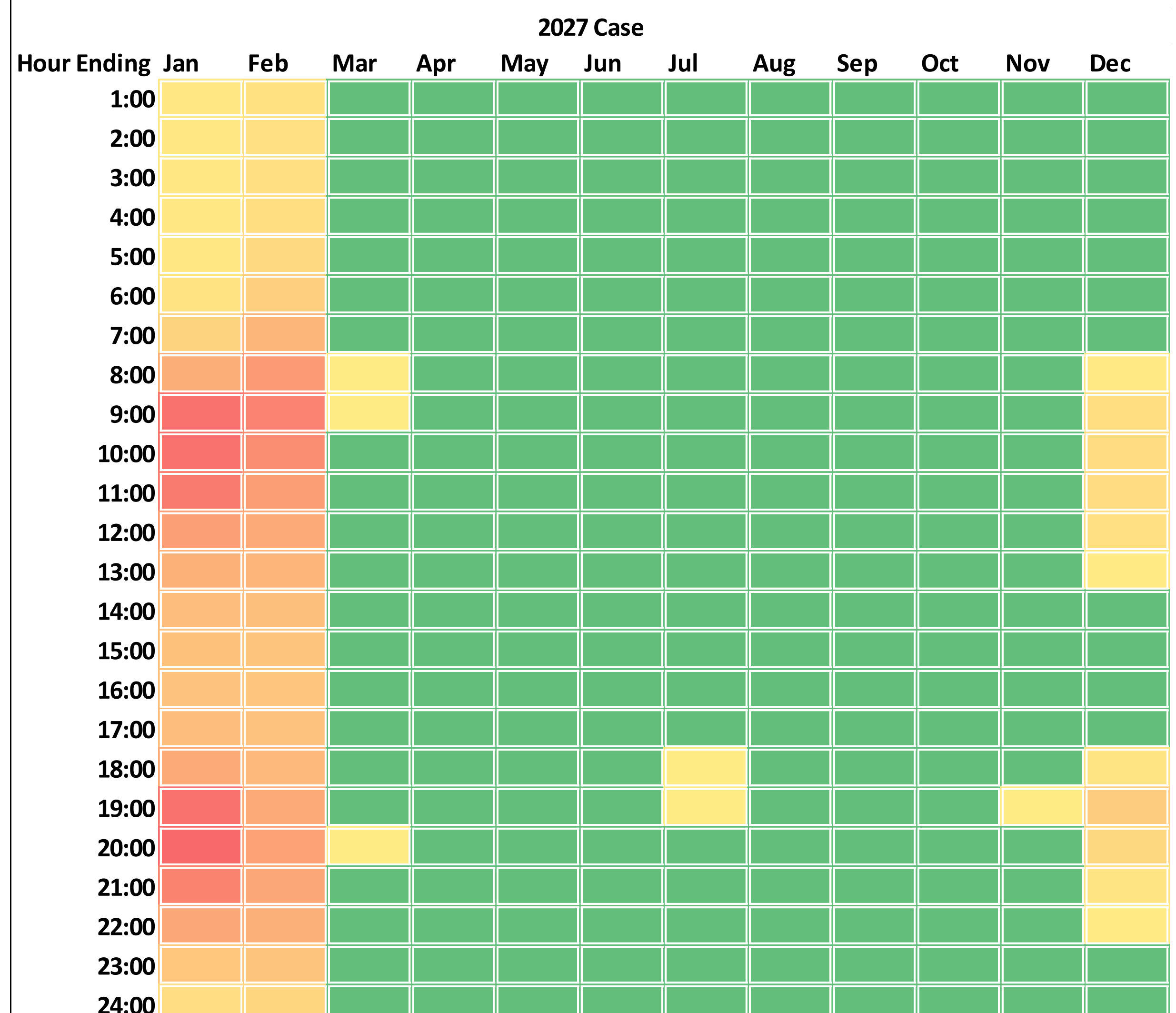
</table>

Feedback Form Date	Stakeholder	Comment	PSE Response
			Figure 3-14: Loss of Load Hours for 2027 
12/21/2020	Katie Ware, Renewable Northwest	Portfolio Draft Results: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest asks why additional peaking capacity resources are added to the portfolio and seemingly displacing dispatch of existing thermal resources.	New peaking capacity resources are added to the portfolio to meet peak capacity, not to provide baseload energy. Baseload energy is being replaced with renewable resources to meet CETA requirements. This is the reason why annual capacity factors of existing thermal resources decline with time. The new peaking capacity is needed to meet demand during hours when there is not enough renewable resources to meet needs. During peak events it may be necessary to dispatch all thermal resources old and new alike.
12/21/2020	Katie Ware, Renewable Northwest	Portfolio Draft Results: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest request an additional sensitivity which includes 6hr Li-Ion battery and 8-10 hr pumped hydro storage resources.	Given the effort required to incorporate a new generic resource into the modeling environment, PSE is not able to incorporate 6hr Li-Ion battery as this point in the process. However, PSE is modeling 8-hour pumped storage hydro in sensitivity N and P and they are described in Chapter 8, Electric Analysis, of the draft 2021 IRP.

Feedback Form Date	Stakeholder	Comment	PSE Response
12/21/2020	Katie Ware, Renewable Northwest	Portfolio Draft Results: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest asks for context around the lower-than-expected ELCC of pumped hydro storage.	Thank you for you feedback and concern for the ELCC analysis. In the draft 2021 IRP, Chapter 7, Resource Adequacy Analysis, PSE describes the analysis around energy storage ELCC.
12/21/2020	Katie Ware, Renewable Northwest	Portfolio Draft Results: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest asks to know the duration of storage resources used in Sensitivity P.	Sensitivity P used a 2hr Li-Ion battery as the selected 'must-take' storage resource, given it has the lowest revenue requirement of any storage resource. A full discussion and results of Sensitivity P are located in Chapter 8, Electric Analysis, of the draft 2021 IRP. PSE also ran a sensitivity P using an 8-hour pumped hydro storage resource and the results are included with sensitivity P in Chapter 8.
12/21/2020	Katie Ware, Renewable Northwest	Portfolio Draft Results: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest requests that PSE model for its draft IRP a sensitivity which, independent of existing natural gas plants (i.e. unlike PSE's anticipated sensitivities N and O), forces the model to select nonemitting capacity resources including batteries, pumped hydro, and renewables on an economic basis. This sensitivity would hone in on the cost and capability of nonemitting resources to provide system flexibility and peak capacity in a strategy most consistent with the state's clean energy standards.	Thank you for your feedback. PSE will follow up with renewable northwest on how this new sensitivity would be different than sensitivities N and O.
12/21/2020	Elyette Weinstein	This analysis proposes gas "peaker plants"' to meet resource adequacy needs. These plants are not necessary to meet such needs after 2026. You have failed to adequately develop demand response resources to meet this need. You have presented no evidence that you persistently have made a good faith effort to meet this need by obtaining renewable power from such entities as BPA. You rely on gas to meet these needs until near the deadline for 100% renewable energy so that the cost of suddenly obtaining such resources will meet the cost cap and you will be off the hook. I expected PSE to "game the system." Once again, you have met my dismal expectations. Your plan does not comply in good faith with CETA's intent.	Thank you for your concern regarding the analysis. PSE has addressed these issues in the draft 2021 IRP now available at www.pse.com/irp. You may consider reviewing Chapters 1, Executive Summary and 3, Resource Plan Decisions. PSE has run several sensitivities N, O, and P where existing thermal resources have been removed from the portfolio and/or no new peaking capacity is allowed to be added to the portfolio. Results of these sensitivities are located in Chapter 8, Electric Analysis. PSE is also exploring alternatives fuels such as hydrogen and biodiesel which are CETA compliant fuels and the analysis will be included in the final IRP.
12/22/2020	Nathan Sandvig, Rye Development LLC	These comments are provided on behalf of the Swan Lake and Goldendale pumped storage projects (the "Projects"). While Puget has provided several sensitivities to its Draft IRP results, Puget has NOT provided a sensitivity where no new natural gas generation is built in the IRP timeframe. Given the political climate and environmental opposition to constructing a new gas-fired generation facility, it is virtually impossible to construct these types of new generation resources. This "no new gas" scenario is also the most likely future scenario, given Washington's enactment of the Clean Energy Transformation Act ("CETA"), which provides very limited circumstances under which Puget could construct new natural gas-fired generation (e.g., RCW 19.405.090). Thus, the Projects strongly urge Puget to conduct an additional sensitivity that prohibits future natural gas development. Furthermore, the Projects request that Puget provide a demonstration that new natural gas-fired generation would be allowable under the few and limited CETA provisions allowing construction of such resources, particularly including violation of	PSE has run two sensitivities where all gas plants are removed by 2030 and 2045. These sensitivities are located in Chapter 8 of the draft 2021 IRP. PSE has added a pumped storage hydro option for sensitivity N and P in the draft 2021 IRP, and are located in chapter 8. PSE experienced some problems with sensitivity O and this will need to be fixed for the final IRP and will run with both a battery storage option and a pumped storage hydro option.

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		reliability standards and, if violations are possible, whether pumped storage could help alleviate or solve those potential violations. Similarly, of the sensitivities run by Puget, the Projects would like to see additional analysis for pumped storage in this IRP, particularly as part of scenarios N, O, and P. The Projects believe these scenarios represent reasonably likely future outcomes, so it is incumbent upon Puget to fully consider all types of storage resources that may be helpful in achieving these reasonably likely outcomes. Additionally, as noted above, a “no new gas” scenario should also analyze whether pumped storage could alleviate the reasons under CETA that would allow Puget to construct a new gas-fired resource. Thus far, Puget has indicated pumped storage was not fully evaluated as part of these draft results and the Projects strongly urge Puget to conduct that additional analysis. Finally, the Projects are also concerned about the over-reliance on batteries in many of Puget’s future scenarios. For example, scenario P calls for nearly 3,800 MW of additional batteries in 2026. Attached to these comments is a series of 3 research papers by Navigant Consulting that highlights some of the complications, challenges, and pitfalls with relying too heavily on batteries, including the significant environmental degradation impacts and hidden costs of those projects. Of particular note, the Projects would highlight for Puget that a key issue with proposing acquisition of Li-ion batteries for raw capacity needs is their likely performance for this new application. For example, a recent presentation by Energy GPS suggests that batteries are well-suited for meeting ancillary services needs; however, they are largely unable provide significant energy or capacity to utilities, meaning they are ill-suited to meet the upcoming capacity deficit in the Pacific Northwest. See, See The Next Technology – Batteries, Energy GPS LLC, Dec. 17, 2020 at 6-11, available at: https://content.energygps.com/files/062e7ca946d147fd1212bcfe5c88a3993ba8cbe9/EGPS_Webinar_TheNextTechnology_Final.pdf. Additionally, there is virtually no data on Li-ion battery performance for utility scale applications. Until battery installations of over 50 MW have run for at least 1-3 years in an operational grid/utility environment, it is impossible to credibly judge whether a four-hour discharge duration and a 10-15 year lifespan (as currently projected) are in fact accurate performance indicators. Currently planned Li-ion battery installations, especially in California, should provide such data, but it will probably not be sufficiently robust to validate (or not) currently advertised Li-ion performance metrics until the post-2025 timeframe. The need for more data is especially important since, in an operational utility environment, these large battery installations will be fully charging and discharging several times/day over a multi-month/year period. Similar to a cell phone battery, the more it is used, the quicker its capacity degrades, meaning the currently-asserted and modeled assumptions regarding charge/discharge and useful life cannot be fully vetted until more information is available. In addition, longer storage durations (which Li-ion batteries currently do not provide) are especially important in the Pacific Northwest where the region is facing multi-hour/multi-day nighttime winter capacity shortages from 2020-2030 as coal plants retire and the no new gas political sentiment prevents construction of new combustion turbines to replace that retiring coal capacity. This dynamic leaves	

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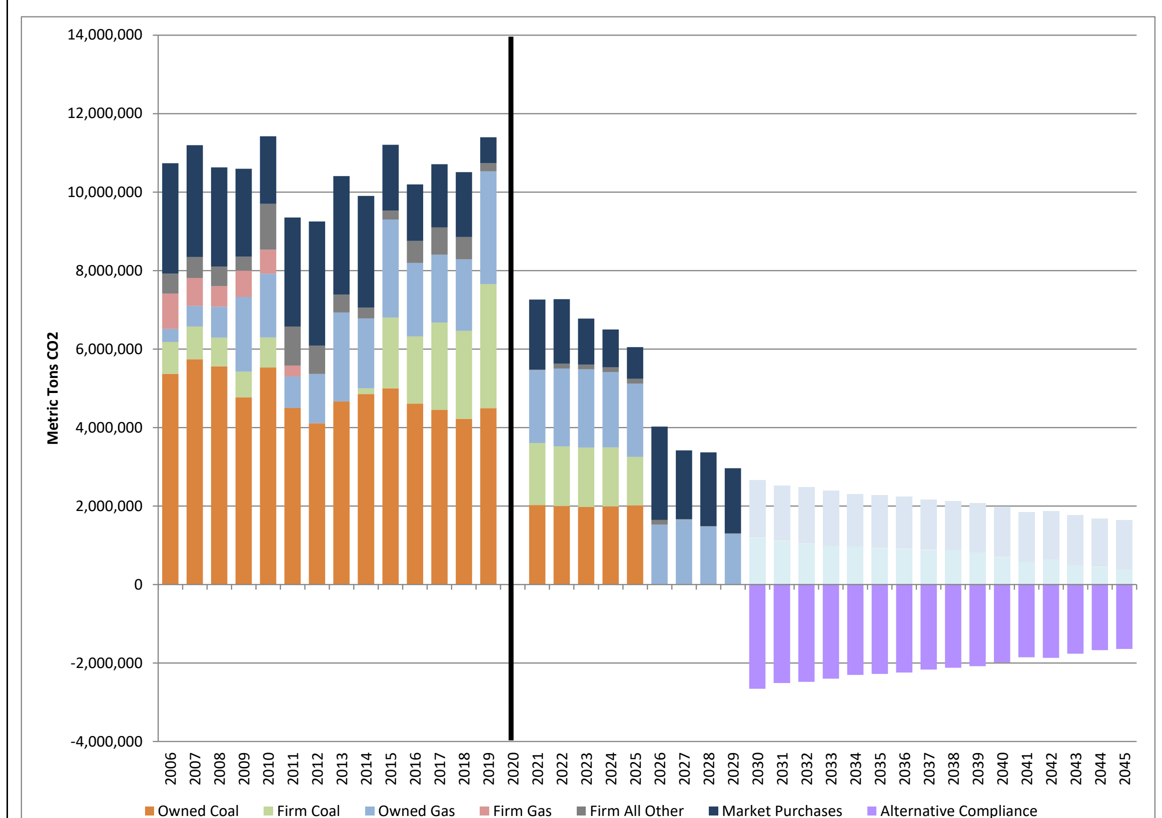
		pumped storage as one of the few remaining viable capacity solutions. Therefore, in light of the numerous issues associated with Li-ion batteries, the Projects request that Puget consider the attached materials in further detail and reflect them in their analysis of batteries as a potential storage solution, particularly as these resources compare to a clean, stable, grid-scale storage project like pumped storage. The Projects look forward to continuing to participate in Puget's IRP process and appreciates the opportunity to provide these comments on the initial, Draft IRP Results.	
12/26/2020	Willard Westre, Union of Concerned Scientists	Slide 11 from first Webinar release (Model Assumptions) – More explanation is needed regarding Economic Retirement of gas fired turbines. Does this mean retirement when fully depreciated or does it mean retirement when operational cost of an existing turbine is higher than the combined operational cost and purchase cost of a new turbine? Or when new renewable energy resources are less costly than existing turbines? Are there current retirement plans for this equipment before 2045? If so, when? This has implications in other slides.	In the retirement decision analysis in the Aurora model, the revenue requirement of an existing resource considered (includes depreciation costs, operational costs, and revenue from energy generated) in comparison to the cost of operating and building a new resource. The model did not select any economic retirement of existing PSE thermal generation resources in the Mid Scenario portfolio. Sensitivity N in the draft 2021 IRP assumes that all existing PSE thermal generation resources are retired by 2030 regardless of economic viability.
12/26/2020	Willard Westre, Union of Concerned Scientists	Slide 17 – Thank you for including this chart, but there are some unclarities: 1. The emissions suggested by the bars in the chart seem to indicate that the reduction achieved by 2029 is closer to 90% than 62%. The 62% seems to be the reduction by 2021. Can you clarify? 2. The chart shows a huge emissions reduction in the owned-gas-bar of about 2200 tons between 2019 and 2021. That reduction is larger than the gas emissions in 2026 indicating a large unused gas MW capacity at that time. This seems to contradict the need for new peakers. Can you explain why the unused existing gas capacity cannot be used instead of new peakers?	You are correct, in preparing the draft IRP, we found an error in this chart. The updated chart is provided in this report and will be included in the final IRP; the reduction from 2019 to 2029 is 75%. 
12/26/2020	Willard Westre,	Slide 21 – A slide in the first release of the webinar presentation (which is now not available) showed a more detailed breakdown of the wind resource additions. It	All 750 MW of available capacity from MT is assumed used by 2026 to meet peak capacity need.

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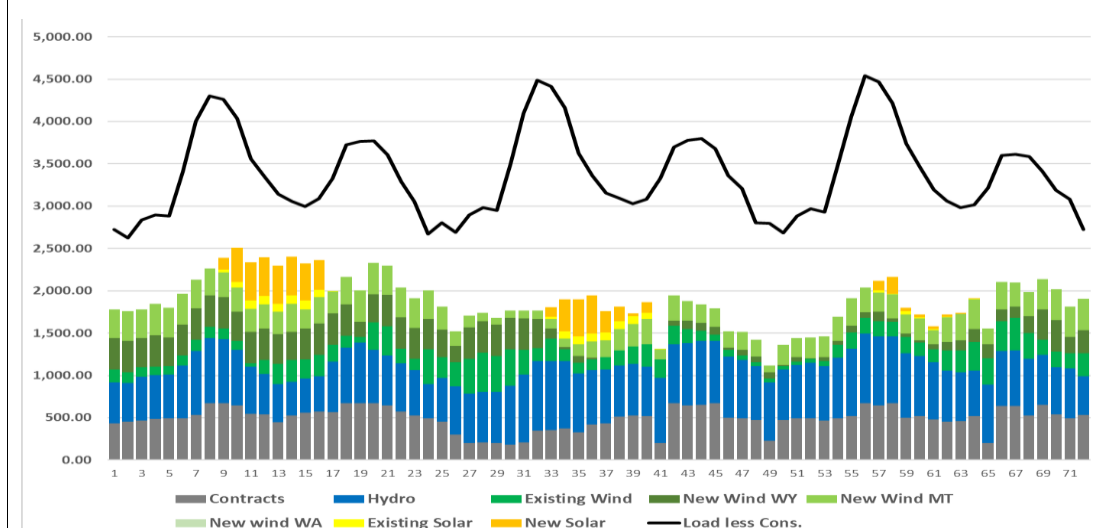
	Union of Concerned Scientists	showed 400 MW addition of MT wind in 2025, 400MW of WY wind in 2026, and 350MW of MT wind in 2044. The choice of MT wind first confirms this is the lowest cost resource. Why is the 350MW of MT wind not chosen next as it is also the lowest cost? It is lower cost than WY wind because WY wind requires new transmission. It is lower cost than WA wind because it has a higher capacity factor and higher resource adequacy. It is lower cost than new peakers. This delay also wastes half of the critical MT transmission resource for 20 years. There should not be a resource adequacy reason for this since the nearly 1000MW of WA wind is already mostly saturated. There seems to be an arbitrary cap on MT wind. Will PSE adhere to the lowest cost requirement and reevaluate this? If the 350MW was moved up to 2026, the addition of the 2 MT (400 & 350) and 1 WY (400) wind resources (1150MW total) provides an equivalent peaking capacity as the 474MW of peakers. This amount could also be increased from 1150-1233MW if PSE agrees to my firm transmission request (noted as Slide 36). Will PSE add the 350MW MT resource and drop the addition of 474MW of peakers in 2026? Also, why does it take 8 years to accelerate the introduction of Demand Response and what does it take to introduce it faster?	
12/26/2020	Willard Westre, Union of Concerned Scientists	Slide 23 - The chart on the upper left does not seem to justify new peakers. It appears that the current CCCT turbine capacity (1293MW) and the current peaker capacity (612MW) are not used at full capacity in concert. This 1905MW of thermal resources should be adequate to handle the 1500MW peaks. Using them at capacity together would appear to eliminate the need for the new peakers at least in the pre-2030 period. Will you please rerun the analysis with full existing peaker and CCCT dispatch allowed? Also, there is no Demand Response shown here. It seems obvious that several DR measures are very useful in addressing peak loads, e.g., timed water heating and car charging and emergency curtailment. The occurrence described here is rare. Will PSE consider increased use of DR to help cover these load peaks?	We apologize for the confusion regarding this chart. This chart shows the dependence on market availability. If no market was available, the largest difference at peak happens on Jan. 3 at 8 am at 4,488 MW and the total renewable resources and contracts adds up to 1,763 MW, leaving the portfolio 2,725 MW short. The existing thermal fleet adds up to 2,070 MW at peak, leaving the portfolio short 655 MW. Which can be filled by the new peaking capacity and demand response added to the portfolio.  PSE will work at look at making the adjustment that you suggest to make this chart more understandable.
12/26/2020	Willard Westre, Union of Concerned Scientists	Slide 36 - Thermal resources operate at near 100% Capacity Factor, renewables much less. So, it takes several times as many nameplate MWs to fill a transmission line to capacity with the current 100% of generation nameplate transmission requirement. This is why the Sensitivity D (Transmission as a % of Nameplate) analysis is important. In the presentation it was stated that the majority of time that a wind turbine is operating it is at nameplate rating. Given a Capacity Factor of 40%, this means that means at nearly 60% of the time it would be producing at zero. This does not meet the "smell test". Will PSE please supply the data that is behind this assertion? This is critical because it defines the time that increased	Thank you for your thoughtful comments. Provided below is a histogram of the hourly capacity factor for Eastern Montana Wind. You are correct, that a great deal of the time, there is no production (left most column). However, when the facility is producing power, it is most often producing rated power (right most column). Therefore, as the analysis shows, even small reductions in transmission capacity result in significant quantities of curtailed energy.

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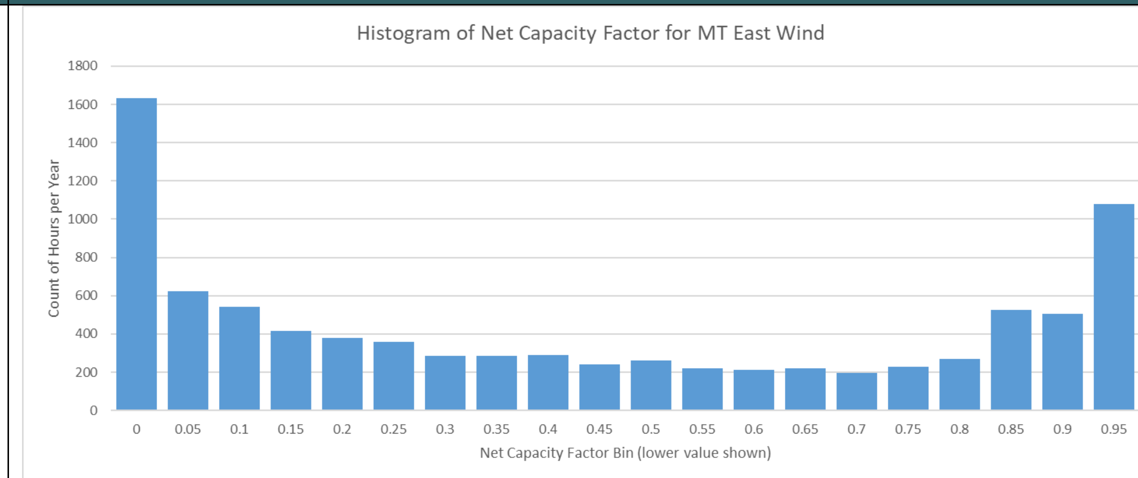
		energy is being produced and the time energy is curtailed. The analysis presented needs that data to be credible. If the analysis does prove to be correct will PSE set its level of firm transmission required for wind and solar resources at 90% as the analysis shows? This would increase the amount of actual transmission capacity at all times other than when the generation was occurring at nameplate capacity. It would allow an increase in the nameplate capacity of renewable resources dependent on limited transmission. For example, it would permit the MT wind capacity to be increased to 750MW / 90% = 833MW of nameplate capacity. It also seems like a small amount of storage equal to the overcapacity curtailed by less-than-100% firm transmission would be attractive. It would increase the amount of actual transmission in a transmission line with limited capacity. Has PSE evaluated this?	 You suggest a transmission model where the transmission capacity is scaled up and down with short term, non-firm transmission to meet periods of nameplate power generation. Considering the rapid development of desirable wind locations, it is unlikely that short-term, non-firm transmission would become available in situations where the wind is generating at nameplate capacity. Other projects are likely to have fully subscribed firm transmission in these 'peak generation' events. Furthermore, flexible transmission strategies such as the one described are extremely difficult to model with existing model frameworks. More time will be required to consider how to approach modeling a flexible transmission strategy as described. You also mention a hybrid wind-storage option to limit to allow for reduced transmission capacity. PSE has performed some initial assessments into shared transmission of co-located resources which suggests that there is strong potential for cost savings. Not only with wind-storage hybrids but also wind-solar hybrids. However, again, it will take time to incorporate complex transmission sharing strategies into existing IRP modeling frameworks. Please look for shared transmission of co-located resources in future IRP cycles.
12/26/2020	Willard Westre, Union of Concerned Scientists	Slide 37 - - I disagree that ELCC will be reduced. I believe additional resource builds will be enabled maintaining the ELCC, by more effectively using existing transmission which will allow the lower cost wind resources (with higher ELCC and previously limited by transmission capacity) to replace higher cost resources and resources with transmission build costs and result in lower overall cost. Will PSE please consider this?	As mentioned in the presentation, PSE understands that there may be specific situations where overbuilding the nameplate capacity of a resources as compared to the available transmission may be beneficial to the portfolio. PSE does not believe the IRP is the correct venue for these specific analyses to occur, instead these options should be considered during the resource acquisition process. Generally speaking, a wind resource constrained by transmission capacity less than the nameplate of the facility, and therefore unable to deliver a significant quantity of energy to the grid, will have a lower ELCC than the same resource with firm transmission capacity equal to the nameplate capacity of the resource. Therefore, more resources must be constructed, which carry with them a large annual revenue requirement for the capital cost of the additional resource capacity. In most cases, this large capital revenue requirement, far outpaces the cost of firm transmission. For example, eastern Washington wind has a firm transmission cost of $33/kW-yr and an annual, capital revenue requirement of approximately $140/kW-yr. Specific scenarios such as maximizing generation around a constrained transmission resource such as the Colstrip line, may have different outcomes with improved benefits for the portfolio. But again, PSE believes these benefits should be explored in the acquisition of specific resources and not applied to generic resources assumptions within the IRP modeling process.
12/27/2020	Virginia Lohr, Vashon Climate Action Group	PSE is not responding to what many stakeholders have been asking them to do in regard to how they use the social cost of carbon (SCC). We heard from Irena Netik in Webinar 5 on the Social Cost of Carbon that discussions between PSE and stakeholders on how to handle SCC began during the 2019 IRP process. They began in the very first meeting of the 2019 IRP (the May 30, 2018 meeting PSE unexpectedly moved to Olympia). These "discussions" continued over the course of the 2019 IRP and began again in the 2021 IRP. To hear Elizabeth Hossner in Webinar 11 characterize what stakeholders are asking for as a "miscommunication"	In the 2019 IPR process, PSE included social cost of greenhouse gases (SCGHG) in the IRP analysis and showed a comparison of the results of different methods of including SCGHG. The presentation that PSE shared with stakeholders is still available online in the Past IRPs tab, December 2019 webinar at the bottom of the page. In this IRP, PSE also plans to include SCGHG and is modeling SCGHG using various methods as requested by stakeholders. PSE conducted outreach to stakeholders on the phone and through e-mail in August during the preliminary discussions of sensitivities in the 2021 IRP. During this time PSE spoke with several stakeholders about Sensitivity I where the SCGHG was treated as an "externality" cost. During this time, the stakeholders confirmed that the externality is defined as a negative cost that is not actually built into the production of a good or service, so this

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		is distressing. PSE has had years to try to understand what stakeholders are asking for. Why have they failed to do so? A year ago, the Governor issued Directive 19-18 on the assessment of greenhouse gas emissions, stating that "Future risks of climate change depend on decisions made today." For PSE, a year after this Directive was issued, to continue to ignore it and wait for all the rules to be finalized before acting on it is not prudent. The Directive clearly stated that current science must be used, yet PSE continues to rely on outdated numbers from the flawed assessment used for their proposed LNG facility in Tacoma. Why does PSE continue to rely on it for decisions being made today that must be made correctly if we and PSE are to have a viable future? I believe that PSE actually understands what many stakeholders, including Robert Briggs, Charlie Black, Joni Bosh, Doug Howell, Tom Eckman, the Govenor, and others, want them to do. Please demonstrate that this is so by running the analyses requested. Show us that you CEO, who we were told was hired to help PSE reduce greenhouse gas emissions and eliminate fossil fuels, is actually leading the way on this. Use the SCC correctly in your analyses to help you determine the best way to reduce your greenhouse gas emissions prudently. Do this for both the electric and the gas sides of your business. It is not appropriate to think that a gas scenario that flatlines gas for decades is acceptable. All greenhouse gas emissions must stop, not just those for the electric side. For PSE to continue to pretend otherwise is also not prudent.	cost is passed to society and further defined the sensitivity where SCGHG does not apply to the operational level decisions. PSE verbally confirmed over the phone and through e-mail that the SCGHG is applied as a dispatch cost in the long term capacity expansion only where the portfolio decision is made. Once the portfolio decision is made and the SCGHG is not included the final hourly dispatch to simulate real world conditions. Sensitivity I follows the stakeholder input on how to treat SCGHG. https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/August_11_webinar/Invenergy_comments_PSE%E2%80%99s_Use_of_the_Social_Cost_of_Carbon_as_presented_on_August_11_2020.pdf As PSE committed earlier in the process, PSE will still model the SCGHG as a dispatch cost during the electric power price run and during the hourly dispatch and those results will be available at the February webinar.
12/28/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Questions and comments from presentation.	Thank you for your questions. PSE inserted each item below along with PSE's responses.
12/28/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 13 – The company must demonstrate that its plan reasonably balances the feasibility of acquiring substantial resources In a short timeline (a good argument to acquire resources in advance of the requirement) with the least-reasonable-cost approach to compliance (a good argument to wait until the last year to take full advantage of resource cost trends, especially in renewables and storage). How is the CETA renewable need modeled "as a linear ramp rate"? Does that mean the 80% to 100% requirement is included as a constraint for each year between 2030 and 2045? Has (or will) PSE explored the impacts of a year-by-year constraint approach as compared to two constraints – one for the 2030 requirement and one for 2045?	The linear ramp rate has been included to ensure that the model does not wait until the very last moment to add renewable resources and rather is adding resources along the way as PSE will also be working towards meeting CETA requirements and not waiting until the last year. The linear ramp rate is modeled as an annual minimum energy requirement for each year of the time horizon. If the requirement is only constrained for the years 2030 and 2045, then the model will wait till the last year to all resources to meet the requirement. Because of the declining cost curve, resources added in later years are lower cost than resources added earlier in the time horizon. The objective of the model is to minimize cost, so it will wait to add resources in order to minimize the total portfolio cost.
12/28/2020	Kyle Frankiewich, Washing	Slides 13 & 14 – Slide 13 shows the amount of renewables PSE forecast it would need to acquire in without DERs, including EE and DR. Slide 14 shows the amount of renewables PSE estimates it would need to acquire under its medium scenario with cost-effective DERs. They do not provide the NPV or Levelized Cost of	Chapter 3 of the draft 2021 IRP addresses the decisions behind the draft preferred portfolio and includes a comparison of costs and builds to the Mid portfolio. PSE will also reach out to the WUTC to clarify our understanding of the question.

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<tr><th>Feedback Form Date</th><th>Stakeholder</th><th>Comment</th><th>PSE Response</th></tr>
<tr><td></td><td>ton Utilities and Transportation Commission</td><td>Resource Plan that would satisfy CETA and EIA without DERs. The “value” of DERs is the difference between the cost of the resources needed to meet the “mid” shown in slide 13 versus the resources shown on slide 14. It would be useful to know the NPV or levelized cost of the resources required to meet the mid-scenario shown on Slide 13. Moreover, as we discuss later regarding PSE’s flexibility analysis, this difference still would fully capture the value of EE.</td><td></td></tr>
<tr><td>12/28/2020</td><td>Kyle Frankiewich, Washington Utilities and Transportation Commission</td><td>Slide 18 – Staff echoes Participant Adcock’s question and concern regarding the use of a California carbon price as a reasonable cost estimate for alternative compliance mechanisms under CETA. Why is this proxy cost estimate appropriate? Is there any connection to be found between the CA carbon market and the various paths to compliance described in CETA, such as energy transformation projects? In its 2017 acknowledgement letter, the Commission encouraged the company to further develop a marginal abatement cost curve, which could help the company and stakeholders more easily compare various compliance approaches.</td><td>PSE first discussed the alternative compliance costs and consulted with stakeholders at the September 1 webinar. PSE requested feedback from stakeholders regarding prioritization of the options for the 20% alternative compliance to reach carbon neutral target by 2030 in the 2021 IRP.

PSE received one suggestion regarding this through the feedback forms.

Feedback from Joni Bosch, NWEC:

In response to the question posed on prioritizing options for the 20% alternative compliance actions that might be addressed in the 2021 IRP, NWEC would urge PSE to model an aggressive amount of conservation and demand response. Beyond the required conservation and demand response required in sections .040 and .050 of CETA, additional innovative conservation, efficiency, storage and demand response should be considered for Energy Transformation Projects. Exploring those has the double impact of further reducing/managing load and achieving additional GHG reductions.

PSE created a portfolio that increased demand response, storage and distributed resources as Sensitivity V and W.

For the baseline assumption and comparison, PSE wanted to use a price forecast for the alternative compliance costs. PSE feels that the California carbon price is a reasonable assumption, however we are open for discussion and can also run another cost forecast to get a range of the alternative compliance costs.</td></tr>
<tr><td>12/28/2020</td><td>Kyle Frankiewich, Washington Utilities and Transportation Commission</td><td>Slides 19, 20 & 21 – These slides compare the amount of peak capacity needed with and without EE and DR and the amount of each resource developed by year. Based on our math from the info on the slides, it looks like the model acquires 476 aMW over the first 10 years. In the first few years the model (apparently due to ramp rate constraint assumptions) is acquiring fewer aMW than PSE’s current program actuals, and below what would be required under EIA’s “pro-rata” provision (i.e., 20% of 10 year cost-effective potential each biennium). We understand that PSE intends to run a “six year” ramp in sensitivity for conservation rather the 10-year ramp currently assumed in their modeling, but it seems that this “sensitivity” assumption is more in line with PSE’s current capabilities to acquire conservation, so may be a more reasonable baseline. This six year ramp will also slightly (75-80 MW) decrease the need for additional peak capacity in 2027. It appears that for every aMW of conservation savings PSE acquires it also gets around 1.8 MW of winter peaking capacity (209 aMW of conservation by 2027 reduces peak demands from 907 MW to 527 MW or 380 MW/209 aMW = 1.81 MW/aMW).</td><td>The model selected bundle 10 in the mid scenario, and the distribution efficiency, both of which are used in setting the program targets. The draft results for the 2 year ramped and 2 year pro-rata share of the 2021 IRP are shown below in comparison to the 2020-21 program targets:

<table><tr><th>Compare 2021 IRP to 2020-21 Program Targets</th><th>2 year</th><th>2 year pro-rata share</th></tr><tr><td>Mid Scenario Cost Effective EE, aMW</td><td>42.37</td><td>54.59</td></tr><tr><td>Current 2020-2021 Targets</td><td>NA</td><td>54.40</td></tr></table>
NOTE: The 2-year pro-rata share savings are obtained by dividing the 10-year savings by 5.

The 6-year ramp sensitivity results will be available with the final IRP. When compared to the Mid Scenario, the 6-year ramp will likely result in a higher 2-year number but the 2-year pro-rata share number will not change, since it’s the same 10-year savings being implemented at a faster pace over 6 years. From a peak contribution perspective the 6-year ramp does provide peak savings at a faster pace as well.</td></tr>
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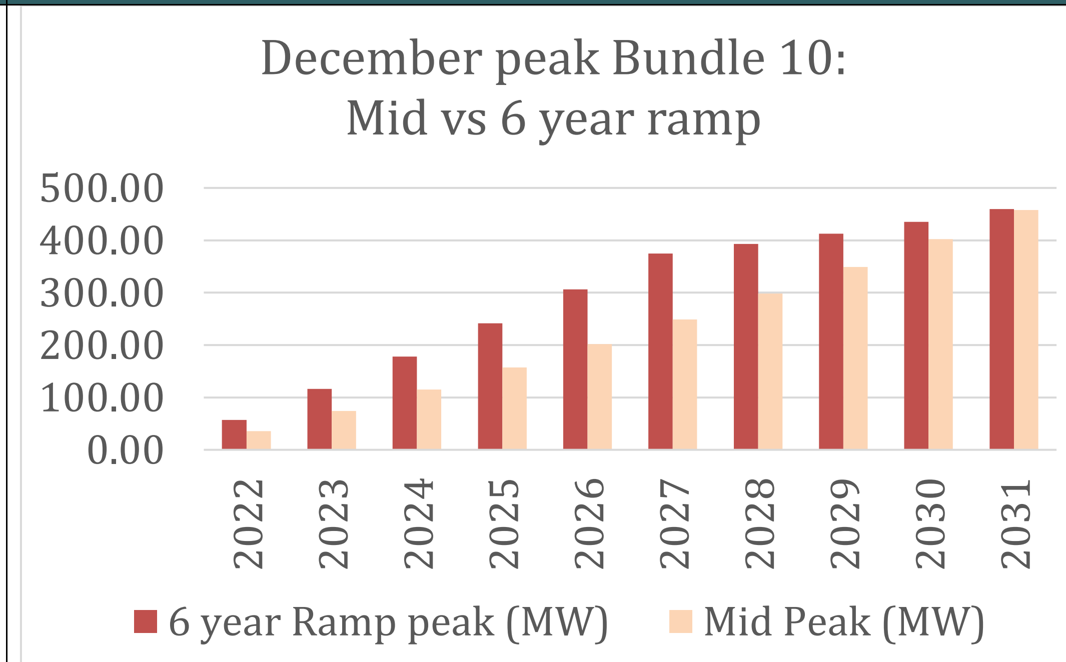
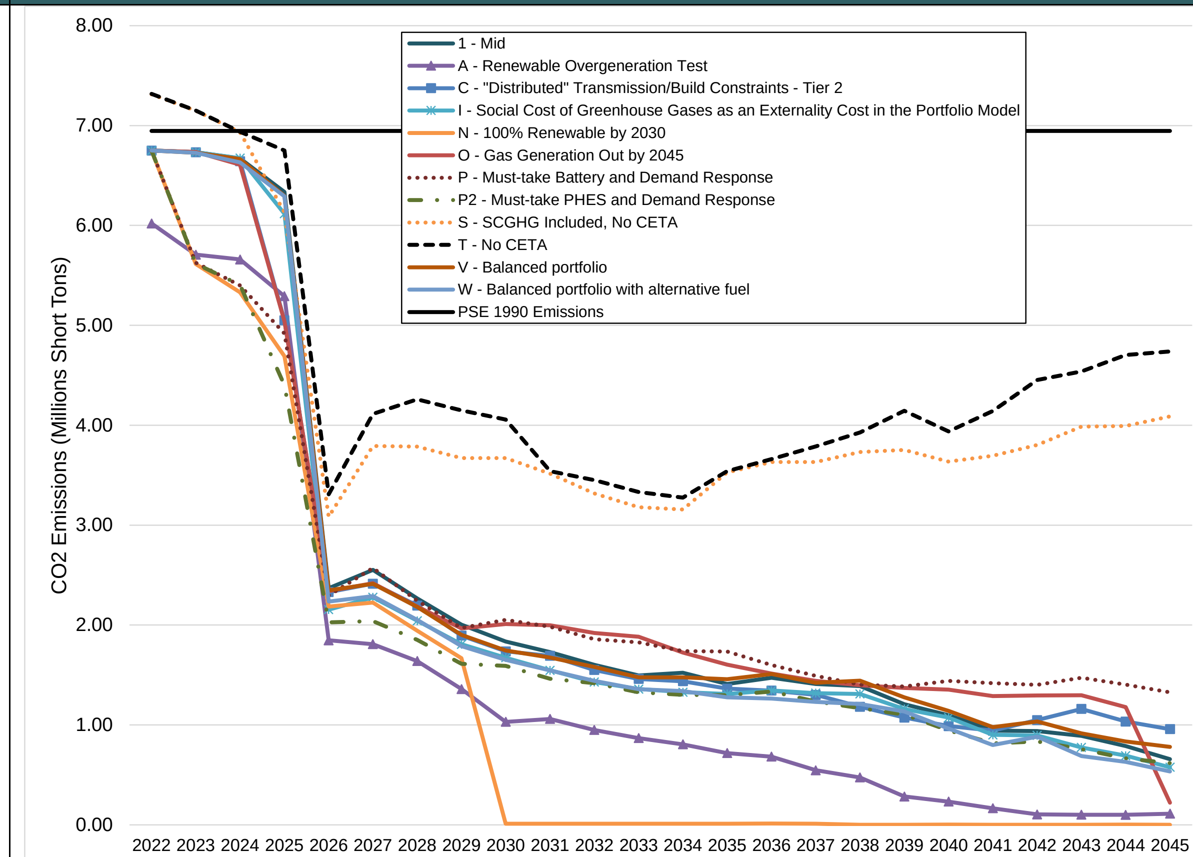
			
12/28/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 23 – While this slide gives a view into PSE's economic dispatch, rather than PSE's owned or controlled capacity available, it illustrates that PSE is exposed to significant market risk during winter peak periods (gray area in chart), and that increased adoption of DR and other DERs would likely have additional risk mitigation value. PSE will not be completing its risk analysis until after it files it draft IRP in early January. This means than any conclusions it draws regarding the value of DR, DERs or battery storage in the draft IRP should be heavily caveated.	Thank you for your feedback. PSE will complete the market risk analysis for the final IRP
12/28/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 28 – Staff have expressed concern that PSE has only one conservation supply curve that is used across all economic forecast scenarios. This has the effect of overstating conservation potential in the low case and understating potential in the high case, even accounting for differences in the "cost-effectiveness" limit for these scenarios. While PSE has stated that the difference in available conservation among the low, mid and high load forecasts is small, staff understands that the NWPCC's methodology has always included potential assessments that are internally consistent with the load forecast being used to identify resource need. Further, it seems to staff that this would not necessitate three separate CPAs or countless hours of consultant or employee time. If PSE holds separate the "lost-opportunity" conservation measures from retrofits, then scales the lost-opportunity potential to the some of the underlying inputs to the load forecast, such as population and employment growth, that should enable conservation resource options that 'match' a given load forecast. With this caveat,	Thank you for the comment. What you suggest is exactly how the supply curve would be adjusted. The impacts from the low and high load forecasts will translate to the lost opportunity measures in the CPA. In the 2021 IRP most stakeholders are inclined to think that the high load scenario is less likely, hence the results we have for the Mid Scenario have the highest likelihood of being the optimal amount. Thus while we could get higher savings in the supply curve associated with the high scenario, if we were to adjust the CPA, it would likely not impact the cost effective amount of conservation for the preferred portfolio. We agree that the results "across the range of load forecast seem reasonable." There will likely be impact on the resource mix in the high scenario, so we think it could be something to pursue in the next IRP.

Feedback Form Date	Stakeholder	Comment	PSE Response
		staff believes the results shared in this presentation across the range of load forecast seem reasonable.	
12/28/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 32 - It appears that through about 2030 the difference in cost between the "mid-case" and this renewables over-generation case is negligible. If so, PSE has several IRP cycles to assess whether storage technology has improved and/or costs have declined before it needs to make a decision about whether to "over-generate and store locally" or sell into the market. Staff looks forward to the market-risk analysis, which will inform the company's understanding of the how to best balance risks related to storage costs, market costs and market availability for both oversupply events and peak demand events. Staff wonders how far storage costs would have to decline - or how volatile the spot market might become - by 2030 such that a strategy to over-generate and store locally might become cost-competitive or valuable as a risk mitigation option.	Thank you for your comments.
12/28/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 37 – Has PSE explored how this Tx-as-%-of-nameplate idea might interact with energy storage sited at a project? It may lower the maximum available energy in a given hour, but the ELCC calculation and the added dispatchability may more than offset the lowered maximum capacity value and the energy value otherwise thrown away with a curtailment.	PSE already includes several hybrid generic resources which combine a generating resource (e.g. solar or wind) with a storage resource (e.g. battery or pumped hydroelectric storage). These hybrid resources assume the storage resource may only be charged from the 'attached' generating resource. The model assumes firm transmission capacity for the hybrid resource is equal to the nameplate capacity of the generating resource only, given it is unlikely both the generating resource and storage resource would need to discharge at the same time. Hybrid resources do have higher ELCC values than a comparable standalone generating resource. PSE has also started to explore the possibility of co-located resources, such as solar and wind located at the same site. Initial work indicates that complementary resource shapes of co-located resources may result in opportunities for reduced firm transmission capacity. PSE aims to expand this analysis in future to include co-located generating resources with independent storage resources (i.e. storage which may charge from the grid). Co-located resources present a significant modeling challenge but PSE hopes to include them in future IRP cycles.
12/28/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slides 38 – 40 – While staff appreciates this modeling exercise and believes the similarities in the portfolios are interesting, we note that the differences between the two portfolios' resource additions prior to 2025 are significant. We still struggle with what the inclusion of SCGHG "as an externality" means in the context of the LTCE model, and how this differs from the other two approaches discussed – as a fixed-cost adder and as a dispatch cost. Staff looks forward to reviewing the sensitivity results for a portfolio optimized around the SCGHG as included in hourly dispatch.	SCGHG as a dispatch cost will be included in the final IRP.
12/28/2020	Kyle Frankiewich, Washington Utilities and Transportation	Slide 42 – The ELCC estimate for batteries feels quite low, though that is purely a 'gut reaction.' It makes sense that, if the weather events that drive PSE's peak capacity needs are more than four hours long, an ELCC calculation for a four-hour duration resource would be low. It also makes intuitive sense that ELCC estimates decrease incrementally for each new wind and solar resource. Would the inverse be true for each incremental battery resource? That is, if PSE adds eight 100 MW bundles of battery resources sequentially, would the ELCC estimate for the ninth bundle of batteries be better, given that 800 MW of batteries has reduced the system's peak need?	The number 12.4% was achieved from the resource adequacy model, which has more constraints. In the resource adequacy model, the ELCC of the battery could be up to 40%. In the 2021 IRP process, PSE only has the info for 100 MW capacity so far. In 2019 IRP, the ELCC of the battery went down with the increase of the capacity. *Figure 7-19: Peak Capacity Credit for Battery Storage Based on EUE at 5% LOLP* <table><tr><th>BATTERY STORAGE</th><th>Capacity (MW)</th><th>2021 IRP Year 2027</th><th>2021 IRP Year 2031</th></tr></table>

<table>
<tr><th>Feedback Form Date</th><th>Stakeholder</th><th>Comment</th><th>PSE Response</th></tr>
<tr><td></td><td>Commission</td><td></td><td>
<table>
<tr><td>Lithium-ion, 2 hr, 82% RT efficiency</td><td>100</td><td>12.4%</td><td>15.8%</td></tr>
<tr><td>Lithium-Iin, 4 hr, 87% RT efficiency</td><td>100</td><td>24.8%</td><td>29.8%</td></tr>
<tr><td>Flow, 4 hr, 73% RT efficiency</td><td>100</td><td>22.2%</td><td>27.4%</td></tr>
<tr><td>Flow, 6 hr, 73% RT efficiency</td><td>100</td><td>29.8%</td><td>35.6%</td></tr>
<tr><td>Pumped Storage, 8 hr, 80% RT efficiency</td><td>100</td><td>37.2%</td><td>43.8%</td></tr>
</table>
</td></tr>
<tr><td>12/28/2020</td><td>Kyle Frankiewich, Washington Utilities and Transportation Commission</td><td>Slide 42 – The ELCC estimate for batteries feels quite low, though that is purely a ‘gut reaction.’ It makes sense that, if the weather events that drive PSE’s peak capacity needs are more than four hours long, an ELCC calculation for a four-hour duration resource would be low. It also makes intuitive sense that ELCC estimates decrease incrementally for each new wind and solar resource. Would the inverse be true for each incremental battery resource? That is, if PSE adds eight 100 MW bundles of battery resources sequentially, would the ELCC estimate for the ninth bundle of batteries be better, given that 800 MW of batteries has reduced the system’s peak need?</td><td>Please see response provided directly above.</td></tr>
<tr><td>12/28/2020</td><td>Kyle Frankiewich, Washington Utilities and Transportation Commission</td><td>Slide 46 – This cost breakout is useful. Staff would appreciate the added context of the SCGHG coming from emissions associated with the “No CETA” portfolio. Please also provide these cost comparisons at the 4-yr (CEIP) and through-2030 timescales, as it would be useful to understand whether the cost differences are driven by resources acquisitions in the earlier or later years. The table format in slide 48 is also well-done.</td><td>Part 1: The 24-year levelized SCGHG costs from emissions associated with the “No CETA” portfolio is $9.56 billion dollars. Below is a table showing the 24-year levelized costs comparisons for the Mid Scenario, SCGHG Only No CETA, No CETA, and No CETA with SCGHG costs portfolios.
<table>
<tr><th rowspan="2">Portfolio</th><th colspan="3">24-yr Levelized Cost ($ Billions)</th></tr>
<tr><th>Revenue Requirement</th><th>SCHGH adder</th><th>Total</th></tr>
<tr><td>1. Mid</td><td>$13.60</td><td>$5.00</td><td>$18.70</td></tr>
<tr><td>S. SCGHG Only, No CETA</td><td>$10.10</td><td>$9.00</td><td>$19.10</td></tr>
<tr><td>T. No CETA</td><td>$9.40</td><td>$0.00</td><td>$9.40</td></tr>
<tr><td>T2. No CETA - with SCGHG Costs</td><td>$9.40</td><td>$9.56</td><td>$18.96</td></tr>
</table>
Part 2: The cost comparisons at the 4-yr (CEIP) and through-2030 timescales will be provided in the consultation update.</td></tr>
</table>

Feedback Form Date	Stakeholder	Comment	PSE Response
12/28/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slides 52-62 – Staff is not yet assured that PSE's analysis fully captures the benefit of EE's impact on the amount of the balancing reserves needed, therefore the cost of those reserves. As shown on slide 55, under PSE's mid forecast they estimate they need (@ 99% error) 190 MW of flex-up and 196 MW of flex-down to balance 875 MW of wind in 2025. By 2030 this increases to 695 MW of flex-up and 749 MW of flex-down to balance 2,375 MW of wind and 1400 MW of solar. PSE's analytical results translate mean that for every 100 MW renewable capacity they add between 2025 and 2030 they need to increase their balancing reserves by just over 17 MW flex-up and 19 MW flex-down. Therefore, when EE reduces the amount of renewables required to meet the 80% CETA requirement by 2030 it also offsets the need to increase balancing reserves. When PSE feels comfortable with its estimates of the cost of provide flexible/balancing reserves, staff recommends that the appropriate avoided cost should be subtracted from the cost of the EE bundles such that their "net cost" is seen in AURORA.	The balancing reserve requirement was calculated on the load less conservation. Since the 2021 was not finished at the time, PSE used the 2019 IRP process conservation.
12/28/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 57: the DR resource examined in this flexibility study is useful, but may be a poor proxy for some other flexible demand programs that are likely to be available at scale in Washington in the near future.	For final IRP, PSE will run three different types of DR programs in the flexibility analysis, 1) 40 hour/season, 4- hour duration max with dispatch in real time, 2) 40 hour/season, 4- hour duration max with dispatch in day ahead, and 3) unlimited dispatch.
12/28/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 64: Staff applauds the company's transparency with this initial effort at understanding the value of flexibility. Unfortunately, we do not have any new information to add. The only component that seems relevant that was not discussed through this presentation is the CAISO EIM. The EIM enables participants to balance across a much larger footprint with a greater diversity of variances, thereby lowering costs for all participants. CAISO's EIM has been operating long enough to use its historical pricing information as some sort of ground-truthing of PSE's results. Could PSE glean some better understanding of the value of up- and down ramps by reviewing its participation in the market or analyzing the market's available data?	The flex up and flex down ramp is mimicking the CAISO EIM market, but we can also look to see if CAISO has done any analysis. PSE has also researched PGE's analysis from the 2019 IRP and has been making adjustments.
12/28/2020	Kyle Frankiewich, Washington Utilities and Transpor	Staff recommendations:	Thank you for your recommendations. PSE inserted each item below along with PSE's responses.

Feedback Form Date	Stakeholder	Comment	PSE Response
	tation Commission		
12/28/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	**Proxy cost for CETA alternative compliance approaches: (slide 18)** Staff recommends developing a stronger rationale for using the California carbon market forwards and forecasts as an estimate for CETA compliance alternatives. To the extent that emissions reduction estimates and program costs related to energy transformation projects are estimable at this time, they should be included in the analysis. To the extent that they are not available, the IRP should include an explanation for why, and a timeline for when ETPs will be understood well enough for inclusion.	Thank you for your recommendation.
12/28/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	**Market reliance analysis and valuation of demand-side resources: (slide 23)** Staff appreciates that some components of the risk analysis done in an IRP must be undertaken toward the end of the IRP process. Still, PSE's modeling of its transmission rights to the Mid-C market as a firm resource that would serve 25% or more of its peak load highlights that risk. It is unfortunate that this analysis, which has been a topic of consistent interest from the commission, will not be included in the draft IRP, and hence will not benefit from the public participation process connected with the draft IRP. Staff hopes that the value of decreased market reliance risk will be fully considered for those resources that insulate PSE from the cost and reliability risks that come with the company's Mid-C-as-firm-resource modeling assumption.	The market risk analysis will be included in the final IRP
12/28/2020	Kyle Kyle Frankiewich, Washington Utilities and Transportation Commission	**GHG emissions for all studies: (slide 46-48)** Given CETA's focus on GHG emissions reduction, it would be useful if PSE provided the cumulative GHG gas emissions for each of its cases/sensitivity studies. With this information, the company and stakeholders can compare the various approaches (and cost) of lowering emissions – knowing the $/ton reduction cost may point to alternative compliance mechanisms that are lower cost than reducing GHG from the power system.	PSE included the GHG emission chart in Chapter 8, electric analysis, page 8-23. *Figure 8-10: CO_2 Emissions by Portfolio* *(does not include alternative compliance to meet carbon neutral standard in 2030 and beyond)*

Feedback Form Date	Stakeholder	Comment	PSE Response
			 PSE will explore the idea of a $/ton reduction cost or carbon abatement curve to use as the alternative compliance cost.
12/28/2020	Court Olson, Optimum Building Consultants LLC	During the webinar I typed a question into the chat box that was not answered. It related to the chart on slide #22 about flexible peaking capacity. In the narrative next to the chart on that slide is the statement: "The resources shown are the least cost optimization results…" I asked if the social cost of carbon was used in the calculations relating to the least cost depictions there? I had a follow up question in mind that I would like to ask now: What specific cost values were input into the modeling program for each of the different types of resources depicted in the chart on slide 22? Finally, I'd like to hear the details behind how PSE calculated the cost value for the Demand Response resource in the slide 22 chart? I look forward to having these questions answered.	Complete details of all costs for each resource is included in Appendix D of the Draft IRP. Demand response assessment is included in Appendix E.
12/28/2020	Anne Newcomb	Happy to see conservation is working out so well to reduce costs! On slide 63 or so I appreciate your realization that it would be helpful to bring in some additional experts or council from other utility's who have been successful in	First year of IRP is 2022, given a 2-year construction time for new resources, the first year available is 2024. As a reference, the 2018 RFP was a 2-year process and the new resources have start dates ranging from 2020 – 2023, 2 – 6 years after the start of receiving the bids.

Feedback Form Date	Stakeholder	Comment	PSE Response
		the transition to clean energy to assist with analyzing some of the modeling and sensitivity input. Please let me know if you need any help locating someone to help. Considering PSE is behind with running the remaining sensitivities, I suggest hiring energy consultants to help. Getting more renewables online between now and 2025 is important! Why are we waiting? I realize Wind Farms can take 2 years to build and in answering a question at the end of the December 11th IRP, Elizabeth stated PSE would need to wait until 2022 to get started on new wind projects. If the WUTC was to approve the building of more renewable resources like Wind and Solar prior to 2022, would PSE agree to getting started in 2021 with renewable resources from previous RFP's? If we look at all of the stacked benefits of battery storage mentioned by Don Marsh they are a good resource and should be ramped up much faster. No new NG Peakers please! A recent article from Inside Climate News (https://insideclimatenews.org/news/10122020/inside-clean-energy-fossil-fuel-power-plants/) has some interesting research showing how if the US doesn't build any new fossil fuel plants to generate electricity there will be very few stranded assets in 2035 when the US may need to generate 100% carbon free electricity under Joe Biden's climate plan. Rather than pay for offsets and stranded assets, lets reduce NG sooner! Hopefully you enjoyed some good time off for the Christmas Holiday!	In October of this year, PSE will be submitting its first clean energy implementation plan (CEIP) for consideration by the Commission, which will include its proposed specific actions and targets with respect to renewable resources. Once the Commission approves the CEIP, PSE can begin acquiring those resources. In the meantime, PSE will continue to look for opportunities to bring new renewable resources online through mechanisms like power purchase agreements to meet identified resource needs. PSE ran sensitivity N, O, P with no new peaking capacity and retiring existing thermal plants. Located in Chapter 8.

PSE IRP Consultation Update
Webinar 11: Flexibility Analyis and Portfolio Draft Results
December 15, 2020

01/19/2021

The following consultation update is the result of stakeholder suggestions gathered through an online Feedback Form, collected between December 8 and December 28, 2020 and summarized in the January 11 Feedback Report. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

Stakeholder questions and suggestions spanned a wide variety of topics and not all are included in this Consultation Update. As always, line-by-line responses to each stakeholder comment are provided in the Feedback Report[1]. Similarly, many stakeholder questions received from the December 15th Webinar have been answered in the Draft IRP, which is now available for review on the IRP website[2]. PSE encourages stakeholders to review these materials in concert with this Consultation Update.

As referenced in the Feedback Report, PSE has contacted the following stakeholders to clarify their comments:

- Katie Ware, Renewable Northwest, was contacted on January 15, 2021 to clarify her request for an additional sensitivity which only allows non-emitting resoureces. This sensitivity is similar to sensitivity P: Must Take Battery or Pumped Hydro, where no new peaker plants are allowed until 2030 and the portfolio model optimization allows the solution to meet peak needs without peaker plants. The lowest cost option optimized to 2-hour lithium Ion batteries. PSE also ran a sensitivity P2 with pumped storage hydro. This request is to add a P3 with 4-hour Lithium Ion batteries.
- Kyle Frankiewich, WUTC, was contacted on January 15, 2021 to clarify his inquiry on the difference in portfolio cost (either net present value or levelized cost) for the Mid portfolio with and without DERs. PSE will add a No DSR portfolio to the portfolio sensitiviites to test.

Alternative Compliance Cost

PSE received feeback from James Adcock and Kyle Frankiewish (WUTC) concerning the use of of the California carbon price as a cost forecast for alternative compliance costs. PSE solicited stakeholder feedback on alternative compliance costs during the September 1 webinar and received a single response from the Northwest Renewable Energy Coalition (NWEC):

> "In response to the question posed on prioritizing options for the 20% alternative compliance actions that might be addressed in the 2021 IRP, NWEC would urge PSE to model an aggressive amount of conservation and demand response. Beyond the required conservation and demand response required in sections .040 and .050 of CETA, additional innovative conservation, efficiency, storage and demand response should be considered for Energy Transformation Projects. Exploring those has the double impact of further reducing/managing load and achieving additional GHG reductions."

PSE acted upon NWEC's suggestions by creating Senstivities V (Balanced Portfolio) and W (Balanced Portfolio with Alterative Fuel for Peaking Capacity) which increase quantities of demand response, storage and distributed resources. PSE still required an alternative compliance price to model and decided the California carbon price is a suitable, real-world example of carbon pricing and therefore a sound starting point. PSE is open to feedback on possible alternatice compliance cost sensitivities to include in future models.

Flexibility Analysis

PSE received feedback from a Katie Ware (Renewable Northwest) and Kyle Frankiewich (WUTC) regarding PSE's intial approach for the flexibility analysis.

Renewable Northwest has suggested that PSE incorporate four dimensions of flexibility into the flexibility assessment: absolute power output capacity, speed of power output change, duration of energy levels and carbon intensity. This suggestion will be taken under advisement.

Renewable Northwest further suggests that the flexibility value of the reciprocating peaker plant ($417.25/kW-yr) may be articificially inflated due to the facilities small nameplate capacity. PSE has adjusted the nameplate capacity of the reciprocating peaker to 216 MW which has changed the flexibility benefit to $35/kW-yr.

Both the WUTC and Renewable Northwest suggest that PSE examine the flexibility benefit and assessment approaches of the CAISO Energy Imbalance Market (EIM).

PSE thanks stakeholders for their thoughtful review and suggestions.

ELCC Values

PSE received feedback from Katie Ware (Renewable Northwest) and Kyle Frankiewich (WUTC) that the effective load carrying capability (ELCC) of storage resources may be low. PSE would direct stakeholders to Chapter 7 of the 2021 Draft IRP for a full discusccion on PSE's ELCC methodology and results. In brief, storage resources are energy limited resources which are assessed with a different set of resource adequacy meterics (expected unserved energy, instead of loss of load probability). Therefore, long-term (i.e. multi-day) peak events which are common in winter months may not be

[1] December 15, 2020 Webinar Feedback Report:
https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/December_15_Webinar/Webinar%2011%20-%20Feedback%20Report.pdf
[2] PSE 2021 Draft IRP: https://pse-irp.participate.online/2021-irp/reports

well served by short-duration storage resources. Kyle Frankiewich suggested that saturation curves for storage resources may reveal increased ELCC with added capacity. PSE will attempt incorporate this suggestion into future IRP cycles.

Portfolio Draft Results

Katie Ware (Renewable Northwest), James Adock, Elyette Weinstein, Nathan Sandvig (Rye Development LLC) and Kyle Frankiewich (WUTC Staff) provided feedback of concerns regarding PSE's portfolio draft results.

Katie Ware and Nate Sandvig requested PSE model a sensitivity which prevent additions of new emitting resources. The Final IRP will include Sensitivities N: 100% renewable by 2030, O: Gas Generation Out by 2045 and P: Must Take Battery or Pumped Hydro Storage which limit new peaking capacity builds and relaying on energy storage resources such as batteries and pumped storage hydro. PSE will also add a portfolio sensitivity that evaluates Montana Wind plus pumped storage hydro and a hybrid resource in 2026.

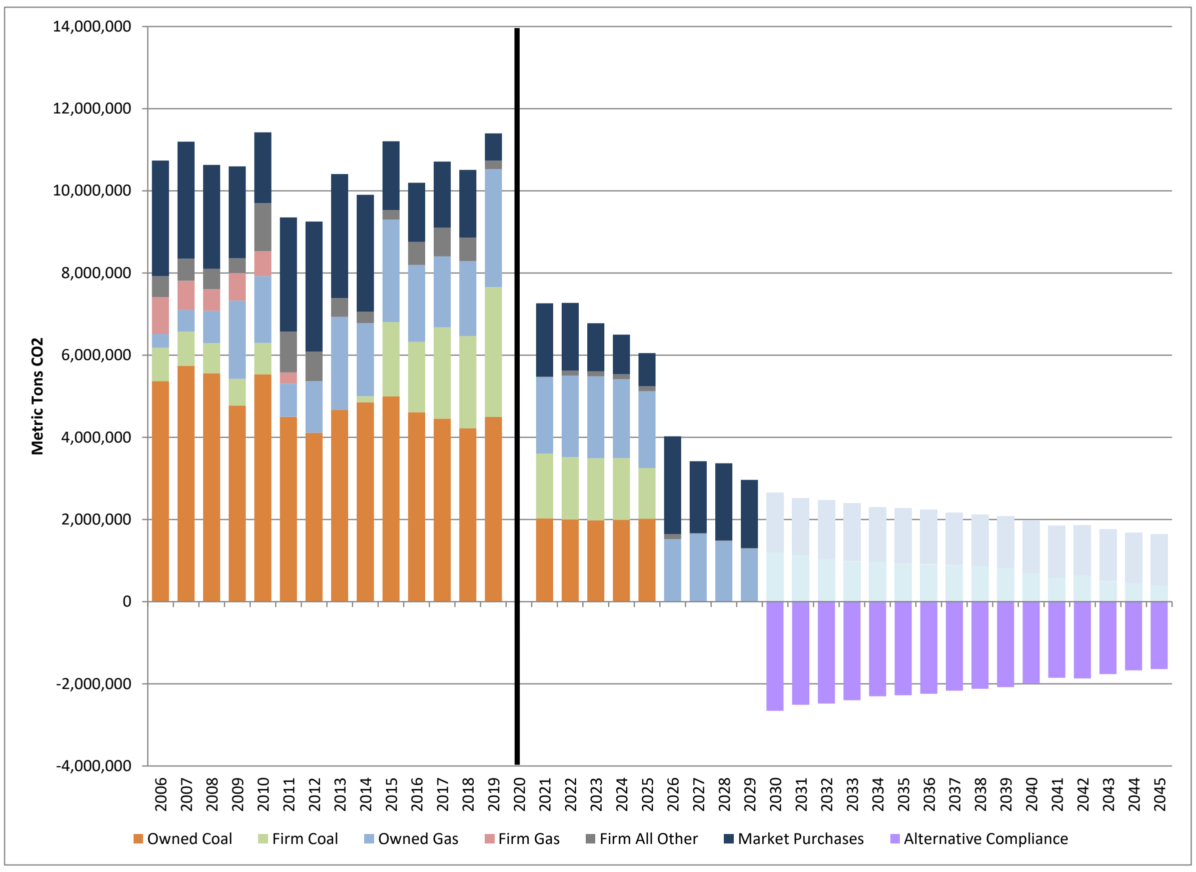
PSE feels these sensitivities adequately reflect possible zero-emission portfolios and can therefore assess the viability of including peaking capacity resources into the preferred portfolio.

Further work as part of Clean Energy Action Plan and Clean Energy Implementation Plan will further assess non-energy benefits and burdens of including peaking capacity resources into PSE's clean energy future.

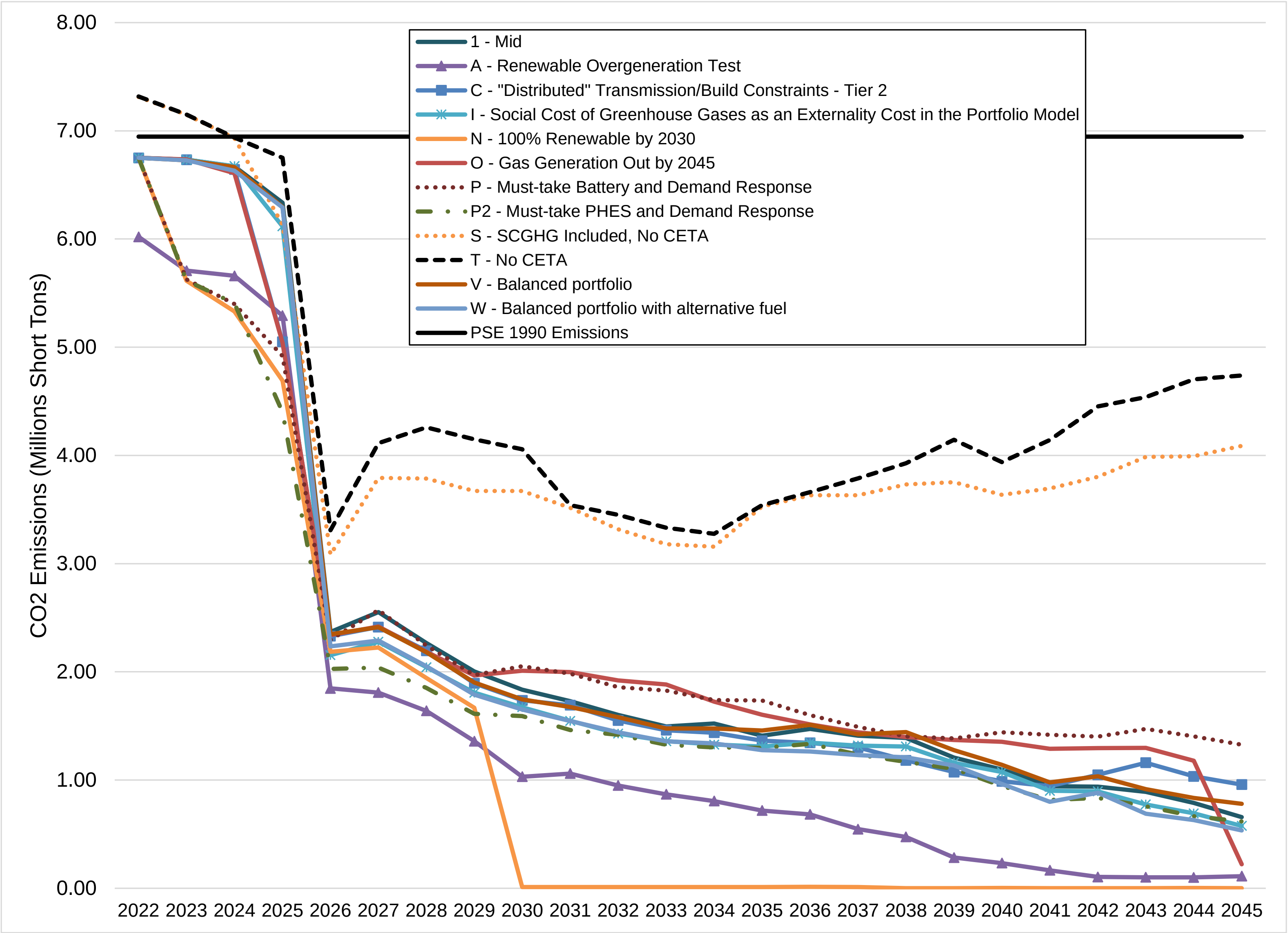
Other Updates

The following items have been updated after the Webinar 11:

1. Willard Westre (Union of Concerned Scientists) asked for clarification on the emissions chart on Slide 17. In the Feedback Report, PSE released a revised version of the chart which addresses Willard's questions. PSE would note that the reduction in greenhouse gas emissions from 2019 to 2029 is 75%.



2. Kyle Frankiewich (WUTC) requested a chart comparing the greenhouse gas emissions for each sensitivity portfolio. PSE has produced this chart as part of Chapter 8 in the Draft IRP. The figure is also provided below on the next page.



3. Kyle Frankiewich (WUTC) requested a table comparing the 4-yr (2022-2025), 9-yr (2022-2030), 20-yr (2022-2041) and 24-yr (2022-2045) portfolio levels costs for the scenarios and sensitivities presented in during the webinar. The table is provided on the next page.

PSE IRP Consultation Update
Webinar 11: Flexibility Analyis and Portfolio Draft Results
December 15, 2020

01/19/2021

(in Billion Dollars, 2022)		4-Yr Levelized Costs (2022-2025)				9-Yr Levelized Costs (2022-2030)				20-Yr Levelized Costs (2022-2041)				24-Yr Levelized Costs (2022-2045)			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid	Revenue Requirement	SCGHG Costs	Total	Change from Mid	Revenue Requirement	SCGHG Costs	Total	Change from Mid	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid	$2.50	$2.06	$4.56		$5.60	$3.26	$8.86		$11.63	$4.72	$16.35		$13.63	$5.04	$18.68	
A	Renewable Overgeneration Test	$2.62	$1.85	$4.47	($0.10)	$5.83	$2.89	$8.72	($0.14)	$12.82	$4.00	$16.82	$0.47	$15.32	$4.24	$19.57	$0.89
C	"Distributed" Transmission/Build Constraints - Tier 2	$2.58	$2.00	$4.58	$0.01	$5.56	$3.20	$8.76	($0.14)	$11.72	$4.70	$16.42	$0.07	$14.53	$5.06	$19.59	$0.91
I	Social Cost of Greenhouse Gases as an Externality Cost in the Portfolio Model	$2.58	$2.03	$4.61	$0.04	$5.62	$3.06	$8.69	($0.14)	$11.54	$4.47	$16.01	($0.34)	$13.65	$4.78	$18.42	($0.25)
N	100% Renewable by 2030	$2.67	$1.80	$4.47	($0.10)	$9.03	$2.62	$11.65	($0.14)	$26.29	$3.23	$29.51	$13.16	$31.14	$3.42	$34.56	$15.89
O	Gas Generation Out by 2045	$2.28	$2.04	$4.32	($0.24)	$4.98	$3.36	$8.33	($0.14)	$21.19	$5.65	$26.84	$10.49	$33.90	$6.24	$40.14	$21.46
P	Must-take Battery	$2.54	$1.87	$4.40	($0.16)	$10.90	$3.34	$14.23	($0.14)	$25.62	$5.53	$31.15	$14.79	$29.09	$6.06	$35.15	$16.47
P2	Must-take PHES	$2.68	$1.82	$4.51	($0.05)	$8.94	$2.66	$11.61	($0.14)	$19.36	$4.03	$23.40	$7.04	$22.35	$4.36	$26.71	$8.04
S	SCGHG Included, No CETA	$2.19	$2.14	$4.34	($0.23)	$4.46	$4.07	$8.53	($0.14)	$8.73	$7.76	$16.49	$0.14	$10.06	$9.01	$19.08	$0.40
T	No CETA	$2.09	$0.00	$2.09	($2.48)	$4.10	$0.00	$4.10	($0.14)	$8.04	$0.00	$8.04	($8.31)	$9.40	$0.00	$9.40	($9.28)
V	Balanced Portfolio	$2.53	$2.05	$4.58	$0.01	$5.65	$3.25	$8.90	($0.14)	$12.16	$4.71	$16.87	$0.51	$14.37	$5.06	$19.43	$0.75
W	Balanced Portfolio with alternative fuel for peakers	$2.60	$2.04	$4.64	$0.07	$5.81	$3.19	$9.00	($0.14)	$12.36	$4.56	$16.92	$0.57	$14.43	$4.86	$19.30	$0.62

Summary of all updates

PSE appreciates the feedback provided by stakeholders. In summary, the following changes will be implemented:

- PSE updated the emissions chart and provided table comparing the 4-yr (2022-2025), 9-yr (2022-2030), 20-yr (2022-2041) and 24-yr (2022-2045) portfolio levels costs for the scenarios and sensitivities presented in during the webinar in this Consultation Update based on stakeholder inquiries.
- PSE has updated the nameplate capacity of reciprocating peakers from 18 MW to 216 MW to obtain a more reasonable flexibility benefit.
- PSE is open to incorporating a range of possible carbon prices to better understand costs of alternative compliance.
- PSE will add the following sensitivities to the list - P3: Must Take Battery or Pumped Hydro with 4-hour lithium Ion battery, X: No DSR, and Y: include MT Wind + Pumped Storage Hydro in 2026.

Webinar 12, February 10, 2021

Electric Portfolio Draft Results, Delivery System and Grid Modernization Solutions, Flexibility Analysis Results and Economic, Health and Environmental Benefits Assessment

Webinar #12: Delivery System and Grid Modernization Solutions, Flexibility Analysis Results, EHEB Assessment, Portfolio Draft Results

February 10, 2020 from 1:00 p.m. to 5:00 p.m. PST

Virtual webinar link: https://global.gotomeeting.com/join/212040181
Access code: 212-040-181

Topic	Lead
Welcome • Agenda review • Safety moment • How to participate • Speaker introductions	EnviroIssues
Public Process Check-in	Irena Netik, Director Resource Planning & Analysis, PSE
Delivery System and Grid Modernization Solutions	Jens Nedrud, Manager System Planning, PSE Elaine Markham, Manager, Grid Modernization Strategy & Enablement, PSE
Flexibility Analysis Results	Elizabeth Hossner, Manager Resource Planning & Analysis, PSE
10-minute break	
Economic, Health and Environmental Benefits (EHEB) Assessment of Current Conditions Status Update	Tyler Tobin, Resource Planning Analyst, PSE
Portfolio Draft Results	Elizabeth Hossner, Manager Resource Planning & Analysis, PSE
Wrap up and next steps • Next steps • Upcoming meeting schedule • Thank you's	EnviroIssues

Call-in telephone number (audio only): +1 (872) 240-3412

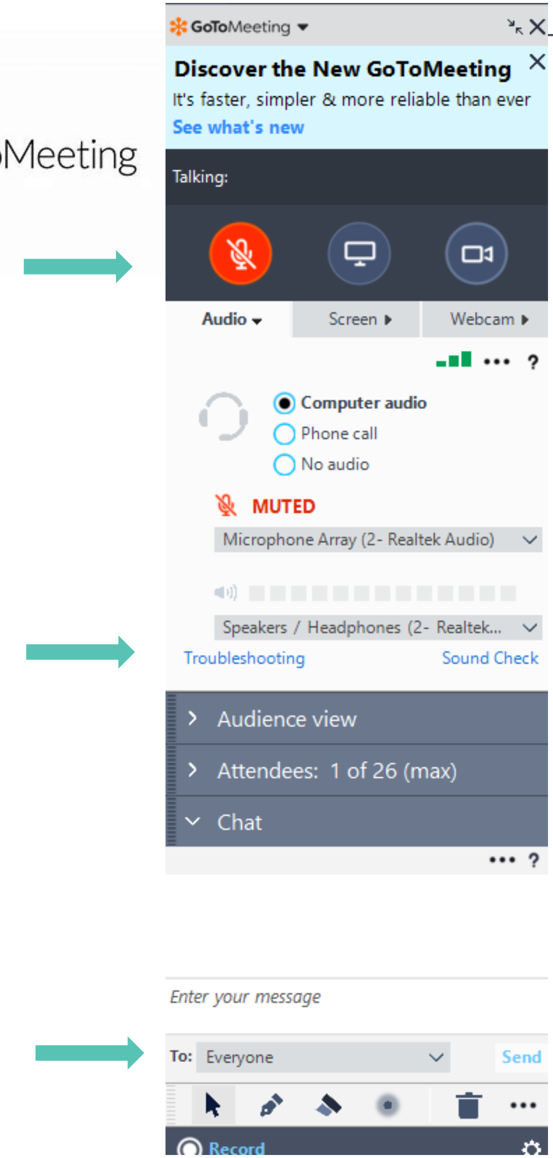
2021 IRP Webinar #12:

Delivery System and Grid Modernization Solutions, Flexibility Analysis results, Portfolio draft results, and Economic, Health and Environmental Benefits Assessment of Current Conditions Status Update

February 10, 2020

Welcome to the webinar and thank you for participating!

GoToMeeting



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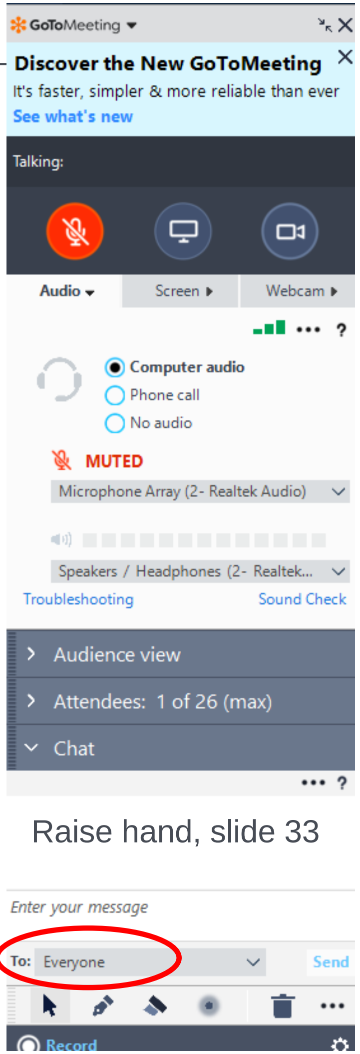
How to participate using Go2Meeting

Presentation Do's

- Mute your mic during the presentation
- You can participate in writing or verbally using the chat window
  - **In writing:** your question will be read
  - **Verbally:** type "Raise hand" and slide #, share with "Everyone"; please wait to be called on to ask your question
- Be considerate of others waiting to participate
- We will try to get to all questions



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Agenda

- Safety Moment
- Public Process Update
- Delivery System and Grid Modernization Solutions
- Flexibility Analysis results
- Economic, Health and Environmental Benefits Assessment of Current Conditions Status Update
- Portfolio draft results with Customer Benefit Indicators

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Safety Moment: Preventing Slips, Trips, and Falls

Working on site or at home can have dangers. Common falls occur when people are getting of cars, rushing to catch a bus or elevator, walking on unstable ground, and navigating the house. To keep safe:

5 fall prevention tips:

- Ensue proper lighting
- Wear non-skid shoes
- Clear the clutter
- Stand up slowly after laying down
- Remove rugs and cord from the floor

And some home safety checks:

- Clear pathways of furniture and clutter
- Secure rugs with double sided tape
- Coil or tape cords against the wall
- Place a lamp within reach of the bed
- Add a nightlight by the doorway

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Today’s Speakers

Elizabeth Hossner
Manager, Resource Planning & Analysis, PSE

Irena Netik
Director, Resource Planning & Analysis, PSE

Jens Nedrud
Manager, System Planning, PSE

Elaine Markham
Manager, Grid Modernization Strategy & Enablement, PSE

Tyler Tobin
Analyst, Resource Planning & Analysis, PSE

Alison Peters & Elise Johnson
Co-facilitators, EnviroIssues

Thank you for your feedback on the draft IRP

Date	Action
May-Dec 2020	2021 IRP process: 10 PSE Webinars, feedback reports, consultation updates and numerous stakeholder engagements & communications
Dec 15, 2020	PSE Webinar 11: draft portfolio sensitivity results
Dec 28, 2020	WUTC adopted final IRP/CEIP rules
Jan 4, 2021	Draft Electric & Gas IRP posted online and filed with WUTC
Feb 5, 2021	End of opportunity to file written comments with WUTC
TODAY Feb 10, 2021	**PSE Webinar 12**
Feb 26, 2021	WUTC Open Meeting on draft IRP
Mar 5, 2021	PSE Webinar 13
Apr 1, 2021	Final Electric & Gas IRP posted online and filed with WUTC

https://pse-irp.participate.online/2021-irp/reports

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2021 IRP modeling process

The 2021 IRP will follow a 6-step process for analysis:

1. Analyze and establish resource need
2. Determine planning assumptions and identify resource alternatives
3. Analyze scenarios and sensitivities using deterministic and stochastic risk analysis
4. Analyze results
5. Develop resource plan
6. 10-year Clean Energy Action Plan

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Delivery System and Grid Modernization Solutions

Participation Objectives

- PSE will review the grid modernization investments that support DER and NWA integration.
- PSE will review the NWA solution process results, key learnings and get feedback from stakeholders on the NWA screening criteria.

IAP2 level of participation:

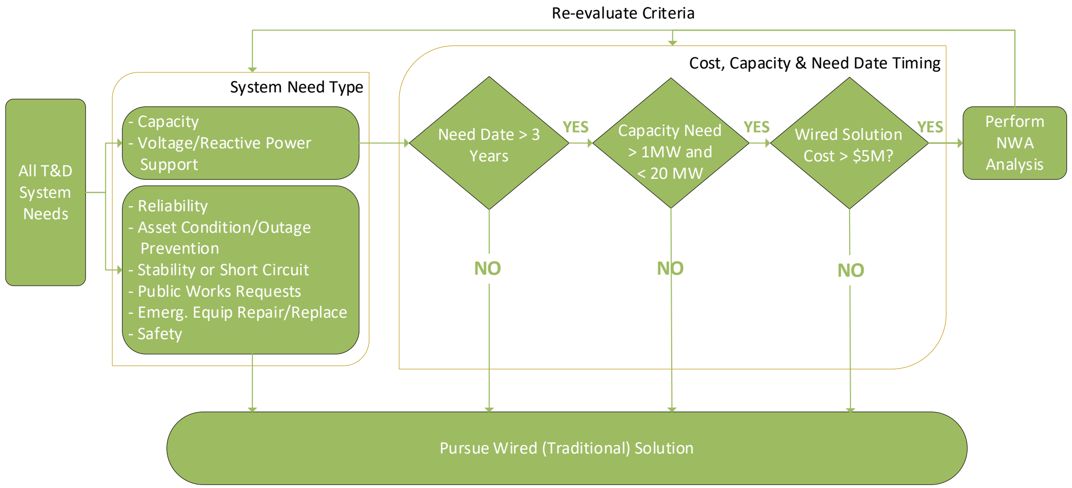
INFORM & CONSULT

Overview

- System investments in Grid Modernization
  - Future Vision: Enterprise Investments
  - Reliability and Resiliency
  - Infrastructure Backbone
- Non-wires alternative progress
  - Deep dive on four focus areas
  - Key learnings from focus areas analysis
  - Non-wires screening process and stakeholder feedback

IRP Stakeholder Feedback Approach

- Obtain feedback on specific NWA analysis criteria necessary to evaluate projects:
  - Proposed criteria
    - Need driver
    - Size of the capacity need
    - Time to implement
    - Cost
  - Other criteria to consider?



Comprehensive Grid Modernization Enables DER Integration and NWAs

Discussed at August Webinar
- Standards for DER Enablement

Discussed at November Webinar
- Geospatial Load Forecasting
- Hosting Capacity Map
- Interconnection Portal
- Alternative Rates and Pricing

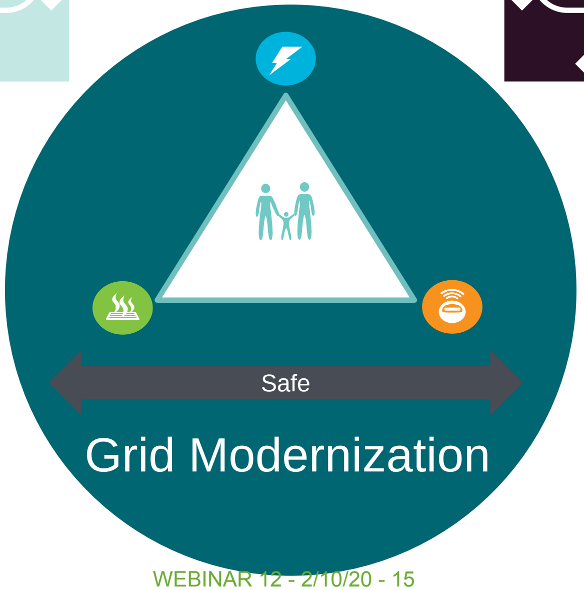
Cybersecurity and Privacy

Integrating DERs

Visibility, Analytics and Control

Discussed at August and November Webinars
- AMI Meter Upgrade
- SCADA
- ADMS
- DERMS

Reliability and Resiliency



Flexible Backbone

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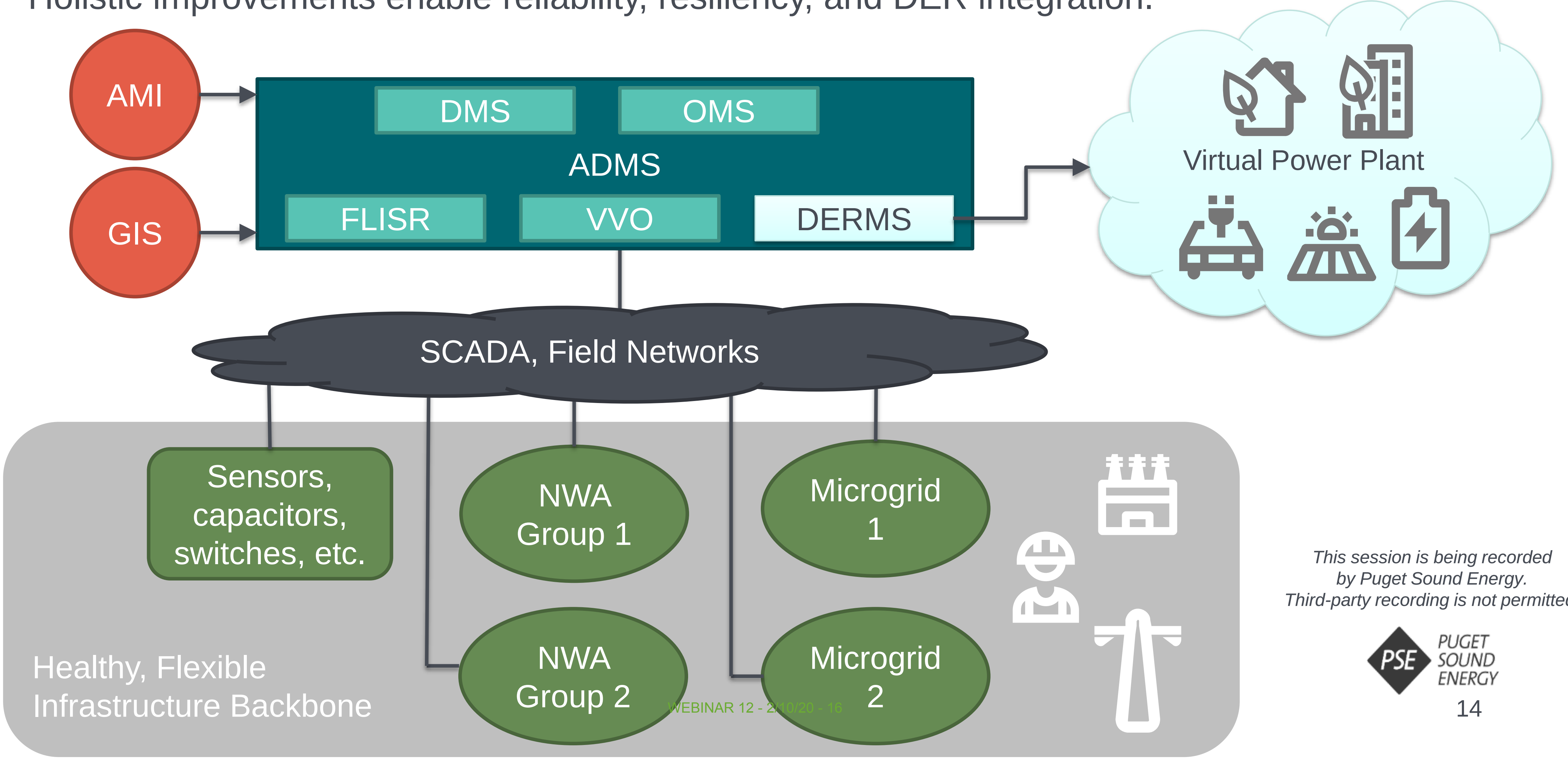
Future Vision: Enterprise Enhancements Support Grid Mod Goals

Holistic improvements enable reliability, resiliency, and DER integration.



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Reliability and Resiliency

Reliability

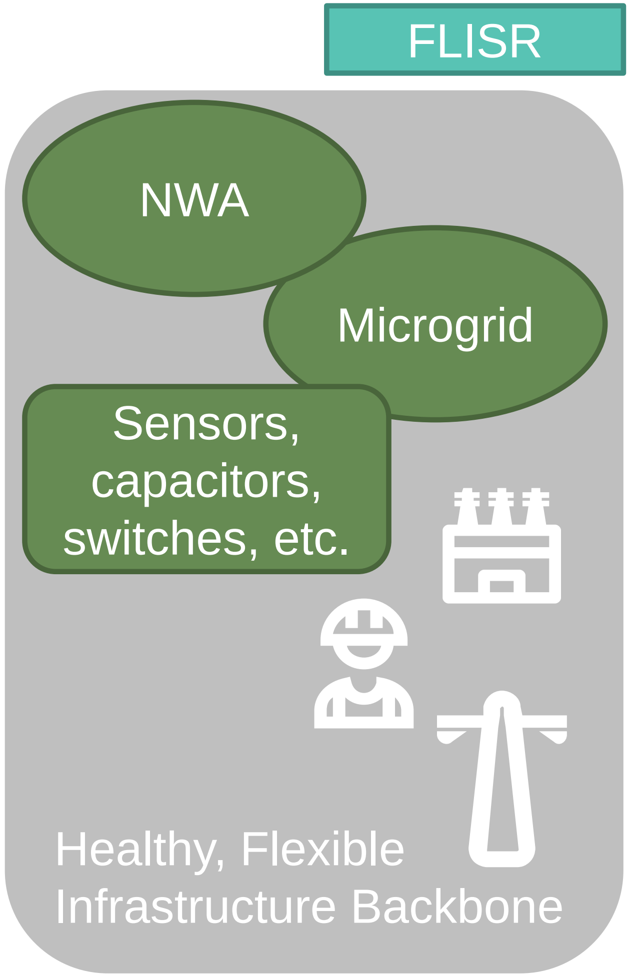
- Duration and frequency of outages to customers

Resiliency

- Planning and preparedness for high impact, low frequency (HILF) events

Types of investments

- Pole replacement
- Vegetation Management
- Asset health, etc.
- Some Non-Wires Alternatives
- Microgrids
- Grid devices such as sensors and switches in support of Fault Location, Operating procedures, Isolation, Service Restoration (FLISR)



Flexible Backbone

Healthy, Flexible Infrastructure Backbone

Delivery System Planning process (developing solutions)

Assumptions, performance targets and modeling input → Establish Grid Needs → Alternative choices and assumptions → Screen and analyze alternatives → Analyze and optimize solution → Initiate project feasibility and planning

Key Capabilities

- Evaluation of wired, non-wired and hybrid solutions
- Inclusion of customer partnership opportunities
- Benefit valuation for non-wire alternatives
- Robust project optimization which maximize benefits to cost for investments

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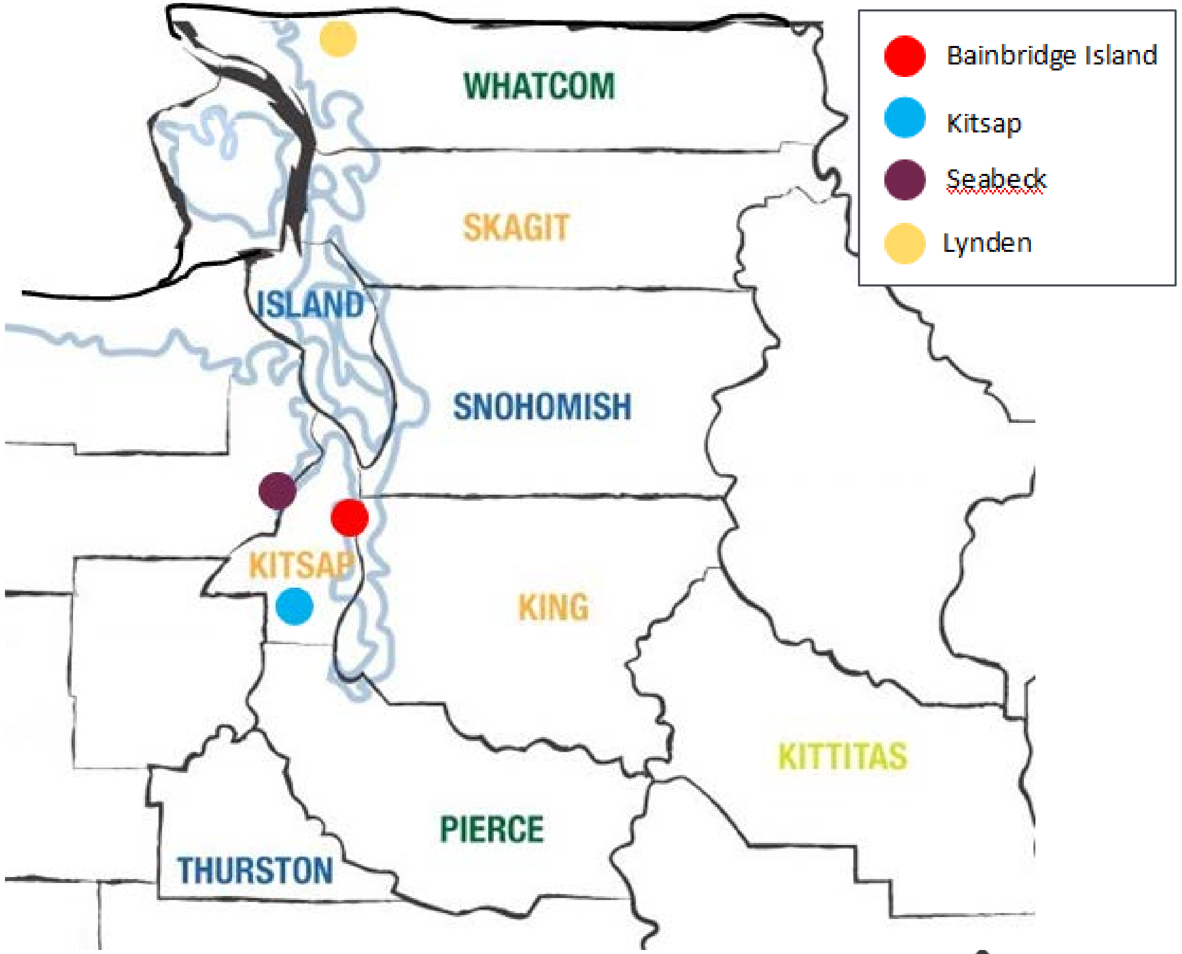
Non-wire Alternative progress

PSE committed to completing Non-Wire Alternative (NWA) analysis on four focus areas

- Solutions considered wired, non-wired and hybrid alternatives
- Diverse drivers
  - Reliability
  - Capacity
  - Aging Infrastructure



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Non-wire Alternative key findings

Capacity	Reliability	Aging Infrastructure	General
NWA effectively addresses capacity needs	Challenging for NWA's due to the long duration	Challenging for NWA's due to the duration.	Type of need influences viability of NWA
Duration affects cost effectiveness	NWA provide limited operational flexibility		Additional time needed to implement
Ineffective at addressing large scale needs	Typically occur on radial parts of the system		

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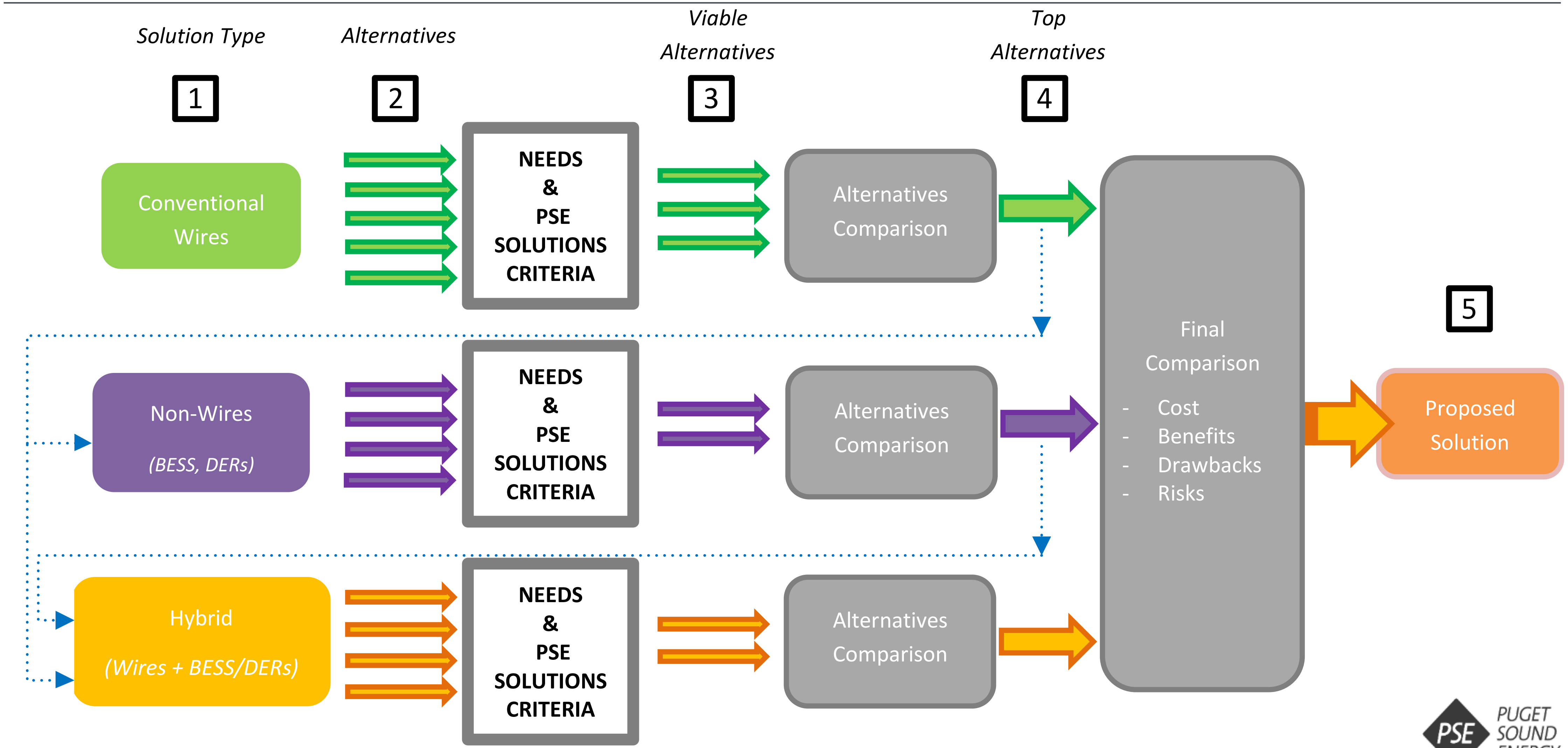
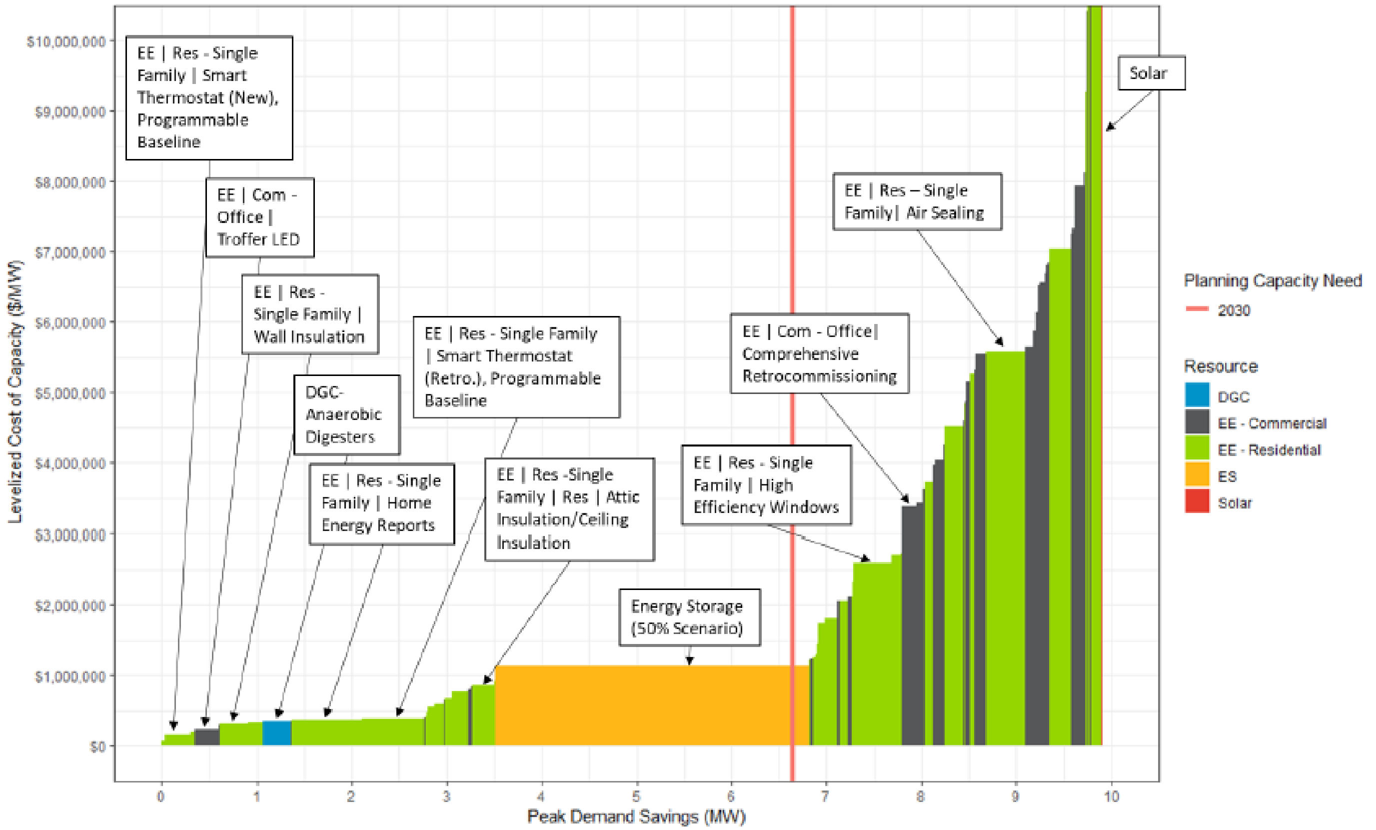
Non-wire Alternative solution process



Non-wire Alternative can addresses capacity need (<20 MW)

- Bainbridge island study
- Non-wires economic analysis included evaluation of costs and benefits for each resource type
- Result is a hybrid solution
  - Wired infrastructure necessary to address reliability need
  - Last-cost portfolio of DER to meet the capacity need



Least cost DER portfolio to address capacity need

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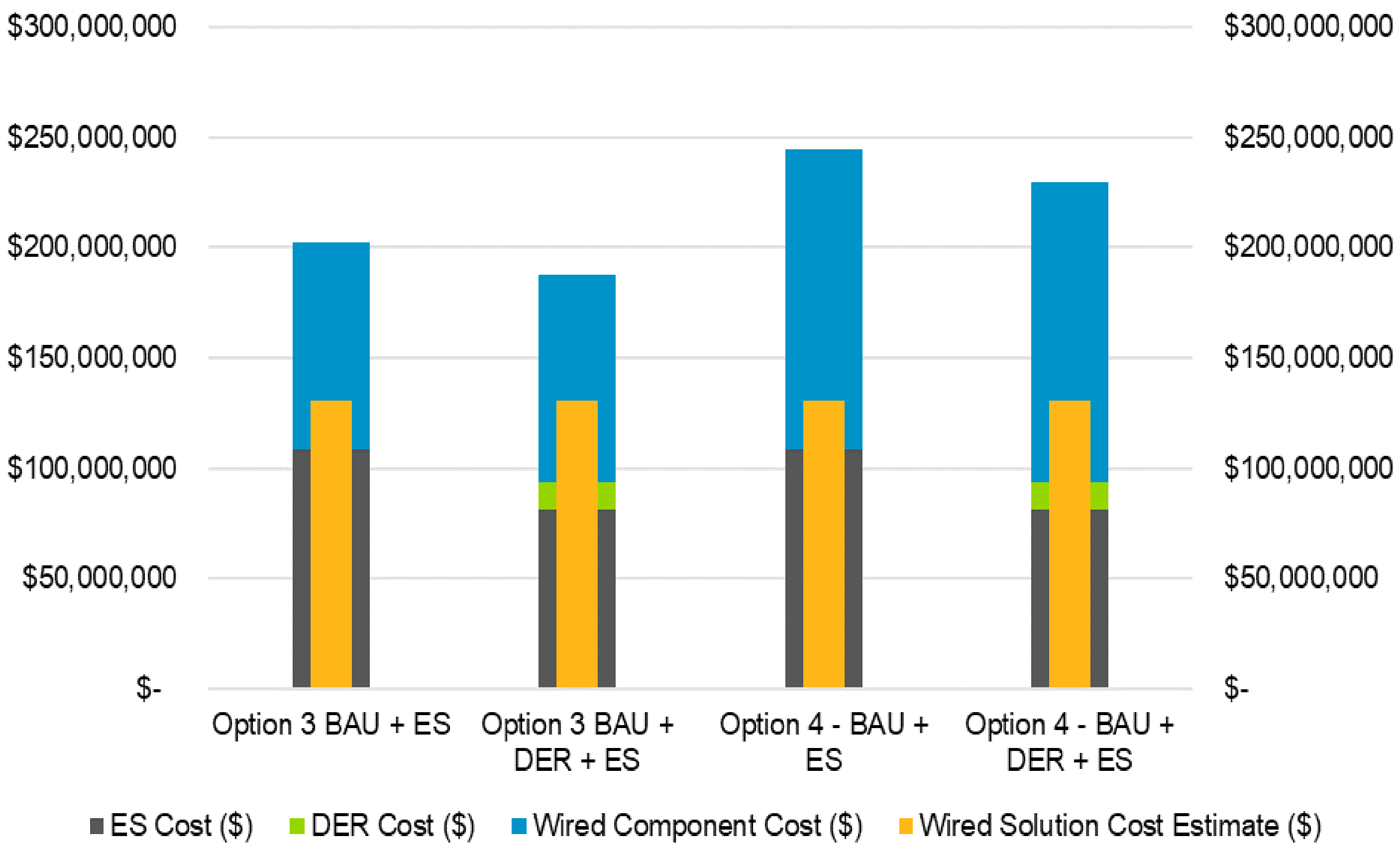
Non-wire Alternative not cost competitive for large capacity needs due to large storage sizing

- Kitsap transmission study
- Needs include aging infrastructure, stability, and capacity
- Specific contingencies result in line overloads/voltage collapse
  - Over 200 MW peak reduction needed
- A range of wired/non-wired solutions was evaluated
  - NWA was not economically competitive to the most viable solutions.



*BAU – Business as usual, ES – Energy storage

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Non-wire Alternative does not address reliability needs due to long duration events and limited operational flexibility

- Seabeck study
- Distribution capacity and reliability needs in Kitsap County
- Reliability needs could not be solved with a non-wires only solution
- Hybrid solution could not address reliability as effectively as a wired solution
  - Challenges with long duration outages
  - Limited operational flexibility

Need Category	Need Attribute	Wires Benefit	Non-Wires Benefit	Hybrid Benefit	Preferred Alternative
Reliability	Outage Prevention	↑	→	↑	Wires
	Customer Exposure	↑	→	→	Wires
	DA Scheme Operation	↑↑	↓	↓	Wires

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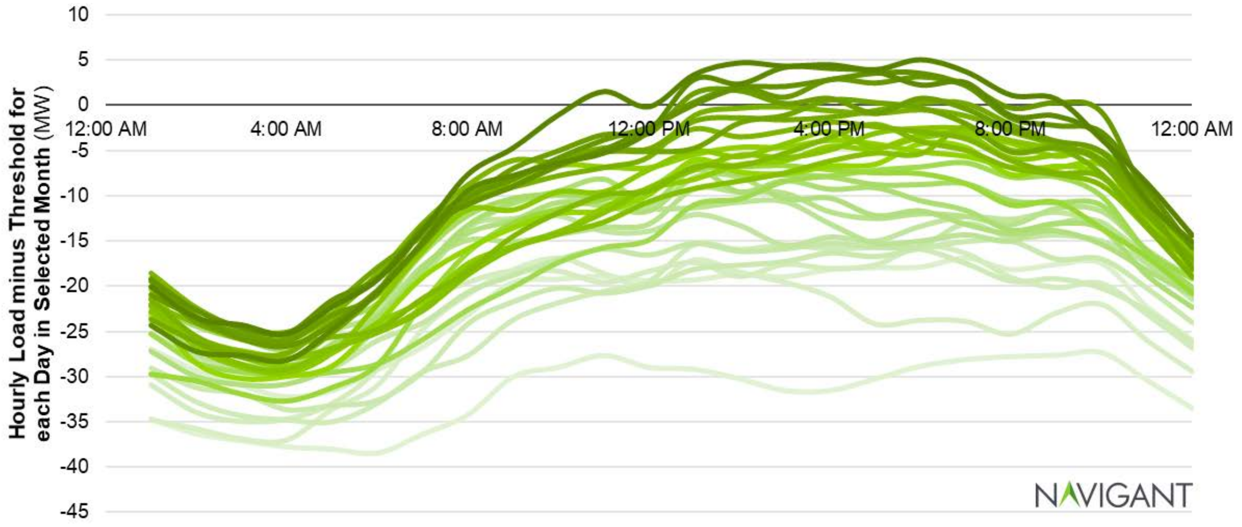
Non-wire Alternative does not address aging infrastructure because of long discharge duration

- Lynden Substation study
- Needs include aging infrastructure, transmission reliability, and operational constraints
- Lynden Substation experiences long summer peaks due to agricultural processes
  - Aging Infrastructure and long peaks difficult to address with NWA

Load forecast with BAU DSM vs Capacity Threshold by day



Dates with hours above the Group Substation Capacity Threshold

Demand Response/Energy Storage Requirements for Peak Days for Group Substation Requirement with Sub Group 2% Growth (Without DER)

Consecutive Dates	Number of Hours → Dates with Excess ↓	Max Consecutive Hours with Peak	Hour Ending → Excess Load (MW) ↓	1 AM	2 AM	3 AM	4 AM	5 AM	6 AM	7 AM	8 AM	9 AM	10 AM	11 AM	12 PM	1 PM	2 PM	3 PM	4 PM	5 PM	6 PM	7 PM	8 PM	9 PM	10 PM	11 PM	12 AM
1	7/16/2018	7														0.0	0.5	0.5	0.9	1.7	2.3	1.8					
2	7/17/2018	7														0.7	1.7	2.0	1.8	1.5	1.7	0.7					
1	7/23/2018	8														4.4	4.1	6.1	6.1	5.8	4.2	4.1	0.1				
2	7/24/2018	9														2.2	3.9	3.1	5.2	4.8	5.2	4.0	1.1	1.0			
3	7/25/2018	7														1.9	3.8	4.2	5.1	5.8	5.6	3.9					
4	7/26/2018	7														3.1	3.5	2.4	3.1	1.6	2.9	1.5					
5	7/27/2018	5															0.2	1.2	3.0	2.7	1.9						
6	7/28/2018	1																		0.5							
1	7/30/2018	12											0.5	3.0	1.5	5.0	6.4	6.2	6.5	6.1	6.9	5.3	2.3	1.3			
2	7/31/2018	2																	0.6	0.1							
1	8/8/2018	8														1.3	4.0	4.5	5.9	6.9	4.7	3.0	0.6				
2	8/9/2018	3																	2.3	0.9	0.2						

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Non-wire Alternative key findings

Capacity

- NWA effectively addresses capacity needs
- Duration affects cost effectiveness
- Ineffective at addressing large scale needs

Reliability

- Challenging for NWA's due to the long duration
- NWA provide limited operational flexibility
- Typically occur on radial parts of the system

Aging Infrastructure

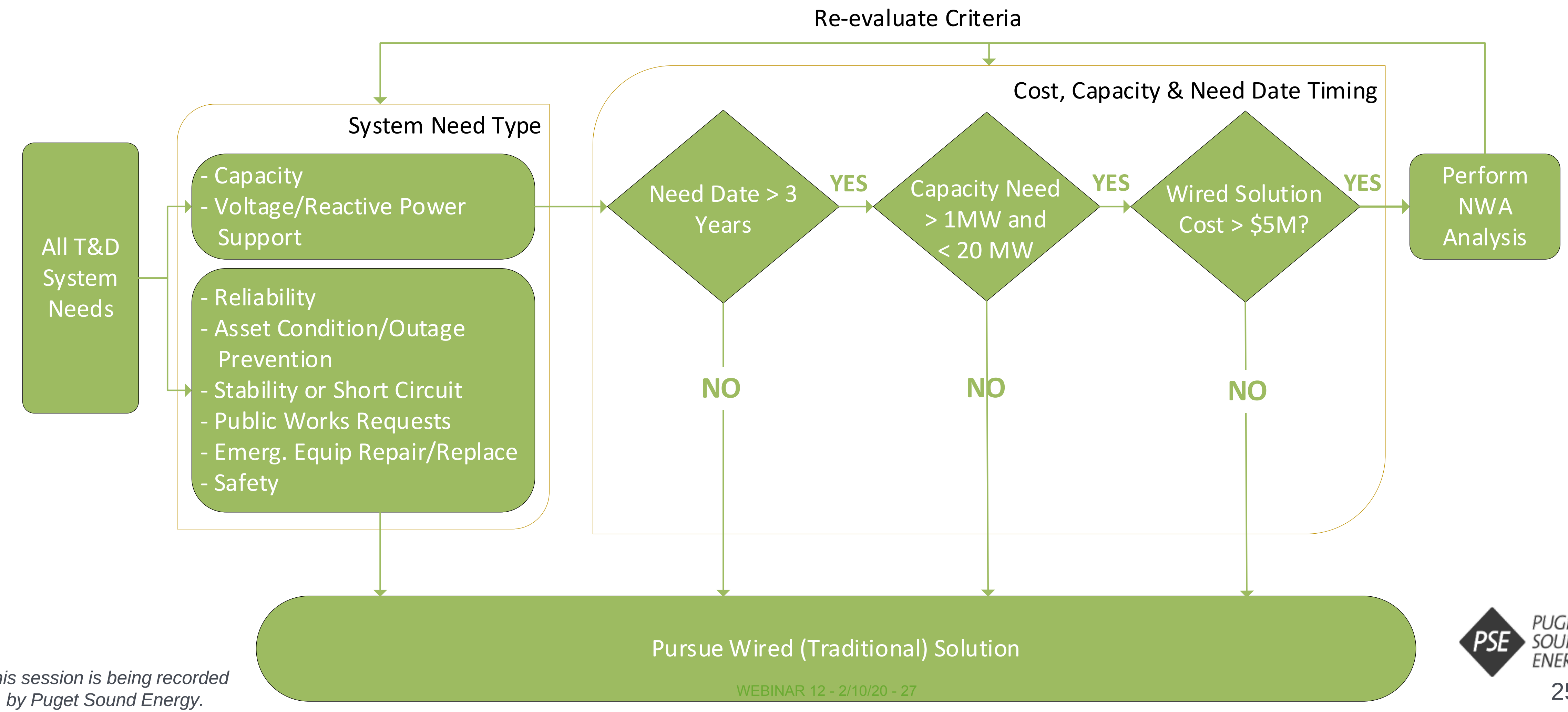
- Challenging for NWA's due to the duration.

General

- Type of need influences viability of NWA
- Additional time needed to implement

Non-wires Alternative screening process based on PSE’s learnings

- Proposed criteria for major project NWA consideration:



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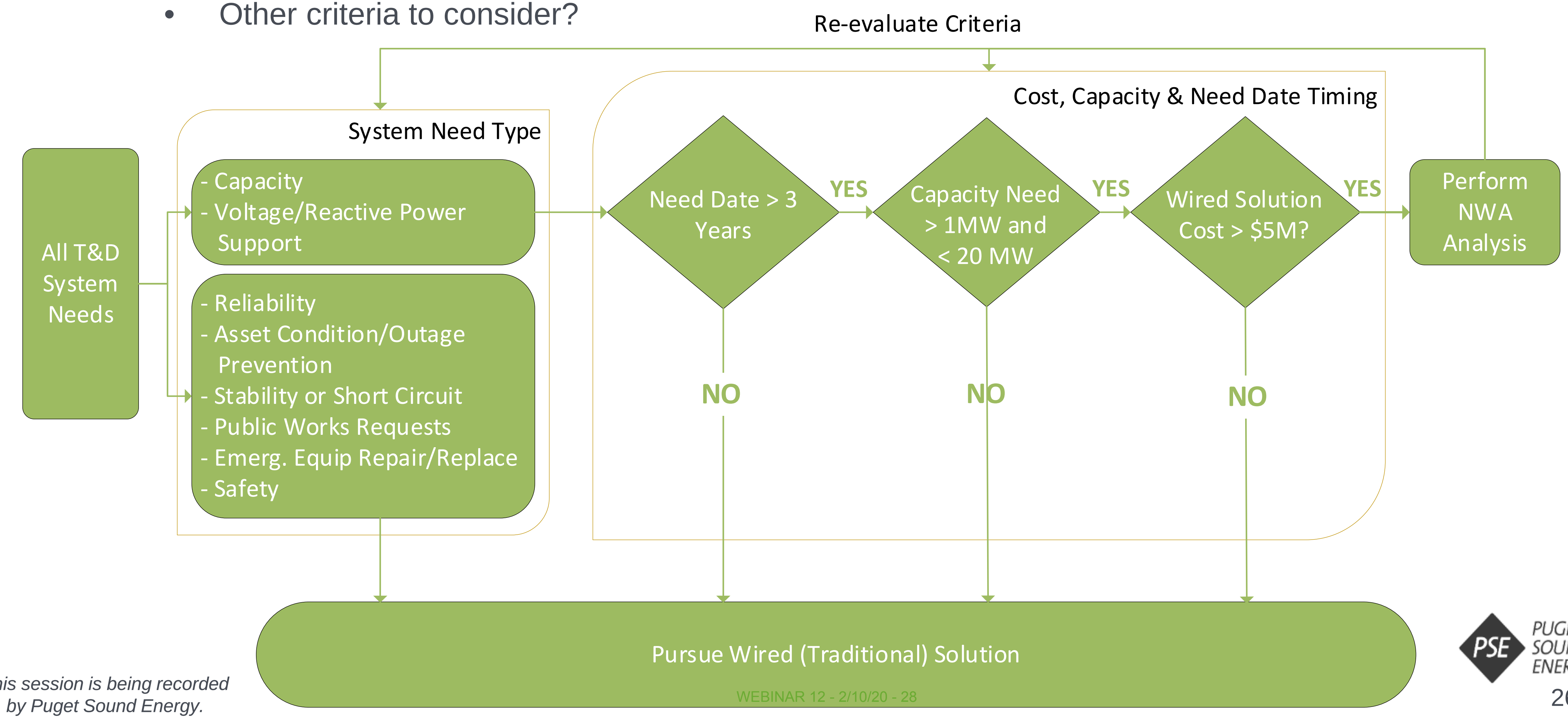
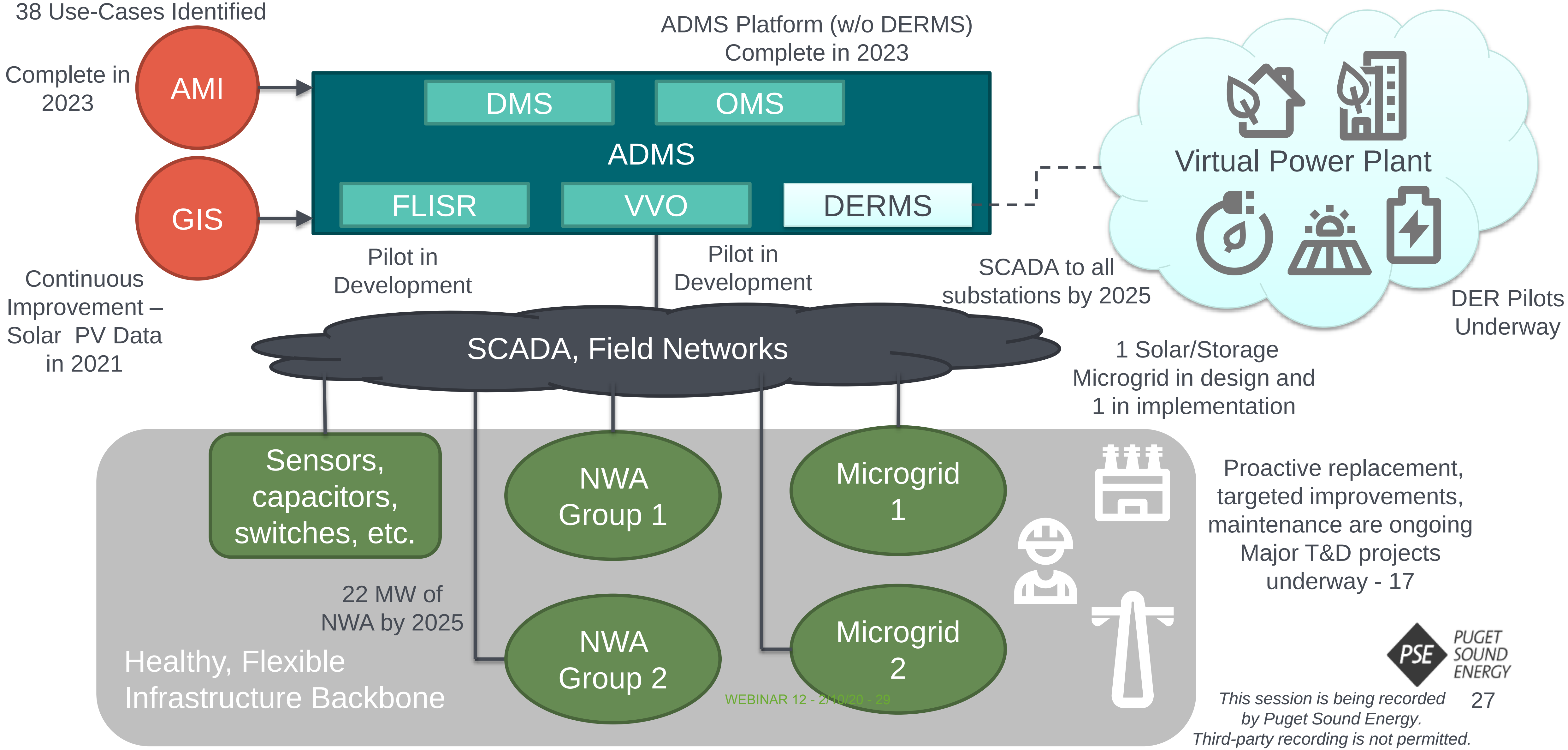
Feedback on the non-wires alternative screening process

- Is there feedback on the criteria or thresholds to evaluate non-wire alternatives from stakeholders?
  - Other criteria to consider?



Future Vision: Enterprise Enhancements Support Grid Mod Goals



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Flexibility Analysis Results

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Participation Objectives

- PSE will review final results of the Flexibility Analysis

IAP2 level of participation: INFORM

Sub-hourly flexibility analysis in Plexos

- To quantify the value of the flexibility that a resource brings into the portfolio, the performance of the portfolio with a new resource is compared to the base case portfolio.

- This analysis is performed in PLEXOS, in order to capture the behavior of the portfolio in 15-minute time steps.

- Comparisons can be made according to multiple criteria:
  - **Flexibility Violations:** The flexibility violations of a portfolio show when a portfolio lacks the ability to adjust supply to meet fluctuations in demand. These include Flex Up (increasing supply) and Flex Down (decreasing supply) violations.
  - **Costs:** The overall price tag of a portfolio changes when a new resource is added. It is a broad metric that captures the mix of resources used in dispatch, as well as the costs of market purchases and flexibility violations.

- The generic resources included in the flexibility analysis of the 2021 IRP include:
  - **Thermal Resources:** Combined Cycle plants, Frame Peakers, Recip Peakers
  - **Storage Resources:** Lithium Ion Batteries (2-hour and 4-hour), Flow Batteries (4-hour and 6-hour), Pumped Hydro Storage
  - **Demand-Side Resources:** Demand Response

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Flexibility Cost Savings

Resource	2017 IRP ($/kw-year)	2021 IRP ($/kw-year)
CCCT	$0.03	$5.27
Frame peaker	$1.15	$23.45
Recip peaker	$8.16	$25.39
Lithium-Ion battery 2hr	$3.11	$20.45
Lithium-Ion battery 4hr	$7.89	$18.45
Flow battery 4hr	$1.53	$23.03
Flow battery 6hr	$7.44	$23.24
Pumped Storage Hydro 8hr	$10.24	$18.41
Demand Response	-	$35.24

- Overall the flexibility savings are higher than the 2017 IRP.
- In all cases, the addition of the new resource decreased the cost of the portfolio and provided a flexibility benefit.

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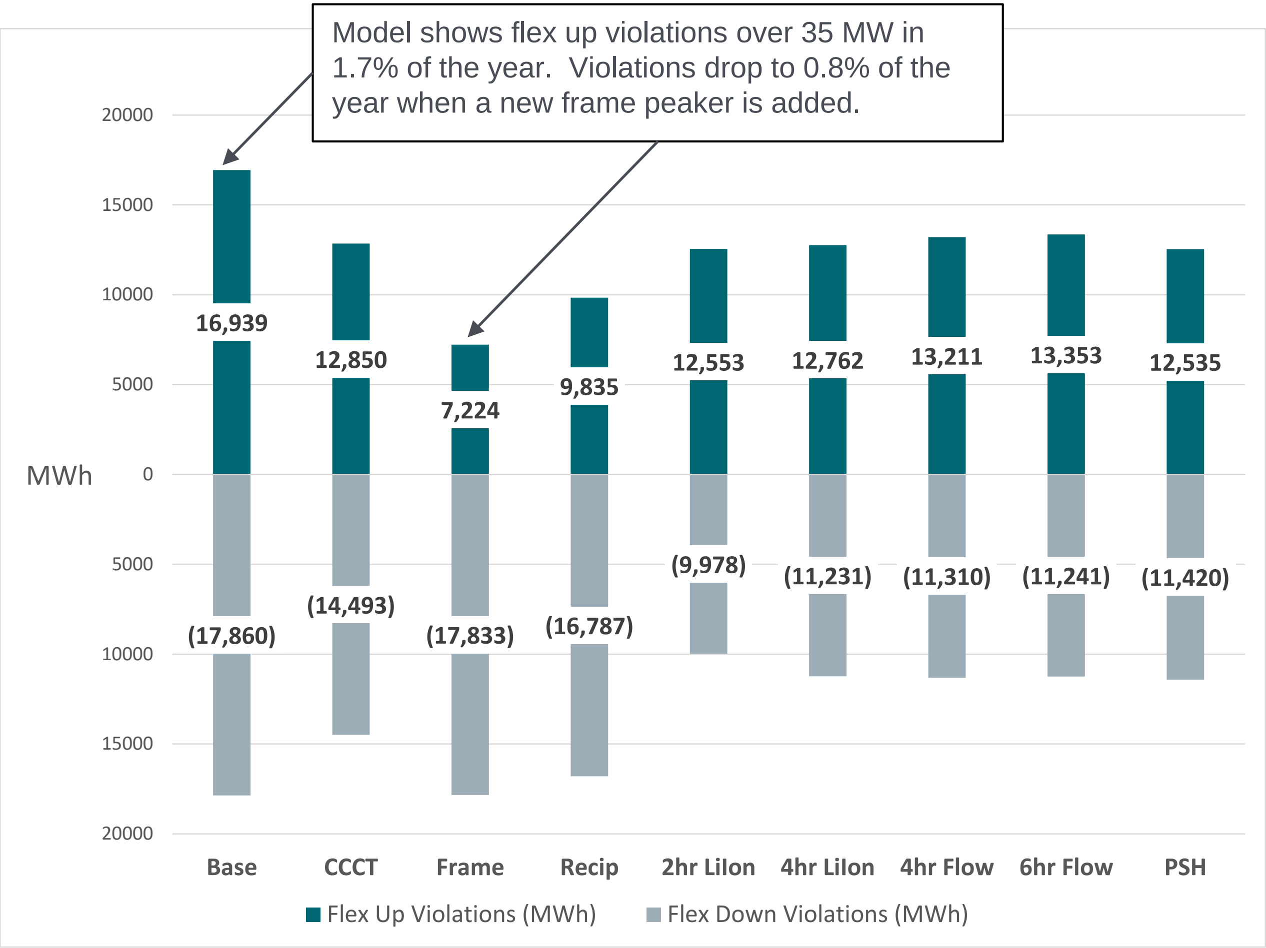
Less flexibility violations increases flexibility benefit

- In all cases, the number of flexibility violation hours decreased with the addition of a new resource.
- PSE expects the addition of a new resource to improve flexibility, since the portfolio has more possibilities available to meet demand.
- Storage resources allow for the most improvement in downward flexibility, as it gives the portfolio an outlet for excess energy besides curtailment.
- Peakers provide the most improvement for upward flexibility, as they do not require charging in order to be dispatched.



Conclusions

- In all cases, the addition of the new resource decreased the cost of the portfolio and provided a flexibility benefit.
- Updated flexibility benefit has been incorporated into portfolio modeling. Portfolio results later in the presentation include the updated flexibility benefit.

10-minute break

Economic, Health and Environmental Benefits Assessment Update

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Participation Objectives

- PSE will provide a status update on the Economic, Health and Environmental Benefits Assessment and solicit feedback on Vulnerable Population definitions.

  IAP2 level of participation:

  INFORM & CONSULT

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Assessment Overview

WAC 480-100-620 (9) Economic, health, and environmental burdens and benefits.

The IRP must include an assessment of energy and non-energy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks; and energy security risk.

The assessment should be informed by the cumulative impact analysis conducted by the department of health.

Assessment

Define named populations:
Highly Impacted Communities
Vulnerable Populations
Tribes

Measure disparities across Assessment Metrics

Defining Named Populations

Highly Impacted Communities

- Defined by Department of Health "Cumulative Impact Analysis"
- CIA still under development
- Assumed Environmental Health Disparities Map Composite Score of 9+

Vulnerable Populations

- Defined broadly in CETA as communities that "experience a disproportionate cumulative risk from environmental burdens due to: Adverse socioeconomic factors, including unemployment, high housing and transportation costs relative to income, access to food and health care, and linguistic isolation; and sensitivity factors, such as low birth weight and higher rates of hospitalization."
- Requires definition

Tribes

- May be informed by CIA
- Areas containing federally recognized tribal lands

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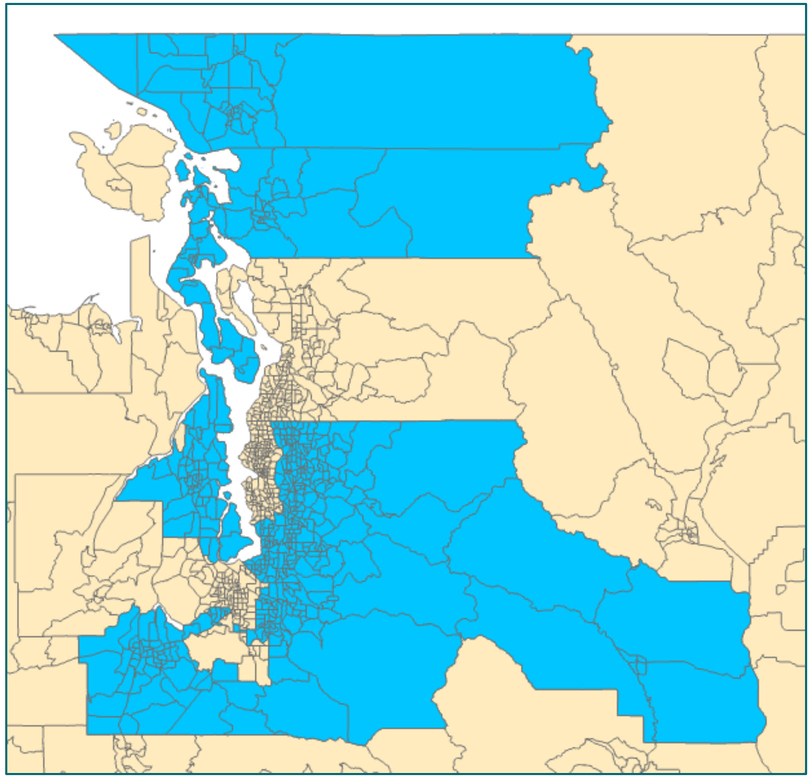
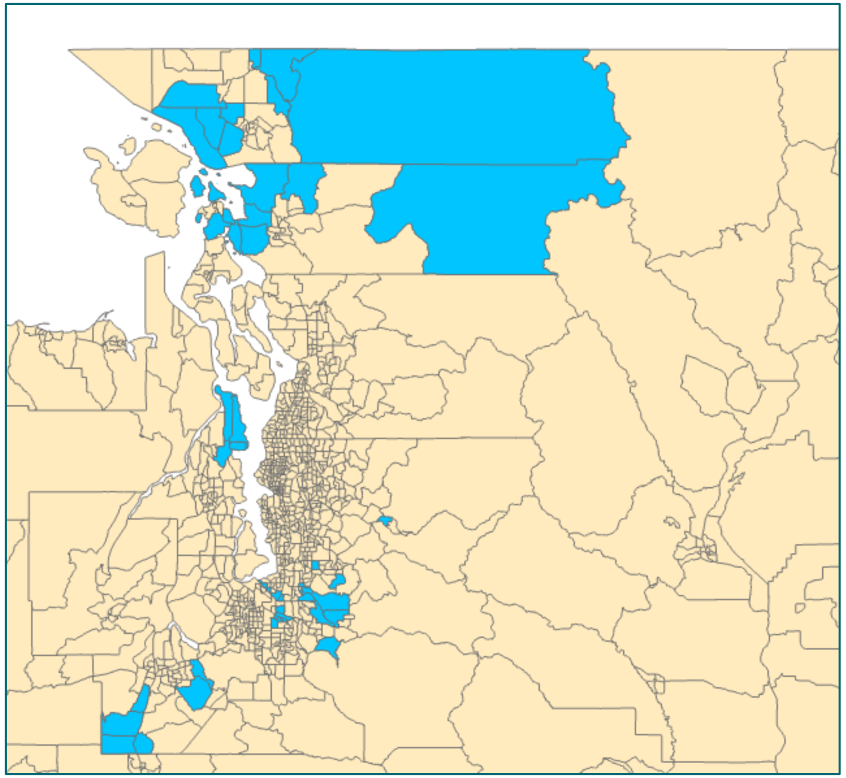
PSE, Tribal Lands and Highly Impacted Communities

PSE



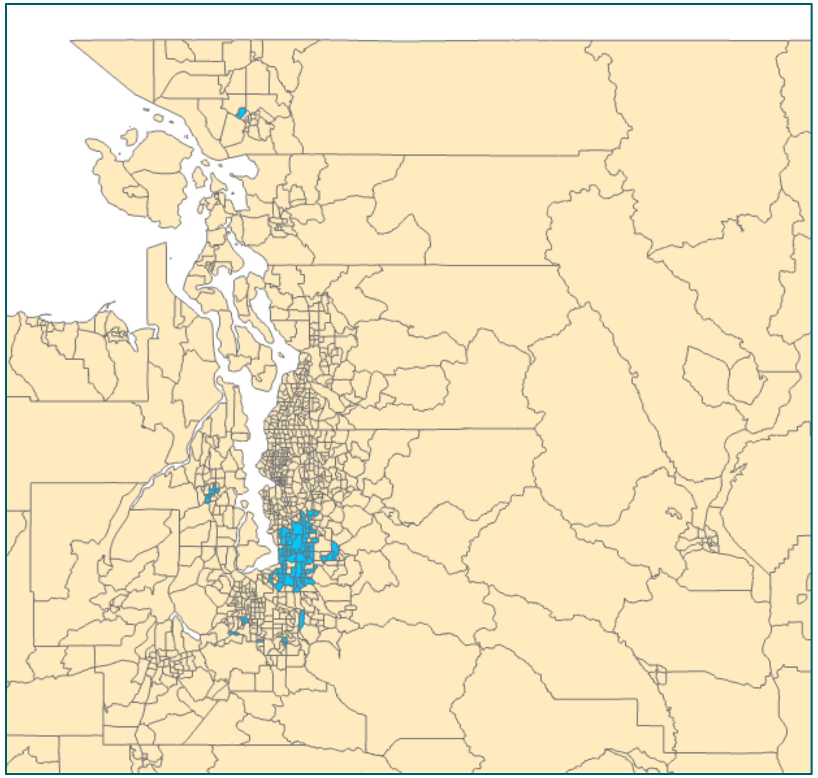
488 Census Tracts

Tribes



47 Census Tracts

Highly Impacted Communities (Temporary)



81 Census Tracts

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Defining Vulnerable Populations

Clean Energy Transformation Act

- Unemployment
- Housing burden
- Transportation expense
- Linguistic isolation
- Low birth weight
- Higher rates of hospitalization (cardiovascular disease)

- ~~Access to food and health care~~

Environmental Health Disparities Map (EHDM)

- Unemployment
- Housing burden
- Transportation expense
- Linguistic isolation
- Low birth weight
- Higher rates of hospitalization (cardiovascular disease)
- Poverty
- Race (People of Color)

Environmental Health Disparities Map w/ Age

- Unemployment
- Housing burden
- Transportation expense
- Linguistic isolation
- Low birth weight
- Higher rates of hospitalization (cardiovascular disease)
- Poverty
- Race (People of Color)
- Age (people under 18 and over 65 years old)

Defined as **Vulnerable Population** if average of scores is: **9+**

(pending Dept. of Health's Cumulative Impact Analysis)

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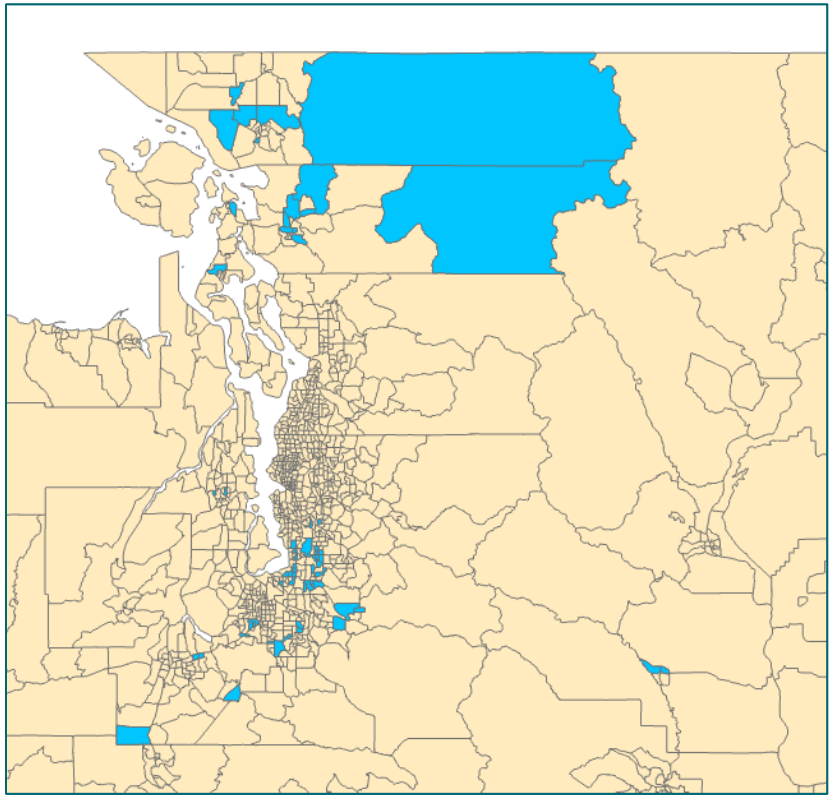
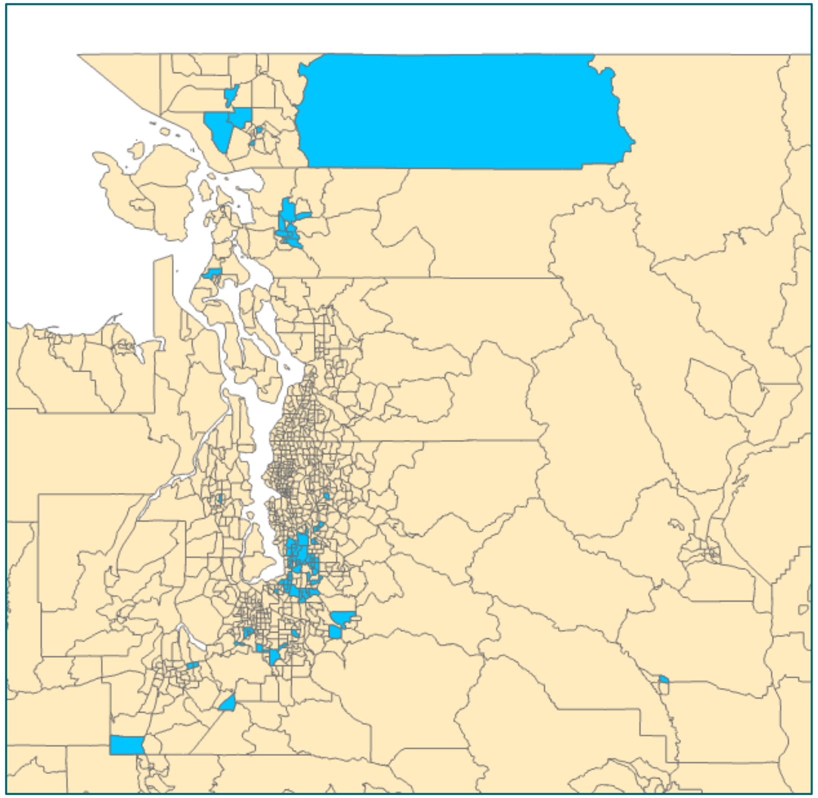
Defining Vulnerable Populations

CETA



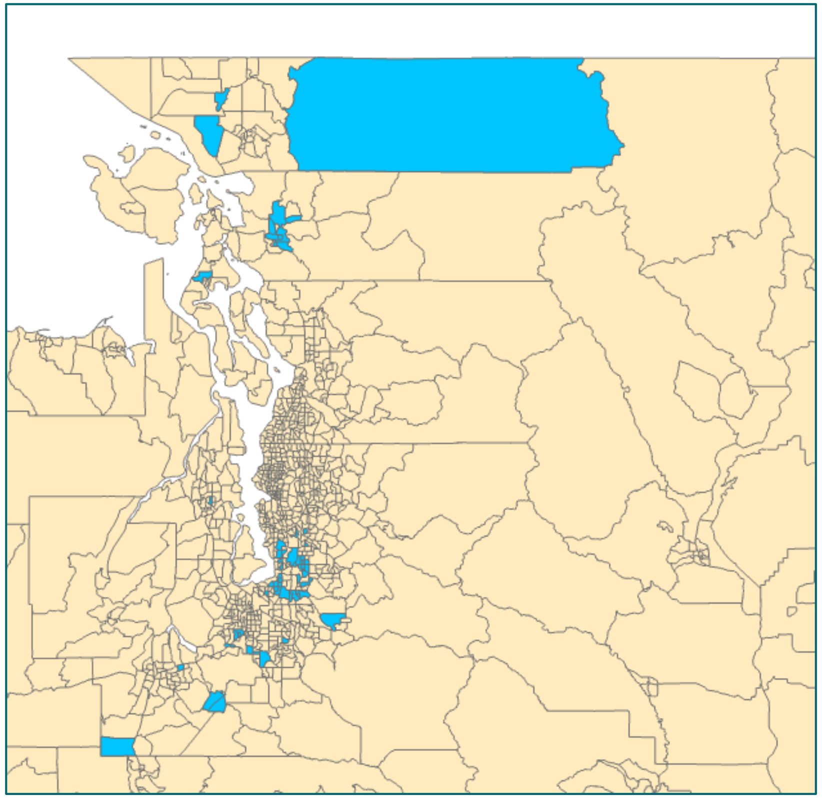
65 Census Tracts

EHDM



79 Census Tracts

EHDM w/ Age



61 Census Tracts

Seeking stakeholder feedback on what metrics should define a Vulnerable Population

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A note on disparity scores

Disparity scores are rated 1-10
(from Dept. of Health EHDM)

1	0% - 10%
2	10% - 20%
3	20% - 30%
4	30% - 40%
5	40% - 50%
6	50% - 60%
7	60% - 70%
8	70% - 80%
9	80% - 90%
10	90% - 100%

The scale corresponds to ranked percentile for that group

Scores are relative, not absolute

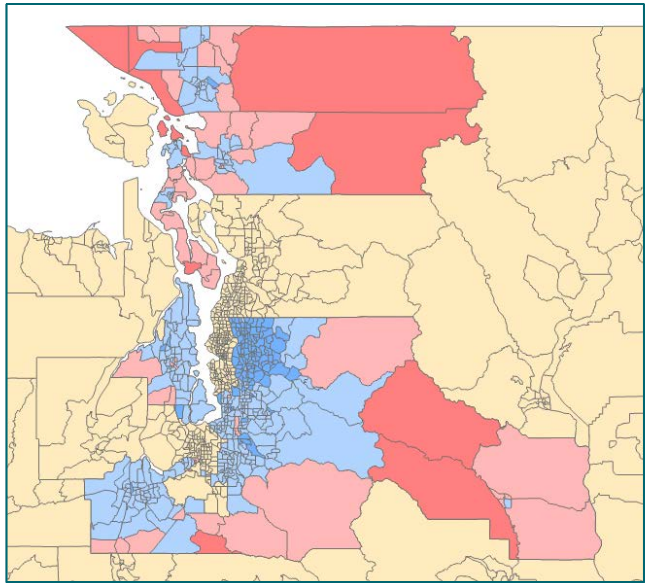
By way of example:

Student	Class A Scores	Class B Scores	Class A Percentile Rank	Class B Precentile Rank
1	100	100	1	1
2	98	85	2	2
3	95	84	4	4
4	95	84	4	4
5	94	80	5	5
6	93	78	6	6
7	92	76	9	9
8	92	76	9	9
9	92	76	9	9
10	90	70	10	10

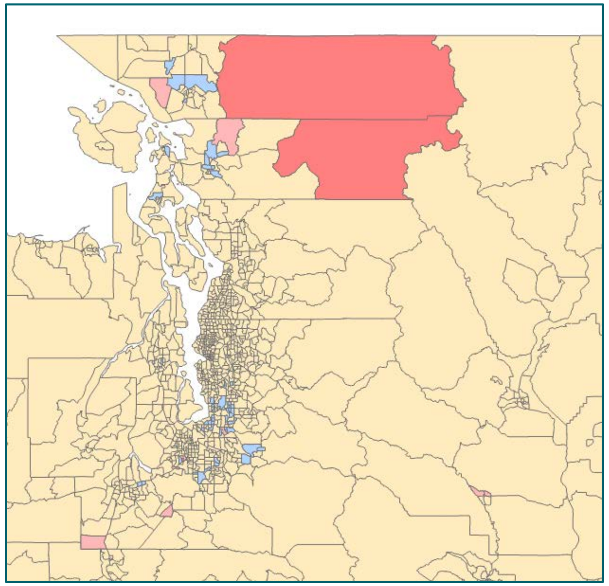
Scores are designed to identify a disparity, not necessary the magnitude of the disparity

Energy Burden

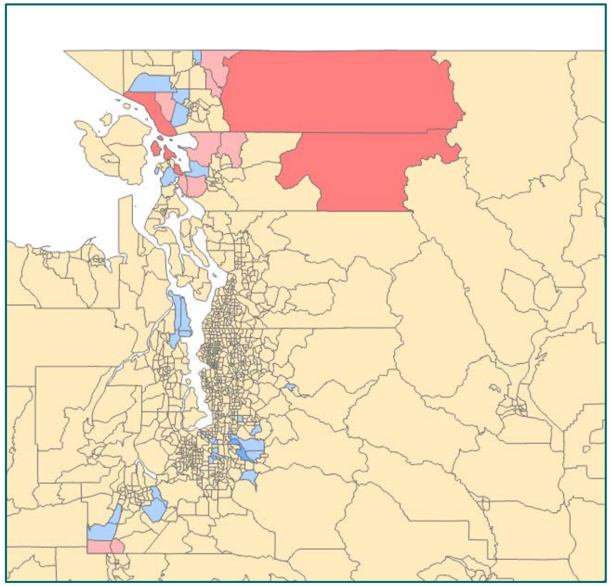
PSE



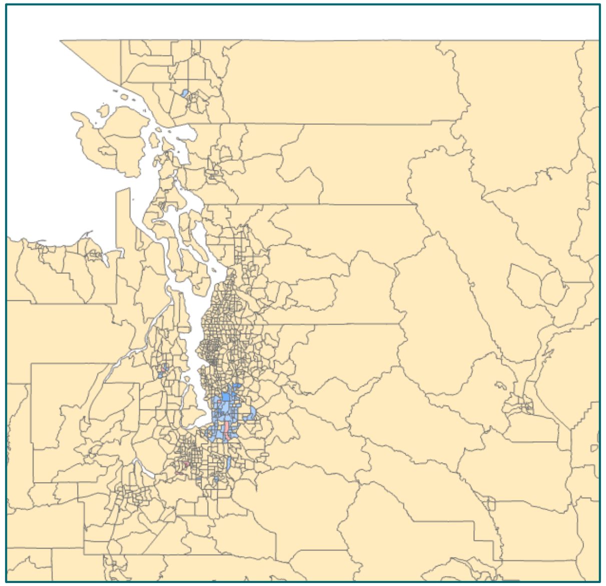
Vulnerable Populations - CETA

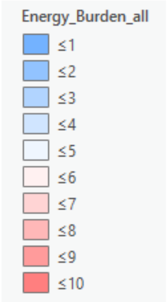


Tribes



Highly Impacted Communities





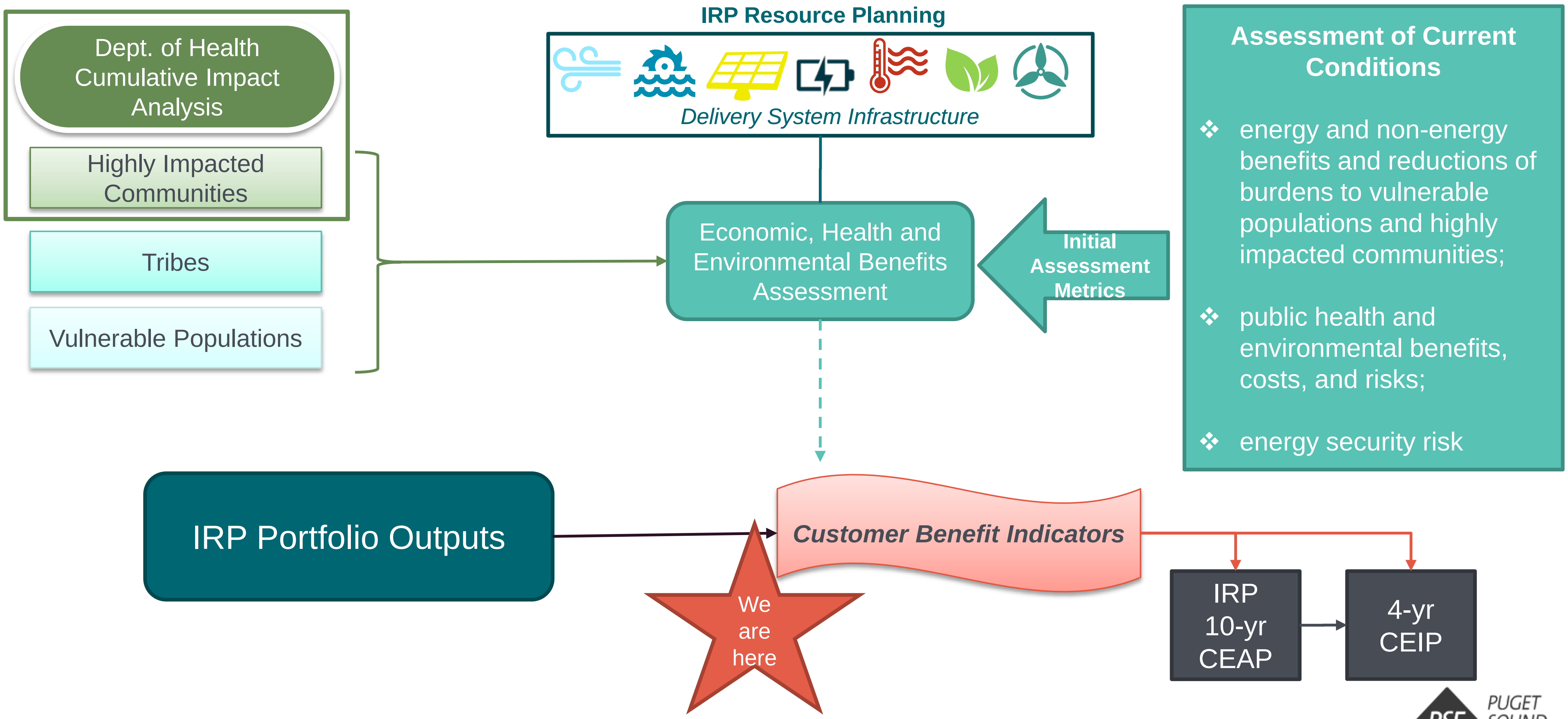
Average Disparity Score	PSE	Vulnerable Populations - CETA	Tribes	Highly Impacted Communities
	3.2	4.0	4.5	3.3

- Energy Burden for all income levels as measured by Department of Energy LEAD Tool
- Scores are reflective of ranked percentile across Washington State
- PSE territory on average has a lower than typical energy burden
- Within PSE territory, rural areas typically have higher energy burden, which is particularly impactful to census tracts containing Tribes and Vulnerable Populations

Uses for the Assessment Tool

Strengths	Weaknesses
• Assessing where disparities exist within PSE's service territory	• Assessing the magnitude of disparities
• Identifying where named populations are concentrated	• Identifying distributions of name populations within a given area
• Understanding if named populations are experiencing greater burdens or fewer benefits	• Capturing qualitative measures of burdens and benefits
• Suggesting what indicators are important to consider when developing a portfolio	
• Developing implementation strategies to reach named populations	

Incorporating the Assessment into the IRP



Assessment Metrics and Customer Benefit Indicators

Health

Air Quality
- SO_2
- NO_x
- Particulate Matter

Public Health
- Environmental Health Disparities Map Composite

Environment

Environment
- Solar Choice
- Green Power

Energy / Non-Energy Benefits

Non-Energy Benefits
- Residential EV hookups
- Workplace and Multifamily EV hookups

Energy Security

Resiliency
- Distribution Redundancy
- Distribution Automation

Economic

Cost
- Energy Burden
- Unemployment
- Poverty
- Net Metering

Category

Customer Benefit Indicator

Assessment Metrics

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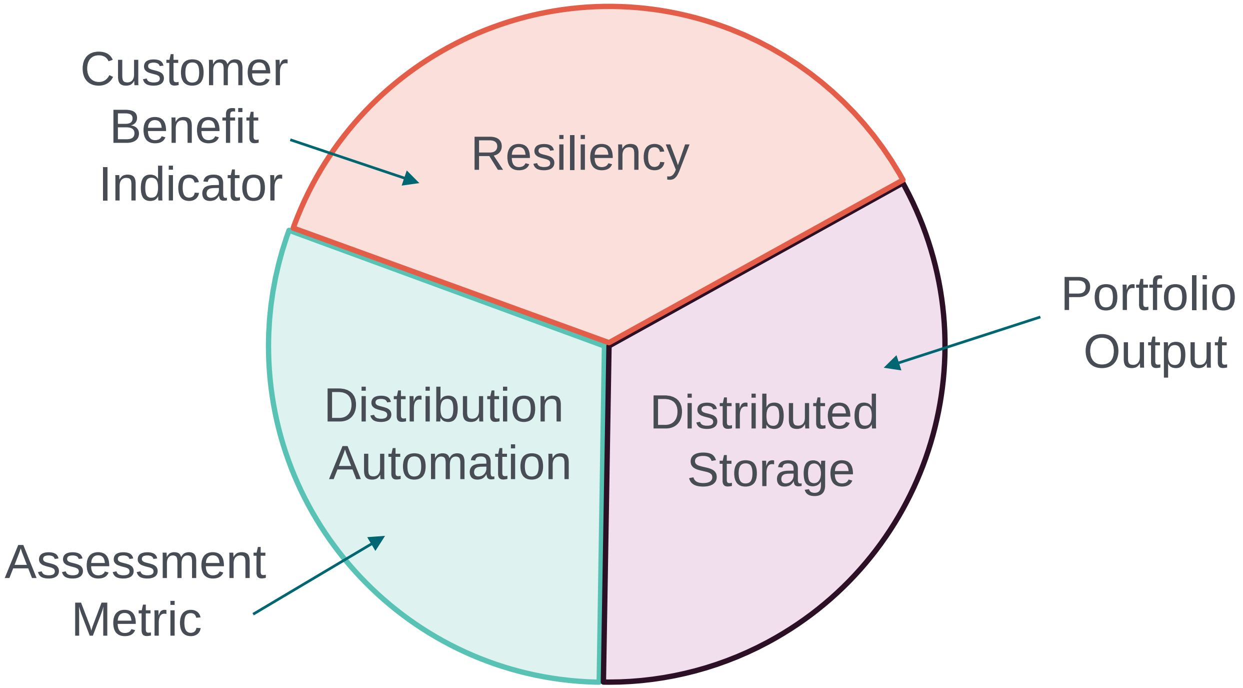
Customer Benefit Indicators in Context



For Example:

Assessing Resiliency as a Customer Benefit Indicator

- The Assessment may indicate specific areas of PSE service territory, which serve named populations, are in need of increased resiliency since those areas contain less Distribution Automation.
- An analyst may increase the quantity of Distributed Storage in a portfolio sensitivity to fulfill this need.
- We can then see how this decision impacts all Customer Benefit Indicators for that portfolio **and** compared to other portfolios [we'll explore this more later].

Electric portfolio draft results

Participation Objectives

- PSE will provide an update on the portfolio results.

  IAP2 level of participation: INFORM

- PSE will seek stakeholder feedback on the Customer Benefit Indicators.

  IAP2 level of participation: CONSULT

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Draft IRP Preferred Portfolio was based on results from individual sensitivities

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Description	**Assumptions and Alternatives Analyzed**
ECONOMIC SCENARIOS		
1	Mid	Mid gas price, mid demand forecast, mid electric price forecast
FUTURE MARKET AVAILABILITY SENSITIVITIES		
A	Renewable Over-generation Test	The portfolio model is not allowed to sell excess energy to the Mid-C market.
TRANSMISSION CONSTRAINTS AND BUILD LIMITATIONS SENSITIVITIES		
C	"Distributed" Transmission/Build Constraints - Tier 2	The portfolio model is performed with Tier 2 Transmission availability.
SOCIAL COST OF GREENHOUSE GASES SENSITIVITIES		
I	Social Cost of Greenhouse Gases as an Externality Cost in the Portfolio Model	The SCGHG is used as an externality cost in the portfolio expansion model.
EMISSION REDUCTION SENSITIVITIES		
N	100% Renewable by 2030	The CETA 2045 target of 100% renewables is moved up to 2030, with no natural gas generation.
O	Natural gas Generation Out by 2045	All existing natural gas plants are retired in 2045.
P	Must-take Battery or Pumped Hydro Storage and Demand Response	Batteries or pumped hydro storage and demand response programs are added before any natural gas plants.
CETA COSTS SENSITIVITIES		
S	SCGHG Included, No CETA	The SCGHG is included in the portfolio model without the CETA renewable requirement.
T	No CETA	The portfolio model does not have CETA renewable requirement or the SCGHG adder.
BALANCED PORTFOLIOS SENSITIVITIES		
V	Balanced Portfolio	The portfolio model must take distributed energy resources ramped in over time and more customer programs.
W	Balanced Portfolio with alternative fuel for peaking capacity	The portfolio model must take distributed energy resources ramped in over time and more customer programs plus carbon free combustion turbines using biodiesel as the fuel.

- Portfolio sensitivities shared in Webinar 11 and included in the draft IRP were used to develop the Balanced Portfolio sensitivities V and W
- Sensitivity W became the Preferred Portfolio included in the draft IRP

Draft IRP Preferred Portfolio Nameplate Additions:

Resource Additions (MW)	2022-2025	2026-2030	2031-2045	Total
Distributed Energy Resources				
Demand-side Resources	256 MW	360 MW	1,168 MW	1,784 MW
Battery Energy Storage	75 MW	125 MW	550 MW	750 MW
Solar - ground and rooftop	80 MW	150 MW	450 MW	680 MW
Demand Response	10 MW	161 MW	44 MW	215 MW
DSP Non-Wire Alternatives	22 MW	24 MW	72 MW	118 MW
Total DER	443 MW	820 MW	2,284 MW	3,547 MW
Renewable Resources	600 MW	1,100 MW	2,762 MW	4,462 MW
Flexible Capacity	0 MW	237 MW	711 MW	948 MW

Draft IRP Preferred Portfolio

Portfolio Model Updates from Draft IRP

- ✓ Included Flexibility Analysis results
- ✓ Corrected transmission costs
- ✓ Included T&D benefit for battery energy storage
- ✓ Aligned build limit for biomass with regional potential (150 MW; 10 units at 15 MW)
- ✓ Developed preliminary Customer Benefit Indicators (CBI) and applied them to some portfolio sensitivities

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Select results from updated portfolio model

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Description	Assumptions and Alternatives Analyzed
ECONOMIC SCENARIOS		
1	Mid	Mid gas price, mid demand forecast, mid electric price forecast
TRANSMISSION CONSTRAINTS AND BUILD LIMITATIONS SENSITIVITIES		
C	"Distributed" Transmission/Build Constraints - Tier 2	The portfolio model is performed with Tier 2 Transmission availability.
CONSERVATION ALTERNATIVES SENSITIVITIES		
F	6-Year Conservation Ramp Rate	Energy efficiency measures ramp up over 6 years instead of 10.
CETA COSTS SENSITIVITIES		
S	SCGHG Included, No CETA	The SCGHG is included in the portfolio model without the CETA renewable requirement.
T	No CETA	The portfolio model does not have CETA renewable requirement or the SCGHG adder.
U	2% Cost Threshold	CETA is considered satisfied once the 2% cost threshold is reached.
BALANCED PORTFOLIOS SENSITIVITIES		
V	Balanced Portfolio	The portfolio model must take distributed energy resources ramped in over time and more customer programs.

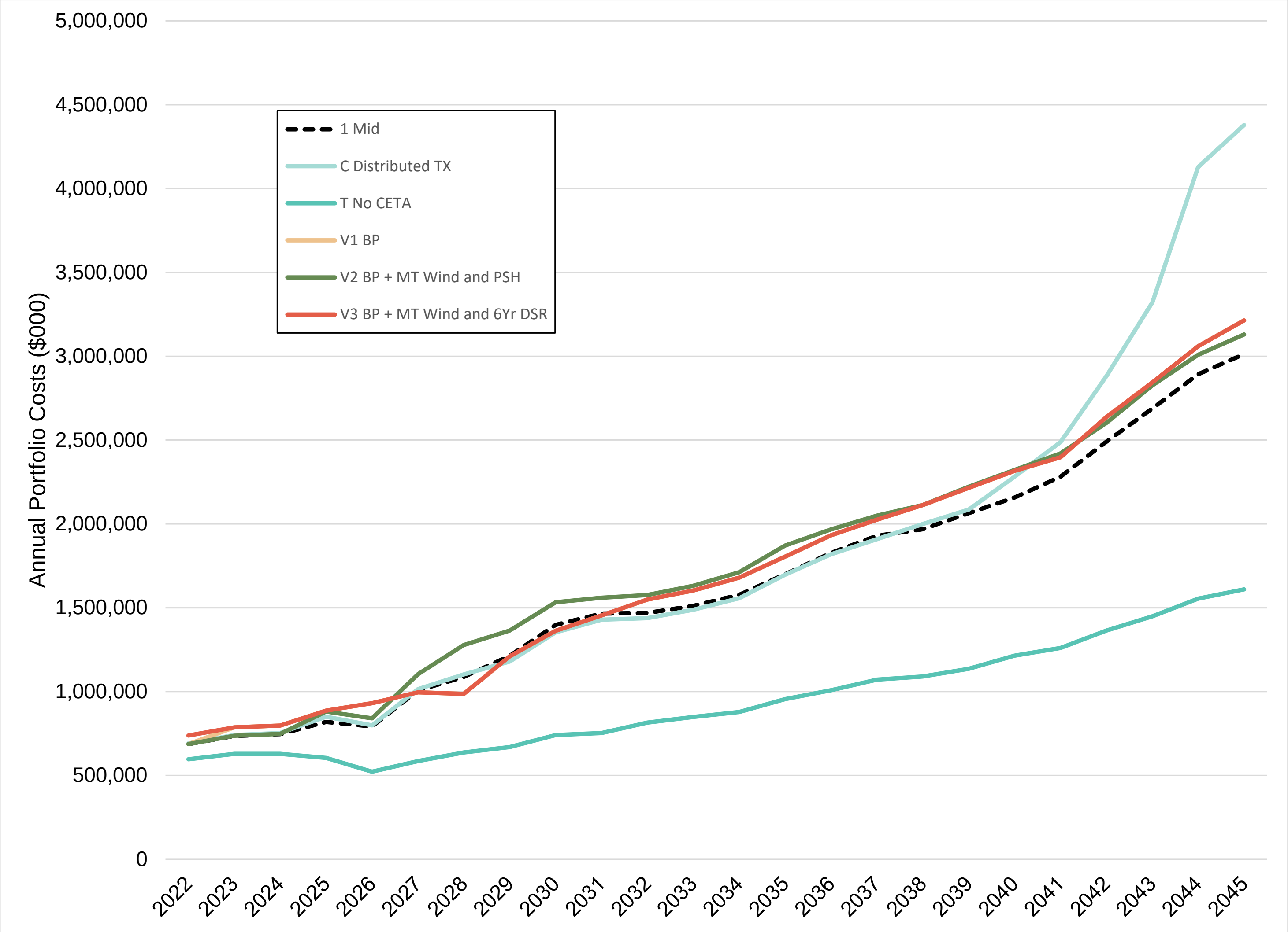
- Portfolio sensitivities modeled to date with updated inputs (described previously)
- All sensitivities will be included in final IRP
- Select sensitivities are included to demonstrate how Customer Benefit Indicators will be used to develop the preferred portfolio
- New sensitivities were added to test specific resources:

ADDITIONAL SENSITIVITIES		
V2	Balanced Portfolio with MT Wind and PSH	Balanced Portfolio with Montana wind and pumped storage hydro.
V3	Balanced Portfolio with 6-year ramp rate for DSR	Energy efficiency measures ramp up over 6 years instead of 10 year for Balanced Portfolio.
AA	MT Wind with PSH in 2028	Must-take Montana wind and pumped storage hydro in 2028.

Portfolio costs and resource additions

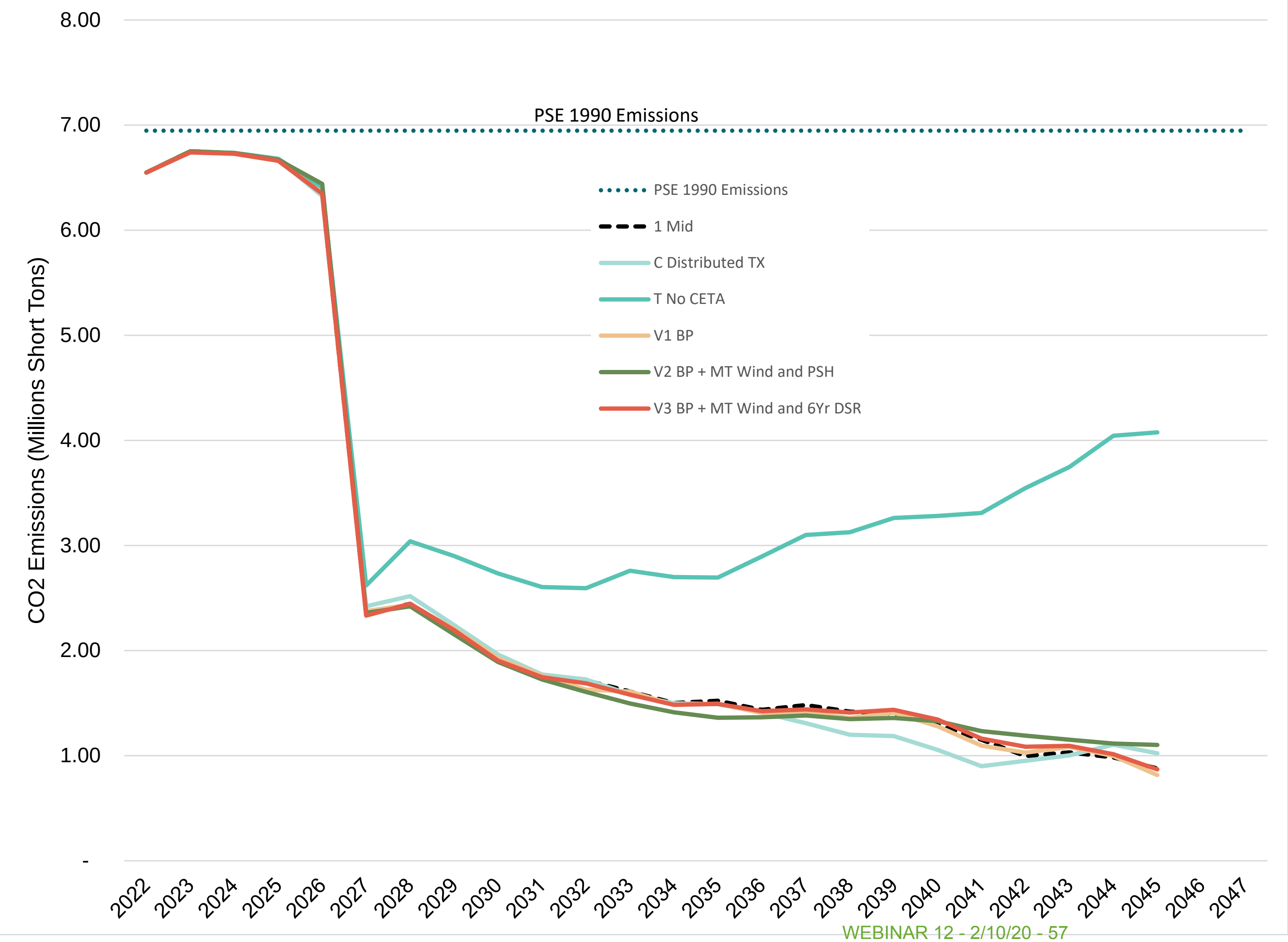
Portfolio	24-year Levelized Cost ($ Billions)		Total Resource Additions by 2045 Nameplate Capacity (MW)								
	Revenue Requirement	SCGHG adder	DSR	DSP NWA & distributed solar	Demand Response	Biomass	Solar	Wind	Renewable + Storage hybrid	Energy Storage	Flexible Capacity
1. Mid	$15.53	$5.03	1,497	118	123	90	1,393	3,350	250	550	948
C. Distributed Transmission (Tier 2)	$16.35	$5.14	1,537	2,818	178	150	500	2,615	125	1,050	1,003
F. 6-year ramp rate for DSR	$15.54	$5.02	1,372	118	175	150	1,394	3,150	500	625	966
S. No CETA with SCGHG adder				118			-	350	-	-	
T. No CETA	$9.32	$9.14	1,042	118	118	-	-	350	-	-	2,032
V. Balanced Portfolio	$16.08	$5.00	1,784	798	217	105	696	3,250	375	450	966
V2. Balanced Portfolio with MT Wind + PSH	$16.62	$5.06	1, 784	798	217	120	895	3,150	425	375	948
V3. Balanced Portfolio with 6-year ramp rate for DSR	$16.27	$4.99	1,658	798	217	120	895	3,450	125	675	1,003
AA. MT Wind + PSH in 2028	$15.84	$5.09	1,497	118	182	150	1,094	3,350	425	300	948

Annual portfolio costs



- The cost increase of Sensitivity C in the last 5 years is due to large amounts of distributed resources being added because the portfolio has utilized the transmission to eastern Washington first.
- The electric portfolio model minimizes total portfolio costs by delaying new resource additions until the last few years of the planning horizon to capture the benefit of declining resource cost curves.

Annual CO2 Emissions



- Emissions include CO_2 emissions at the generation plus upstream emissions.
- Emissions from unspecified market purchases are not included.
- Emission offsets through alternative compliance mechanisms are not shown but will be included in the final IRP.
- Starting in 2030 PSE will be carbon neutral as required by CETA.

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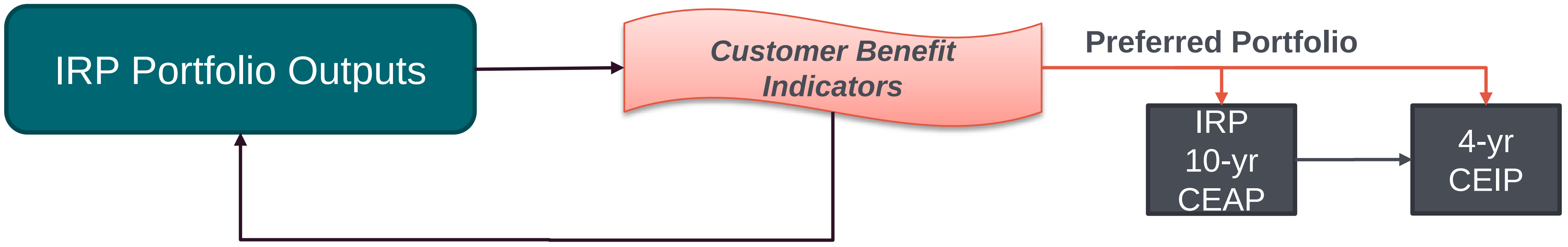
Developing preferred portfolio informed by Customer Benefit Indicators

1. Model portfolio sensitivities with updated inputs
2. Evaluate portfolio output with Customer Benefit Indicators
3. Use Customer Benefit Indicators to inform the preferred portfolio for the final IRP



Preliminary Customer Benefit Indicators for this IRP

Category	Customer Benefit Indicator	Portfolio Output
Environment	Climate Change	GHG Emissions
	Environment	Renewable Generation, Customer Programs, Energy Efficiency, Distributed Generation
Health	Air Quality	SO_2 NO_x PM
Economic	Market Position	Market Purchases
	Cost	Portfolio Cost
Energy Security & Resiliency	Resource Adequacy	Market Reliance, Demand Response
	Resiliency	Storage

PUGET SOUND ENERGY

Using portfolio output and ranks to compare sensitivities

Customer Benefit Indicator	Cost	Climate Change		Air Quality			Market Position	Environment				Resource Adequacy		Resiliency
Portfolio Output	24-yr Portfolio Cost	SCGHG	CO2 Emissions	SO2	NOx	PM	Market Purchases	Renewable Generation	Energy Efficiency	Distributed Generation	Customer Programs	Market Reliance	Demand Response	Distributed Storage
1. Mid	$15.53	$5.02	777,018	8	395	25	2,523,005	21,177,795	5,969,983	355,423	656,726	1,479	123	639
C. Distributed Tier 2 Transmission	$16.35	$5.14	1,000,086	10	945	34	2,946,470	16,652,161	6,112,842	4,351,476	656,726	1,479	178	1,139
F. 6yr Ramp Rate for DSR	$15.54	$5.02	773,251	8	519	25	2,571,955	21,697,533	5,460,256	355,423	656,726	1,479	175	714
S. SGCHG Only, No CETA	$11.95	$8.98	4,944,494	33	9,706	139	9,299,208	7,454,379	4,052,696	355,423	656,726	1,479	190	2,614
T. No CETA	$9.32	$9.14	3,964,257	40	2,114	134	10,981,466	7,546,023	3,331,365	355,423	656,726	1,479	118	89
V1. Balanced Portfolio	$16.06	$5.00	759,074	7	502	25	2,536,212	19,117,749	5,971,509	1,552,256	1,493,182	1,479	217	539
V2. Balanced Portfolio w/ MT Wind + PHES	$16.61	$5.06	833,441	8	427	27	2,516,854	18,879,956	5,969,903	1,550,653	1,493,182	1,479	217	464
V3. Balanced Portfolio w/ Mt Wind 2026 + 6yr DSR Ramp	$16.26	$4.99	797,220	8	761	27	2,566,699	19,606,509	5,462,125	1,552,389	1,493,182	1,479	217	764
AA. MT Wind + PHES	$15.84	$5.09	733,210	7	379	24	2,657,404	20,940,400	5,969,607	355,423	656,726	1,479	182	389

Run Portfolio Model

	Cost	Climate Change		Air Quality			Market Position	Environment				Resource Adequacy		Resiliency
Indicator	24-yr Portfolio Cost	SCGHG	CO2 Emissions	SO2	NOx	PM	Market Purchases	Renewable Generation	Energy Efficiency	Distributed Generation	Customer Programs	Market Reliance	Demand Response	Distributed Storage
1. Mid	3	4	4	4	2	3	2	2	3	7	6	1	8	5
C. Distributed Tier 2 Transmission	8	7	7	7	7	7	7	7	1	1	6	1	6	2
F. 6yr Ramp Rate for DSR	4	3	3	3	5	4	5	1	7	7	6	1	7	4
S. SGCHG Only, No CETA	2	8	9	8	9	9	8	9	8	6	5	1	4	1
T. No CETA	1	9	8	9	8	8	9	8	9	5	4	1	9	9
V1. Balanced Portfolio	6	2	2	2	4	2	3	5	2	3	2	1	1	6
V2. Balanced Portfolio w/ MT Wind + PHES	9	5	6	6	3	6	1	6	4	4	1	1	1	7
V3. Balanced Portfolio w/ Mt Wind 2026 + 6yr DSR Ramp	7	1	5	5	6	5	4	4	6	2	2	1	1	3
AA. MT Wind + PHES	5	6	1	1	1	1	6	3	5	7	6	1	5	8

Rank Portfolios

Sensitivity	Cost	Climate Change	Air Quality	Market Position	Environment	Resource Adequacy	Resiliency	Overall Rank
1. Mid	3	4	3	2	5	5	5	2
C. Distributed Tier 2 Transmission	8	7	7	7	4	4	2	8
F. 6yr Ramp Rate for DSR	4	3	4	5	5	4	4	4
S. SGCHG Only, No CETA	2	9	9	8	7	3	1	7
T. No CETA	1	9	8	9	7	5	9	9
V1. Balanced Portfolio	6	2	3	3	3	1	6	1
V2. Balanced Portfolio w/ MT Wind + PHES	9	6	5	1	4	1	7	6
V3. Balanced Portfolio w/ MT Wind 2026 + 6yr DSR Ramp	7	3	5	4	4	1	3	3
AA. MT Wind + PHES	5	4	1	6	5	3	8	5

Average ranked scores by Customer Benefit Indicator

- This process reveals which portfolios are performing well in which areas.
- Allows for development of new portfolios which provides options for different ways the CBIs can be balanced to arrive at a preferred portfolio.
- These tables are also provided in a spreadsheet at pse.com/irp.

Table of Customer Benefit Indicators for portfolios

Sensitivity	Cost	Climate Change	Air Quality	Market Position	Environment	Resource Adequacy	Resiliency	Overall Rank
1. Mid	3	4	3	2	5	5	5	2
C. Distributed Tier 2 Transmission	8	7	7	7	4	4	2	8
F. 6yr Ramp Rate for DSR	4	3	4	5	5	4	4	4
S. SGCHG Only, No CETA	2	9	9	8	7	3	1	7
T. No CETA	1	9	8	9	7	5	9	9
V1. Balanced Portfolio	6	2	3	3	3	1	6	1
V2. Balanced Portfolio w/ MT Wind + PHES	9	6	5	1	4	1	7	6
V3. Balanced Portfolio w/ MT Wind 2026 + 6yr DSR Ramp	7	3	5	4	4	1	3	3
AA. MT Wind + PHES	5	4	1	6	5	3	8	5

- The Mid Portfolio provides a starting point from which to develop a preferred portfolio.
- Through selection of more distributed resources (C), we can improve Environment, Resource Adequacy and Resiliency indicators at the expense of other indicators.
- A 6-yr ramp rate (F) provides middling results for all indicators, but lags behind the Mid Portfolio in most.
- Accelerating MT Wind adoption and PHES (AA) improves Climate Change and Air Quality indicators significantly.
- Combining elements of all these sensitivities, we derive the Balanced Portfolio (V1) which provides the best balance of all indicators.

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Questions for Stakeholders

PSE appreciates stakeholder feedback during the webinar or in the feedback report:

1. Do stakeholders agree with PSE’s preliminary Customer Benefit Indicator approach for this IRP?
2. Are there other Customer Benefit Indicators that should be included?
3. Are portfolio output correctly aligned with Customer Benefit Indicators?
4. Are there other portfolio output that should be included?

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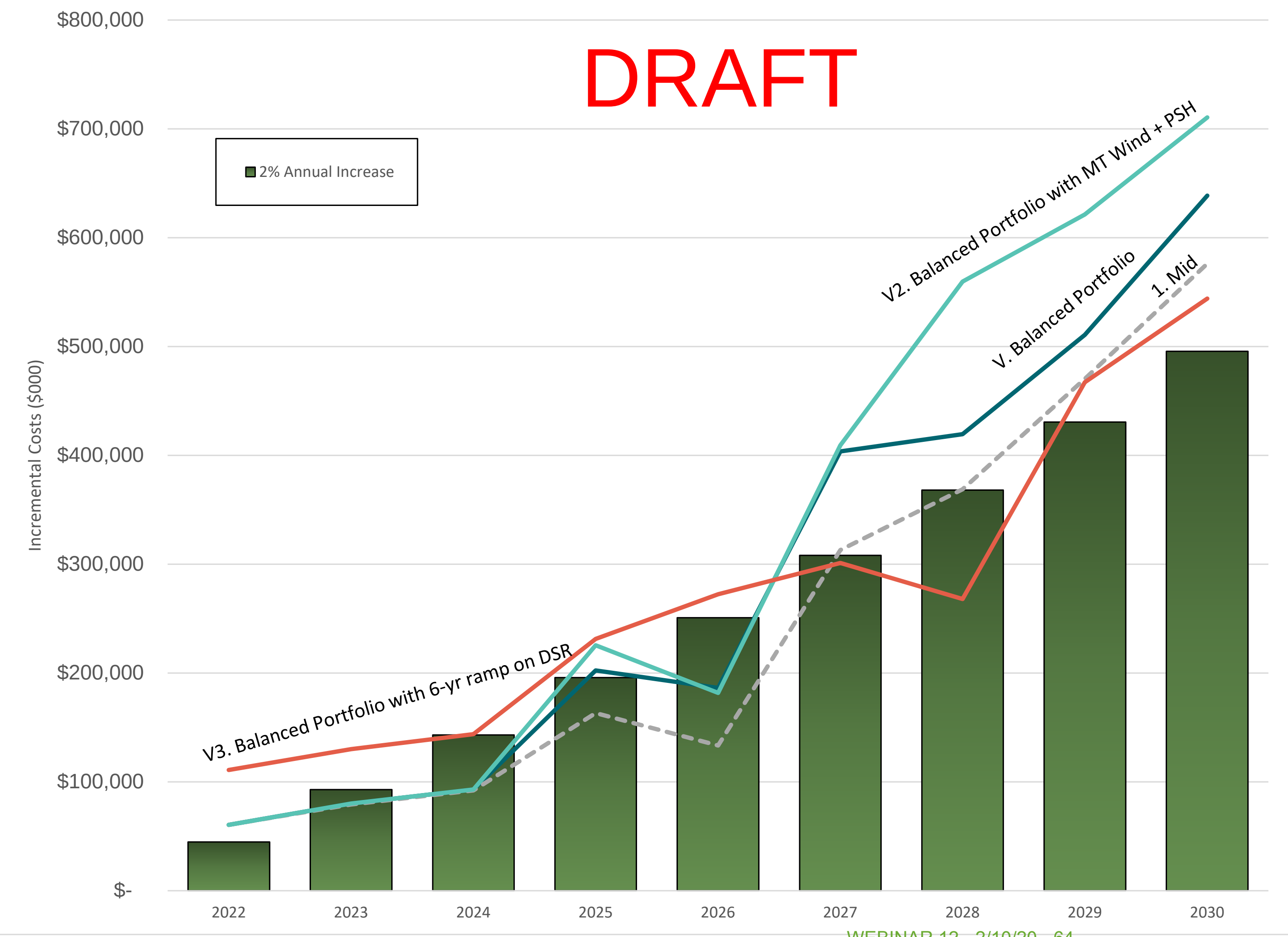
CETA Incremental Cost of Compliance

RCW 19.405.060

Clean energy implementation plan—Compliance criteria—Incremental cost of compliance.

(3)(a) An investor-owned utility must be considered to be in compliance with the standards under RCW 19.405.040(1) and 19.405.050(1) if, over the four-year compliance period, the average annual incremental cost of meeting the standards or the interim targets established under subsection (1) of this section equals a <u>two percent</u> increase of the investor-owned utility's weather-adjusted sales revenue to customers for electric operations above the previous year, as reported by the investor-owned utility in its most recent commission basis report. All costs included in the determination of cost impact must be directly attributable to actions necessary to comply with the requirements of RCW 19.405.040 and 19.405.050.

Incremental cost of CETA compliance



- Green bars represent compounding annual 2% increase.
- Portfolio sensitivities revenue requirement is compared with Sensitivity T (No CETA with SCGHG adder).
- Annual portfolio costs only include costs associated with generating resources modeled in the IRP.
- Cost of compliance will be calculated based on the final preferred portfolio and available in the final IRP.
- All costs associated with CETA implementation will be available through the Clean Energy Implementation Plan.

Questions & Answers

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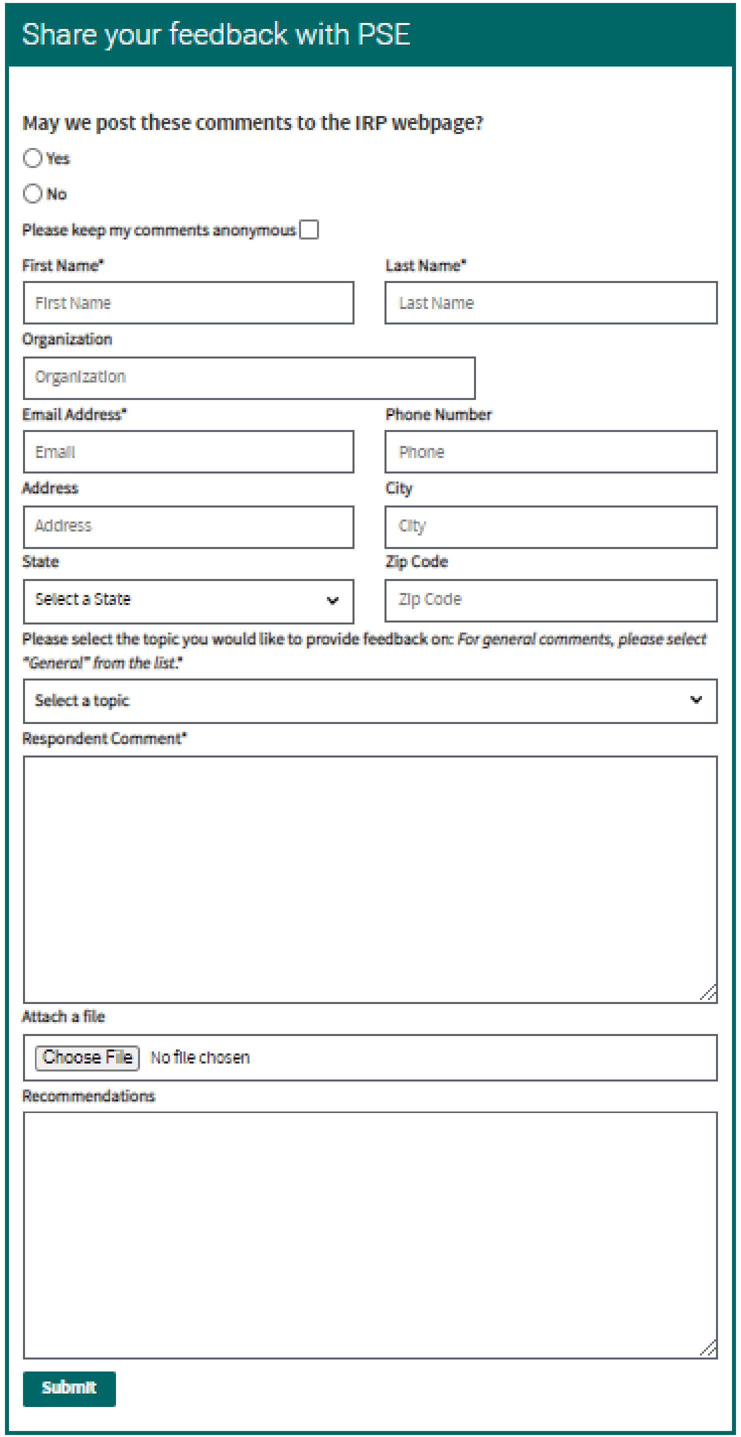
Third-party recording is not permitted.

Feedback Form

- An important way to share your input
- Available on the website 24/7
- Comments, questions and data can be submitted throughout the year, but timely feedback supports the technical process
- Please submit your Feedback Form within a week of the meeting topic


Share your feedback with PSE

May we post these comments to the IRP webpage?

Yes

No

Please keep my comments anonymous

First Name* | Last Name*

First Name | Last Name

Organization

Organization

Email Address* | Phone Number

Email | Phone

Address | City

Address | City

State | Zip Code

Select a State | Zip Code

Please select the topic you would like to provide feedback on: *For general comments, please select "General" from the list.*

Select a topic

Respondent Comment*

Attach a file

Choose File No file chosen

Recommendations

Submit

Next steps

- Submit Feedback Form to PSE by **February 17, 2021**
- A recording and the chat from today's webinar will be posted to the website **tomorrow**
- PSE will compile all the feedback in the Feedback Report and post all the questions by **February 24, 2021**
- The Consultation Update will be available on pse.com/irp on **March 3, 2021**

Upcoming meetings and key dates

Date	Topic
February 26, 2021 9:30 am	WUTC recessed open meeting
March 5, 2021 1:00 – 5:00 pm	Stochastic analysis Market risk sensitivity Preferred Portfolio Clean Energy Action Plan
April 1, 2021	FINAL 2021 Electric and Natural Gas IRP filed with the WUTC

Details of upcoming meetings can be found at [pse.com/irp](pse.com/irp)

Thank you for your attention and input.

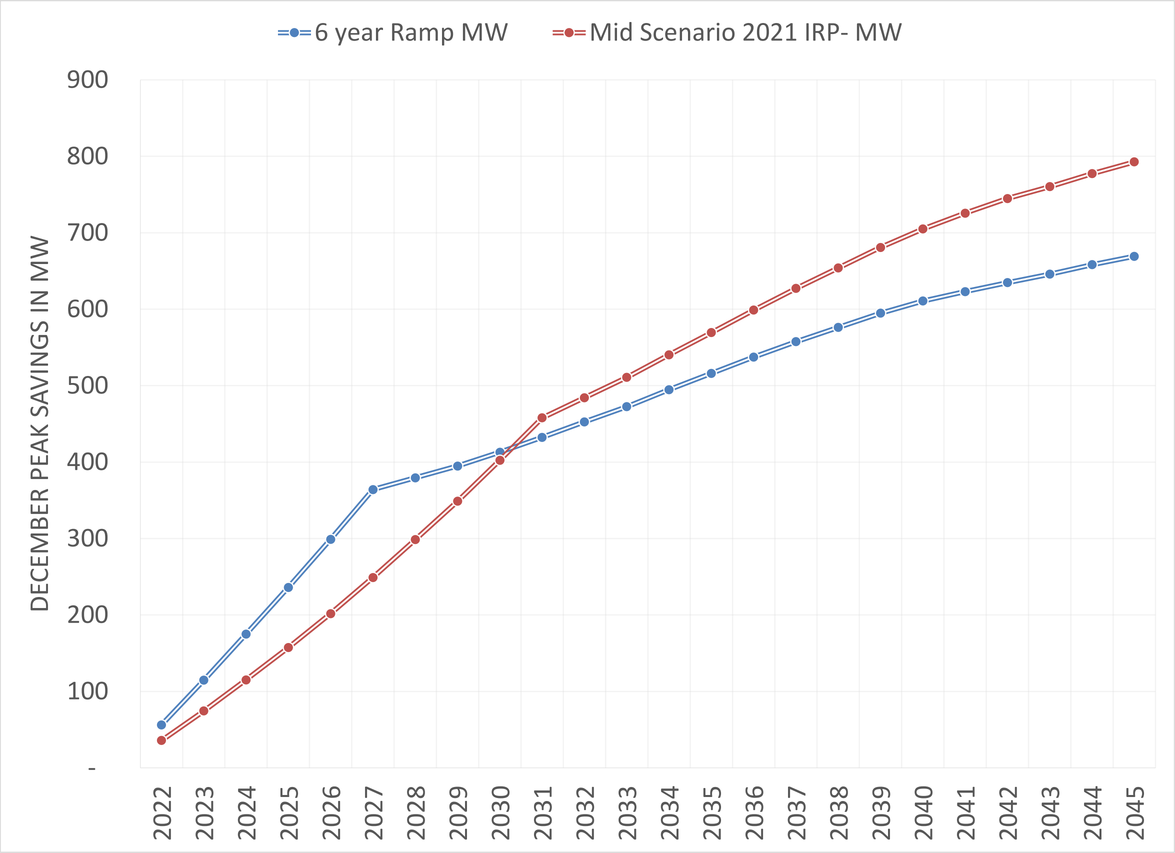
Please complete your Feedback Form by February 17, 2021

We look forward to your attendance at PSE’s next public participation webinar on March 5, 2021

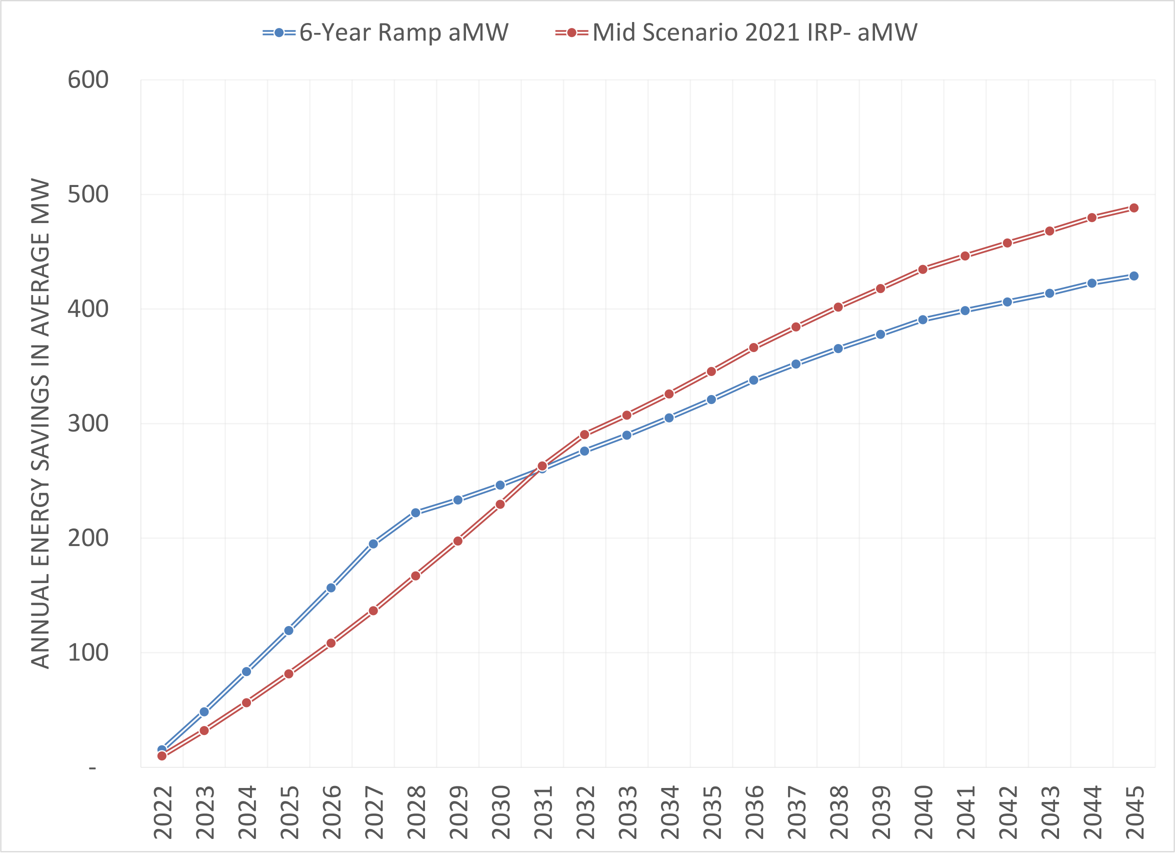
Appendix

PUGET SOUND ENERGY

Compare cost effective DSR: 6 year ramp portfolio vs. Mid portfolio



Peak Savings (MW)



Energy Savings (aMW)

PSE 2021 PRELIMINARY
IRP CUSTOMER BENEFIT INDICATORS
EXCEL SPREADSHEET

Click this link to download the spreadsheet:

https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/Feb_10_Webinar/PSE_2021_Preliminary_IRP_Customer_Benefit_Indicators.xlsx

The February 10, 2021 PSE IRP public stakeholder presentation contains many acronyms. To increase accessibility, PSE has compiled a list of acronyms used in the presentation and their meanings.

Acronym	Meaning
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
BAU	Business-as-Usual
BESS	Battery Energy Storage System
CBI	Consumer Benefit Indicators
CCCT	Combined Cycle Combustion Turbine
CEAP	Clean Energy Action Plan
CEIP	Clean Energy Implementation Plan
CETA	Clean Energy Transformation Act
CIA	Community Impact Assessment
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DMS	Distribution Management System
DSM	Demand Side Management
EHDM	Environmental Health Disparities Map
EV	Electric Vehicles
FLISR	Fault Location, Operating Procedures, Isolation, Service Restoration
GIS	Geospatial Information System
HILF	High Impact, Low Frequency Events
Nox	Nitrogen Oxides
NWA	Non-Wire Alternatives
OMS	Outage Management System
PHES	Pumped Hydro Electric Storage
PM	Particulate Matter
RCW	Revised Code of Washington
SCADA	Supervisory Control and Data Acquisition
SO2	Sulfur Dioxide
T&D	Transmission and Distribution
VPP	Virtual Power Plant
VVO	Voltage and VAR Optimization
WAC	Washington Administrative Code

PUGET SOUND ENERGY

Webinar #12: Delivery System and Grid Modernization Solutions, Flexibility Analysis results, Portfolio draft results, and Economic, Health and Environmental Benefits Assessment of Current Conditions Status Update

2/11/2021

Overview

On February 10, 2021 Puget Sound Energy hosted an online meeting with stakeholders to discuss the delivery system and grid modernization solutions, the flexibility analysis results, the electric portfolio draft results as well as a status update on the Economic, Health and Environmental Benefits Assessment of Current Conditions. Additionally, participants were able to ask questions and make comments using a chat box provided by the Go2Meeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendee

A total of 67 stakeholders and PSE staff attended the webinar, plus another 8 attendees who called into the meeting and did not identify themselves (75 people total).

Attendees included: Alexandra Streamer, Andrew Israelson, Anne Newcomb, Anthony O'Rourke, Ben Farrow, Benjamin Zwirek, Bill Pascoe, Bill Westre, Bob Williams, Brandon Capps, Brett Rendina, Brian Grunkemeyer, Bryan Tyson, Bruce Boram, Cathy Koch, Charlie Black, Charlie Inman, Christine Bunch, Colin Crowley, Court Olson, David Mills, David Tomlinson, Diann Strom, Don Marsh, Doug Howell, Elaine Markham, Elise Johnson, Elanor Ewry, Elizabeth Hossner, Eric Kang, Fred Heutte, Gurvinder Singh, Hayden Harvey, Irena Netik, Jennifer Magat, Jens Nedrud, Jeremy Ciarabellini, Jessica Yarnall Loarie, Jim Tarpey, Joni Bosh, Kara Durbin, Katie Ware, Kendra White, Kyle Frankiewich, Lance Rottger, Leslie Almond, Lori Elworth, Marty Saldivar, Michael Goggin, Michael Rooney, Michele Kvam, Nate Sandvig, Norm Hansen, Pete Stoppani, Peter Tassani, Rahul Venkatesh, Renchang, Ryan Sherlock, Sachi Begur, Sarah Laycock, Scott Williams, Shaughn Ryan, Stephanie Chase, Steve Greenleaf, Therese Miranda-Blackney, Tom Flynn, Tracy Rolstad, Tyler Tobin, Virginia Lohr, Warren Halverson, Wendy Gerlitz, Wiemin Dang, Zac Yanez, and Zhi Chen.

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 1:00 PM PDT and ended at 5:00 PM PDT.

Name	Time Sent	Comment
Virginia Lohr	**1:01 PM**	The link distributed to me when I preregistered was wrong.
Elise Johnson	**1:02 PM**	Hi Virginia, I'm sorry to hear that! Did others have trouble with their link?
Virginia Lohr	**1:02 PM**	I don't know. This is the meeting number I was sent: 413142693
Elise Johnson	**1:03 PM**	Thank you, Virginia. I will work on troubleshooting this.
Don Marsh	**1:20 PM**	raise hand #12
Don Marsh	**1:34 PM**	Slide 17. Can you provide the full list of benefits associated with non-wires alternatives?
Joni Bosh	**1:40 PM**	Slide 19 - do you have some speicific definition of "long term" that you are using?
Warren Halverson	**1:42 PM**	Would you please share PSE's specific use of batteries (grid, buildings etc) in the next 5 years, relate to eliminating or downsizing distribution and transmission lines.
Fred Huette	**1:42 PM**	Question on slide 19
Don Marsh	**1:42 PM**	Question on 21
Christine Bunch	**1:45 PM**	How does the "missing link" planning work integrate with non-wire alternative planning?
Norm Hansen	**1:45 PM**	Norm Hansen. What about undergrounding? This increases the reliability remarkedly during storms. With current technology it is economically feasible PSE could look at their peers for successes. What is PSE willing to do?
Don Marsh	**1:46 PM**	Question on 22
Kyle Frankiewich	**1:46 PM**	Q on slide 21
Joni Bosh	**1:46 PM**	+1 to Christine Bunch question
Don Marsh	**1:47 PM**	Why don't we go back, slide by slide, and address all questions on each slide. Otherwise, we're going to go back and forth a lot.
Don Marsh	**1:48 PM**	Question on 23
Warren Halverson	**1:49 PM**	The WSJ Feb 6-7 "The Birth of the Super Battery" -- excellent article the experts say the cost of batteries per kwh is go from $125kwh tdy; $80kwh 3yrs; $50kwh? What are implications to your plan and IRP decisions?
Joni Bosh	**1:49 PM**	Slide 22, how much of Kitsap are you looking at? the entire county? just a single feeder? Limited to Seabeck as on slide 23?
Don Marsh	**1:52 PM**	Question on 24
Brian Grunkemeyer	**1:52 PM**	Slide 21 - On Bainbridge Island, there are about 435 Tesla and Nissan cars there, which could be contributing up to 2.6 MW of load on weeknights, and this will grow with new EV's over time. However, I suspect some aggregators may not have participated because of a need to have already signed up drivers before starting the project. You might want to consider a marketing ramp-up period with PSE marketing materials in future program design, to get the right level of customer engagement.
Kyle Frankiewich	**1:57 PM**	slide 25: 'operational flexibility' - what benefits does this phrase refer to?

Anne Newcomb	**1:58 PM**	Thanks Jens, what is the configuration of solar panels on these projects? Are the centralized or dispersed from site to site and how many are you using? This is very inspiring to see you are working on these non-wire projects. We want to support you in whatever way possible. Would it help to connect you with others around the world like in the UK who are having good success?
Don Marsh	**1:59 PM**	Question on 26
Don Marsh	**2:02 PM**	What would you say your most successful NWA projects are? Did they provide even more benefits than you anticipated?
Katie Ware	**2:04 PM**	What battery energy storage systems (and what durations) were modeled both in the non-wires runs and the hybrid runs?
Warren Halverson	**2:06 PM**	What factors are built into your IRP cost comparison analysis of brick old age type solutions versus newer technologies? Simply off shelf price comparison; flexibilities in the network; elimination of other elements; .... the next few years prices are going to really go down .... yet you are building, for example, transmission lines that have a life of 50 years. Comments?
Brian Grunkemeyer	**2:08 PM**	Have you considered structuring pricing for NWA projects based on aggregating devices (water heaters, air conditioners & EVs) to accept bids per kW, but with a dialable, variable total amount of power based on future marketing spend & consumer adoption rates? It may be less useful for system planning, but it's also hard to aggregate devices without a pilot or program in place in the first place. The ramp up time might only be 3-6 months, but the marketing campaign needs to be built in.
Anne Newcomb	**2:08 PM**	Are utilities able to make a profit on distributed energy? If not would new laws to address this be helpful?
David Tomlinson	**2:09 PM**	Jens, When you say the duration of energy storage limits its value, can you provide more definition on what duration lengths would be ideal for each of your four example projects. 24 hours, 72 hours or 3 weeks for example?
Charlie Black	**2:13 PM**	What price forecast for CARB GHG emissions allowances did PSE use?
Doug Howell	**2:13 PM**	I am still not clear if a cost of carbon was included in the benefits -- even without CETA -- and what was the carbon value that was attributed?
Joni Bosh	**2:14 PM**	Thanks
Jim Tarpey	**2:15 PM**	How long do you anticipate a NWA solution to last?
Anne Newcomb	**2:17 PM**	Is PSE looking for good locations for pumped hydro storage? Old mines are working well!
Anne Newcomb	**2:20 PM**	good thoughts Fred!
Brian Grunkemeyer	**2:28 PM**	I'm happy to follow-up offline with additional thoughts on my comments.
Katie Ware	**2:34 PM**	Do the flexibility cost savings incorporate the SCGHG?
Doug Howell	**2:34 PM**	Slide 32. Do the gas plants include CETA's $74/ton social cost of carbon?
Brian Grunkemeyer	**2:35 PM**	Elizabeth, is that flexibility value of DR in addition to say the normal market price for DR, of up to say $100-$120/kW-yr? Or is that $35 embedded in the market price for DR?
Bill Pascoe	**2:37 PM**	Question on 32

Charlie Black	**2:37 PM**	What did PSE's flexibility analysis assume about flexibility capabilities of CCCTs? For example, did PSE look at costs for incrementally increasing or decreasing generation from a starting point of partial loading on a CCCT?
Anne Newcomb	**2:37 PM**	on slide 33, what is your base load?
Kyle Frankiewich	**2:38 PM**	slide 33: I don't understand exactly how the analysis works and these figures are calculated. Why would a 4-hr Li-ion battery perform worse than a 2-hr?
Anne Newcomb	**2:38 PM**	Also, this is great to see!
Charlie Black	**2:40 PM**	For clarification, did PSE include Social Cost of Carbon as a variable cost of dispatch?
Kyle Frankiewich	**2:41 PM**	slide 32: iirc, the fixed-cost SCGHG adder is being included as a $/kw-yr. Is this correct? If so, then do these cost savings include adjustments made to that SCGHG fixed-cost adder to account for any changes in a thermal resource's dispatch?
Katie Ware	**2:42 PM**	We recommend additional considerations to operational flexibility (both up & down) offered by controllable solar and wind power plants
Joel Carlson	**2:44 PM**	When will the Tono solar project in Thurston County be built?
R.C. Olson	**3:03 PM**	I’ve lost audio.
Alexandra Streamer	**3:06 PM**	Court, it's still coming through on our end. Are you able to leave and return to the meeting?
Fred Heutte	**3:28 PM**	Have a question…
Doug Howell	**3:30 PM**	Have you been consulting with Front & Centered on equitble distribution of benefits?
Doug Howell	**3:39 PM**	Slide 52. How do you define biomass? Just this include forest biomass? How does this align with Dept of Commerce that says development of renewable natural gas is very limited? * Does this include forest biomass?
Katie Ware	**3:48 PM**	Elizabeth, we spoke in January about PSE modifying sensitivity P to allow the model to consider a mix of storage resources (4-hour standalone storage, 8-10 pumped hydro, solar/wind paired with 4-hour storage and demand response) -- will this be included in the final IRP?
Don Marsh	**3:48 PM**	Slide 56: We are still emitting 1 million tons of CO2 in 2045? Is that compliant with CETA?
Bill Pascoe	**3:49 PM**	Question on 52
Charlie Black	**3:50 PM**	Are resource additions available by type of resource on an annual basis?
Fred Huette	**3:50 PM**	Have a comment about the 6-year EE/DSR ramp scenario.
Charlie Black	**3:50 PM**	Especially interested in annual resource additions by type of resource during 2021-2030.
Charlie Black	**4:04 PM**	It is very disappointing that PSE is not sharing any detail on the types of resources being added in the different portfolios, except as an aggregate total between 2021 and 2045. This makes it almost impossible to assess the reasonableness of PSE's analysis and results. It's also disapointing that the resource portfolio results are being kept so opaque at such a late stage in PSE's 2021 IRP process.

Christine Bunch	**4:07 PM**	Are non-energy benefits quantified for the ranking analysis related to customer benefit indicators? Examples might include fossil fuel savings from oil, propane, diesel, health/comfort, etc.)?
Pete Stoppani	**4:08 PM**	Is anyone from Front and Centered here? If not, will you get their feedback before moving forward on the benefits?
Christine Bunch	**4:10 PM**	Other indicators should be specific to energy burden - % of participation in EE programs from low-income households, % of households participating in weatherization programs, % getting access to utility discounts, etc.
Doug Howell	**4:14 PM**	Slide 63 - This looks as though you exceed the cost cap
Anne Newcomb	**4:15 PM**	why do you think 6yr DSR drops and then goes up sharply?
Bill Westre	**4:16 PM**	S-62 What discount rate was used for amortization of the scenario costs?
Joni Bosh	**4:17 PM**	Slide 63 the incremental cost calculations are between the preferred portfolio and the alternative portfolio. Is Sensitivity T the preferred portfolio?
Bill Westre	**4:18 PM**	Another question on S62
R.C. Olson	**4:18 PM**	What is the amortization period used in spreading the resource costs in slide 63?
Katie Ware	**4:19 PM**	Will the new portfolio adjusting for the 2% threshold consider altered timelines for new resource procurements, new resource mixes altogether, or both?
R.C. Olson	**4:21 PM**	When can we expect to see the new "adjusted portfolio" and the mix of resource acquisitions schedule?
R.C. Olson	**4:23 PM**	What resource life values are you using for utility solar and for wind farms?
Bill Westre	**4:24 PM**	How many years was used in the analysis?
R.C. Olson	**4:27 PM**	On slide 63 what electricity demand curve projection for the future are you using. Was it changed since Dec 15th. Is it projected to stay flat?
R.C. Olson	**4:28 PM**	Is that base demand forcast the same as it was in Dec 15th
Don Marsh	**4:28 PM**	I have a couple of questions in the first section.
Bill Westre	**4:33 PM**	Will you run the analysis (S62) with a 2.5% discount rate?
Anne Newcomb	**4:37 PM**	From what I understand solar panels are under warranty for 25 years but actually last much longer. have you considered adding longer lifespans into your modeling? don't wind turbines live longer than 25 years as well?
Pete Stoppani	**4:45 PM**	#27 If a solution is not needed for 3 years, shouldn't "Perform NWA Analysis" come after "Need Date > 3 Years" rather than after the capacity and cost tests?
Anne Newcomb	**4:47 PM**	considering onshore wind and solar are the lowest cost energy resources in 2020 and 2021 why does your modeling show it is expensive?

PSE IRP Feedback Report
Webinar 12: Delivery System Planning 10-year Plan, Flexibility Analysis Results, Economic, Health and Environmental Benefit (EHEB) Assessment, of Current Conditions Status Update, Portfolio Draft Results
February 10, 2021

2/24/2021

The following stakeholder input was gathered through the online Feedback Form, from February 3 through February 17, 2021. PSE's response to the feedback can be found in the far-right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on March 3, 2021.

Feedback Form Date	Stakeholder	Comment	PSE Response
2/3/2021	Stephanie Chase, Sarah Laycock; Public Counsel Unit, Washington State Attorney General's Office	Public Counsel has reviewed PSE's draft IRP and appreciates the Company's efforts in this planning process. We have a few comments and questions for the Company: Public Counsel understands that PSE has started the process to develop an equity advisory group has begun reaching out to stakeholders. How will that development be described in the final IRP? Is the goal to include more detailed plans for outreach and development of the advisory group in the final IRP? Can PSE provide more detail about what the 'assessment of current conditions' references on page 2-5 includes? Page 2-13 refers to a figure "2-XX." It is unclear which figure this should be and the figure number should be updated. Thank you for your attention and response. Sincerely, Stephanie Chase & Sarah Laycock Regulatory Analysts Public Counsel	PSE is actively working towards forming the PSE's Equity Advisory Group, and anticipates commencing meetings in mid-March. The Final IRP will describe the work PSE has completed as of the filing deadline in regards to consultation and launch of the first Equity Advisory Group. PSE plans to file the Clean Energy Implementation Plan's Public Participation Plan with the Commission in May 2021, which will highlight engagement with customers and advisory groups over the course of the CEIP development. The reference to "assessment of current conditions" corresponds with the process PSE is taking to develop the Economic, Environmental, Health and Environmental Benefits Assessment of Current Conditions. This assessment is needed to provide insight to the existing conditions of PSE customers, based on the assessment metrics proposed by PSE. PSE takes a "snapshot" of existing PSE customers based on metrics identified in the Assessment, in order to capture the conditions of each defined customer group, as well as determine where the disparities may be within each named customer group. PSE describes the assessment further in Appendix K, which will be updated for the Final IRP. The correct figure number is 2-8. PSE appreciates Public Counsel for bringing this to our attention. The reference will be corrected in the Final IRP.
2/8/2021	Keith Dunbar	I read through the draft report. While I see the prospect of 3 or more pumped storage projects (which in my mind will help meet night time electrical demand of non-day light hours for solar cell electrical generation, and non-sustained wind days for wind turbines), I do NOT see any consideration of one or more waste to energy plants being considered. For example, the West Palm Beach County, Florida waste to energy plant provides 95 Megawatts of dependable and sustained energy to the region. In my mind, Snohomish, King and Pierce Counties alone could sustain at least one of these plants. Harmful chemicals are removed, and air quality controls limit emissions. It could be a win-win situation providing a solution to the large majority of solid waste disposal needs of these large populated counties, and would provide dependable energy to PSE and the region. The siting of such a facility should be adjacent to existing rail corridors. County waste management centers and transfer stations could locate adjacent to rail lines as well to transport waste material to the plant. This would help to eliminate long-haul of waste along the regions transportation network, help in reducing congestion and fuel use of trucks that would reduce long haul trips. Another waste to energy plant could be considered for the northern service area in Whatcom and Skagit Counties as well. Along with additional research on Hydrogen Fusion as a potential energy source, one or more waste to energy plants should be studies. Spokane, WA has one, but it is an older and much less efficient plant than those found in West Palm Beach County and other locales.	Thank you for the suggestions concerning PSE acquiring power from waste-to-energy plants and input concerning resource siting and recommendation for close proximity to rail. Currently, PSE purchases electricity produced through a waste-to-energy project via a power purchase agreement under a Schedule 91 contract. PSE also purchases the pipeline quality natural gas from the largest landfill in PSE's service territory, the Cedar Hills landfill. Waste-to-energy projects are discussed in PSE's Draft IRP in Appendix D on pages D-71 and D-72.
2/17/2021	Orijit Ghoshal, Invenergy	<u>General comments on Webinar 12</u>: Invenergy is concerned that PSE is not providing clear and detailed information about its assumptions, analyses and results for the 2021 IRP. These concerns were reinforced during Webinar #12. The vague and insufficiently detailed information being provided by PSE makes it difficult to assess whether the Flexibility Analysis and Portfolio Draft Results presented on February 12, 2021 are sound and reasonable. While this has been an ongoing concern, PSE's willingness to share meaningful information and constructively respond to stakeholder questions and comments appears to be degrading further.	Thank you for your general comments and specific comments to include the Social Cost of Greenhouse Gases in the Flexibility Analysis, revise flexibility cost savings, perform portfolio analysis using SCGHG as an incremental cost of dispatch, and to provide more detail on the timing of resource additions. Your letter is included as an attachment to this report, and individual questions and PSE's responses provided below.

Feedback Form Date	Stakeholder	Comment	PSE Response
2/17/2021	Invenergy	Specific comments on Webinar 12 (Flexibility Analysis, Question 1): Social Cost of Greenhouse Gas (SCGHG): It was not clear from PSE's presentation whether or how it has included the SCGHG flexibility analysis it performed using the PLEXOS model. In response to stakeholder questions, PSE initially stated that the SCGHG was included "in the portfolio model". However, the portfolio model is separate from PLEXOS. When prompted, PSE admitted that it did not include the SCGHG in the flexibility analysis. Invenergy continues to urge PSE to include the SCGHG as a variable cost of dispatch for GHG-emitting generation, including in the flexibility analysis. Not including the SCGHG in the flexibility analysis ignores the environmental externality costs of dispatching GHG-emitting resources. It also biases PSE's results in favor of more GHGintensive peaking generation relative to less GHG-intensive combined-cycle combustion turbine (CCCT) generation.	PSE models SCGHG as a planning adder, not as a dispatch cost, since we are trying to model real-world dispatch of resources. However, PSE evaluated a portfolio sensitivity where the SCGHG was included as a dispatch cost. Detailed portfolio results will be available in the Final IRP. Since the purpose of the flexibility analysis is to track the dispatch changes from the day ahead to the real time, fixed costs are not included in this modeling process, just variable costs. The SCGHG is accounted for in the portfolio modelling rather than the Flexibility Analysis.
2/17/2021	Invenergy	Specific comments on Webinar 12 (Flexibility Analysis, Question 2): Flexibility Cost Savings: Slide 32 of PSE's presentation shows flexibility cost savings of $23.45- $25.39/kilowatt-year for peaking generation and $5.27 per kilowatt-year for CCCT generation. If PSE's analysis only addressed intra-hour (e.g., 15-minute) Flex Up and Flex Down violations, the results appear quite high, especially for peaking generation. Alternatively, if the flexibility analysis also addressed flexibility benefits across longer time increments (e.g., hourly, diurnal) – as it should – PSE's assumptions about the flexibility capabilities of CCCTs are unrealistically restrictive. In addition, if PSE's flexibility analysis treats all CCCTs as being dispatched on a concurrent basis, this would further under-value the flexibility benefits of CCCTs compared to a more realistic operational approach that allows CCCTs to be dispatched on a sequential basis (i.e., not necessarily at the same time). Under a sequential dispatch approach, a group of CCCTs could provide flexibility cost savings because only one or a few CCCTs would need to be operated at partial-loading at any given point in time.	CCCT's are non-cycling units since they cannot be turned on and off every hour like a more flexible SCCT or battery. So they are dispatched in the day ahead model and in the hourly model. When moving into the real time model, if the unit is already on, they can be flexed from min load (partial load) to full load. The decision to commit a CCCT in the model is done through the unit commitment logic. This logic is applied individually to each unit (sequential basis), however the decision to commit a unit is dependent on what has already been committed. Below is an excerpt from the manual located in the help function of the AURORA model on how the unit commitment logic works: Unit Commitment is used for all non-cycling units and commitment decisions evaluated and updated for every hour of the dispatch. This method uses zone-specific, 168 hour-ahead, internal market price forecasts to evaluate the economics of unit commit and de-commit decisions. The internal zone forecasts use observed zonal price history in conjunction with other observed simulation parameters to produce the 168 hour-ahead forecast. The internal forecasts are updated dynamically each hour as model chronology proceeds. At the beginning of each dispatch hour, all non-cycling units are classified according to their commitment eligibility. Units that have been offline for at least their minimum down time are eligible for commitment. Those that have been running for at least their minimum up time are eligible for de-commitment. For commitment eligible units, an algorithm is run to determine the unit's expected pattern of operation and resulting cash flow over its minimum up time, if started in the hour, and compensated according to the hourly price profile contained in the internal forecast. Unit minimum capacity, heat rate at minimum, bid factors, start up costs, start up fuel, and operating fuel choice decisions are fully represented in this algorithm. If estimated profit over the minimum up period exceeds the economic hurdle rate for commitment (specified through the unit's non-cycling factor), a decision is made to commit the unit (unless the forecasted value of operation in the first hour is negative, excluding all start-up costs). A similar process is used to evaluate the economics of shut down decisions for any non-cycling units that are eligible for de-commitment in the hour. The model will decide to either continue operating the unit for an additional hour, or to shut the unit down (de-commit), depending on the expected consequences (profitability) of continued operation. Those consequences are estimated by examining hours successively farther into the future, one hour at a time, until the accumulated forecasted operating results satisfy one of two alternative conditions; either accumulated value (revenues – variable costs) is a loss that exceeds start-up cost, or accumulated value is positive.
2/17/2021	Invenergy	Specific comments on Webinar 12 (Portfolio Analysis Results, Question 3): Social Cost of Greenhouse Gas (SCGHG): From PSE's presentation, it is not clear whether it has performed meaningful portfolio analyses that include the SCGHG as an incremental cost of dispatch for GHG-emitting generation. Instead, PSE continues to treat the SCGHG as a fixed cost, calculated after-the-fact, based on generation dispatch costs that exclude the SCGHG. Invenergy has previously	PSE appreciates Invenergy's extensive comments regarding SCGHG. However, PSE believes that CETA is clear that SCGHG should be applied as a cost adder and disagrees with Invenergy's position to apply the SCGHG as a dispatch cost. Nevertheless, in response to Invenergy's and other stakeholder's feedback, PSE has modeled SCGHG as a dispatch cost as

Feedback Form Date	Stakeholder	Comment	PSE Response
		submitted extensive comments, including in PSE's 2021 IRP process and in the Clean Energy Transformation Act (CETA) rulemakings that explain why the SCGHG must be included as an incremental cost of dispatch. Invenergy continues to encourage PSE to include the SCGHG as an incremental cost of dispatch for GHG-emitting generating resources, including in its portfolio analyses.	one of the portfolio sensitivities. The portfolio modeling was not finished for the Feb. 10 webinar and will be included in the final IRP. Stakeholders will see that including SCGHG as a dispatch cost does not have any meaningful change on the portfolio results.
2/17/2021	Invenergy	Specific comments on Webinar 12 (Timing of Resource Additions, Question 4): PSE's presentation of the results from its updated portfolio analysis provides a startling lack of detail about the timing of new resource additions. The only place where new resource additions are presented for PSE's updated portfolio analysis is on Slide 54, entitled "Portfolio costs and resource additions". This slide only provides total additions for each type of resource over the entire period from 2022-2045. No information is provided for the timing of resource additions within the 24-year planning horizon. As a result, this makes it very difficult to assess the validity of PSE's portfolio analysis and results. In particular, it obscures results for resource additions during the critical upcoming period, including the next five years. That is the most important timeframe for the 2021 IRP, in part because PSE will be able to use its 2025 IRP to update its resource strategy for the latter half of the coming decade. Invenergy considers it highly unusual for PSE to obscure the results of its portfolio analysis in this way, and at such a late stage in the 2021 IRP process. Invenergy requests that PSE provide more detailed information as soon as possible about the timing of the resource additions in its portfolio analysis, including annual resource additions, by type of resource, during 2022-2029.	The portfolio modeling was not finished for the Feb. 10 webinar and PSE did not want to share partial results. Detailed portfolio results, including the annual builds will be available for each portfolio in the final IRP.
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Questions and comments from presentation.	Thank you for your questions. PSE inserted each item below along with PSE's responses.
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 12: Where do the proposed criteria come from? Why 3+ yrs, for example? We gather that depending on the circumstances, storage could be implemented as fast or faster than traditional wire solutions.	Getting any type of planned project completed in today's environment is a lengthy process. A pole replacement project takes 2 years and cable replacement project takes 3 years from the beginning of the planning analysis to completion. While it would seem like the 3+ year timeframe is long, it is quite typical. Let's break the process down for better understanding. Year 1 is the planning analysis, gathering data to identify the need and alternatives. For non-wires solutions and hybrid analysis this is about a 6 month process. Then any solution is evaluated through PSE iDOT model and funding is determined. Year 2 encompasses about 6 months for performing design and permitting which may include a lengthy RFP procurement process. For solutions that need land or right of way, it may take even longer depending on the public participation. This permitting process takes the same amount of time even for replacing an asset in place or installing on PSE property. Year 3 is spent in construction. For DERs, like behavior based demand response, additional time is needed to market, procure, integrate, test, and confirm that expected results work. Some traditional wire solutions take a long time due to public participation processes, processes that may impact DER solutions in a similar way. PSE will continue to evaluate this time criteria as more projects are implemented and can be learned from. Additionally, leading utilities also use a timeframe of 3-5 years as key suitability criteria to consider non-wire alternatives. Finally, PSE's own experience with Bainbridge Island for which study work began in 2018 will only begin to implement its demand response program in 2021 and battery in 2022.
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 19: PSE's guiding question seems to be - does the company have enough time? Is there a reason why PSE would or would not see system needs coming pretty far in the future? It is a 10-year plan, after all. Could the company provide some examples of what would occur that would cause a change in planning requirements for a circuit that would not be identified in the 10-year plan?	By looking out at least 3+ years and into the horizon of 10 years, there is enough time to analyze for future non-wire analysis. However, like the IRP that is iterative, assumptions change and therefore needs not previously identified may surface. Assumptions regarding load and local customer request routinely reshape the plan. PSE's 10-year plan is based on system forecasts fully including conservation efforts. This process does identify our large growth areas well, however, there are still near term changes

Feedback Form Date	Stakeholder	Comment	PSE Response
			that can accelerate growth in a local area. We have seen this in many of our downtown cores as they rapidly build out to meet demand, or in other warehouse districts where high energy density companies have taken up occupancy. Those have consisted of data centers in the past and more recently, office buildings implementing a high number of EV chargers have accelerated growth in local areas. These changes in assumptions has surfaced new near term needs in some cases.
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 21: This graph is useful. Is there a wired solution cost estimate that could be included in this graph?	The levelized cost of capacity graphic is a very good way to detail the stack of cost-effective non-wire alternatives. More information regarding the costs for the wired and non-wired alternatives can be found in the Bainbridge Island study in Appendix M of the IRP and also on the project website at https://psebainbridge.com/reliability-and-grid-modernization.
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 22: To what degree does this analysis hinge on battery valuation? If option 3 BAU + DER + ES is clearly more expensive, but the value stream of the related resources may provide more benefits than just solving local capacity constraints.	Part of the feasibility analysis is determining if the cost difference between a wired solution vs a non-wired (or hybrid) solution is close enough to complete a more detailed economic evaluation considering the additional value streams of energy storage. In the case of Kitsap, our industry experts recommended no further analysis as the benefit streams from energy storage would not be able to offset a cost delta of $100-130M to implement the energy storage system. In addition, this would be a very large battery system estimated at 45 MW, and 250+ MWh's of storage. There are very few examples of energy storage deferring this large of a transmission deferral need in the industry. Based on this as well as the significant cost increase to address this need with non-wire alternatives, the wired solution was recommended.
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 24: This is also a useful chart, but it seems that the NWA solution works in many scenarios. For a diurnal need such as this circuit shows, a longer- but not multi-day solution may be workable. Is there a $/kw-yr cost threshold that would beat the traditional wired solution? A tipping-point analysis on how cheap batteries need to be to beat the traditional solution may be informative.	As the lower graphic shows, the discharge time is up to 12 consecutive hours in year 1 and this will increase as load grows over time. When sizing an energy storage system both the discharge and recharge time including round trip efficiency losses need to be taken into account. Thus, a larger energy storage system is needed to fully address the capacity needs for the Lynden substation. Regarding an overall cost tipping point, we evaluate each project alternative comparing the portfolio cost to implement and thus address each need. In this case, the cost for a hybrid alternative using energy storage to address the capacity needs was over twice the cost of the wired alternative. For future optimistic pricing considerations, a tipping-point analysis could be helpful in identifying when a non-wire alternatives should consider a certain technology. This is something we will be continually updating as new technologies evolve and cost to implement decrease.
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slides 37-38: Census tracts at least partially on Indian Country as Highly Impacted Communities. They are not a separate designation under CETA. We suggest nesting tribes under HIC's header.	Thank you for clarifying the relationship between Highly Impacted Communities and Tribes. PSE will include census tracts at least partially located on Indian Country as Highly Impacted Communities in the assessment results provided in the Final IRP. These results will be available in Appendix K. PSE will continue to engage with Tribes to better understand the designation for these named communities for the CEIP.
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 38 - under vulnerable populations: it's probably just semantics, but rather than saying "requires definition" it may be more accurate to say "requires selection of specific adverse socioeconomic factors and sensitivity factors"	Thank you for the suggestion of language that more clearly explains the process of identifying Vulnerable Populations. Future work will endeavor to incorporate this language when describing assessment methodology.
2/18/2021	Kyle Frankiewich, Washington	Slide 40: This is something that took a few conversations to click, but vulnerable populations are more about demographics, and highly impacted communities are more geographically defined. Of course, there will be overlap, but identifying vulnerable populations means selecting factors, not scores on the map.	Thank you for clarifying the relationship between Highly Impacted Communities and Vulnerable Populations; where HICs are characterized by the Cumulative Impact Analysis (a largely geographic analysis) and VPs are characterized by selected demographics.

Feedback Form Date	Stakeholder	Comment	PSE Response
	Utilities and Transportation Commission	○ Map scores may be useful for understanding geographic distribution of those demographics (which is relevant to disparities mapping and program design), but it's important to clarify that vulnerable populations are first and foremost a demographic designation. ○ All factors must be linked to either adverse socioeconomic factor or vulnerability factor; it would be helpful to say whether a given factor is related to one of these two categories of factors, and to provide some justification for each bulleted factor being considered – this will be needed in CEIPs. ○ Note: Vulnerable populations are not covered by DOH's CIA – per statute, CIA is specific to highly impacted communities. DOH's mapping may help identify relevant factors as one possible data source, but UTC rules require utilities to propose specific factors in their CEIPs. Designation is not about averages; it is a binary yes/no regarding whether a customer meets the threshold of one or more of the sensitivity factors/adverse socioeconomic factors. ▪ If, for example, one factor is low-income status based on 200 percent FPL, any customers meeting that threshold are vulnerable even if they don't meet any of the other factors' thresholds, and even if they are not in an area identified as a highly impacted community. ○ Equitable distribution determination may allow for consideration of degrees of vulnerability, but we need to start by understanding the full universe of vulnerable populations.	PSE had previously interpreted the rulemaking to mean that HICs and VPs were both geographically defined, with HICs characterized by the CIA and VPs characterized by a subset of indicators specifically related to vulnerability (socioeconomic factors and sensitive populations). PSE sees the value in approaching the assessment from both a geographic and demographic perspective. However, given time constraints, demographic characterization of VPs will not be incorporated into the 2021 IRP. PSE will make efforts to revise the assessment in time for the Clean Energy Implementation Plan. As part of the CEIP process, PSE will work with the Equity Advisory Group and customers to refine the definition of vulnerable populations, including the demographic factors: • VPs characterized by demographic indicators • VP demographic indicators will be justified as either an adverse socioeconomic factor or vulnerability factor • VPs will be characterized on a binary basis, whereby if an individual meets any demographic criteria, that individual will be considered vulnerable • Customer and Equity Advisory Group feedback
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 41: For CEIPs, utilities need to be conducting customer outreach on vulnerable populations factors, then bring that research to the stakeholder process for help processing customer input. The customer input component doesn't seem to be included or at least not clearly identified.	Thank you for the guidance regarding customer feedback on vulnerable populations and the assessment. PSE has incorporated stakeholder feedback from the November Webinar into the Economic, Health and Environmental Benefits Assessment and will continue to incorporate additional feedback from this and future meetings. PSE is in the process of establishing the public participation process, including the formation of an Equity Advisory Group, to provide additional guidance on these matters as the CEIP is developed. Through the public participation process, PSE envisions engaging customers across the service area, and using this feedback in conversations with the EAG and other advisory groups.
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 43: How can this assessment be supplemented with a demographic analysis rather than being purely geographic?	PSE had previously not understood the assessment to require a demographic analysis component. It will take time to gather relevant data and establish methods and criteria. Please look for progress on this topic as the CEIP is developed. Also see responses above.
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 44: CIA ranks have limited use for understand magnitudes, but the map includes underlying data that can be used to understand magnitude of disparities. Are you going to supplement the tool with other analysis including demographic and qualitative analysis? How is the assessment tool helpful for understanding indicators since customer benefit indicators must be developed based on customer input?	Underlying data used to develop ranks may always be consulted by PSE when interpreting the results of the assessment. PSE has elected to not include underlying data in the public facing assessment to facilitate comparisons between disparate data types, allow for combinations of disparate data types and allow for sharing of otherwise confidential/proprietary information. Supplementary demographic information will be included in future work related to CEIP development (see responses above). Qualitative analysis will be included in narrative discussion of the assessment metrics within Appendix K of the Final IRP and further developed in the CEIP. PSE expects the Economic, Health and Environmental Benefit Assessment and customer benefit indicators to evolve as the long term planning process transitions from the IRP to the CEIP. The Equity Advisory Group will have an opportunity to inform assessment methodology, criteria and indicators. These insights will then be incorporated into future work in an iterative

Feedback Form Date	Stakeholder	Comment	PSE Response
			process. This first assessment is intended to begin the conversation and assess current conditions at PSE.
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 45: This slide may still need more lines including between: 1) CBIs and IRP [this is reflected on slide 56], and 2) HICs/VPs and CBIs. Line from assessment should be linked to plans, not CBIs as those stem directly from customer outreach.	Thank you for sharing this feedback on our concept flow diagram. PSE is still actively developing its understanding of how these new ideas and how workflows will mesh together throughout the power planning process. PSE will incorporate this guidance into its practice and future communications.
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 46: CBIs are about benefits/burdens, not programs, data sources etc. ○ CBIs on this list could benefit from some translation of current format to outcomes ○ Economic CBIs of energy burden, unemployment, poverty and health CBIs of SO2, NOx, and PM seem the most like outcomes. ○ CBIs are what are called "assessment metrics" on this slide. If a label is needed for the "resiliency"-level element, I'd recommend CBI area or category. It may still be helpful to have assessment metrics based on their correlation with CBIs ○ Generally speaking, the examples of this slide warrant a conversation about how specific CBIs should be. Is resiliency specific enough or should CBIs be specific measures of resiliency? UTC rules contemplated multiple CBIs could/should roll up to the CBI areas listed in the statute/UTC rules.	Thank you for the feedback on Customer Benefit Indicators. Your insights are very helpful as PSE develops its understanding of CBIs. • Outcomes – Thinking of CBIs as outcomes is a very useful tool. PSE acknowledges that several CBIs listed on this slide may align more closely with programs, than outcomes. PSE will work to re-align Assessment CBIs to be more outcome focused, however, the outcomes of this effort will not appear in the Final IRP, but will be available for the CEIP. • PSE will adjust messaging away from "Assessment Metrics" and instead use CBI to describe specific measures of benefits and burdens. To aid in organization and workflow, CBIs will be grouped by "CBI Type". These changes will be incorporated into the Final IRP and future communications. • PSE will continue to explore the specificity of CBIs both internally and with stakeholders as CBIs are further developed.
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 47: We believe the term assessment metrics might be used in multiple ways. We suggest dropping the term from this slide and calling them CBI categories. ○ In the context of the assessment, relationship between "assessment metrics" and CBIs might be correlated or not. For example, people who experience bad air quality might really care about air quality improvement, or not--maybe they care more about jobs. This is why it is important to include customer input in this process.	Thank you for this comment. It helps to clarify the relationship between "Assessment Metrics" and "Customer Benefit Indicators". In the Final IRP and in future communications, PSE will use the term "Customer Benefit Indicator" instead of "Assessment Metric". Furthermore, customer input will be used to further develop Customer Benefit Indicators as the Equity Advisory Group is established.
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 57: Do talking points include comments about updating these CBIs in the CEIPs based on customer input?	Thank you for the question. Yes, CBIs will be informed by customer input as the Equity Advisory Group is established and the public participation process is implemented for the CEIP. These changes will not be incorporated in to the Final IRP due to time constraints, but will be available for the CEIP.
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 58: Does PSE consider values in addition to ranks? Adoption order describes max. customer benefit scenario in terms of maximizing CBI values.	Thank you for the question. PSE has elected to use ranks because: 1) Ranks distill complex, nuanced information into a more palatable format; and 2) Ranks allow for combination of different data types into an overall value while preserving relative order (i.e. averaging across CBIs). PSE would contend that ranks are derived from and therefore representative of CBI values. Furthermore, CBI values for each portfolio will be included and discussed in narrative in the Final IRP. PSE will discuss weighting factors through the public participation process and EAG discussions for the CEIP, which may provide more insight to the value of customer benefit indicators.

Feedback Form Date	Stakeholder	Comment	PSE Response
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 59: We appreciate discussion of tradeoffs on this slide. How does PSE expect this process to evolve in the next IRP when weighting factors have been developed/approved in the CEIP?	Thank you for the comment. PSE fully expects the CBI/portfolio development process to evolve in future IRP cycles, and PSE looks forward to continued community engagement on the process.
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide ~60: Fellow participant Christine Bunch of the City of Seattle highlighted the possible underinclusion of factors connected to vulnerable populations. With her comment that some metrics could be specific to energy burden - % of participation in EE programs from low-income households, % of households participating in weatherization programs, % getting access to utility discounts, etc.	Thank you for reiterating these comments. PSE recognizes that these are important CBIs to consider in the portfolio development process. However, these indicators are not native outputs to existing portfolio modeling processes which makes incorporation of these concepts difficult. PSE is developing strategies to broaden the capacity of the portfolio development process to integrate these "non-native" data types. Results of this research will not be available for the Final IRP, but will develop for future IRP cycles and the CEIP.
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 63: This slide is fascinating and brings up a lot of complicated issues. ○ How was the green area calculated? What extrapolations were made and what was the starting point for the baseline costs? Do these connect to a recent GRC, to the most recent commission basis report, or the company's most recent revenue forecast? ○ The preferred portfolio has historically been the company's least-reasonable-cost plan to comply with all statutory requirements. However, with CETA, it could be that the 80%-by-2030 requirement and the 2% cost constraint are mutually exclusive. In that case, staff believes the preferred portfolio should prioritize the 2030 requirement. The company's forecasting of the 2% cost constraint and adjusting any resource acquisitions based on this constraint is analysis that should be contained in the CEIP.	1. The green shaded area of the graph starts with the 2019 GRC revenue requirement, then PSE assumes 2.5% each year for inflation. The first year, 2022, is calculated as 2% of the assumed 2021 revenue requirement (2019 revenue requirement plus 2.5% added in 2020 and 2021). The second year is calculated as 2% of the 2023 assumed revenue requirement (2022 assumed revenue requirement plus 2.5%) plus the 2% spent in 2022. This compounding 2% calculation continues for each year through 2030. 2. PSE agrees that the adjusting of the resource additions by the 2% cost constraint should be done in the CEIP. The cost analysis in the IRP is based on a lot of assumptions around resource costs and the underlying revenue requirement. The cost calculation should be done on actual resource costs and revenue requirement.
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Staff recommendations.	Thank you for your recommendations. PSE inserted each recommendation below along with PSE's responses.
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	**EHEB - Review of distinction between demographic analysis and geospatial analysis**: Our commentary is contained above, but the core idea is that CETA's requirements regarding highly impacted communities and vulnerable populations require two distinct methods of analysis. We see PSE's analysis as, thus far, being focused primarily, maybe exclusively, performed from a geospatial lens. For example, slide 41 implies that vulnerable populations are effectively the CIA list of highly impacted communities with a few other factors considered, and the analysis is done on a census tract level. The demographic lens is also critical, and appears to be missing. **a.** Step 1a: ID communities based on CIA and selected adverse socioeconomic factors and vulnerability factors **b.** Step 1b: determine "assessment metrics" based on what's listed in rule/statute (e.g., energy/non-energy benefits, public health, etc.) **c.** Step 1c: compare disparities between "assessment metrics" for named communities vs. non-named. It seems like PSE is equating those socioeconomic/vulnerability factors with assessment metrics **d.** Step 2: Solicit customer input to determine what those communities and populations want the CBIs to be. We're happy to discuss this further.	Thank you for the commentary on Highly Impacted Communities and Vulnerable Populations. PSE sees the value in approaching the assessment from both a geographic and demographic perspective. However, given time constraints, demographic characterization of VPs will not be incorporated into the 2021 IRP. PSE will make efforts to revise the assessment in time for the Clean Energy Implementation Plan. As revisions to PSE's Highly Impacted Communities and Vulnerable Populations assessment are enacted, PSE will be sure to subscribe to the steps laid out in this recommendation.

Feedback Form Date	Stakeholder	Comment	PSE Response
2/18/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	**2% revenue increase constraint**: PSE is welcome to perform some analysis in the IRP to better understand what a portfolio which is limited by the 2% cost cap might look like. However, we believe those competing requirements in CETA are reconciled in the CEIP. We recommend that the preferred portfolio in the IRP should contain the company's least-reasonable-cost approach to meeting all other requirements in CETA.	PSE agrees that the preferred portfolio will meet the CETA requirements without any adjustment for the 2% constraint. The IRP will include the cost calculation as information to stakeholders to estimate the costs associated with acquiring new resources to meet CETA.
2/19/2021	Renewable Northwest	The letter dated February 17, 2021 submitted in feedback form and sent to PSE on February 19, 2021, is uploaded as part of the Feedback Report.	Thank you for your letter. PSE inserted the recommendations and questions from the letter along with PSE's responses below and noted the questions that will be addressed in the Consultation Update available on February 24, 2021.
2/19/2021	Renewable Northwest	We recommend PSE design the incremental cost of compliance threshold (as shorthand, just "cost threshold") sensitivity as a split analysis, considering how various resource configurations or planning decisions will affect how closely the company tracks to the cost threshold and, thus, how likely it is the company will achieve its 2045 clean energy commitment. At minimum, PSE should consider (3 specific suggestions inserted by PSE below):	Thank you for the general recommendation.

2/19/2021	Renewable Northwest	**How altered procurement timelines may adjust the portfolio's diversion from the cost threshold.** In the slide deck, PSE reveals that the Mid Scenario falls below the cost threshold until around 2026, when coal-fired resources must be removed from PSE's allocation of electricity. First, PSE should clarify whether the Mid Scenario reported in the draft IRP 5 accounts for the SCGHG of gas-enabled combustion turbines, as it's not currently clear that alternative fuels will be comparable in cost and, thus, least cost. And if the Mid Scenario actually mirrors sensitivity W, which ramps in distributed energy resources ("DERs") over time and includes biodiesel-fueled combustion turbines, PSE should revise its fuel cost assumptions, as biodiesel will not remain at a stale price across the planning horizon. Beyond that, PSE notes in the draft IRP that the model prefers to procure DERs near the end of the planning horizon to realize cost reductions, and that sensitivities V and W are performed to spread those procurements at only a slight increase in levelized cost. However, the actual "spread" of procurements is still back-end heavy, with the Mid Scenario reporting nearly two-thirds of the DER procurements in the 2031 to 2045 timeframe. PSE should analyze how a more evenly-distributed DER procurement schedule may - at a minor increase in cost - allow PSE to remain below the cost threshold beyond 2026.	Thank you for your comments; responses below:
			• The Mid Scenario from the Draft IRP assumes frame peaker plants will operate on natural gas with the SCGHG.
			• Price futures for alternative fuels such as biodiesel and hydrogen are wildly uncertain. PSE could not source reliable prices futures during this IRP cycle, but aims to include a more nuanced approach in future IRP cycles.
			• For the Balanced Portfolio, distributed resources were ramped in evenly over time, as follows:
			  ○ Distributed ground-mounted solar: 50 MW in 2025
			  ○ Distributed rooftop solar: 30 MW/year from the year 2025 to 2045 for a total of 630 MW by 2045
			  ○ Battery energy storage: 25 MW/year 2025 to 2031 for a total of 175 MW by 2031

2/19/2021	Renewable Northwest	**How portfolios with a slightly higher levelized cost in the near term (from 2022 to 2026) may extend the number of years PSE falls below the cost threshold.** Renewable Northwest has urged PSE in previous comments to consider how the model's preference for lowest-cost resources may be undervaluing the dynamic, long-term contributions of slightly higher cost resources. For example, PSE has indicated in various sensitivity analyses and in past webinars that the model selected the 2-hour Li-ion battery because it was least cost. However, because this resource does not offer as much flexibility value and resource adequacy contribution as a 4-hour Li-ion battery or a solar + 4-hour Li-ion battery hybrid resource, there may be unrealized cost reductions to procuring these resources earlier in the planning period. Because the capital cost is higher, the extra margin below the cost threshold in the near term should prompt PSE to study whether earlier investments in these resources may not only track PSE closer to the cost threshold beyond 2026, but also improve the flexibility of PSE's system by a means compliant with CETA.	PSE has incorporated a flexibility benefit, which is modeled as a cost-reducer, to storage resources. PSE's analysis shows that the flexibility benefit for 4hr Li-Ion batteries ($18.45/kW-yr) is lower than for 2hr Li-Ion batteries ($20.45/kW-yr). PSE understands this result to stem from a need to increase market purchases to ensure the larger batteries are adequately charged. PSE intends to review its modeling storage logic to ensure these state-of-charge decisions are accurate representations of reality in future IRP cycles. Furthermore, PSE has modeled additional sensitivities to investigate the difference between different storage types/durations. These sensitivities include N 100% Renewable by 2030 selecting for 1. Batteries (2hr Li-Ion) and 2. PHES (8hr); O Gas Generation out by 2045 for 1. Batteries (2hr Li-Ion) and 2. PHSE (8hr); and P No New Thermal before 2030 for 1. 2hr Li-Ion, 2. PHES (8hr) and 3. 4hr Li-Ion. These results will be included in the Final IRP.
2/19/2021	Renewable Northwest	**How revising resource assumptions to better align with current estimates alters the Mid Scenario's relationship to the cost threshold.** See the comments of Renewable Northwest, submitted to docket UE-200304, for details and references.	Thank you for your comments submitted to PSE's electric IRP docket.
2/19/2021	Renewable Northwest	Regarding the flexibility analysis, we have a few clarifying questions and comments which would be helpful for this process in the current IRP as well as going forward. (3 specific questions inserted by PSE below):	Thank you for your questions.

Feedback Form Date	Stakeholder	Comment	PSE Response
2/19/2021	Renewable Northwest	It would be helpful if staff provides a detailed look at the magnitude and duration of the flex violations coming out of the model. As we mentioned in our previous comments, flexibility is not uni-dimensional but involves four key dimensions, each of which should be accounted for in the modeling effort. This would provide a better understanding as to what resource types and technologies would be most efficient and cost-effective in treating those violations. For example, battery storage resources of smaller sizes (30-minute or 1-hour duration) may be more cost-effective in providing flexibility (both up and down) reserves if the both the magnitude and duration of the majority of flex violations are shorter in nature.	PSE will provide a detailed Flexibility Analysis description in the Final IRP document which will address the details requested.
2/19/2021	Renewable Northwest	In the webinar, staff mentioned that the reason the flexibility value or benefit for 4-hour battery storage is lower is because that resource requires to be charged using market purchases which have an associated social cost of greenhouse gas ("SCGHG"). **Hybrid resources**, on the other hand, can assist PSE meet its CETA goals, can provide clean, non-emitting energy to charge the battery, and can capture the sizable federal ITC, ensuring cost-effectiveness. It would be helpful if staff can run the flexibility analysis to evaluate the flexibility benefits of a solar + 2-hour Li-ion and solar + 4-hour Li-ion battery configurations.	Thank you for your feedback. For the 2021 IRP, PSE did not model hybrid resources in the flexibility analysis. PSE continues to make improvements to the modeling work and will evaluate hybrid resources as part of future IRPs.
2/19/2021	Renewable Northwest	To what level of detail does this analysis evaluate other flexibility-related value streams such as **fast-frequency response and voltage (volt/var) support?** As conventional power plants retire, these key grid services will become increasingly important, and resources like batteries which are able to provide these services should be valued accordingly in flexibility analyses.	The Plexos model is not set-up to evaluate voltage support or frequency response. The IRP team has investigated other flexibility value streams, but was not able to include the analysis in this IRP. PSE will work to include a more robust flexibility analysis in future IRPs.

Invenergy Comments on Puget Sound Energy (PSE) 2021 Integrated Resource Plan (IRP) Webinar #12
Comments Submitted February 17, 2021

General Comments on Webinar #12

Invenergy is concerned that PSE is not providing clear and detailed information about its assumptions, analyses and results for the 2021 IRP. These concerns were reinforced during Webinar #12. The vague and insufficiently detailed information being provided by PSE makes it difficult to assess whether the Flexibility Analysis and Portfolio Draft Results presented on February 12, 2021 are sound and reasonable. While this has been an ongoing concern, PSE's willingness to share meaningful information and constructively respond to stakeholder questions and comments appears to be degrading further.

Specific Comments on Webinar #12

Flexibility Analysis

1. *Social Cost of Greenhouse Gas (SCGHG):* It was not clear from PSE's presentation whether or how it has included the SCGHG flexibility analysis it performed using the PLEXOS model. In response to stakeholder questions, PSE initially stated that the SCGHG was included "in the portfolio model". However, the portfolio model is separate from PLEXOS. When prompted, PSE admitted that it did not include the SCGHG in the flexibility analysis. Invenergy continues to urge PSE to include the SCGHG as a variable cost of dispatch for GHG-emitting generation, including in the flexibility analysis. Not including the SCGHG in the flexibility analysis ignores the environmental externality costs of dispatching GHG-emitting resources. It also biases PSE's results in favor of more GHG-intensive peaking generation relative to less GHG-intensive combined-cycle combustion turbine (CCCT) generation.
2. *Flexibility Cost Savings:* Slide 32 of PSE's presentation shows flexibility cost savings of $23.45-$25.39/kilowatt-year for peaking generation and $5.27 per kilowatt-year for CCCT generation. If PSE's analysis only addressed intra-hour (e.g., 15-minute) Flex Up and Flex Down violations, the results appear quite high, especially for peaking generation. Alternatively, if the flexibility analysis also addressed flexibility benefits across longer time increments (e.g., hourly, diurnal) – as it should – PSE's assumptions about the flexibility capabilities of CCCTs are unrealistically restrictive. In addition, if PSE's flexibility analysis treats all CCCTs as being dispatched on a concurrent basis, this would further under-value the flexibility benefits of CCCTs compared to a more realistic operational approach that allows CCCTs to be dispatched on a sequential basis (i.e., not necessarily at the same time). Under a sequential dispatch approach, a group of CCCTs could provide flexibility cost savings because only one or a few CCCTs would need to be operated at partial-loading at any given point in time.

Portfolio Analysis Results

3. *Social Cost of Greenhouse Gas (SCGHG):* From PSE's presentation, it is not clear whether it has performed meaningful portfolio analyses that include the SCGHG as an incremental cost of dispatch for GHG-emitting generation. Instead, PSE continues to treat the SCGHG as a fixed cost, calculated

after-the-fact, based on generation dispatch costs that exclude the SCGHG. Invenergy has previously submitted extensive comments, including in PSE's 2021 IRP process and in the Clean Energy Transformation Act (CETA) rulemakings that explain why the SCGHG must be included as an incremental cost of dispatch. Invenergy continues to encourage PSE to include the SCGHG as an incremental cost of dispatch for GHG-emitting generating resources, including in its portfolio analyses.

4. *Timing of Resource Additions:* PSE's presentation of the results from its updated portfolio analysis provides a startling lack of detail about the timing of new resource additions. The only place where new resource additions are presented for PSE's updated portfolio analysis is on Slide 54, entitled "Portfolio costs and resource additions". This slide only provides total additions for each type of resource over the entire period from 2022-2045. No information is provided for the timing of resource additions within the 24-year planning horizon. As a result, this makes it very difficult to assess the validity of PSE's portfolio analysis and results. In particular, it obscures results for resource additions during the critical upcoming period, including the next five years. That is the most important timeframe for the 2021 IRP, in part because PSE will be able to use its 2025 IRP to update its resource strategy for the latter half of the coming decade. Invenergy considers it highly unusual for PSE to obscure the results of its portfolio analysis in this way, and at such a late stage in the 2021 IRP process. Invenergy requests that PSE provide more detailed information as soon as possible about the timing of the resource additions in its portfolio analysis, including annual resource additions, by type of resource, during 2022-2029.

February 17, 2021

Puget Sound Energy
IRP Team

RE: Feedback of Renewable Northwest, 2021 IRP Webinar 12
Puget Sound Energy's February 10, 2021, Webinar Relating to Delivery System and Grid Modernization Solutions, Flexibility Analysis results, Portfolio draft results, and Economic, Health and Environmental Benefits Assessment of Current Conditions Status Update.

I. INTRODUCTION

Renewable Northwest thanks Puget Sound Energy ("PSE") for this opportunity to provide feedback as a stakeholder in the company's effort to develop its 2021 Integrated Resource Plan ("IRP"). This feedback is in response to PSE's February 10, 2021, webinar and associated materials regarding various updates and draft results for the continued development of the 2021 IRP.

Renewable Northwest participated in the webinar and asked various clarifying questions throughout. Below, we first follow up on PSE's request for stakeholder feedback to help develop the sensitivity to model the effect of the incremental cost of compliance, as outlined by the Clean Energy Transformation Act ("CETA"), on the preferred portfolio.[1] We also provide feedback on PSE's flexibility analysis results.

II. FEEDBACK

A. Incremental Cost of Compliance

For the final IRP, PSE will be testing its preferred resource mix against the two-percent cost threshold outlined by CETA (RCW 19.405.060(3)(a)), an alternative compliance mechanism.[2] In the slide deck associated with the most recent IRP webinar, PSE revealed that the Mid Scenario and three newly-modeled sensitivities exceed the two-percent cost threshold at some point over the planning horizon.[3] To ensure PSE's energy transition follows a trajectory toward

[1] RCW 19.405.060(3)(a)
[2] RCW 19.405.060(3)(b)
[3] Slide 63, Webinar 12

meeting CETA's clean energy mandates and the company's own internal carbon reduction commitments, PSE must minimize its use of alternative compliance mechanisms.[4] As PSE prepares for submission of its first Clean Energy Implementation Plan ("CEIPs") per WAC 480-100-640, the company should take full advantage of the modeling tools deployed during IRP development to understand the effect of the incremental cost of compliance on the preferred portfolio.

We recommend PSE design the incremental cost of compliance threshold (as shorthand, just "cost threshold") sensitivity as a split analysis, considering how various resource configurations or planning decisions will affect how closely the company tracks to the cost threshold and, thus, how likely it is the company will achieve its 2045 clean energy commitment. At minimum, PSE should consider:

a. **How altered procurement timelines may adjust the portfolio's diversion from the cost threshold.**
In the slide deck, PSE reveals that the Mid Scenario falls below the cost threshold until around 2026, when coal-fired resources must be removed from PSE's allocation of electricity.[5] First, PSE should clarify whether the Mid Scenario reported in the draft IRP accounts for the SCGHG of gas-enabled combustion turbines, as it's not currently clear that alternative fuels will be comparable in cost and, thus, least cost. And if the Mid Scenario actually mirrors sensitivity W, which ramps in distributed energy resources ("DERs") over time and includes biodiesel-fueled combustion turbines, PSE should revise its fuel cost assumptions, as biodiesel will not remain at a stale price across the planning horizon.
Beyond that, PSE notes in the draft IRP that the model prefers to procure DERs near the end of the planning horizon to realize cost reductions, and that sensitivities V and W are performed to spread those procurements at only a slight increase in levelized cost. However, the actual "spread" of procurements is still back-end heavy, with the Mid Scenario reporting nearly two-thirds of the DER procurements in the 2031 to 2045 timeframe. PSE should analyze how a more evenly-distributed DER procurement schedule may - at a minor increase in cost - allow PSE to remain below the cost threshold beyond 2026.

b. **How portfolios with a slightly higher levelized cost in the near term (from 2022 to 2026) may extend the number of years PSE falls below the cost threshold.**

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[4] PSE sets "Beyond Net Zero Carbon" goal (Jan. 21, 2021), *available at* https://www.pse.com/press-release/details/pse-sets-beyond-net-zero-carbon-goal?utm_source=Social&utm_medium=LINKEDIN&utm_campaign=TOGETHER.
[5] RCW 19.405.030(1)(a)

Renewable Northwest has urged PSE in previous comments to consider how the model's preference for lowest-cost resources may be undervaluing the dynamic, long-term contributions of slightly higher cost resources. For example, PSE has indicated in various sensitivity analyses and in past webinars that the model selected the 2-hour Li-ion battery because it was least cost. However, because this resource does not offer as much flexibility value and resource adequacy contribution as a 4-hour Li-ion battery or a solar + 4-hour Li-ion battery hybrid resource, there may be unrealized cost reductions to procuring these resources earlier in the planning period. Because the capital cost is higher, the extra margin below the cost threshold in the near term should prompt PSE to study whether earlier investments in these resources may not only track PSE closer to the cost threshold beyond 2026, but also improve the flexibility of PSE's system by a means compliant with CETA.

c. **How revising resource assumptions to better align with current estimates alters the Mid Scenario's relationship to the cost threshold.**
See the comments of Renewable Northwest, submitted to docket UE-200304, for details and references.[6]

B. Flexibility Analysis

Regarding the flexibility analysis, we have a few clarifying questions and comments which would be helpful for this process in the current IRP as well as going forward.

1. It would be helpful if staff provides a detailed look at the **magnitude and duration** of the flex violations coming out of the model. As we mentioned in our previous comments, flexibility is not uni-dimensional but involves four key dimensions, each of which should be accounted for in the modeling effort. This would provide a better understanding as to what resource types and technologies would be most efficient and cost-effective in treating those violations. For example, battery storage resources of smaller sizes (30-minute or 1-hour duration) may be more cost-effective in providing flexibility (both up and down) reserves if the both the magnitude and duration of the majority of flex violations are shorter in nature.

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[6] Renewable Northwest comments re: PSE Draft IRP (Feb. 5, 2021), Docket UE-200304, *available at* https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/CaseItem.aspx?item=document&id=00026&year=2020&docketNumber=200304&resultSource=&page=1&query=200304&refiners=&isModal=false&omItem=false&doItem=false.

2. In the webinar, staff mentioned that the reason the flexibility value or benefit for 4-hour battery storage is lower is because that resource requires to be charged using market purchases which have an associated social cost of greenhouse gas ("SCGHG"). **Hybrid resources**, on the other hand, can assist PSE meet its CETA goals, can provide clean, non-emitting energy to charge the battery, and can capture the sizable federal ITC, ensuring cost-effectiveness. It would be helpful if staff can run the flexibility analysis to evaluate the flexibility benefits of a solar + 2-hour Li-ion and solar + 4-hour Li-ion battery configurations.
3. To what level of detail does this analysis evaluate other flexibility-related value streams such as **fast-frequency response and voltage (volt/var) support**? As conventional power plants retire, these key grid services will become increasingly important, and resources like batteries which are able to provide these services should be valued accordingly in flexibility analyses.

III. CONCLUSION

Renewable Northwest thanks PSE for its consideration of this feedback. We look forward to continued engagement as a stakeholder in this 2021 IRP process.

Sincerely,

/s/ Katie Ware
Katie Ware
Washington Policy Manager
Renewable Northwest
katie@renewablenw.org

/s/ Sashwat Roy
Sashwat Roy
Technology & Policy Analyst
Renewable Northwest
sashwat@renewablenw.org

PSE IRP Consultation Update
Webinar 12: Delivery System Planning 10-year Plan, Flexibility Analysis Results, Economic, Health and Environmental Benefit (EHEB) Assessment of Current Conditions Status Update, Portfolio Draft Results
February 10, 2021

03/03/2021

The following consultation update is the result of stakeholder suggestions gathered through an online Feedback Form, collected between February 3 and February 17, 2021 and summarized in the Feedback Report dated February 24. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

Stakeholder questions and suggestions spanned a wide variety of topics and not all are included in this Consultation Update. As always, line-by-line responses to each stakeholder comment are provided in the Feedback Report[1]. Similarly, many stakeholder questions received from the December 15th Webinar have been answered in the Draft IRP, which is now available for review on the IRP website[2]. PSE encourages stakeholders to review these materials in concert with this Consultation Update.

PSE has contacted the following stakeholders to clarify their comments:

- Bill Pascoe, Pascoe Energy, was contacted on February 12 to clarify his request for clarification concerning Pumped-Hydro Energy Storage (PHES) and Montana Wind. The correspondence was conducted outside of the feedback form, but the outcome is included in this Consultation Update to communicate the result of the inquiry for all stakeholders.

Delivery System Planning 10-Year Plan

PSE received several clarifying questions from Kyle Frankiewich (WUTC) concerning the 10-year Plan developed by the Delivery System Planning group. PSE would direct stakeholders to the feedback report for specific line-by-line responses to these questions.

PSE would highlight one WUTC recommendation to incorporate a “tipping-point analysis” into the framework for determining the efficacy of non-wire alternatives. PSE’s Delivery System Planning group agrees a tipping-point analysis may be beneficial for decision making and will work to incorporate this methodology into future assessments.

Economic, Health and Environmental Benefit (EHEB) Assessment of Current Conditions Status Update

PSE received stakeholder feedback from Kyle Frankiewich (WUTC) concerning the Economic, Health and Enviornmental Benefits (EHEB) Assessment. PSE was able to incorporate some recommendations from WUTC staff into the Final IRP EHEB Assessment, but some recommendations will be incorporated at later date due to time constraints.

Recommendations incorporated into the Assessment are:

- Incorporation of tribes into the highly impacted communities named population
- Alignment of naming convention to switch “assessment metrics” to “customer benefit indicators” and “customer benefit indicators” to “customer benefit indicator areas”

Recommendations which will be incorporated at a later data include:

- Identification of vulnerable populations based on demographic, instead of geographic criteria
- Identification of vulnerable populations based on a binary criteria, instead of based on averages of multiple criteria
- Incorporation of customer input into customer benefit indicators and other components of the Assessment

Flexibility Analysis

PSE received feedback from Invenergy and Renewable Northwest concerning calculation of resource Flexiblity Benefit. Further detail into the flexibility modeling process and results will be made available with the Final IRP filing. PSE also looks forward to continuing to develop our modeling procedures and will investigate inclusion of hybrid resources, fast-frequency response and voltage support in future IRP cycles.

Other Updates

The following items have been updated after the Webinar 12:

1. Bill Pascoe, Pascoe Energy, asked for clarification concerning Pumped-Hydro Energy Storage (PHES) and Montana Wind. A call was arranged between Bill Pasoce and Elizabeth Hossner, Manager, Resource Planning

[1] February 10, 2021 Webinar Feedback Report:
https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/Feb_10_Webinar/Webinar%2012%20-%20Feedback%20Report.pdf
[2] PSE 2021 Draft IRP: https://pse-irp.participate.online/2021-irp/reports

and Analysis. This was also followed with a discussion with the developers of the Gordon Butte Pumped storage hydro project in Montana. Both discussions suggested some updates to the operating characteristics of pumped storage hydro. Since it was too late to incorporate this information in the 2021 IRP, PSE will update the pumped storage hydro operating characteristics for future IRPs.

2. During the webinar, Bill Pascoe asked about the updated transmission cost assumptions. Since PSE did not have the table immediately available during the webinar, it is provided below. The following figure has been updated from the draft IRP with updated costs, and will also be available in the Final IRP (in Chapter 5):

Transmission Costs by Generic Resource Type (in 2020 $)

Generic Resource	Fixed Transmission Cost ($/kW-yr)	Variable Transmission Cost ($/MWh)
CCCT	0.00[a]	0.00
Frame Peaker	0.00[a]	0.00
Recip Peaker	0.00[a]	0.00
WA Solar East - Utility Scale	30.48	9.53
WA Solar West - Utility Scale	8.28	9.53
Idaho Solar – Utility Scale	154.78	9.53
WY Solar East – Utility Scale	227.90	9.53
WY Solar West – Utility Scale	207.80	9.53
DER WA Solar - Rooftop	0.00[a]	0.00
DER WA Solar – Ground-mount	0.00[a]	0.00
WA Wind	33.36	9.53
MT Wind – East	49.65	9.53
MT Wind - Central	49.65	9.53
ID Wind	157.66	9.53
WY Wind East	230.78	9.53
WY Wind West	210.68	9.53
Offshore Wind	33.36	9.53
Pumped Storage	22.20	0.00
Battery 2hr Li-Ion	0.00[a]	0.00
Battery 4hr Li-Ion	0.00[a]	0.00
Battery 4hr Flow	0.00[a]	0.00
Battery 6hr Flow	0.00[a]	0.00
Solar + Battery	30.48	9.53
Wind + Battery	33.36	9.53
Wind + Pumped Storage	49.65	9.53
Biomass	22.20	0.00

NOTE

a. Fixed transmission cost is not applied, because the resource is assumed to be built within PSE service territory.

February 26, 2021

WUTC Recessed Open Meeting
PSE Presentation of the 2021 Draft IRP

PSE 2021 Electric and Natural Gas Draft Integrated Resource Plans

PUGET SOUND ENERGY

February 26, 2021

Irena Netik, Director Resource Planning & Analysis

Elizabeth Hossner, Manager Resource Planning & Analysis

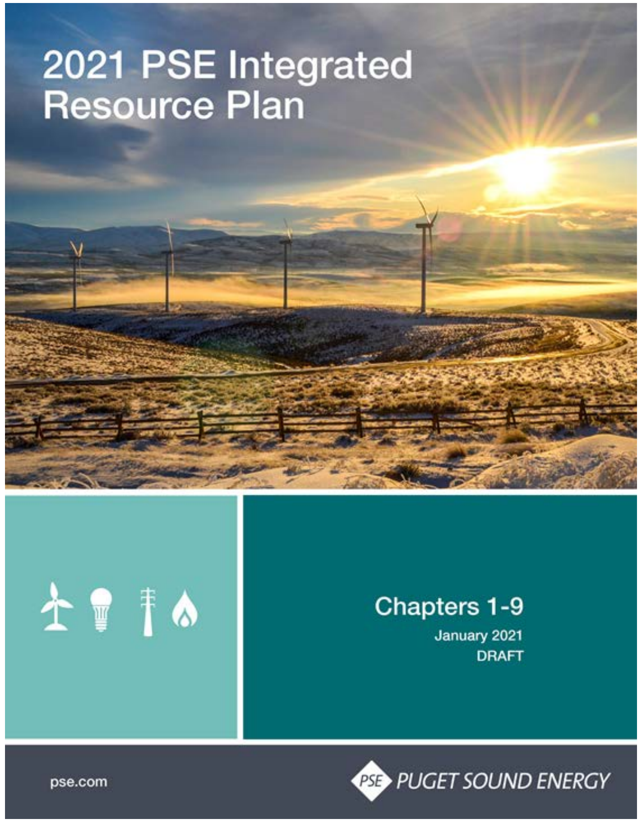
Development of Electric and Natural Gas IRPs

Updates since draft IRP:

- Finalized Flexibility Analysis
- Made portfolio model updates: corrected transmission costs, included T&D benefit for battery energy storage, updated biomass build limit
- Completed Economic, Health and Environmental Benefits Assessment
- Developed preliminary Customer Benefit Indicators for portfolio evaluations to inform the preferred portfolio

For stakeholder review on March 5 and final IRP:

- Complete electric and natural gas stochastic analyses
- Finalize all electric and natural gas portfolio scenarios and sensitivities
- Solicit feedback on market risk assessment
- Develop preferred portfolio and Clean Energy Action Plan



2021 IRP modeling process is iterative and includes numerous opportunities for stakeholder input

- Improved stakeholder engagement and made measurable progress towards CETA implementation under tight time constraints, incomplete rules and a global pandemic.

- Resource outlook includes accelerated acquisition of energy conservation, increased demand response and distributed energy resources and a significant investment in utility-scale renewable resources while maintaining resource adequacy.

- The CEIP and the procurement process will evaluate costs, permitting and other challenges and opportunities and make the final resource decisions.

PSE achieved significant improvement in stakeholder engagement

Increased access through online webinars

12
IRP webinars recorded

68
Average number of webinar participants

201
Unique individual have participated in webinars

Improved stakeholder communication

29
Email communications distributed

1,441
Total audience members receiving IRP email communication

12,197
Visits to the website between May and February

20%
Average message open rate for all newsletters

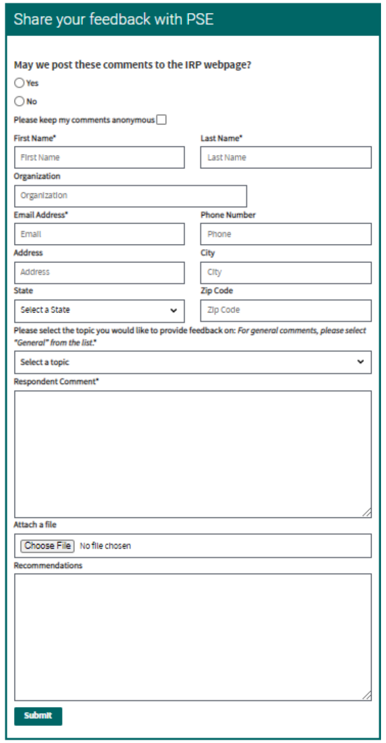
Developed an online process for stakeholder feedback

Feedback Form → **Feedback Report** → **Consultation Update**

295
Feedback forms received

11
Feedback Reports provide PSE's responses to 621 stakeholder comments

11
Consultation Updates document how PSE used stakeholder feedback


Share your feedback with PSE

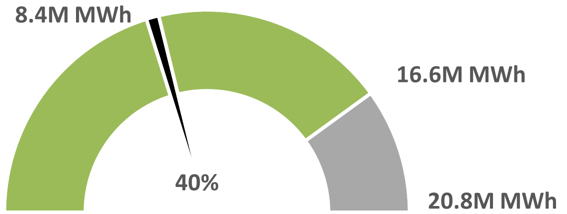
May we post these comments to the IRP webpage?
Yes
No
Please keep my comments anonymous
First Name*
Last Name*
Organization
Email Address*
Phone Number
Address
City
State
Zip Code
Please select the topic you would like to provide feedback on: *For general comments, please select "General" from the list.**
Select a topic
Respondent Comment*
Attach a file
Choose File No file chosen
Recommendations
Submit

1 Establish Resource Needs

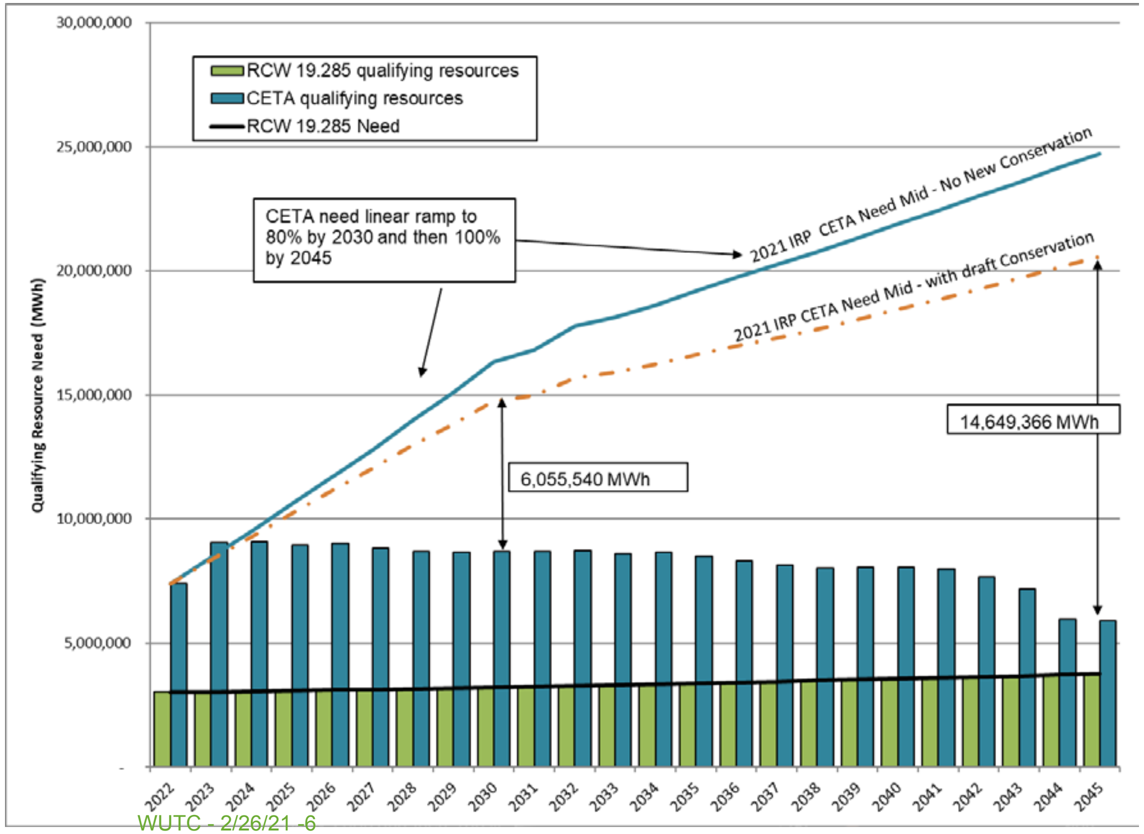
Three types of resource needs must be satisfied: renewable energy, peak hour capacity and hourly energy.

Resource Need	Requirement
Renewable Energy	RCW 19.285 CETA: 80% renewable target by 2030; 100% renewable target by 2045
Hourly Energy	2021 IRP demand forecast
Peak Capacity	Resource adequacy analysis

Current status towards 2030 CETA Target



Renewable Energy Need



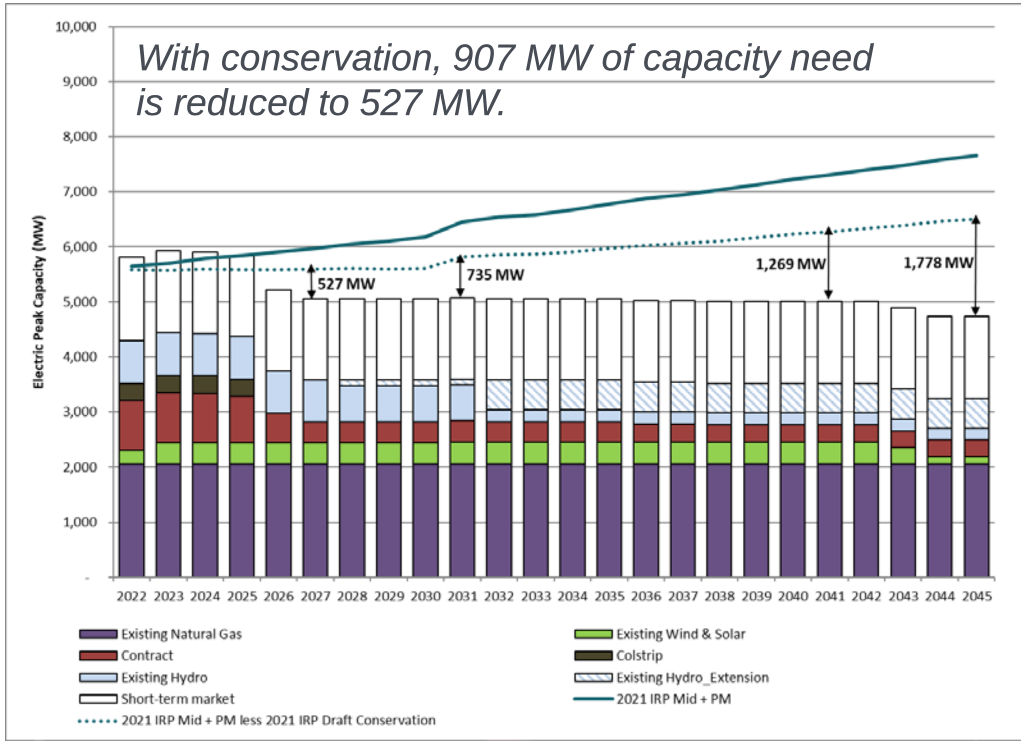
WUTC - 2/26/21 -6

PUGET SOUND ENERGY

1 Establish Resource Needs: Resource Adequacy

Resource adequacy must be maintained to support the clean energy transition.

- Over 740 MW of firm capacity is removed from PSE portfolio at the end of 2025.
- Without new capacity, the loss of load probability is over 68%.



- RA analysis determined that 907 MW by 2027 is needed to achieve 5% loss of load probability.
- RA analysis ensures that customer load is met across a wide range of conditions with sufficient resources and considers variability in load, temperatures, hydro generation, wind and solar generation, potential outages and availability of Mid-C market.
- Energy efficiency, renewable resources, demand response and distributed generation contribute to meeting capacity needs.

PUGET SOUND ENERGY

2 Planning Assumptions and Resource Alternatives

The portfolio planning assumptions were developed with stakeholder input.

- Electric price forecast
- Natural gas price forecast
- Social Cost of Greenhouse Gases
- New resource alternatives
- Transmission constraints
- Flexibility benefit

- Portfolio modeling meets 80% renewable resources target in 2030.
- Evaluated two cost alternatives to achieve the carbon neutral standard in 2030 and beyond:
    1. California carbon tax as a proxy for compliance cost *(selected).*
    2. 100% renewable energy target starting in 2030.

Findings

✓ Increase in renewable resources depresses wholesale electric market prices in comparison to past IRPs but increase the hourly volatility.
✓ Natural gas prices remain low with a slight decline.
✓ 25 unique supply-side resources evaluated and stakeholders helped to establish resource costs and assumptions.
✓ As more renewable resources are added, more balancing reserves are needed and flexible resources, such as demand response and energy storage, have higher flexibility benefits.

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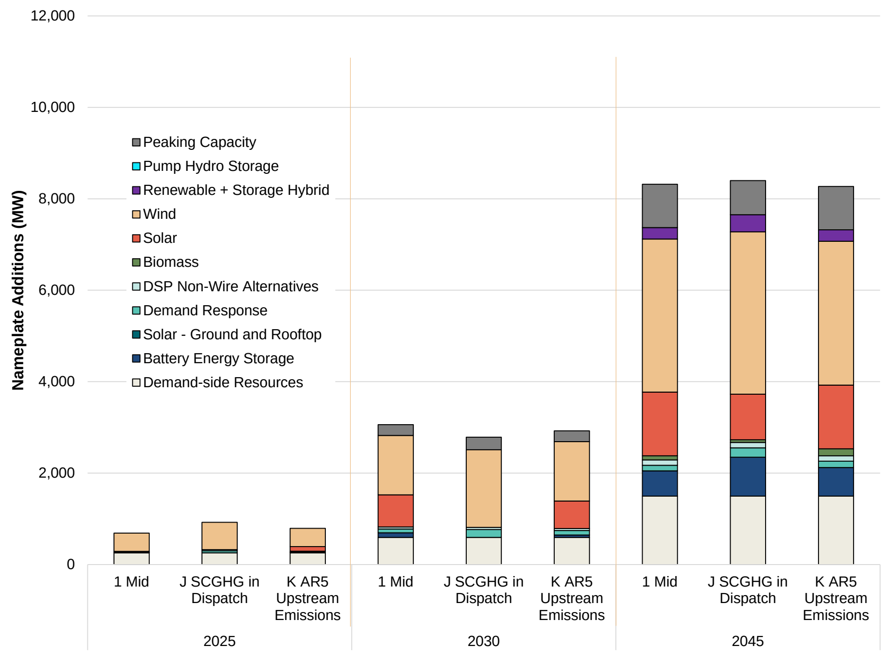
2

Planning Assumptions and Resource Alternatives: **Social cost of greenhouse gases and upstream emissions**

SCGHG is applied as a cost adder when evaluating conservation and resource additions. Upstream emissions AR4 methodology is used.



- Both 2019 and 2021 IRPs analyzed multiple modeling approaches for social costs of greenhouse gases.
- Renewable resources required to comply with CETA is the key constraint driving portfolio resource additions and costs.
- PSE assumes upstream emissions consistent with AR4 and evaluated AR5 in response to stakeholder requests.

Findings

✓ Different social cost of greenhouse gases modeling approaches do not have an impact on the cost-effective amount of conservation, demand response and other resource additions or retirements.

✓ Using upstream emissions consistent with AR5 does not change resource builds and portfolio costs in comparison to utilizing AR4.

WUTC - 2/26/21 -9

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2

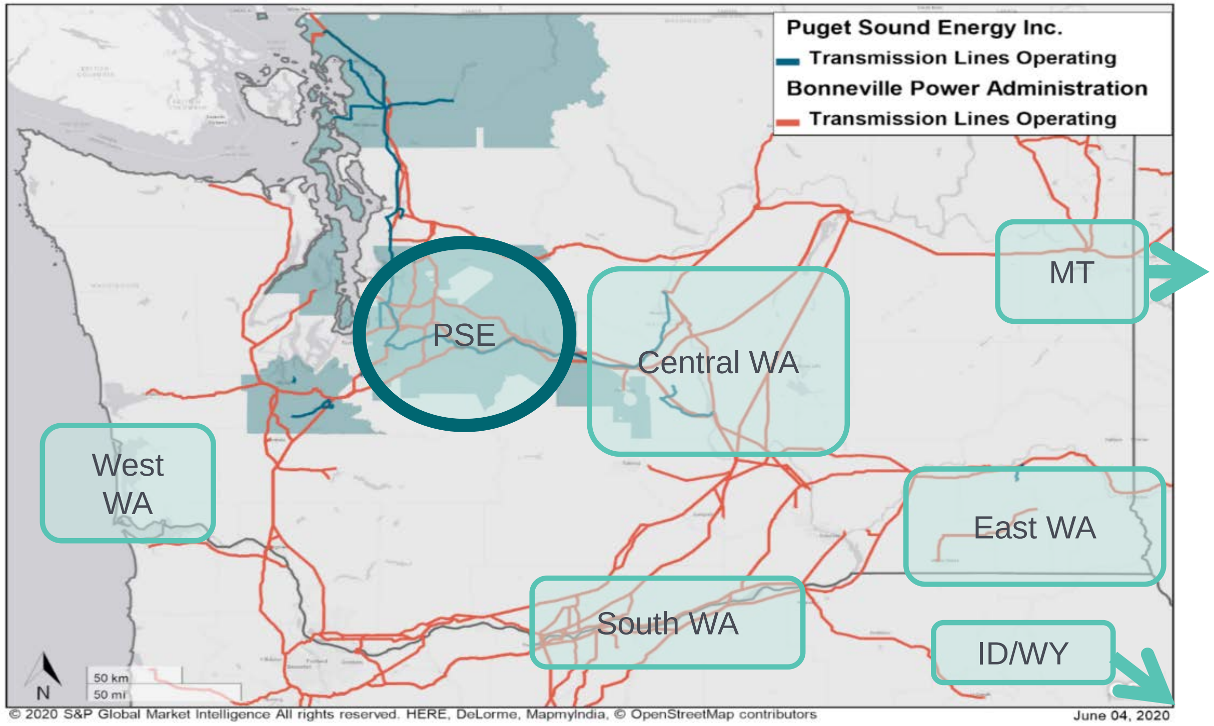
Planning Assumptions and Resource Alternatives: **Transmission Constraints**

Incorporated transmission constraints as aggregated resource build limits.

- New to the 2021 IRP.
- 7 resource group regions identified align with existing transmission resources.
- Evaluated long-term firm transmission rights acquisitions at less than resource capacity.

Findings

- Transmission constraints limit large scale resources, so lower capacity factor, higher cost distributed resources are substituted to meet CETA requirements.
- Montana and Wyoming wind offer higher capacity value and bring resource diversity along with some transmission risk.



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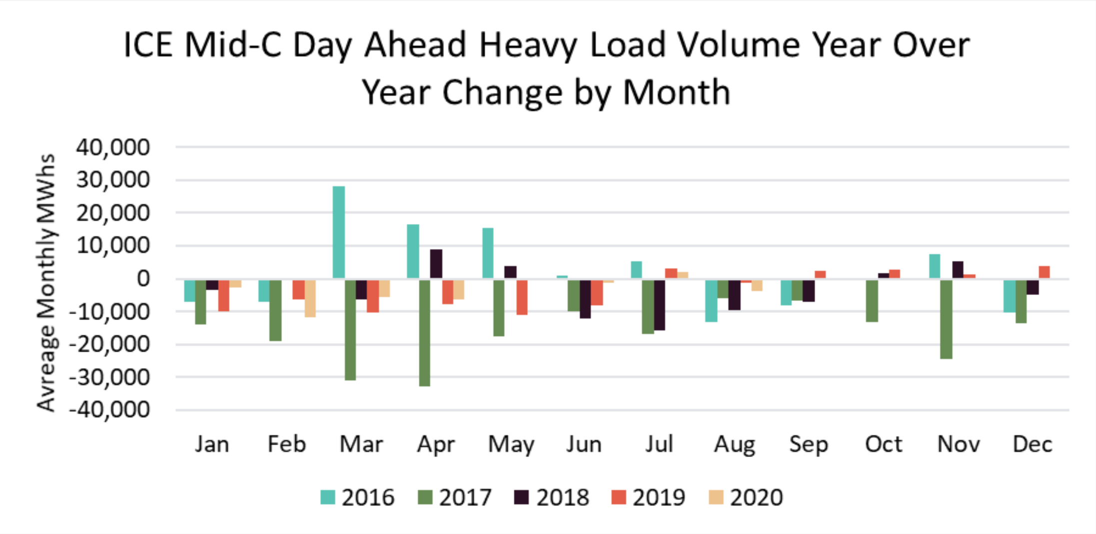
2 Planning Assumptions and Resource Alternatives: **Market Risk Assessment**

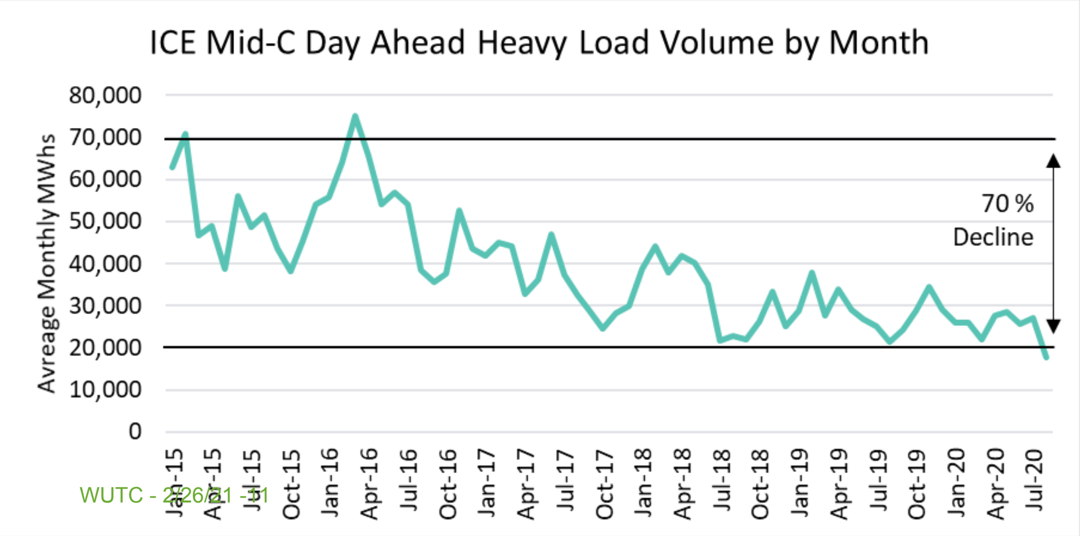
Market risk assessment will be discussed with stakeholders at March 5 webinar.

Several indicators show that PSE's market purchase limit for peak capacity planning is too high:

- Expected retirement of dispatchable, high-capacity resources throughout the WECC.
- PSE's market limit is higher when benchmarked with other IOUs.
- Several recent studies have concluded that the PNW faces a capacity shortfall in the near term.
- Trading volumes of day ahead physical energy for delivery at the Mid-C market hub have trended downward.

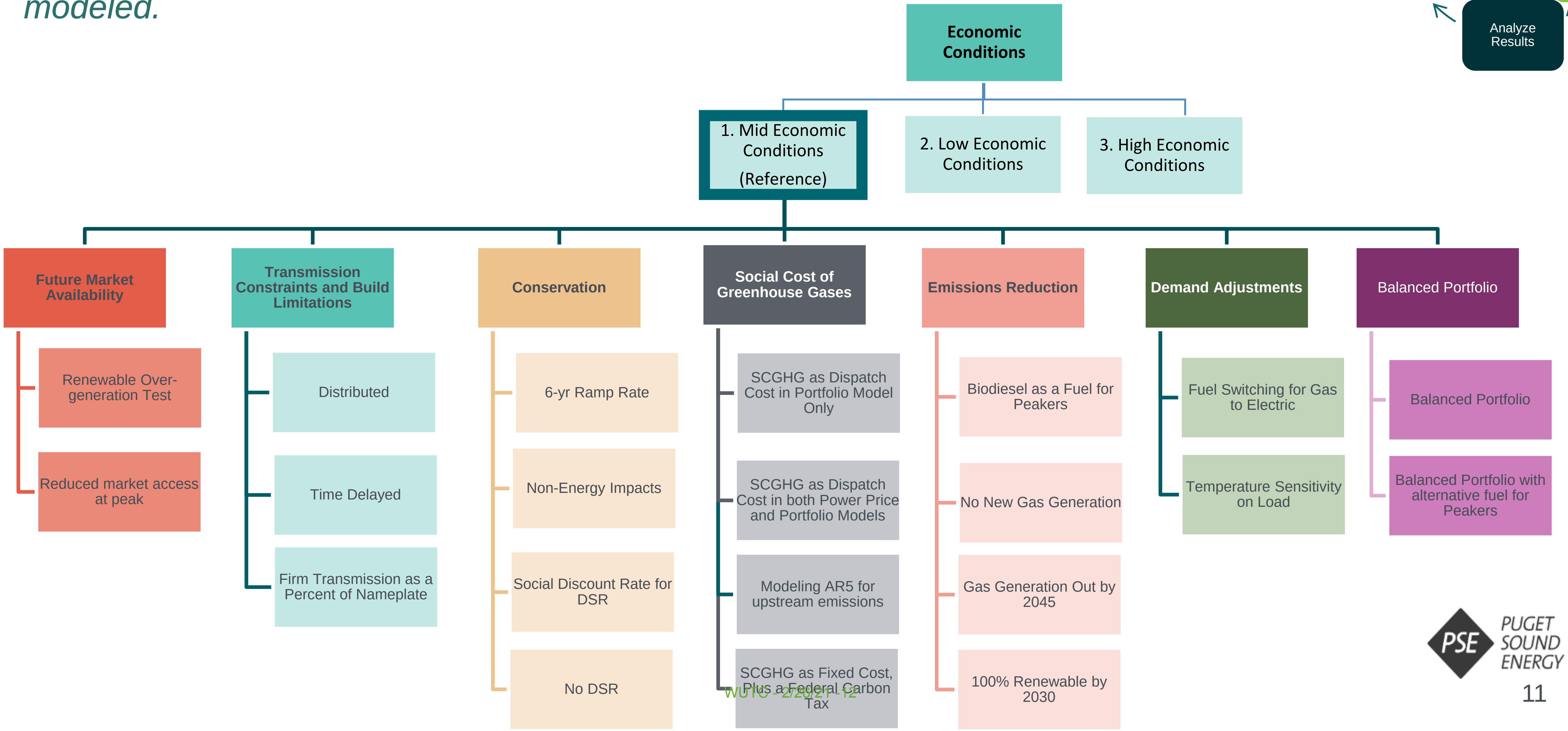
Anticipated 2021 IRP recommendation: Develop a resource procurement strategy to gradually decrease market purchases by 2027. A market risk adjusted capacity need will be reflected in the final IRP.





3 Analyze Alternatives and Portfolios

Over 35 integrated scenarios and sensitivities, requested by stakeholders have been modeled.



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4 Analyze Results: Distributed Energy Resources

Distributed energy resources are a significant component of the draft preferred portfolio.

Resource Additions (MW)	2022-2025	2026-2030	2031-2045	Total
Distributed Energy Resources				
Energy Efficiency	157 MW	245 MW	390 MW	793 MW
Distribution Efficiency	4 MW	6 MW	4 MW	15 MW
Codes & Standards	92 MW	71 MW	191 MW	354 MW
Battery Energy Storage	25 MW	150 MW	275 MW	450 MW
Solar - ground and rooftop	82 MW	188 MW	1,032 MW	1,302 MW
Demand Response	29 MW	154 MW	34 MW	217 MW
DSP Non-Wire Alternatives	22 MW	24 MW	72 MW	118 MW
Total DERs	412 MW	838 MW	1,999 MW	3,249 MW

- Delivery system planning (DSP) and IRP integration supports DERs.
- DSP Non-wire alternative solutions provide a DER forecast to the IRP.
- Further DER feasibility assessment will be required in the CEIP and ongoing learning through implementation.

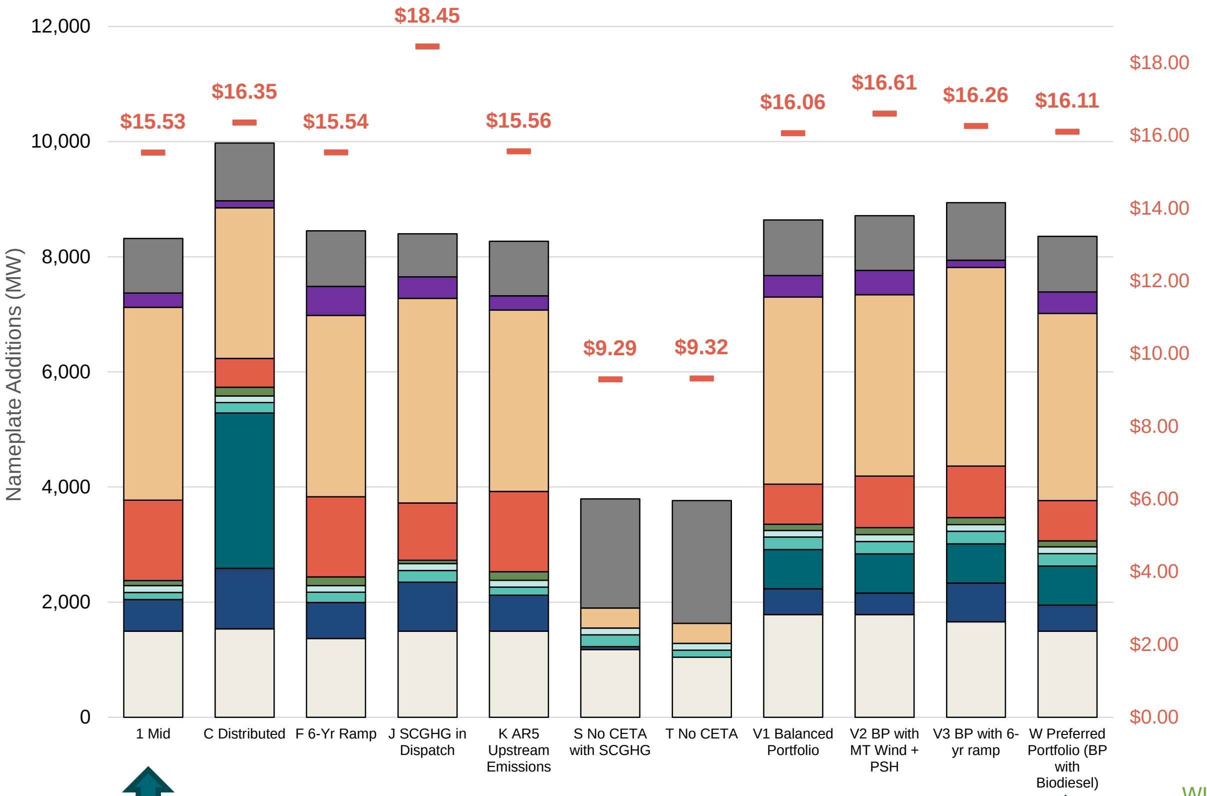
Findings

- ✓ DERs have lower peak capacity contributions and increased cost but improve customer benefits such as resiliency, air quality and environment.
- ✓ Almost all technically feasible demand response programs evaluated are included in the preferred portfolio which means that 217 MW of 222 MW of demand response is included
- ✓ Energy efficiency is a low cost way to decrease renewable requirements and resulted in a 71% increase when compared to no CETA portfolios.

4 Analyze Results: Resource Additions and Costs

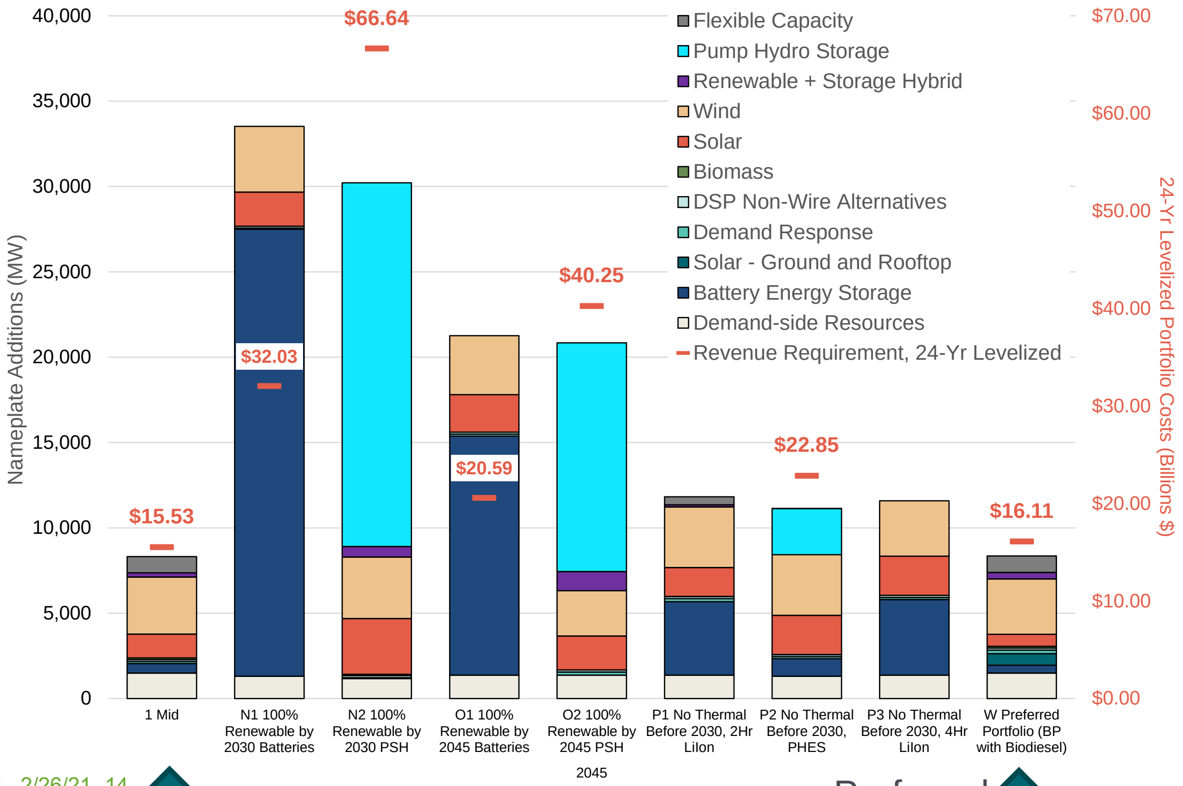
Portfolio sensitivity modeling evaluates tradeoffs between different resource additions and portfolio costs.

The procurement process will drive the acquisition of clean resources and will evaluate costs, permitting and other challenges and benefits.



Least Cost

Preferred Portfolio



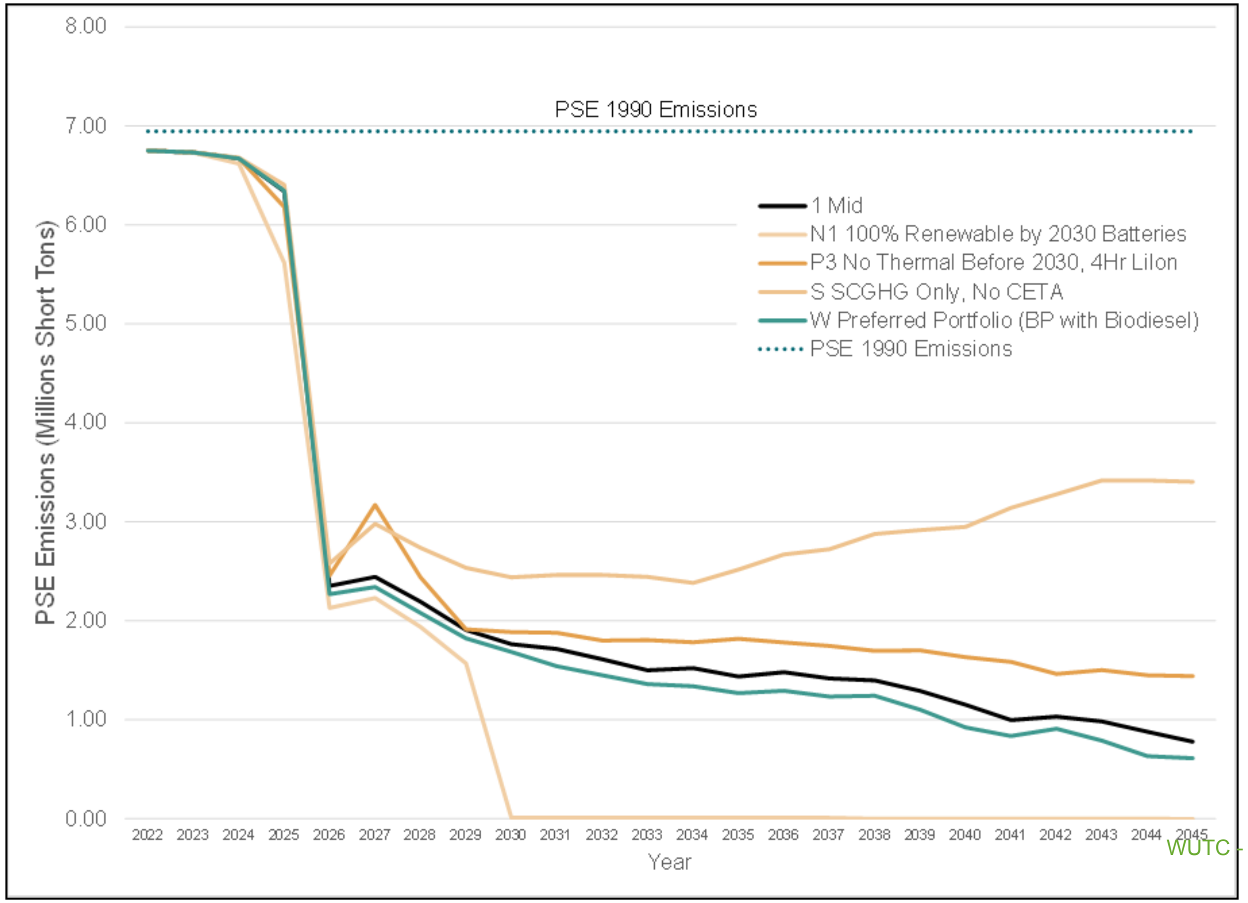
Least Cost

Preferred Portfolio

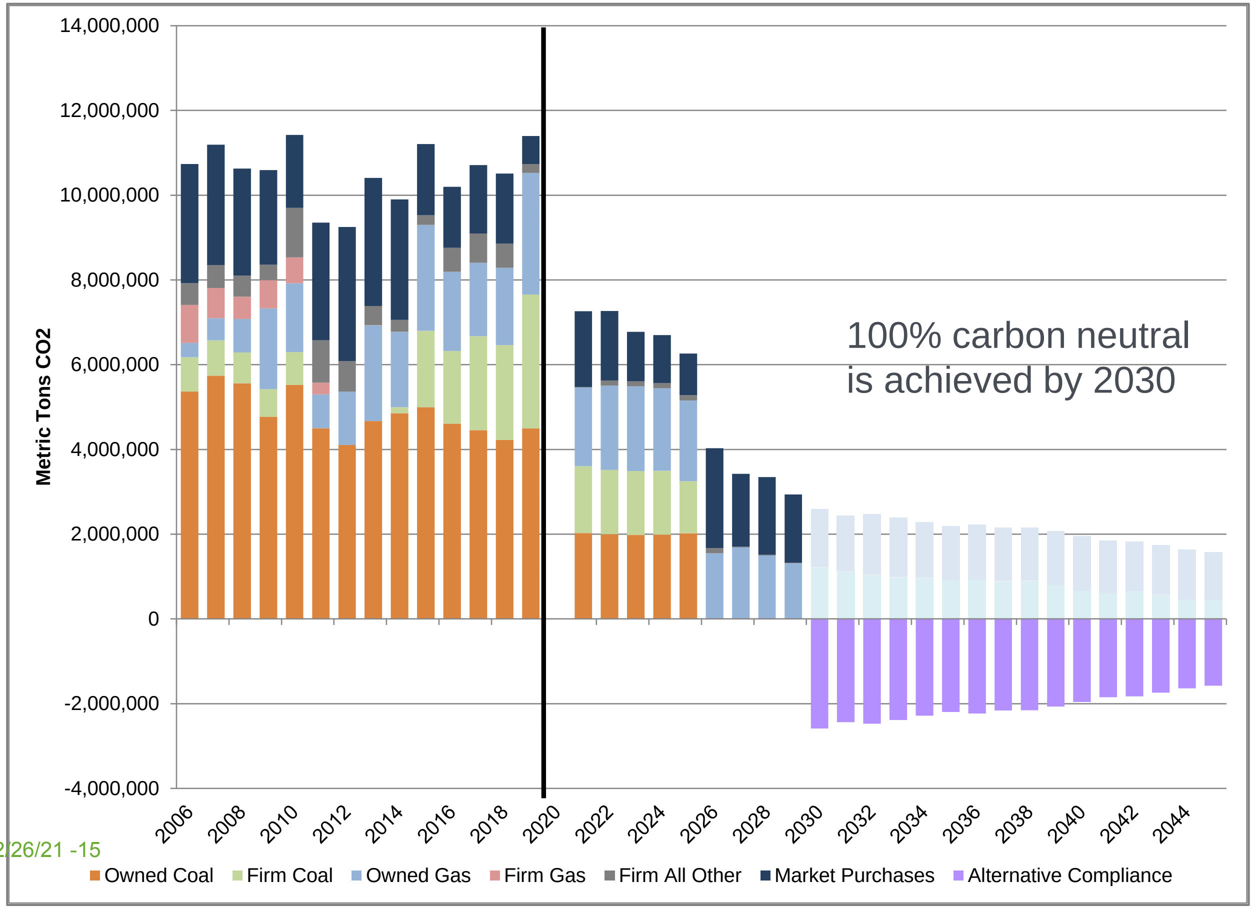
4 Analyze Results: Emissions

Significant emission reductions are achieved with the additions of non-emitting resources, retirement of coal resources and lower dispatch of existing resources.

Comparison of Direct CO2 Emissions & Upstream Emissions

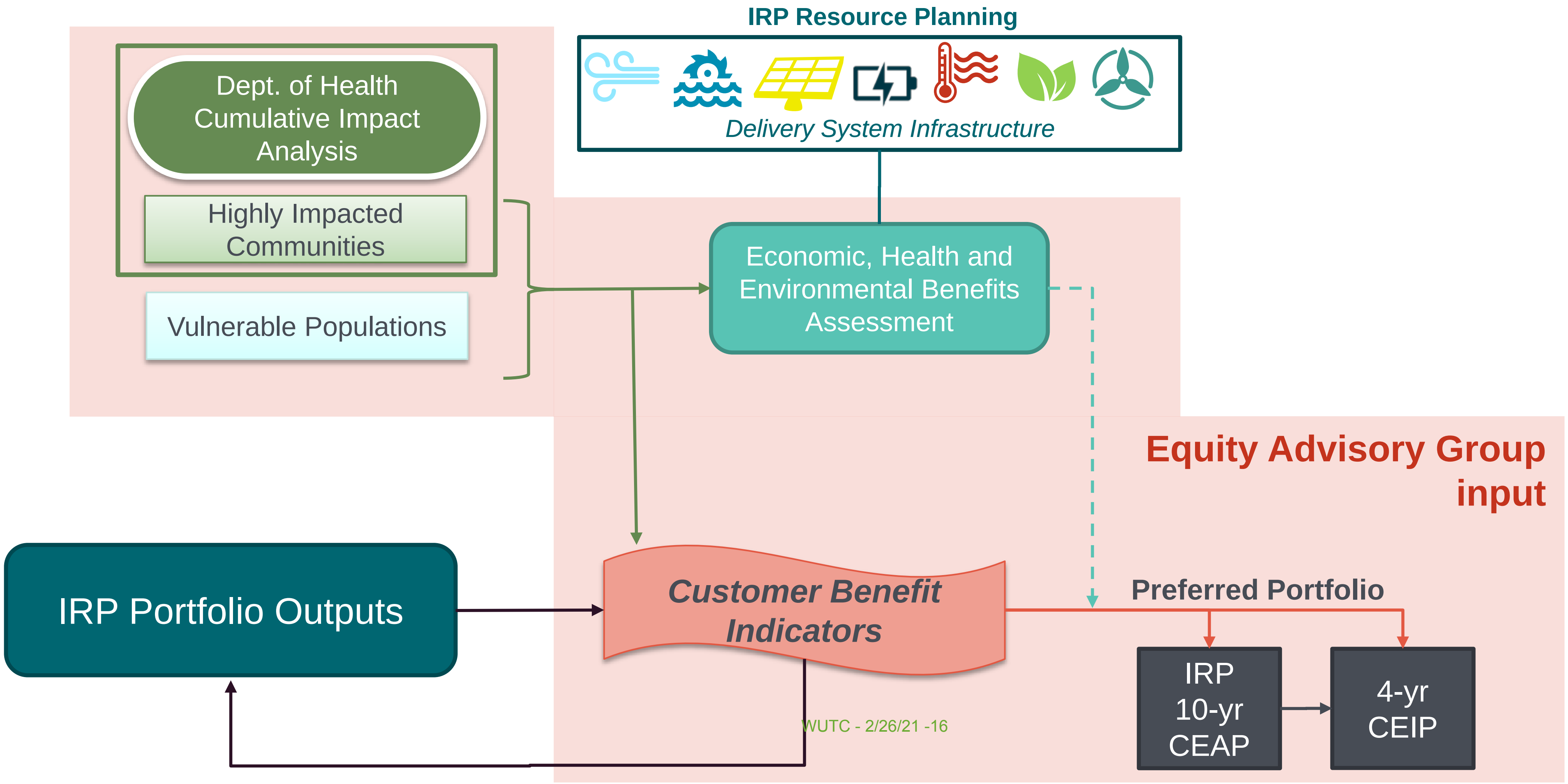


Historical Emissions and Projected Emissions for Draft Preferred Portfolio



5 Develop Resource Plan: Assessing Current Conditions

Assessment of current conditions in the path to equitable transition to clean energy is evaluated through Economic, Health and Environmental Benefits Assessment.



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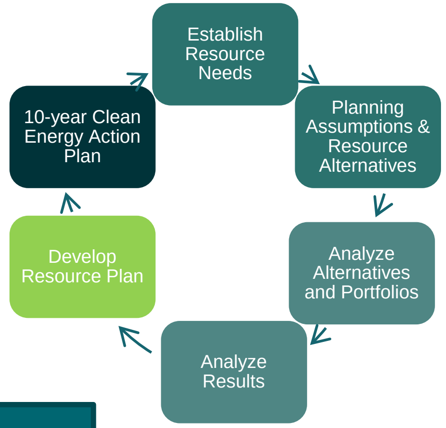
5 Develop Resource Plan: Incorporating Customer Benefits



Customer benefit indicators inform PSE's preferred portfolio.

Category	Customer Benefit Indicator Type	Customer Benefit Indicator
Environment	Climate Change	GHG Emissions
	Environment	Renewable Generation, Customer Programs, Energy Efficiency, Distributed Generation
Health	Air Quality	SO_2 NO_x PM
Economic	Market Position	Market Purchases
	Cost	Portfolio Cost
Energy Security & Resiliency	Resource Adequacy	Market Risk, Demand Response
	Resiliency	Storage

6 Clean Energy Action Plan

Clean Energy Transformation Standards are met in the Draft Preferred Portfolio.

Draft Preferred Portfolio achieves:

- *100% carbon neutral by 2030*
- *100% carbon free by 2045*

Incremental Resource Additions (Nameplate MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Distributed Energy Resources											
Demand-side Resources	74	64	61	57	63	66	82	75	75	81	696
Battery Energy Storage	-	-	-	25	25	25	25	25	50	25	200
Solar - ground and rooftop	-	-	-	80	30	30	30	30	30	30	260
Demand Response	-	5	6	18	27	34	41	27	26	13	195
DSP Non-Wire Alternatives	3	6	9	4	3	5	6	5	4	4	50
Total DERs	77	75	76	184	148	160	184	162	185	153	1,401
Renewable Resources											
Wind	-	-	-	400	200	400	-	200	200	100	1,500
Solar	-	-	-	-	-	100	-	100	199	-	398
Total Renewable Resources	-	-	-	400	200	500	-	300	399	100	1,898
Flexible Capacity	-	-	-	-	255	-	-	-	-	-	255

PUGET SOUND ENERGY

Natural gas IRP results in increased and continued conservation investments

- Conservation investments will eliminate the need for future regional pipeline infrastructure expansion for PSE’s natural gas customers.
- Inclusion of social cost of greenhouse gases and upstream related carbon emissions have a significant impact on the amount of cost-effective conservation.

Short-term Comparison of Natural Gas Energy Efficiency	MDth over 2-year program
2018-2019 Actual Achievement	699
2020-2021 Target	795
2022-2023 Economic Potential in 2021 IRP Scenarios	1,192

Natural Gas Resource Plan Takeaways

✓ Increased and continued conservation investments are expected to meet future peak day natural gas capacity needs for PSE’s natural gas customers.

✓ Further analysis of greenhouse gas reduction opportunities is needed, including fuel-switching.

Webinar 13, March 5, 2021

Market Risk Assessment, Electric and Natural Gas Stochastic Analysis, Preferred Portfolio, Clean Energy Action Plan, Overview of the Clean Energy Implementation Plan and Public Participation

Webinar #13: Market Risk Assessment, Stochastic Analysis, Preferred Portfolio and Clean Energy Action Plan, Overview of the CEIP and Public Participation March 5, 2020 from 1:00 p.m. to 5:00 p.m. PST

Virtual webinar link: https://global.gotomeeting.com/join/965402149
Access code: 965-402-149; Call-in telephone number (audio only): +1 (872) 240-3311

Topic	Lead
Welcome • Agenda review • Safety moment • How to participate • Speaker introductions	EnviroIssues
Market Risk Assessment	Paul Wetherbee Director Energy Supply Merchant, PSE
Stochastic Analysis	Jennifer Magat, Senior Resource Planning Analyst, PSE Gurvinder Singh Senior Resource Planning Analyst, PSE
Preferred Portfolio and Clean Energy Action Plan	Elizabeth Hossner, Manager Resource Planning & Analysis, PSE
Overview of the Clean Energy Implementation Plan (CEIP) and Public Participation	Brian Tyson, Manager, Clean Energy and Implementation, PSE Diann Strom, Strategic Engagement Lead, Clean Energy Strategy, PSE
Wrap up and next steps • Next steps • Upcoming meeting schedule • Thank you's	EnviroIssues

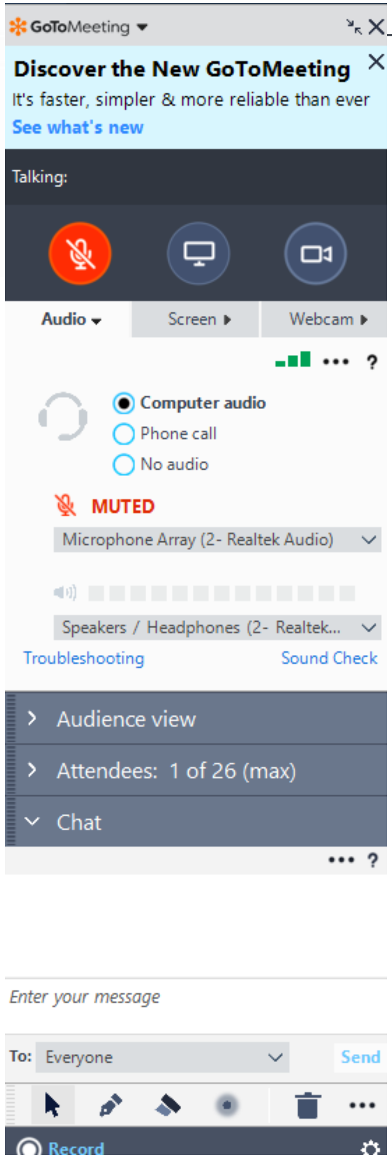
2021 IRP Webinar #13:

Market Risk Assessment, Stochastic Analysis, Preferred Portfolio and Clean Energy Action Plan, CEIP

PUGET SOUND ENERGY

March 5, 2021

Welcome to the webinar and thank you for participating!



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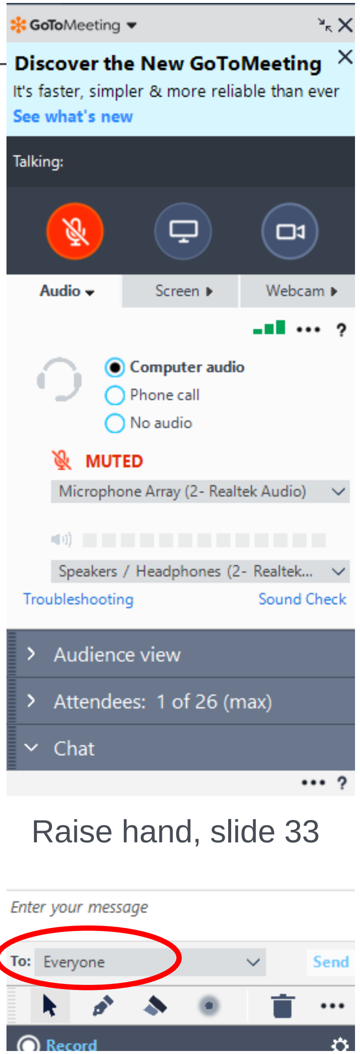
  - **In writing:** your question will be read
  - **Verbally:** type "Raise hand" and slide #, share with "Everyone"; please wait to be called on to ask your question
- Be considerate of others waiting to participate
- We will try to get to all questions



Agenda

- Safety Moment
- Market Risk Assessment
- Electric and Natural Gas Stochastic Analyses
- Preferred Portfolio and Clean Energy Action Plan
- Overview of the Clean Energy Implementation Plan (CEIP) and Public Participation

Safety moment: Call 811 before you dig

Know what's below. Call before you dig.

Dial 811 at least **two full business days** (not including the day you call) before you plan to dig, no matter the size of your project. It's not only smart, **it's the law**.

- It's important to have the locations of underground utilities verified and clearly marked
- Striking a natural gas or electric line may result in service disruptions, bodily harm, fines and/or repair costs

pse.com/pages/know-whats-below

PUGET SOUND ENERGY

Today’s Speakers

Gurvinder Singh
Senior Resource Planning Analyst, PSE

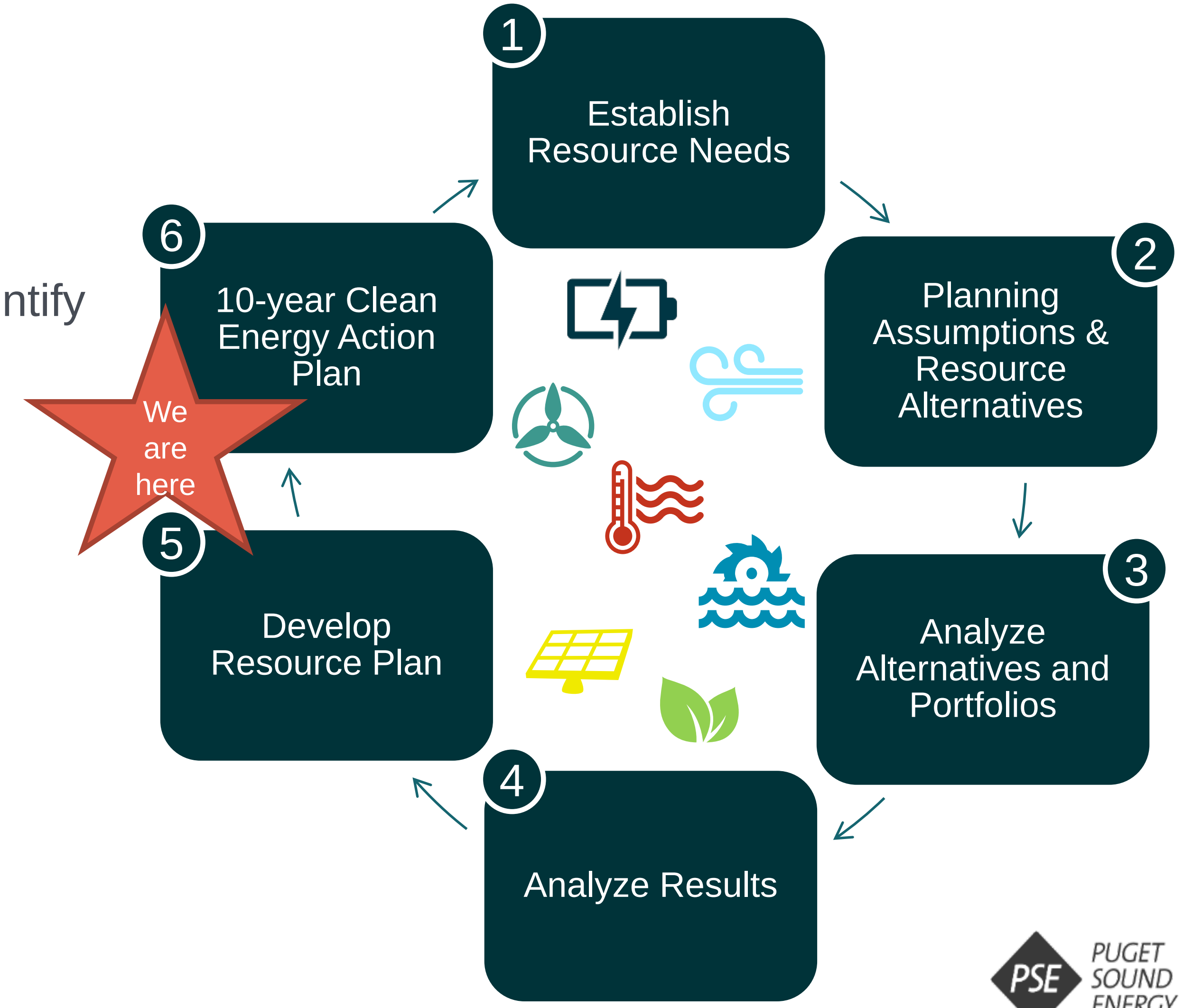
Diann Strom
Stakeholder Engagement Consultant, Clean Energy Strategy, PSE

Brian Tyson
Manager, Clean Energy Planning and Implementation, PSE

2021 IRP modeling process

The 2021 IRP will follow a 6-step process for analysis:

1. Analyze and establish resource need
2. Determine planning assumptions and identify resource alternatives
3. Analyze scenarios and sensitivities using deterministic and stochastic risk analysis
4. Analyze results
5. Develop resource plan
6. 10-year Clean Energy Action Plan



Thank you for participating in our IRP public process

Date	Action
May-Dec 2020	2021 IRP process: 10 PSE Webinars, feedback reports, consultation updates and numerous stakeholder engagements & communications
Dec 15, 2020	PSE Webinar 11: draft portfolio sensitivity results
Dec 28, 2020	WUTC adopted final IRP/CEIP rules
Jan 4, 2021	Draft Electric & Gas IRP posted online and filed with WUTC
Feb 5, 2021	End of opportunity to file written comments with WUTC
Feb 10, 2021	PSE Webinar 12
Feb 26, 2021	WUTC Open Meeting on draft IRP
Mar 5, 2021	**PSE Webinar 13**
Apr 1, 2021	Final Electric & Gas IRP posted online and filed with WUTC

Documentation of sensitivities analyzed in this IRP is included in Appendix A.

Draft 2021 IRP Report

- Letter from President and CEO, Mary Kipp
- 2021 Draft IRP Filing Cover Letter
- 2021 Draft IRP Chapter Book [full compressed PDF, 34 MB]
- 2021 Draft IRP Appendix Book [full compressed PDF, 51.5 MB]

Individual chapters and appendices can be found below.

Chapters +

Appendix –

- Cover page and contents
- Appendix A: Public Participation
- Appendix B: Legal Requirements
- Appendix C: Environmental Regulations

https://pse-irp.participate.online/2021-irp/reports

PSE PUGET SOUND ENERGY

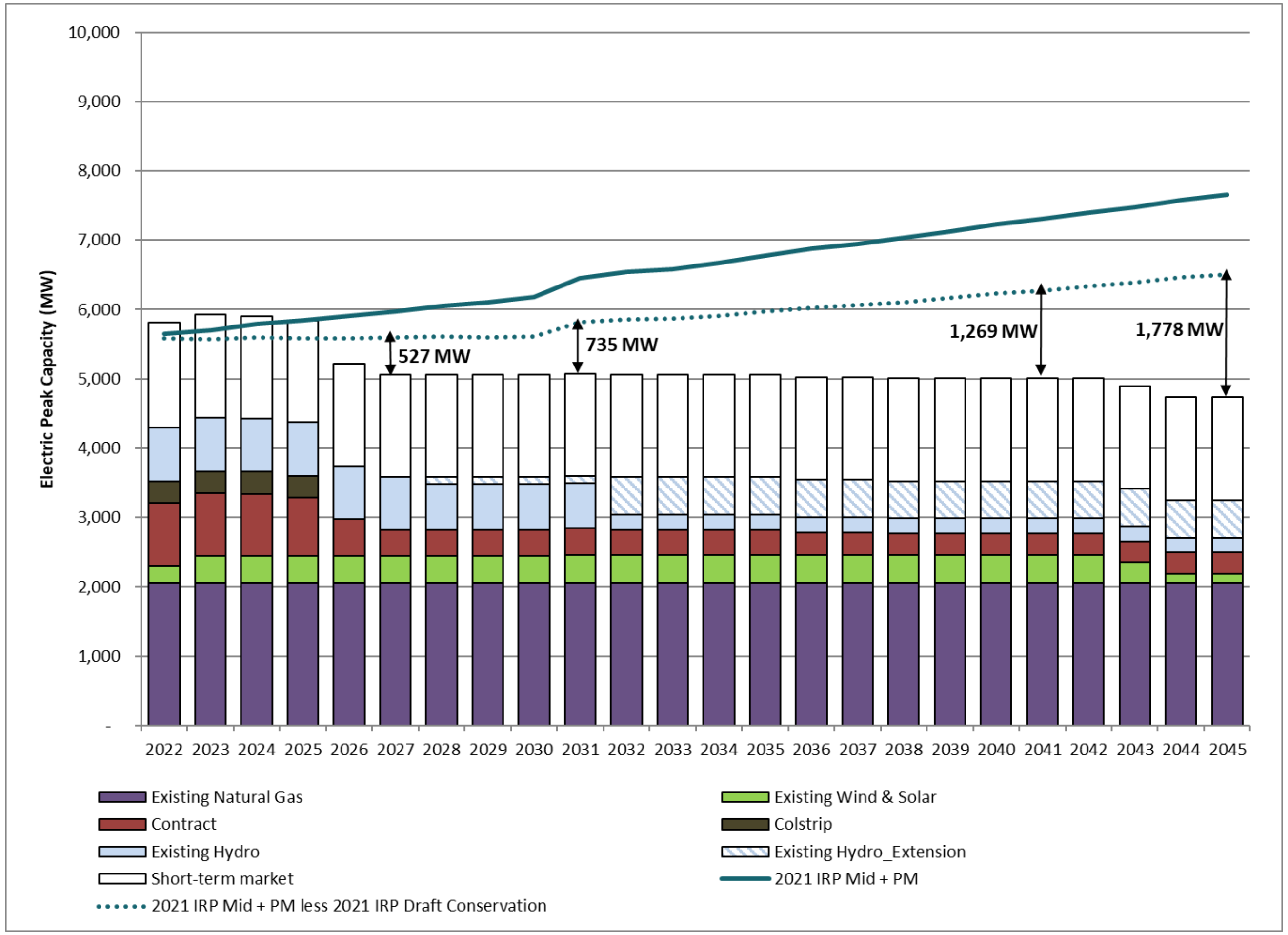
Market Risk Assessment

Participation Objectives

- PSE will consult with stakeholders on the approach for reducing market purchases for peak capacity planning.

IAP2 level of participation:
CONSULT

Peak Capacity Need assumes 1500 MW of Mid-C market purchases

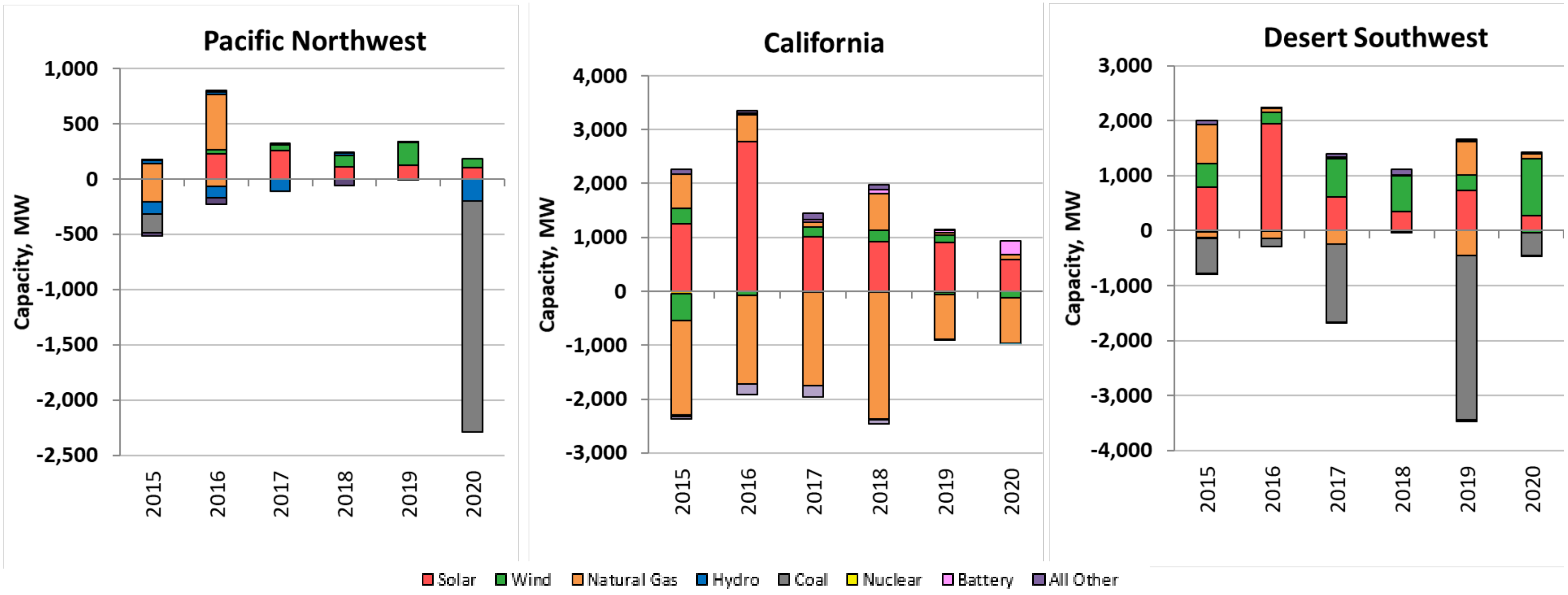


- PSE's current transmission portfolio includes 1,500 MW of firm transmission rights that can be used to purchase energy at the Mid-C and deliver to PSE.
- PSE relies on the 1500 MW of Mid-C market purchases for peak capacity planning (white bars on the chart).

PUGET SOUND ENERGY

Dispatchable high-capacity resources are declining in the West

- While substantial wind and solar resources have been built in the West, dispatchable high-capacity thermal generation has been retired.
- Pacific Northwest coal retirements in 2020 reduce the energy available to procure through bilateral transactions at the Mid-C trading hub.



PUGET SOUND ENERGY

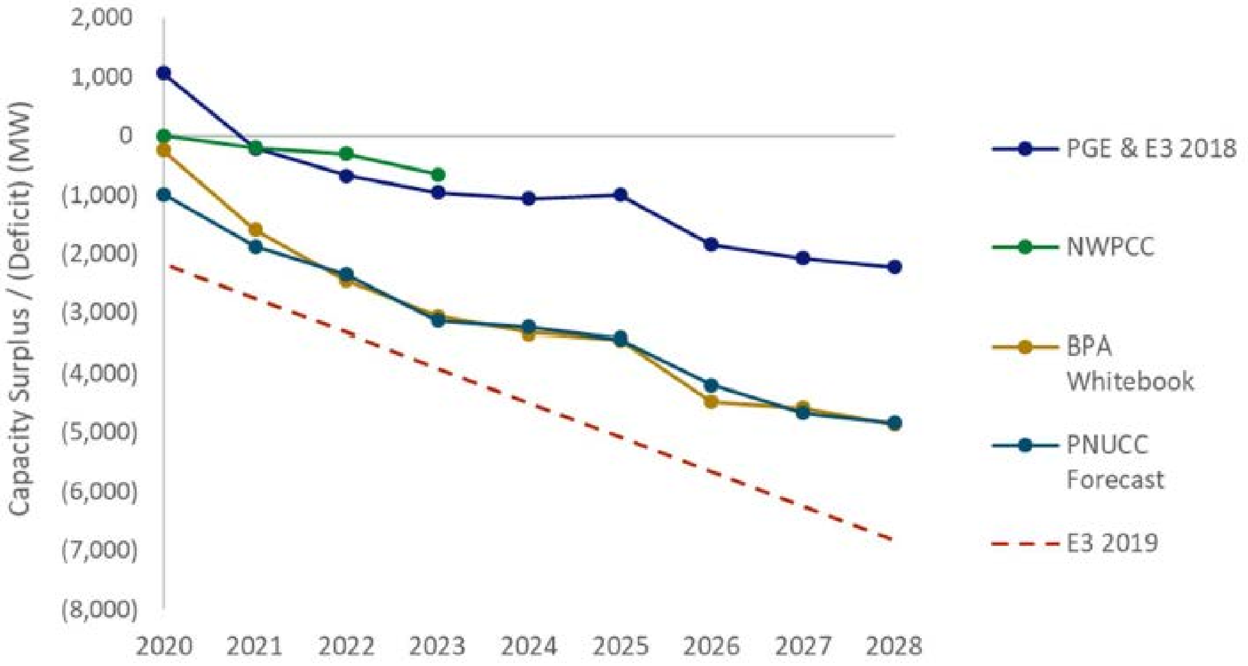
PSE market purchases are higher than other IOUs

Entity	Planned Summer Market Reliance Limit (MW)	Planned Winter Market Reliance Limit (MW)	Commentary
Avista	330	330	From the draft 2021 IRP. Market purchases are limited to 500 MW during 'unconstrained' hours, and 330 MW during 'constrained' hours
Idaho Power	N/A	N/A	The current IRP (2019) assumes market purchases of 500 MW in the summer and 425 MW in the winter. Specific market purchase limits are not defined in the IRP.
PacifiCorp	500 – Aggregate 150 – Mid-C Seasonal HLH	1000 – Aggregate 0 – Mid-C Seasonal HLH	Proposed Front Office Transaction Limits for the 2021 IRP cycle.
Portland General Electric	50	0	Estimates from recent PGE capacity studies.
Puget Sound Energy	1,500	1,500	From the draft 2021 IRP. PSE counts historical energy offers at the Mid-C hub as available capacity to meet peak demand needs in the winter and summer.

Predicted capacity deficits could reduce Mid-C bilateral transactions

- Recent studies have concluded that the PNW faces a capacity shortfall in the near term.
  - PGE (2018)
  - NWPCC (2020)
  - BPA (2020)
  - PNUCC (2020)
  - E3 (2019)
- Current investigations into August 2020 events point to material resource adequacy failures in the western interconnect.
  - CA Joint Committee (2021)
  - CAISO DMM (2020)
  - WECC (2020)
  - FERC (2020)

Several recent regional studies predict a capacity deficit

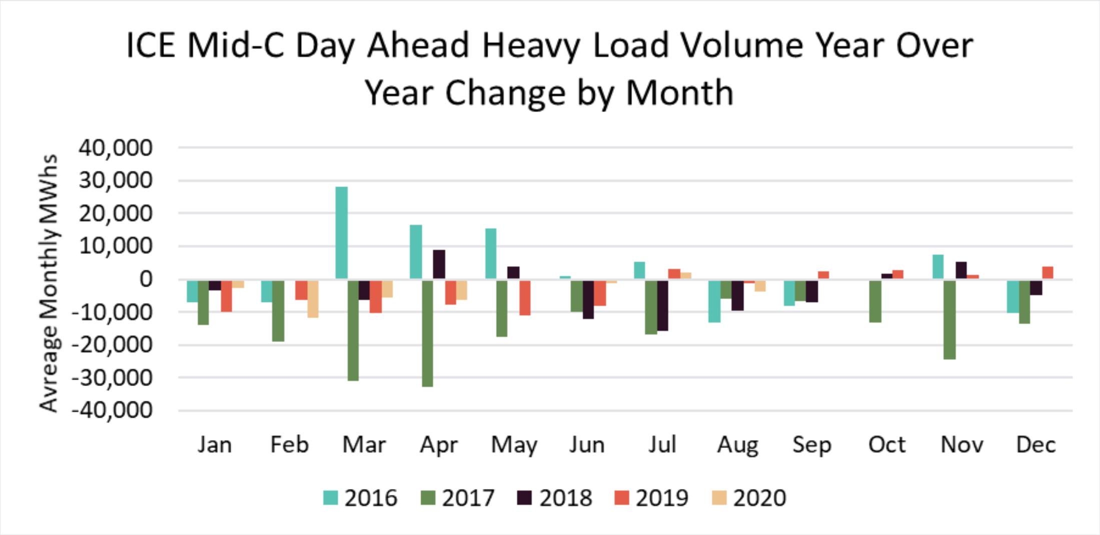


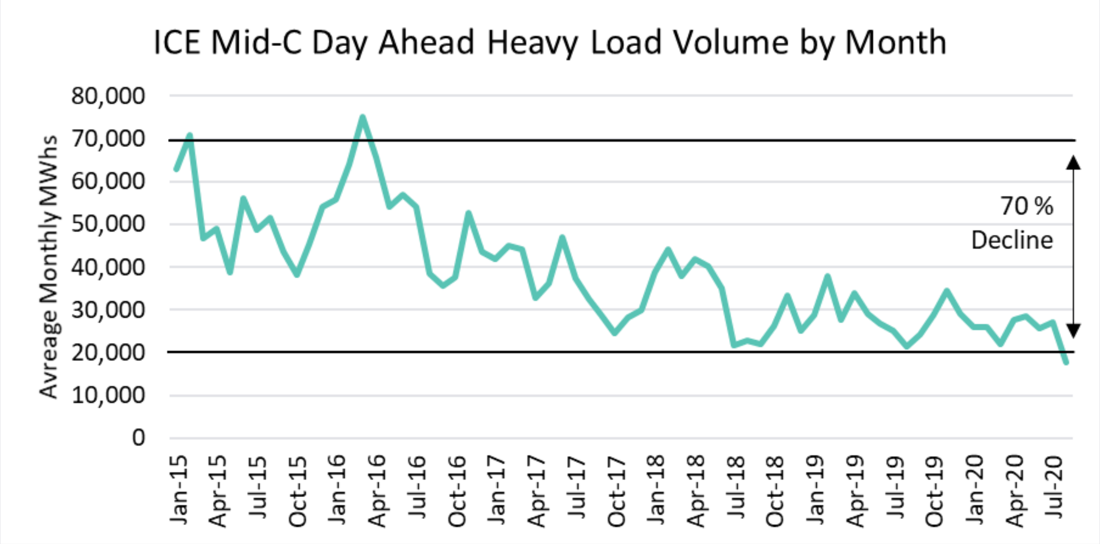
Source: NWPP Exploring a Resource Adequacy Program for the West, October 2019

Trading volumes are declining at the Mid-C bilateral hub

- Trading volumes of day ahead physical energy for delivery at the Mid-C market hub have trended downward.
  - Average monthly peak profile day ahead spot transactions have consistently decreased year over year.
  - Month over month volumes are also trending lower.

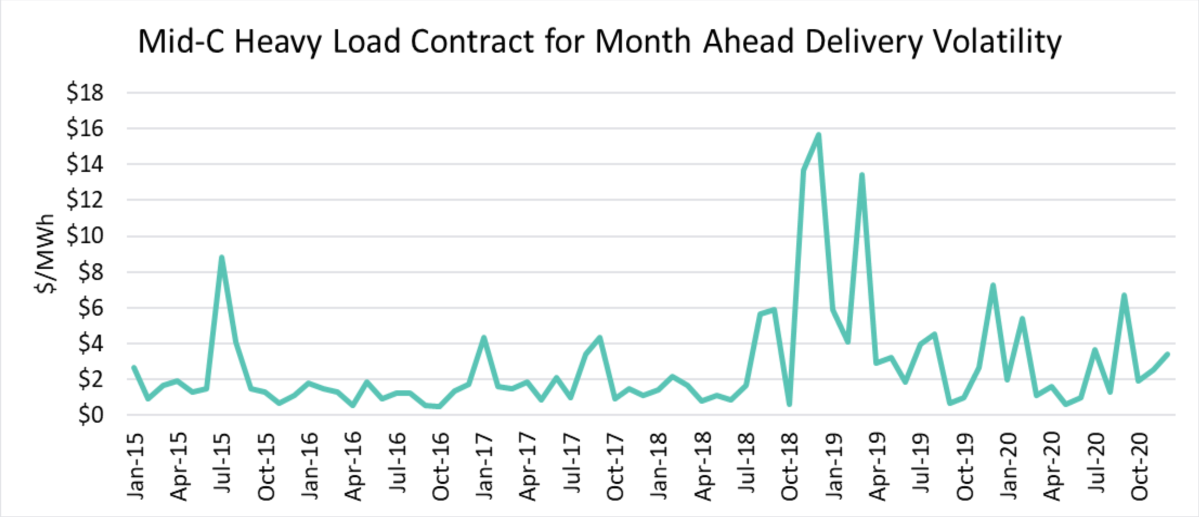
- Reduced spot market liquidity drives increases in spot price volatility.

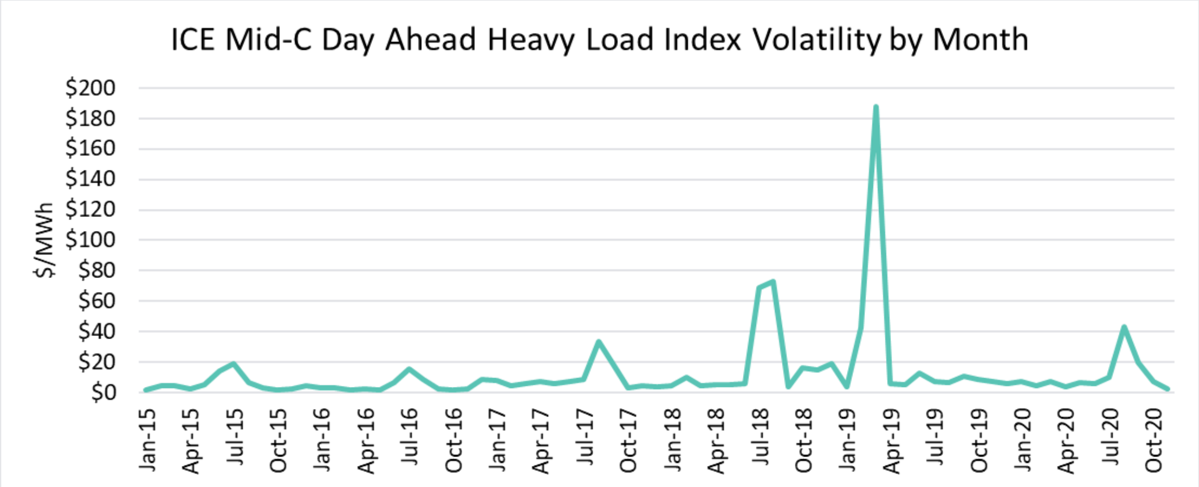




Short-term market volatility has increased

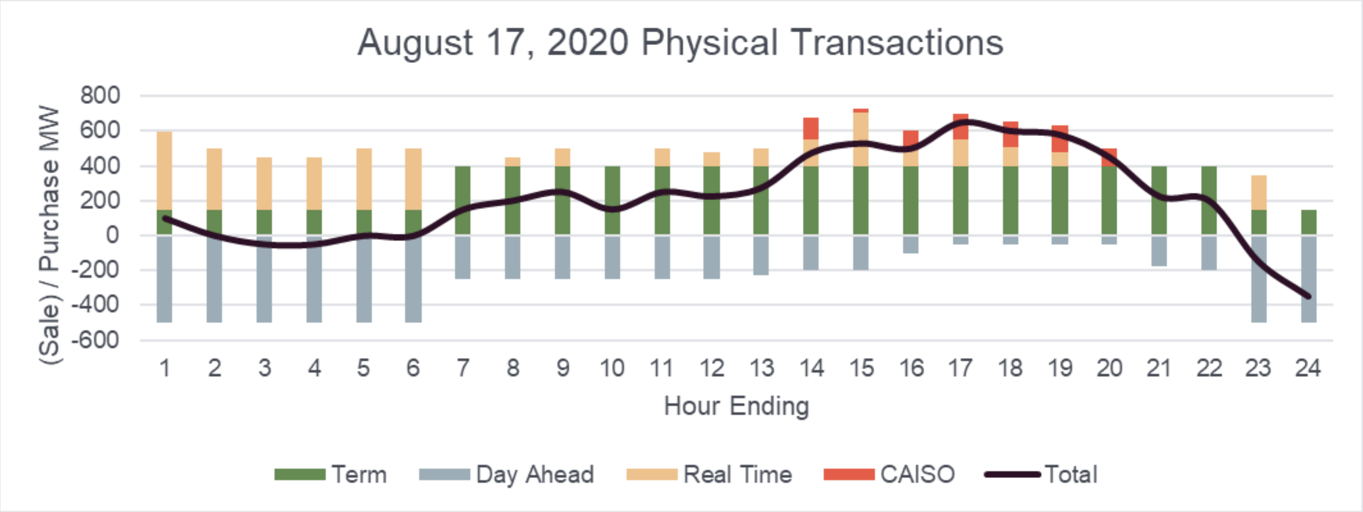
- Term volatility in the forward market has remained relatively stable and range bound, but has increased in the spot market.
- Price volatility has increased at the Mid-C in the spot market in response to tighter supply/demand fundamentals.
- High prices are indications of near misses
    - Summer 2018 – hot regional temperatures coinciding with Colstrip forced outages
    - March 2019 – cold regional temperatures coinciding with reduced Westcoast pipeline and Jackson Prairie storage availability
    - August 2020 – West-wide heat event





Mid-C bilateral liquidity evaporated in August 2020

- Several entities in the WECC declared energy emergencies during the west-wide heat wave of August 14th - 19th, 2020.
  - CAISO progressed to stage 3 on August 14th and 15th and was forced to cut firm load.
  - PSEI declared a stage 1 emergency on August 17th, as we anticipated that supplies required to meet demand could not be procured from resources or the market – PSE's total Mid-C market reliance was 400-505 MW during this time.



PUGET SOUND ENERGY

PSE would like stakeholder feedback on an anticipated IRP recommendation

- Draft IRP included a capacity need that will not change for the final IRP.
- PSE proposes to include a market risk adjusted capacity need in the final IRP with a gradually declining market purchase limit from 1500 MW to 500 MW by the year 2027.
- PSE's resource procurement strategy will include the market risk adjusted capacity need.

Electric and Natural Gas Stochastic Analyses

Participation Objectives

- PSE will review the Stochastic Analysis approach and preliminary results.

  IAP2 level of participation: INFORM

Electric Stochastic Analysis

Purpose of the stochastic analysis:

The goal of the stochastic modeling process is to understand the risks of portfolios in terms of portfolio costs and resource needs.

Stochastics	Stochastics: Mid-C Prices	Stochastics: PSE Portfolio
• Input	• Regional Demand • Natural gas prices • Hydro generation • Wind generation	• Natural gas prices • Mid-C power prices • PSE electric demand (energy and peak) • Hydro generation • Wind generation • Solar generation • Plant forced outages
• Output	• The different combination of inputs results in different power prices.	• The different combination of inputs results in different dispatch and revenue requirement.

Portfolios to be modeled in stochastic analysis

- Mid scenario (1)
- Preferred portfolio (W)
- Preferred Portfolio with market reduction (X)
- No DSR portfolio (Z)

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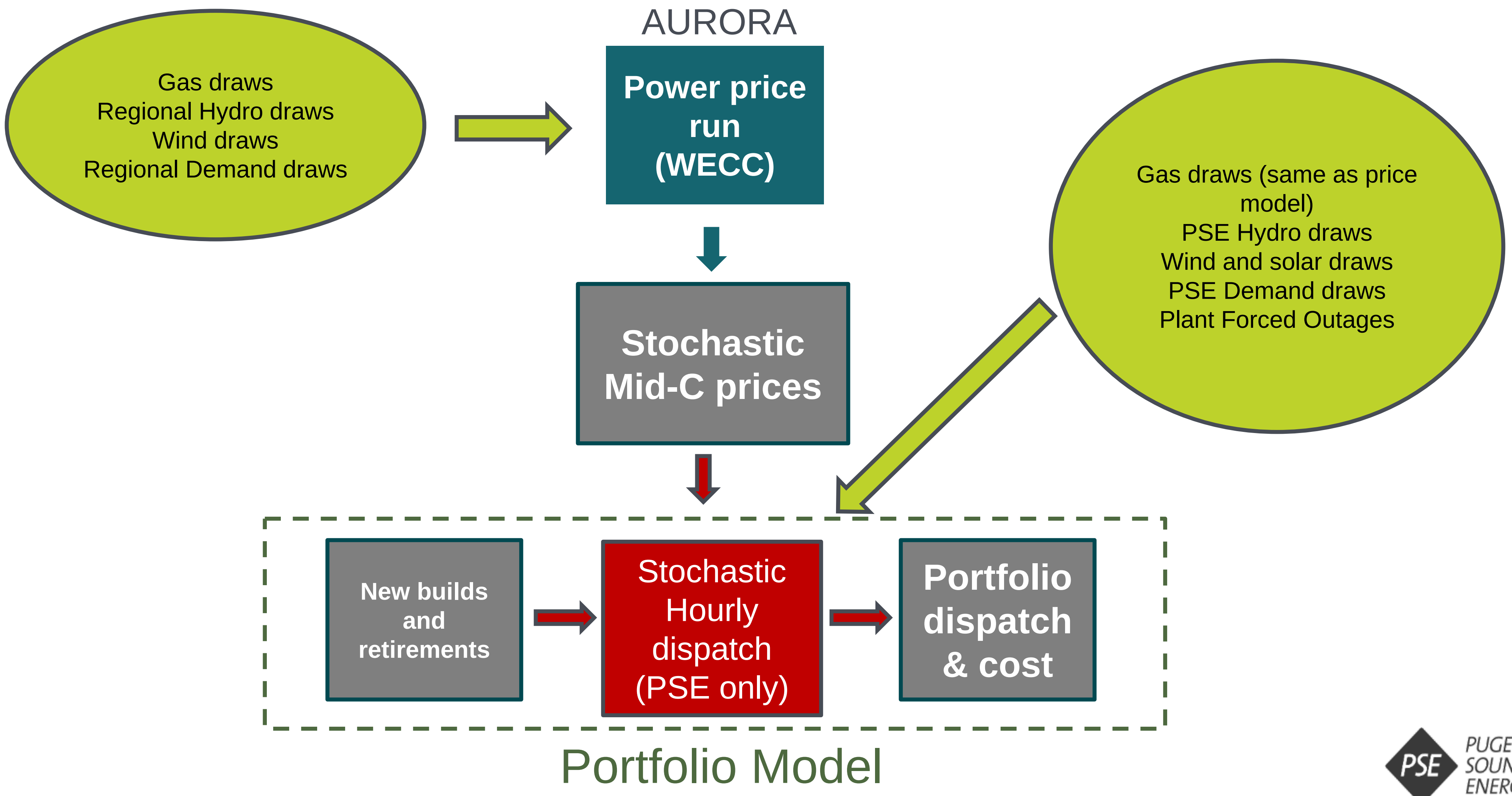
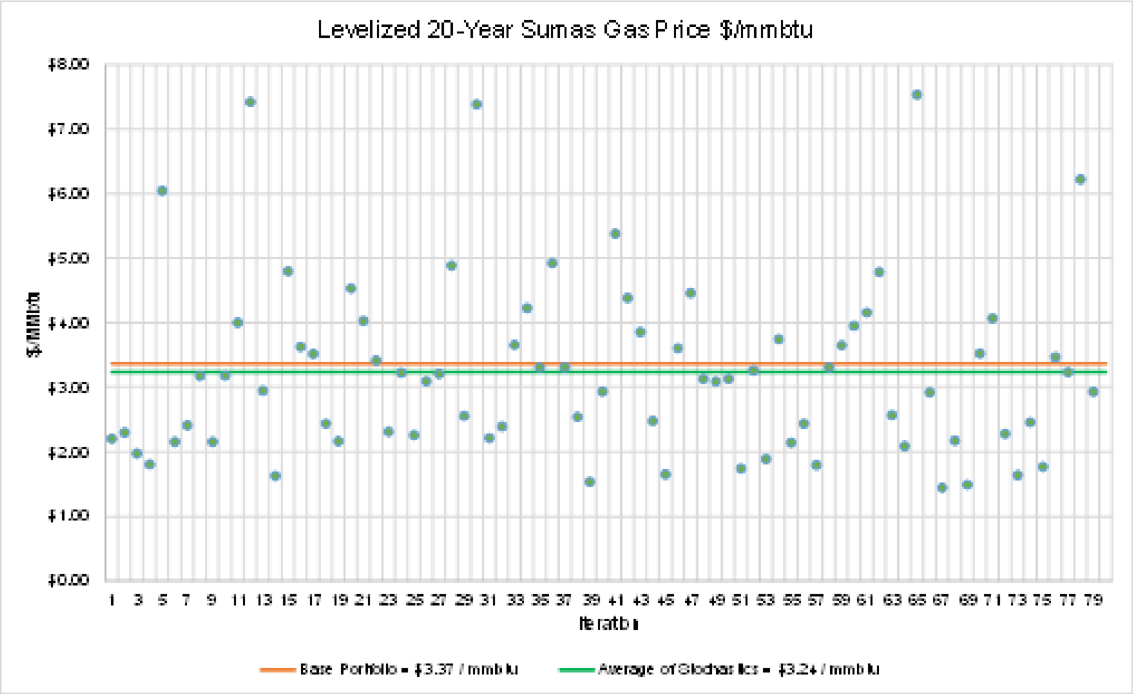
Electric Stochastic Modeling Process



Natural gas prices

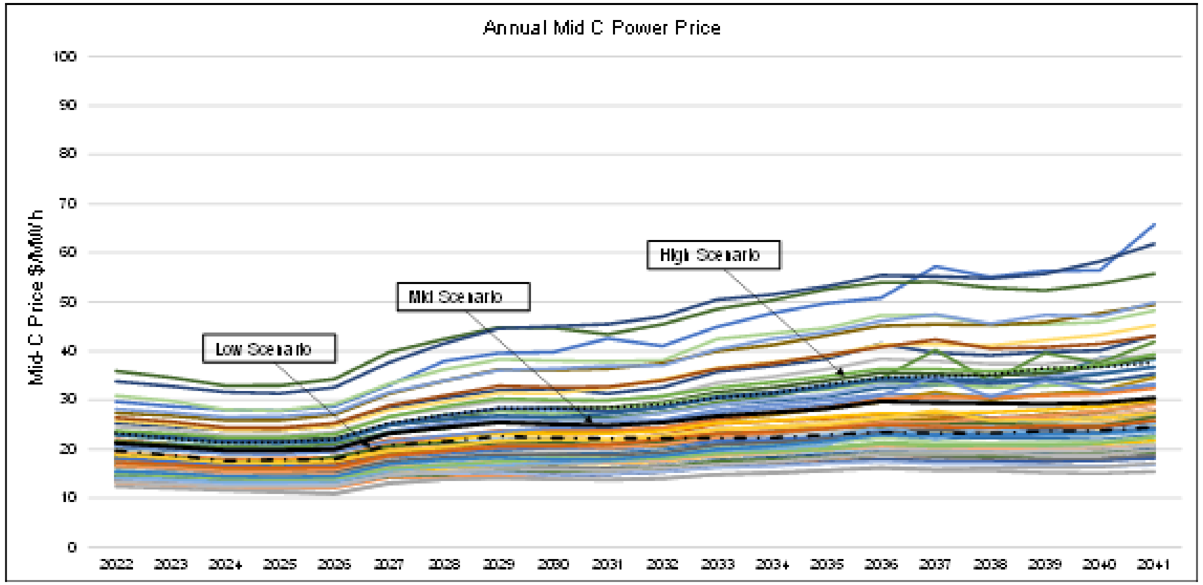
- The correlation of gas prices from Sumas, Rockies (Opal), AECO, San Juan, Malin, Topock, Stanfield and PGE City Gate to Henry Hub were calculated using data from Wood Mackenzie's Spring 2020 Long Term View Price Update.
- Low, Medium, and High gas prices were evaluated for each hub to determine the average and standard deviation for each calendar month.
- The correlation and standard deviation are used as input to Aurora Risk Functionality logic to generate 80 draws of gas prices for the fuel hubs.

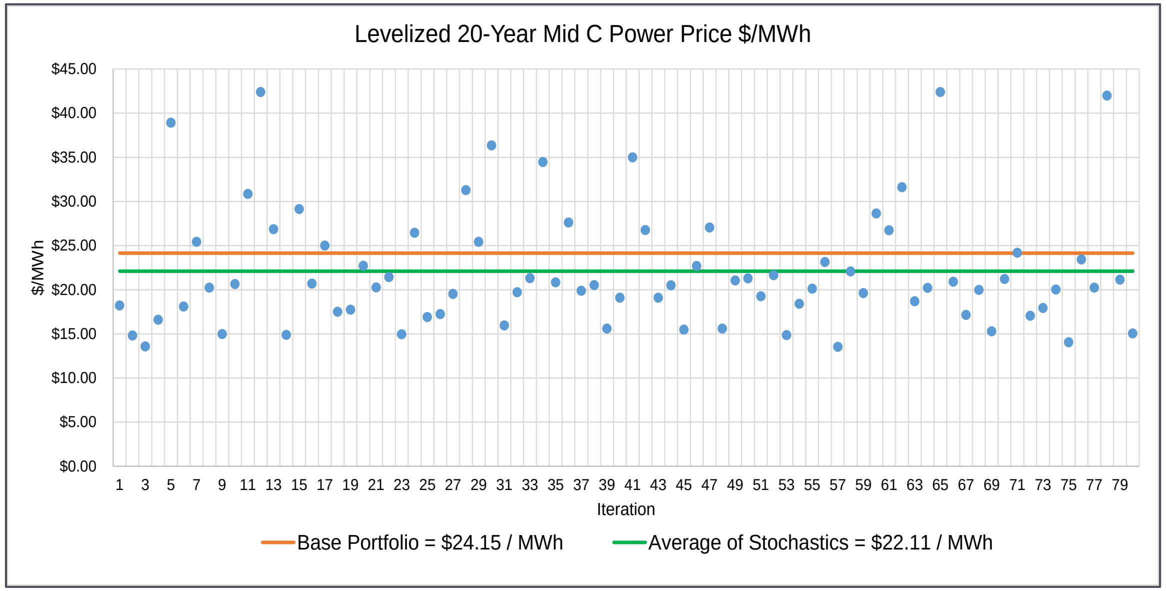


Electric price draws

- Using the pre-defined 80 iteration set for Demand, Fuel, Hydro and Wind, Aurora is able to generate 80 iterations of power price forecast.
  - Demand
    - The regional demand used in the 2021 IRP for the Low, Medium, and High scenarios were evaluated to get a spread of possible demand futures. This is applied to the WECC load and Aurora generated 80 possible load futures through its Risk Sampling functionality.
  - Natural gas price
  - Hydro generation
  - Wind generation
    - PSE sampled from hourly wind shapes developed by Energy Exemplar. Energy Exemplar utilized generation estimates from the National Renewable Energy Laboratory's (NREL) Wind Integration National Database (WIND) Toolkit.

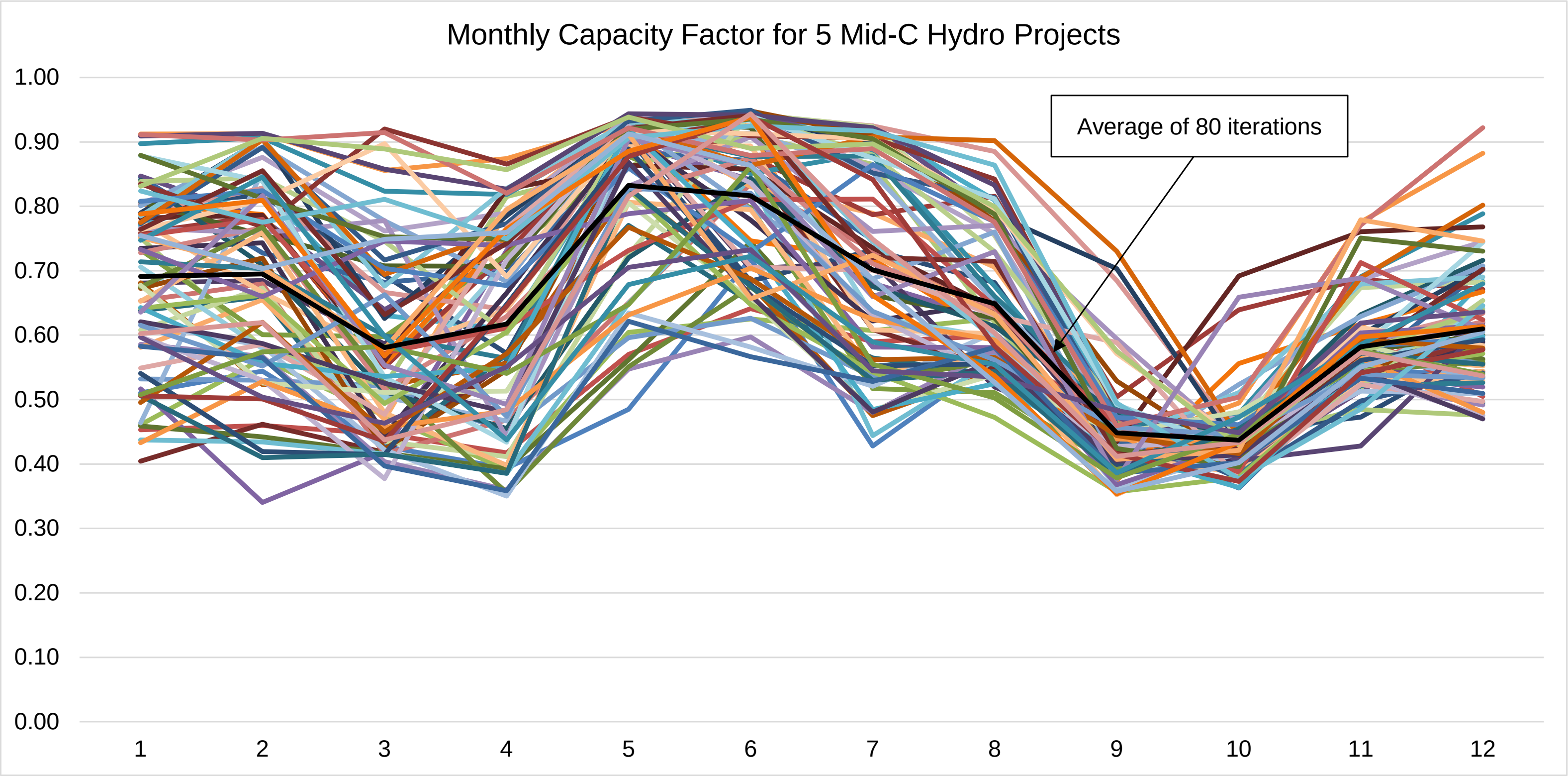
Electric price charts





Hydro draws

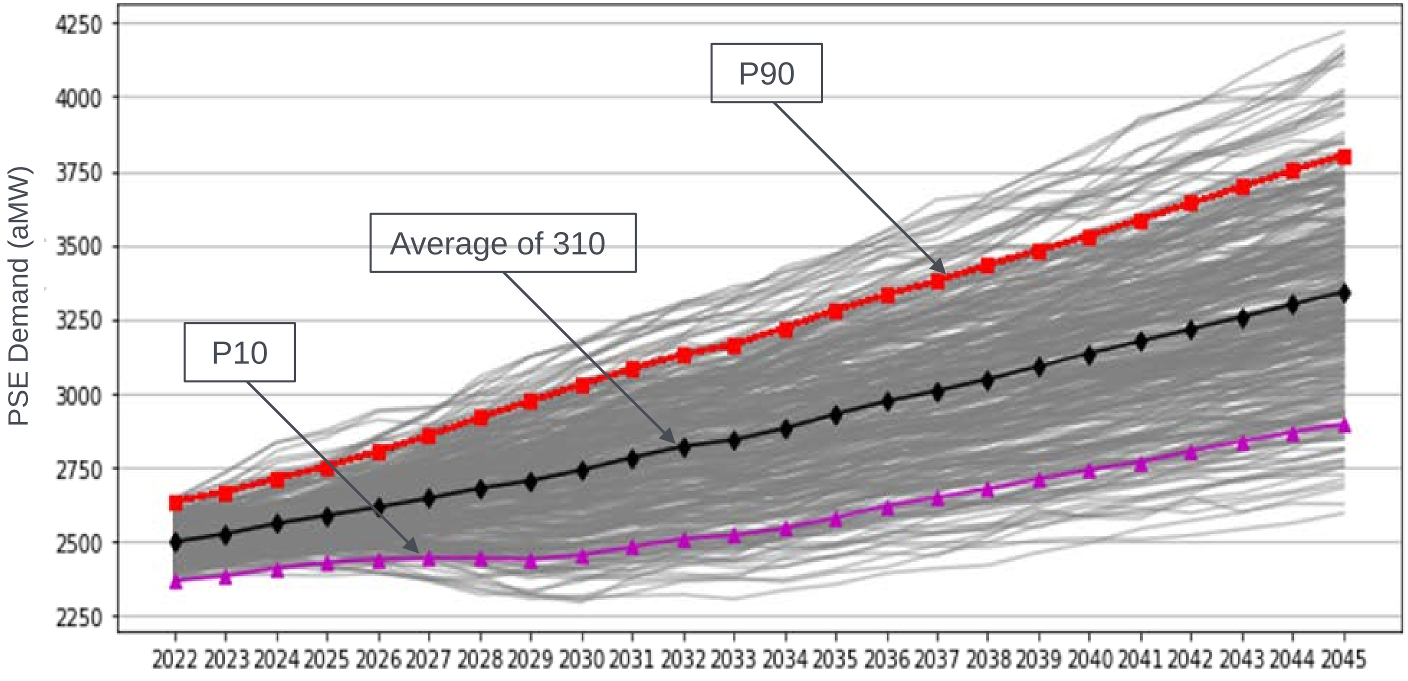
- Monte Carlo simulations for each of PSE's hydro projects were obtained using the 80-year historical Pacific Northwest Coordination Agreement Hydro Regulation data (1929-2008).
- 80 hydro years is equivalent to 80 iterations and repeated 4 times to generate 310 draws.



PSE demand draws

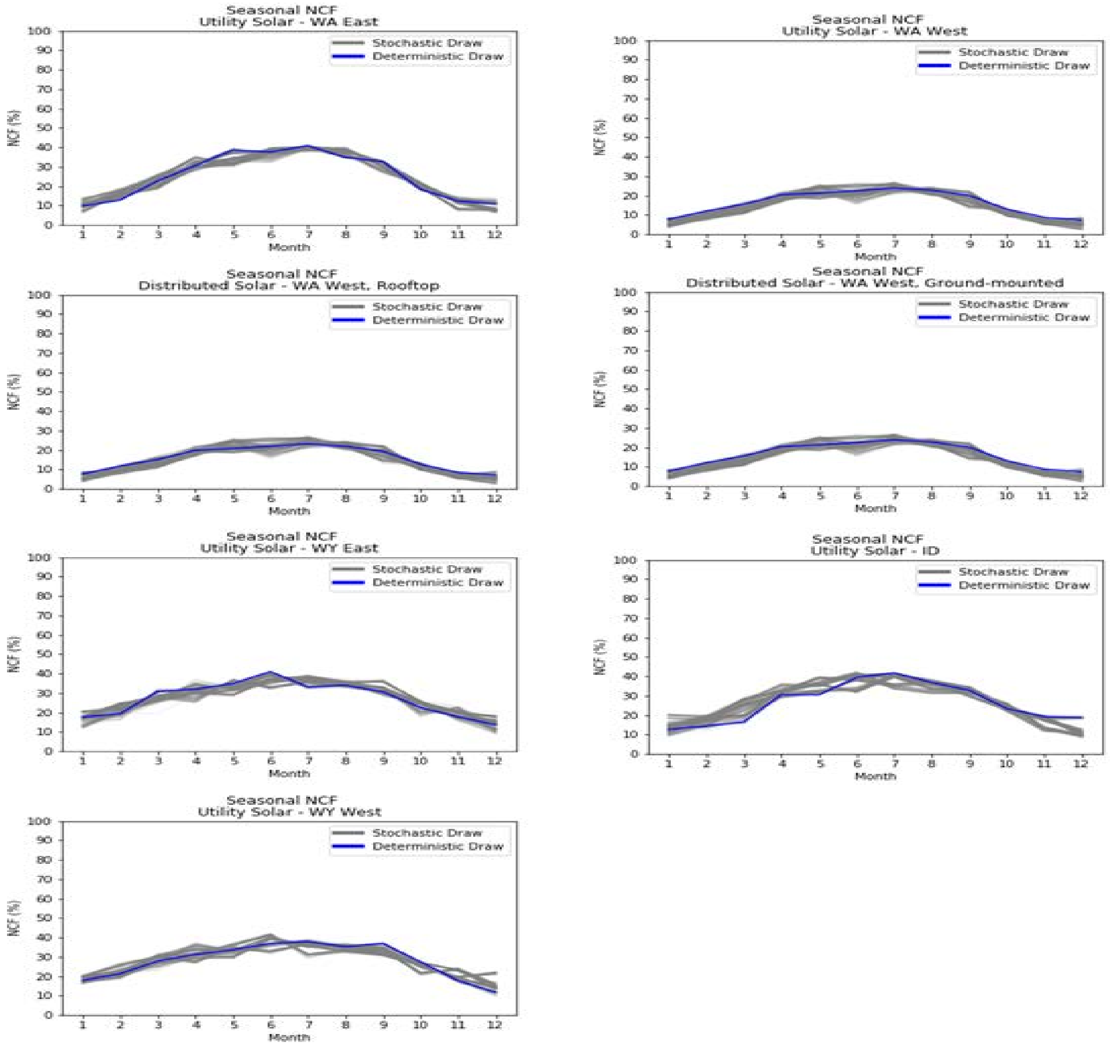
- To create the set of stochastic electric demand forecasts, the demand forecasts assume economic/demographic, temperature, electric vehicle and model uncertainties.
- The high and low demand forecasts are derived from the distribution of these stochastic forecasts at the monthly and annual levels.

Load Forecast Simulations – Annual Energy (aMW)



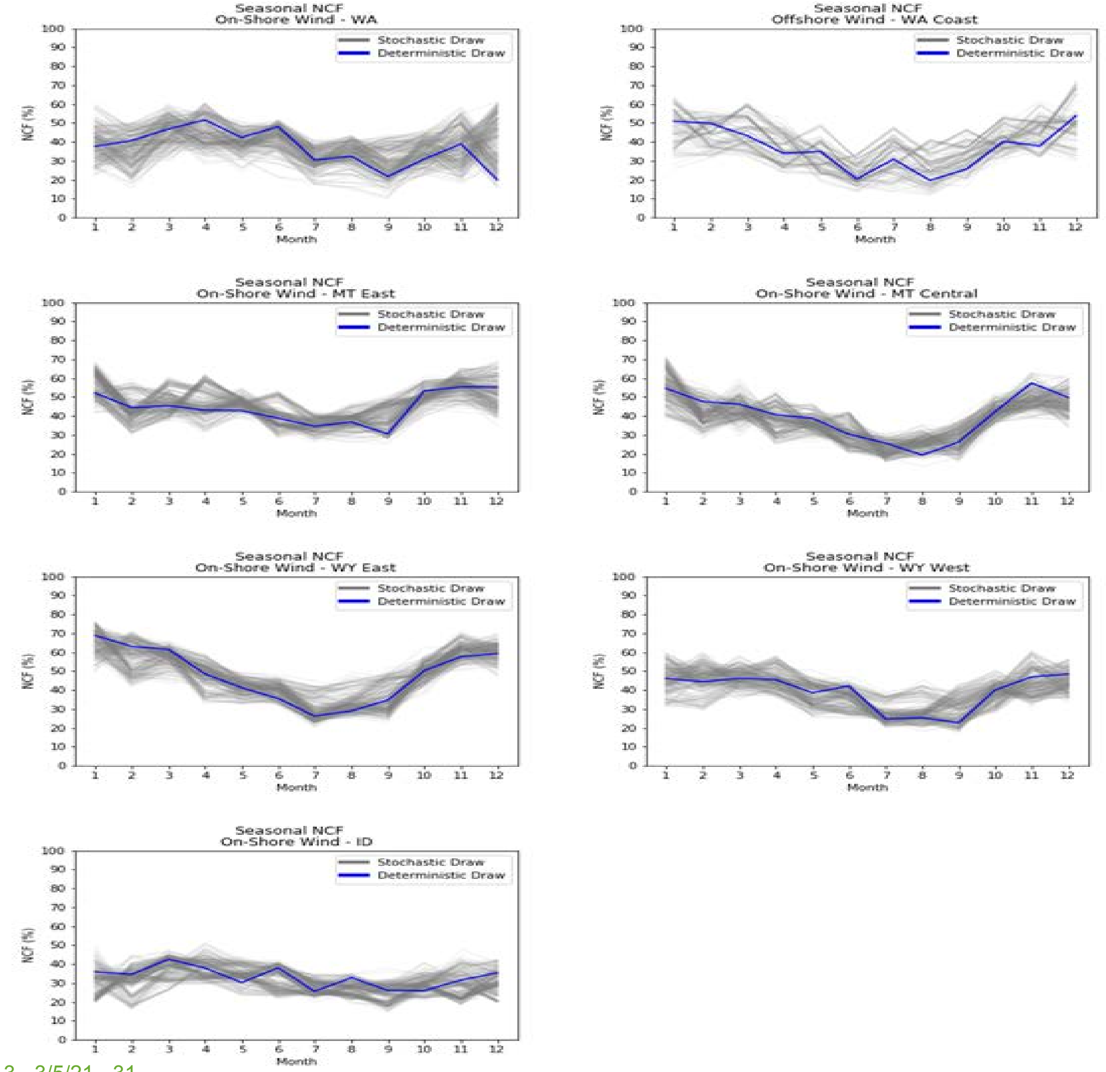
Solar draws

- PSE has evaluated six solar resources: utility-scale solar PV in eastern Washington, western Washington, eastern Wyoming, western Wyoming, Idaho and residential-scale rooftop-mounted PV solar in western Washington.
- PSE used NREL's National Solar Radiation Database (NSRDB) and System Advisory Model (SAM) to create realistic generation profiles for each location.
- 250 representative draws are selected from the complete list based on nearness to the annual average production of all the solar profiles sampled



Wind draws

- Wind was modeled in the following locations: eastern Washington, central and eastern Montana, western and eastern Wyoming, eastern Idaho and Washington offshore.
- Specific wind speed shapes were derived for each generic wind resource using NREL's Wind Toolkit database processed with a heuristic wind production model.
- 250 representative draws are selected based on a least-squares regression to the seasonal average production of all the wind profiles sampled.

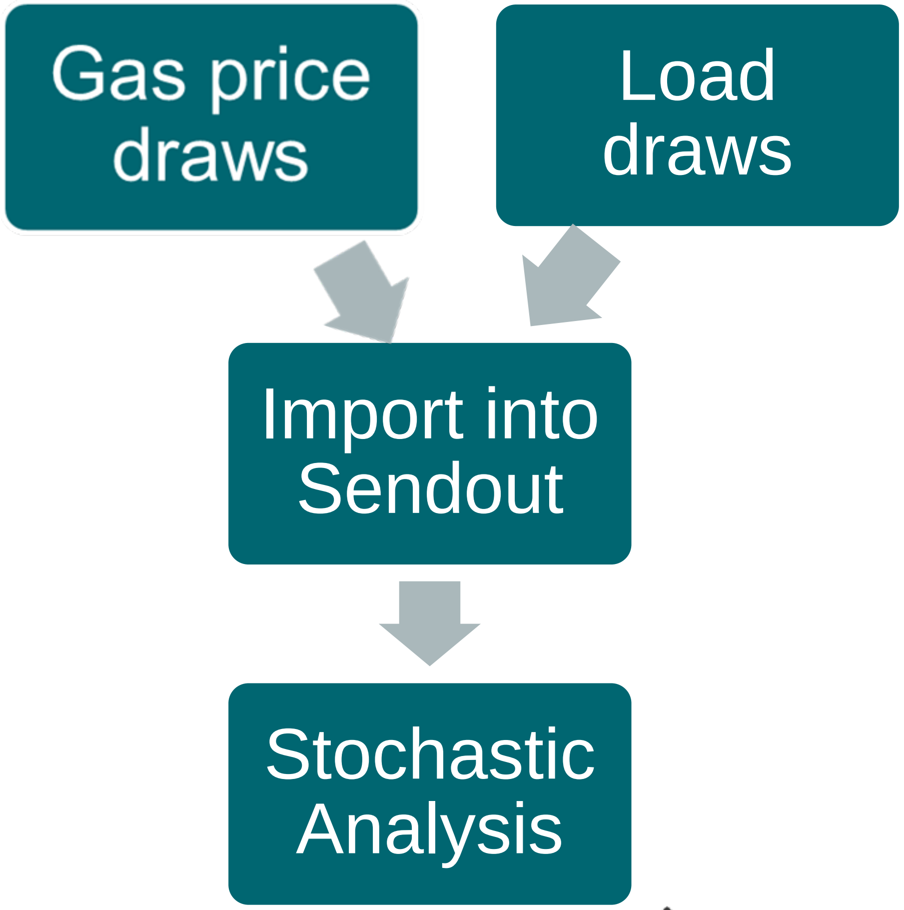


Plant forced outages

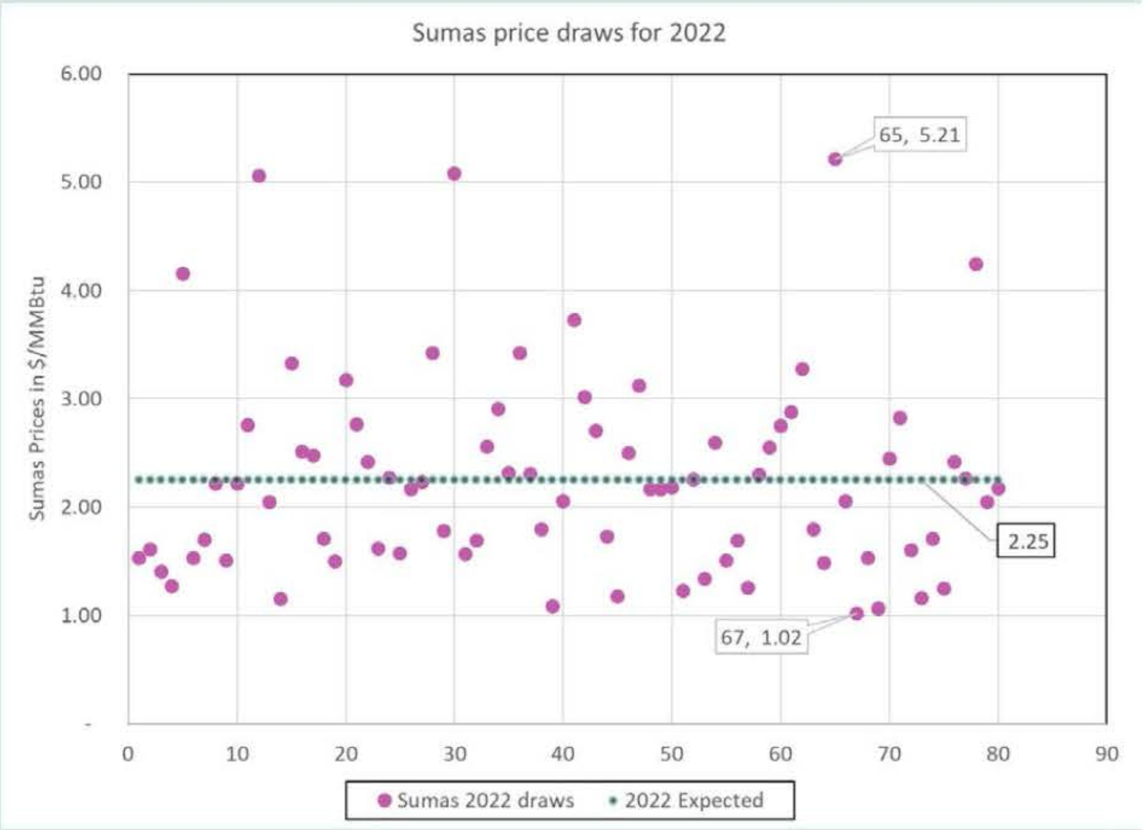
- PSE uses the “Frequency Duration” outage method in AURORA to model unplanned outages (forced outage) for thermal plants.
- The logic considers each unit’s forced outage rate and mean repair time.
- If a unit is on an outage, it is unavailable to dispatch until the repair time has elapsed.

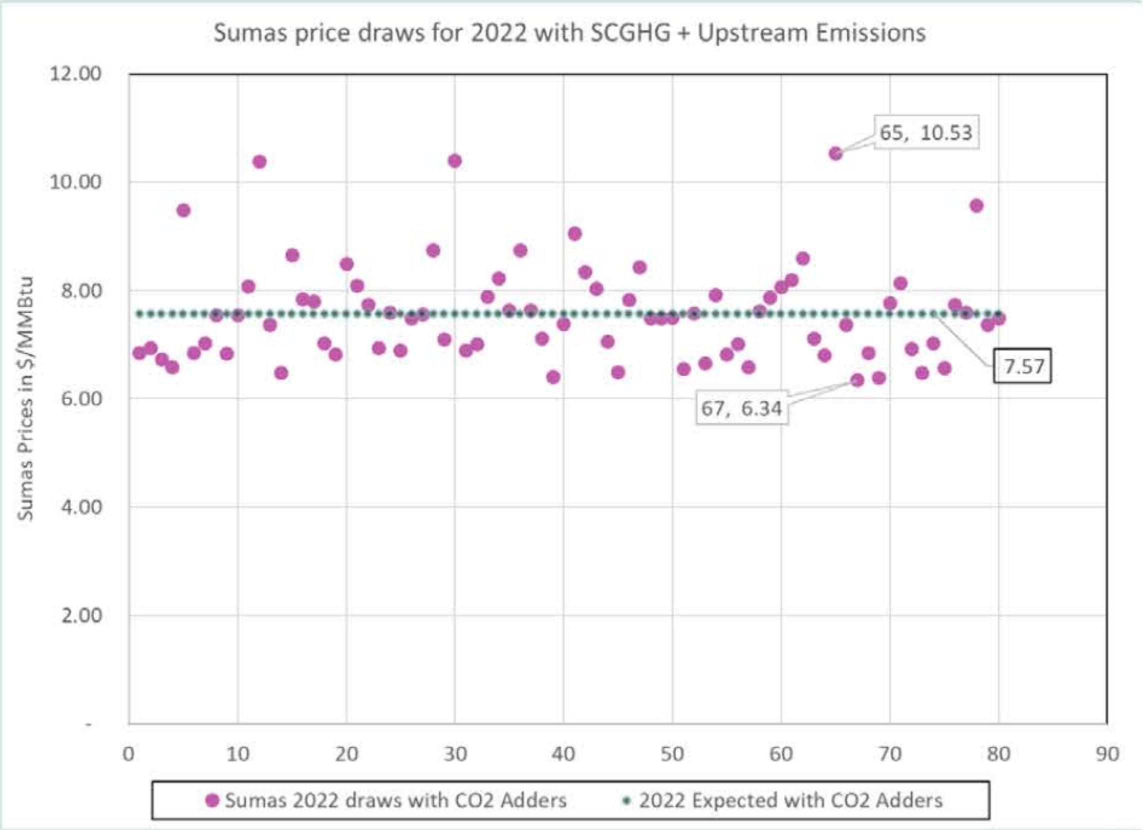
Natural Gas Stochastic Analysis

- 250 load forecast draws
- 80 gas price draws same as used in electric analysis modeling
  - Natural gas prices were repeated to create 250 draws
  - Added deterministic SCGHG and upstream emissions in each draw
- Three stochastic runs:
  1. <u>Optimized: </u>Let Sendout optimize the capacity expansion from all the load and price draws.
  2. <u>No DSR: </u>Let Sendout optimize the capacity expansion without DSR.
  3. <u>Mid Fixed Portfolio: </u>Test the Mid deterministic portfolio with natural gas and price draws.



Natural Gas Price Draws – Sumas year 2022 draws





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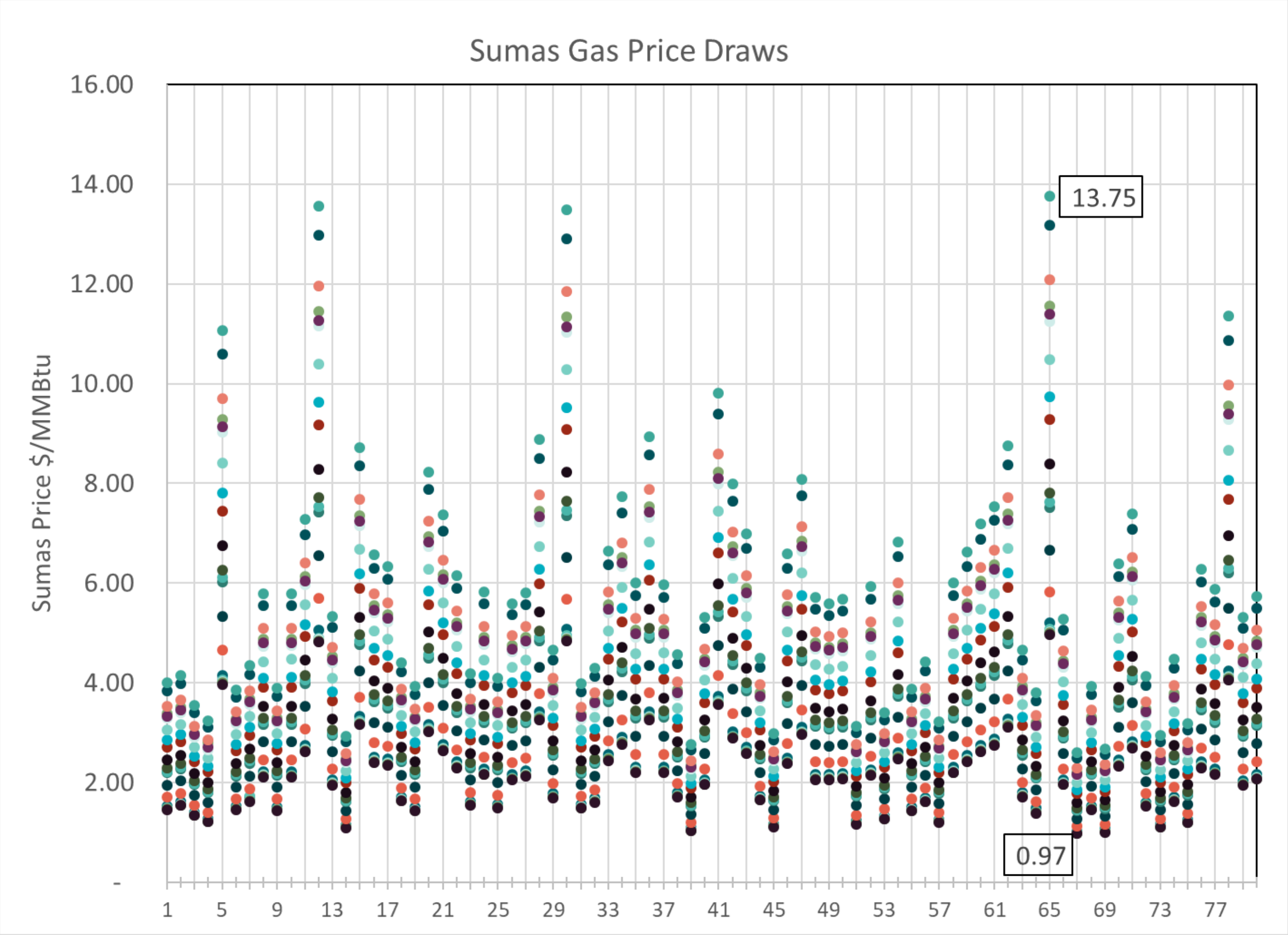
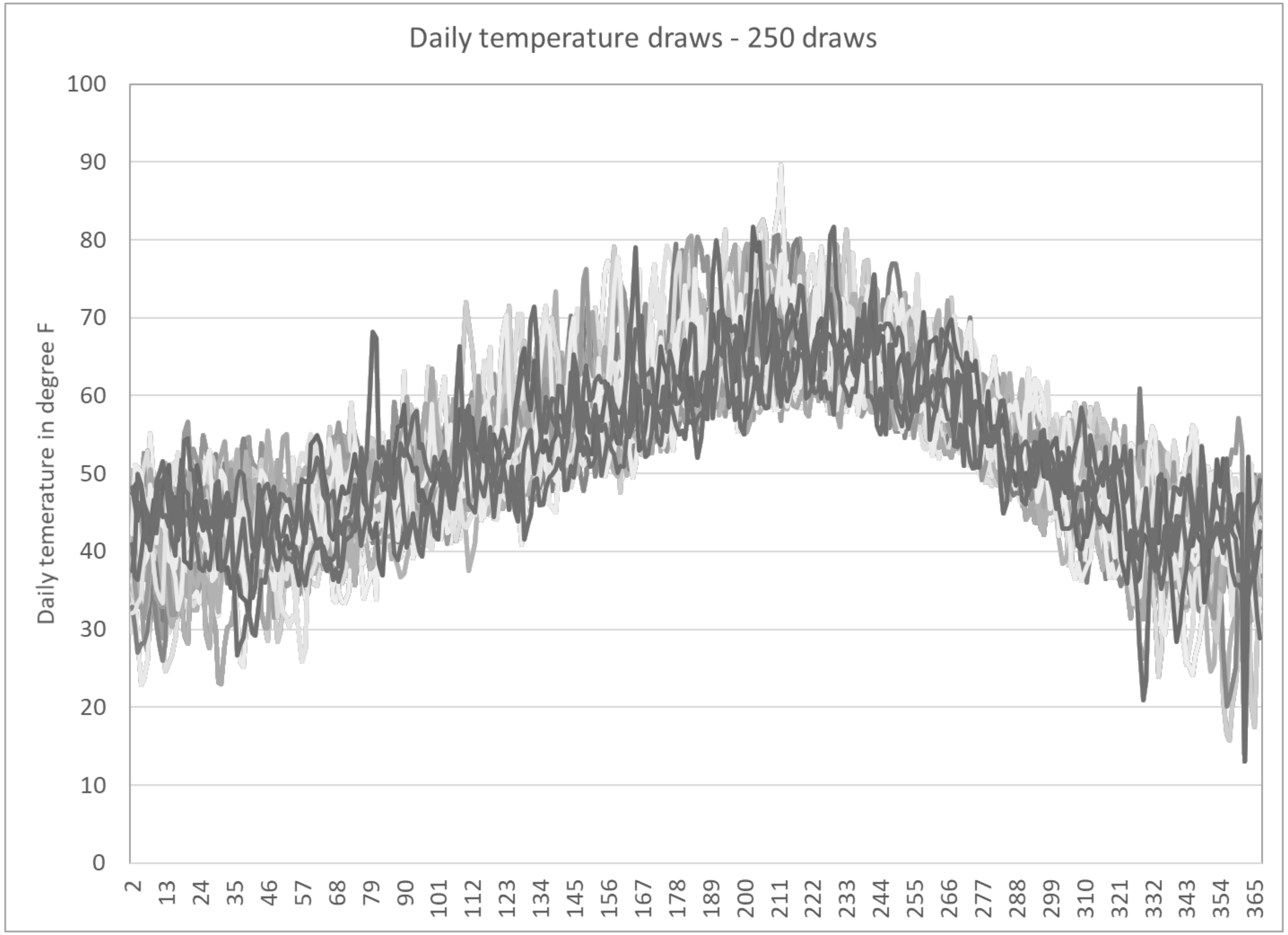
Natural Gas Price Draws – Sumas all draws



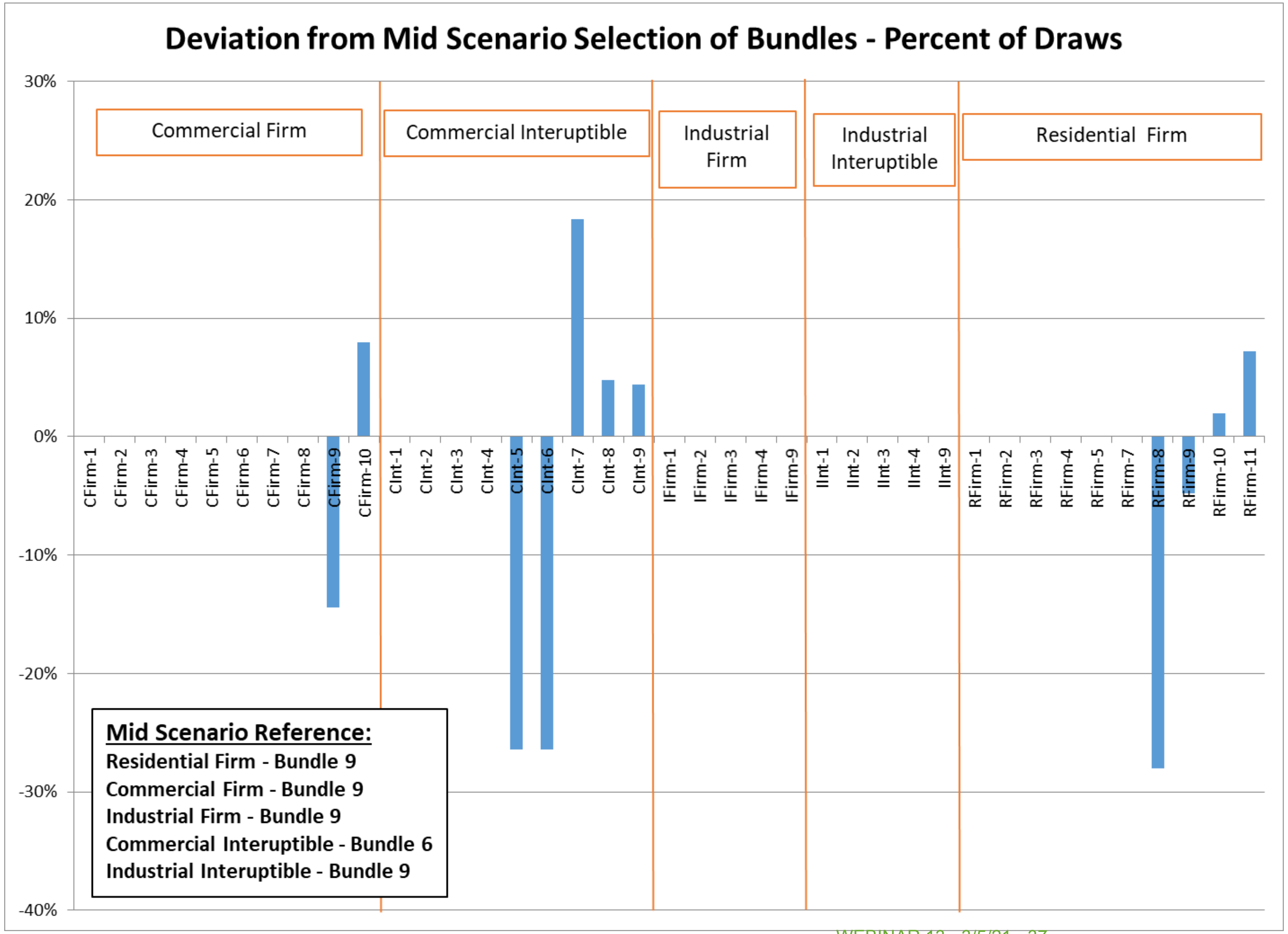
Similar draws for all the other gas hubs:
AECO, Malin, Stanfield, Station2, and Rockies

Demand draws



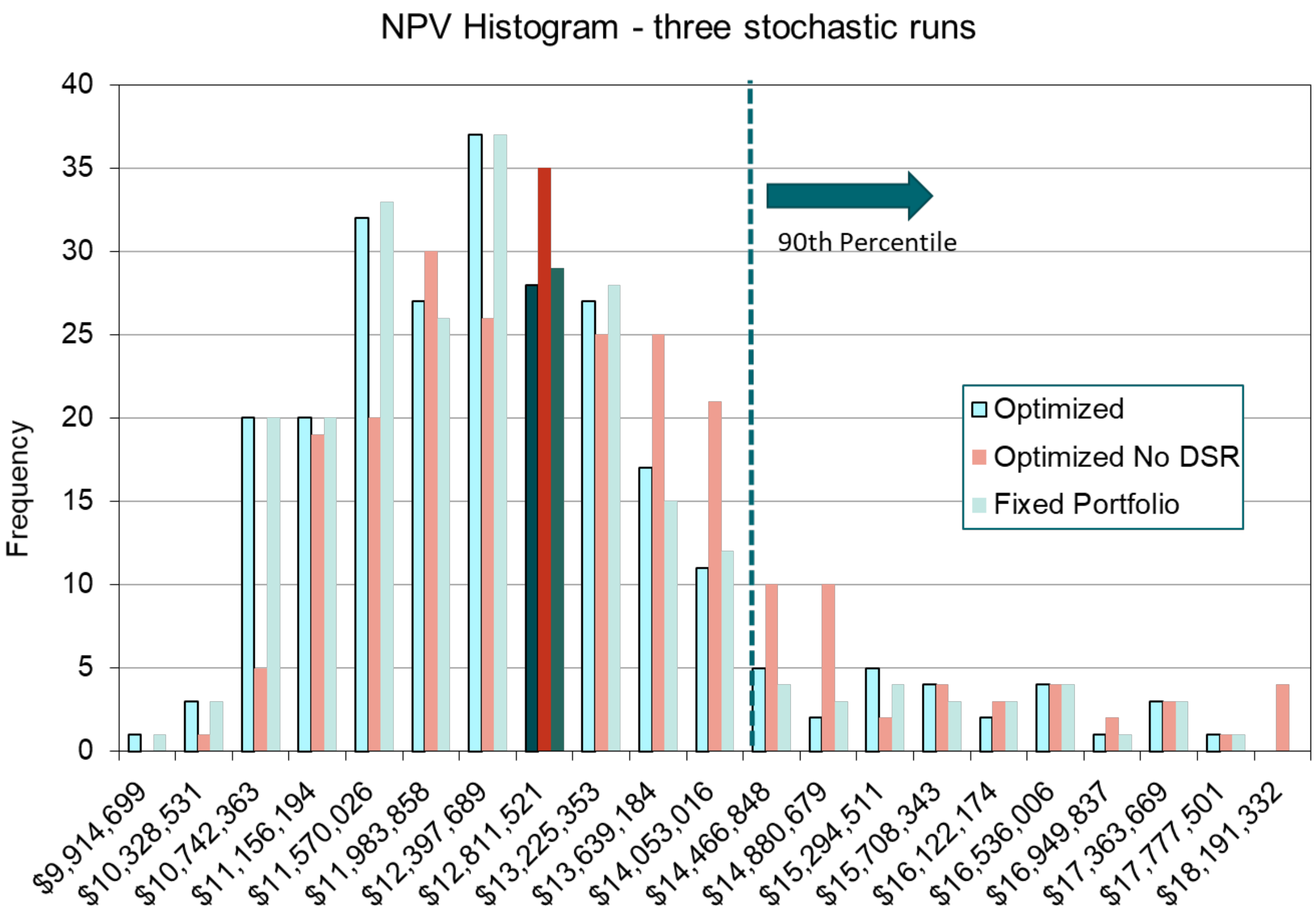
- 250 annual draws with daily temperatures.
- Same draws used to develop the low and high demand.
- Includes gas planning standard peak day in December.
- Demand in Sendout is a function of temperature.
- For each of the daily temperatures, Sendout will calculate the demand and resource need.

Results of natural gas stochastic portfolio analysis – DSR Optimized



- This shows the results of DSR selections in the 250 optimizations in the Optimized run when compared to the Mid Scenario deterministic run.
- Most of the DSR bundles optimized at the same level as in the Mid Scenario in deterministic.
- Conclusion: Mid scenario cost effective DSR is robust in all draws.

Results of gas stochastic portfolio analysis – Total System Costs



- The Expected NPV values are close.
- Optimized portfolio has lowest expected NPV.
- No DSR portfolio cost are higher and more draws in the tail - 90th percentile.
- Conclusion: DSR reduces costs and risk.

10-minute break

Preferred Portfolio and Clean Energy Action Plan

Participation Objectives

- PSE seeks stakeholder feedback on the preferred portfolio.

  IAP2 level of participation:

  INFORM & CONSULT

Updates since the February 10th webinar

- ✓ Almost all portfolio sensitivities have been modeled in Aurora.
  - ✓ Excel file with the portfolio results is available at pse.com/irp.
  - ✓ Sensitivities not yet complete: temperature sensitivity, gas to electric conversion sensitivity and market risk sensitivity.

- ✓ Customer benefit indicator rankings have been updated with the completed portfolio sensitivities.
  - ✓ Not all sensitivities are included in the customer benefit indicator rankings. More discussion later in the presentation.

Preferred Portfolio

Distributed energy resources are a significant component of the draft preferred portfolio, but additional flexible capacity is needed to maintain resource adequacy.

Resource Additions (MW)	2022-2025	2026-2030	2031-2045	Total
Distributed Energy Resources				
Demand-side Resources	256 MW	360 MW	1,168 MW	1,784 MW
Battery Energy Storage	25 MW	150 MW	275 MW	450 MW
Solar - ground and rooftop	80 MW	150 MW	450 MW	680 MW
Demand Response	29 MW	154 MW	34 MW	217 MW
DSP Non-Wire Alternatives	22 MW	24 MW	72 MW	118 MW
Total DERs	412 MW	838 MW	1,999 MW	3,249 MW
Renewable Resources				
Wind	400	1,000	1,850	3,250
Solar	-	400	297	696
Biomass	-	-	105	105
Renewable + Storage hybrid	-	-	375	375
Total Renewable Resources	400 MW	1,400 MW	2,627 MW	4,426 MW
Flexible Capacity	-	255 MW	711 MW	966 MW

- Delivery System Planning (DSP) Non-wire alternative solutions provide a DER forecast to the IRP.
- Further DER feasibility assessment will be required in the CEIP and ongoing learning through implementation.
- Over 2,000 MW of new renewable resources added by 2030 to meet CETA requirements

Findings

✓ DERs have lower peak capacity contributions and increased cost but improve customer benefits such as resiliency, air quality and environment.

✓ Energy efficiency is a low cost way to decrease renewable requirements and resulted in a 71% increase when compared to no CETA portfolios.

PSE PUGET SOUND ENERGY

How did the final preferred portfolio change from the draft?

What is the same?

- ✓ Demand side resources
- ✓ Distributed solar
- ✓ Flexible capacity

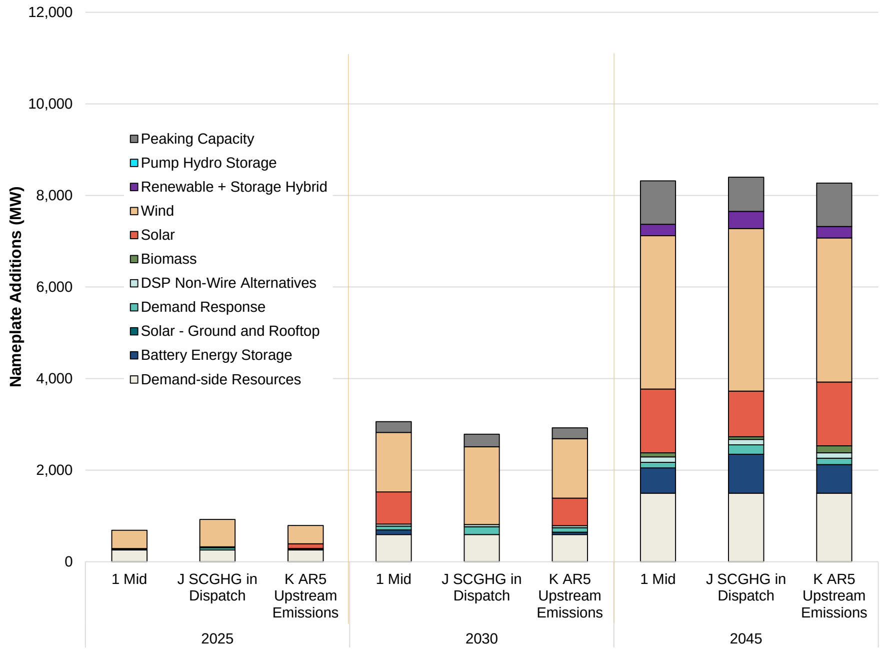
What has changed?

- ⇧ Demand response increased: 29 MW by 2025 instead of 10 MW by 2025
- ⇩ Battery Energy storage decreased: With the updated assumptions there is 25 MW less by 2030 and 300 MW less by 2045
- ⇨ Renewable resources: with updated assumptions around transmission costs, wind resources in Wyoming and Montana delayed by a few years, but the same amount of renewable is still added by 2045

Social cost of greenhouse gases and upstream emissions

SCGHG is applied as a cost adder when evaluating conservation and resource additions. Upstream emissions AR4 methodology is used.

- Both 2019 and 2021 IRPs analyzed multiple modeling approaches for social costs of greenhouse gases.
- Renewable resources required to comply with CETA is the key constraint driving portfolio resource additions and costs.
- PSE assumes upstream emissions consistent with AR4 and evaluated AR5 in response to stakeholder requests.



Findings

- ✓ Different social cost of greenhouse gases modeling approaches do not have an impact on the cost-effective amount of conservation, demand response and other resource additions or retirements.
- ✓ Using upstream emissions consistent with AR5 does not change resource builds and portfolio costs in comparison to utilizing AR4.

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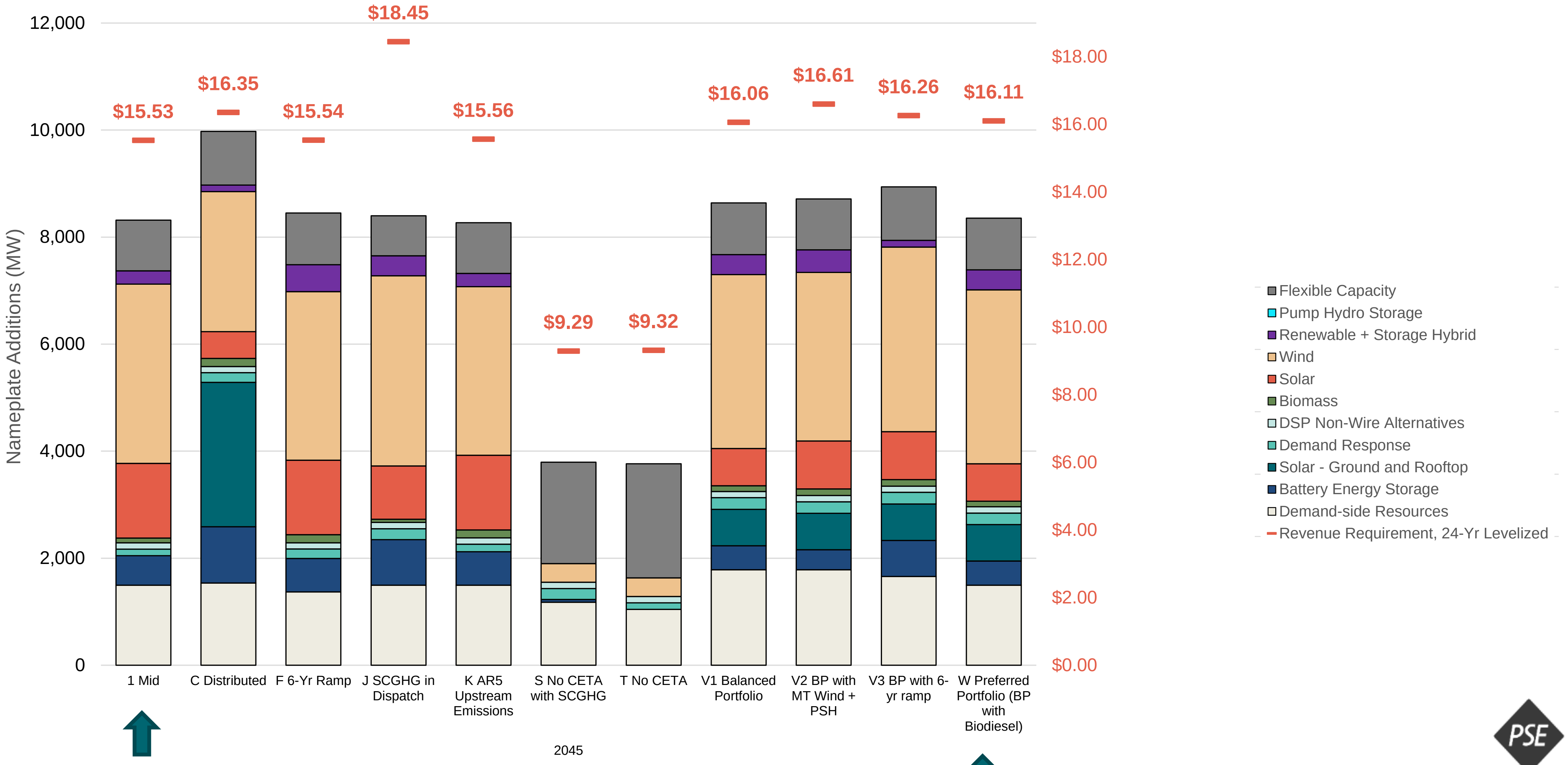
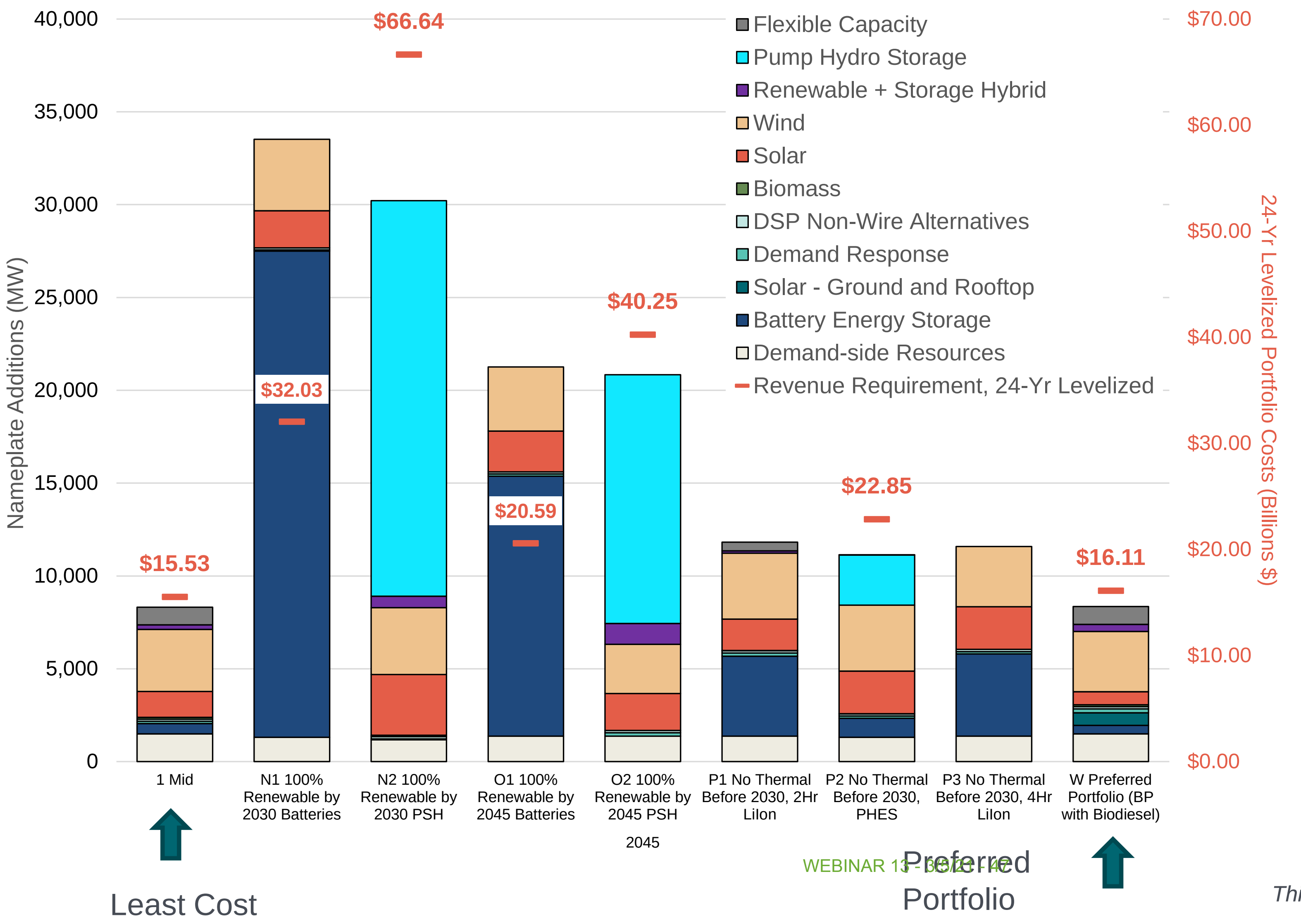
Resource Additions and Costs



Least Cost

Preferred Portfolio

Resource Additions and Costs

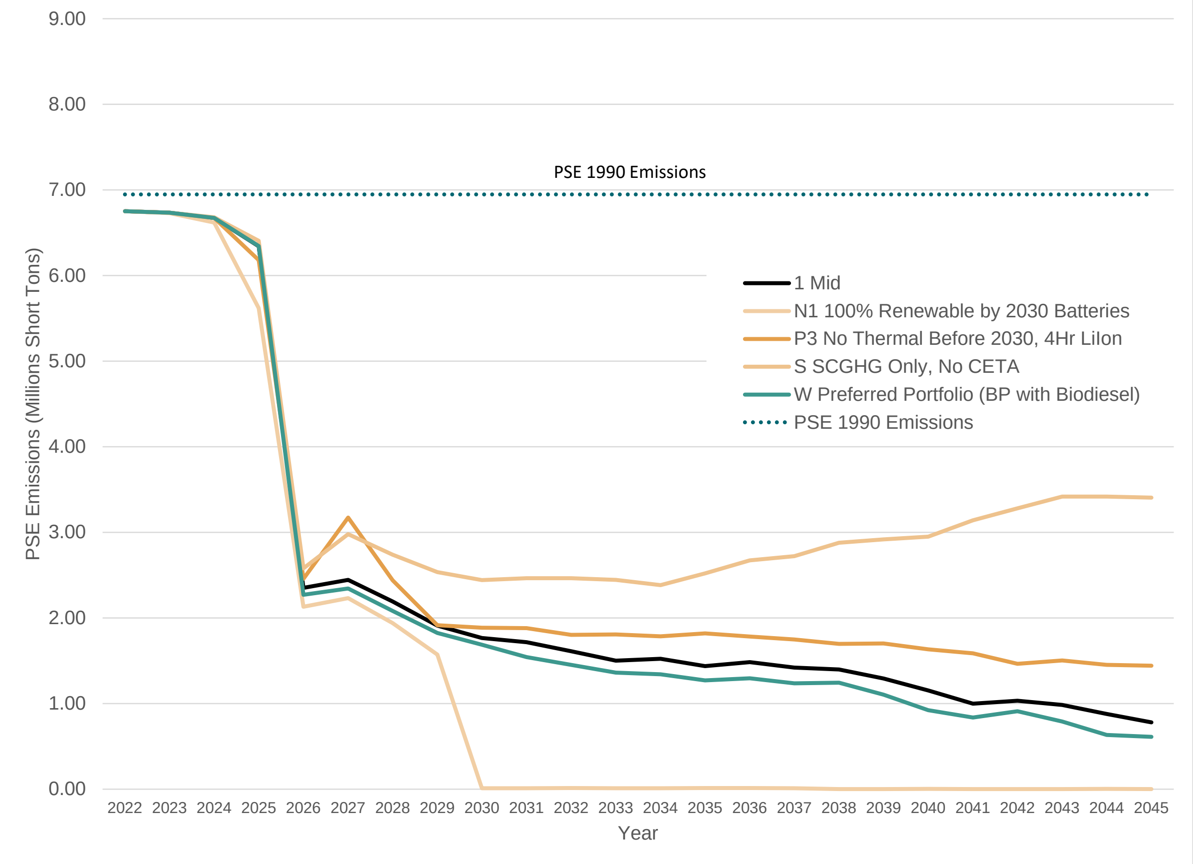


- Portfolio sensitivity modeling evaluates tradeoffs between different resource additions and portfolio costs.
- The procurement process will drive the acquisition of clean resources and will evaluate costs, permitting and other challenges and benefits.

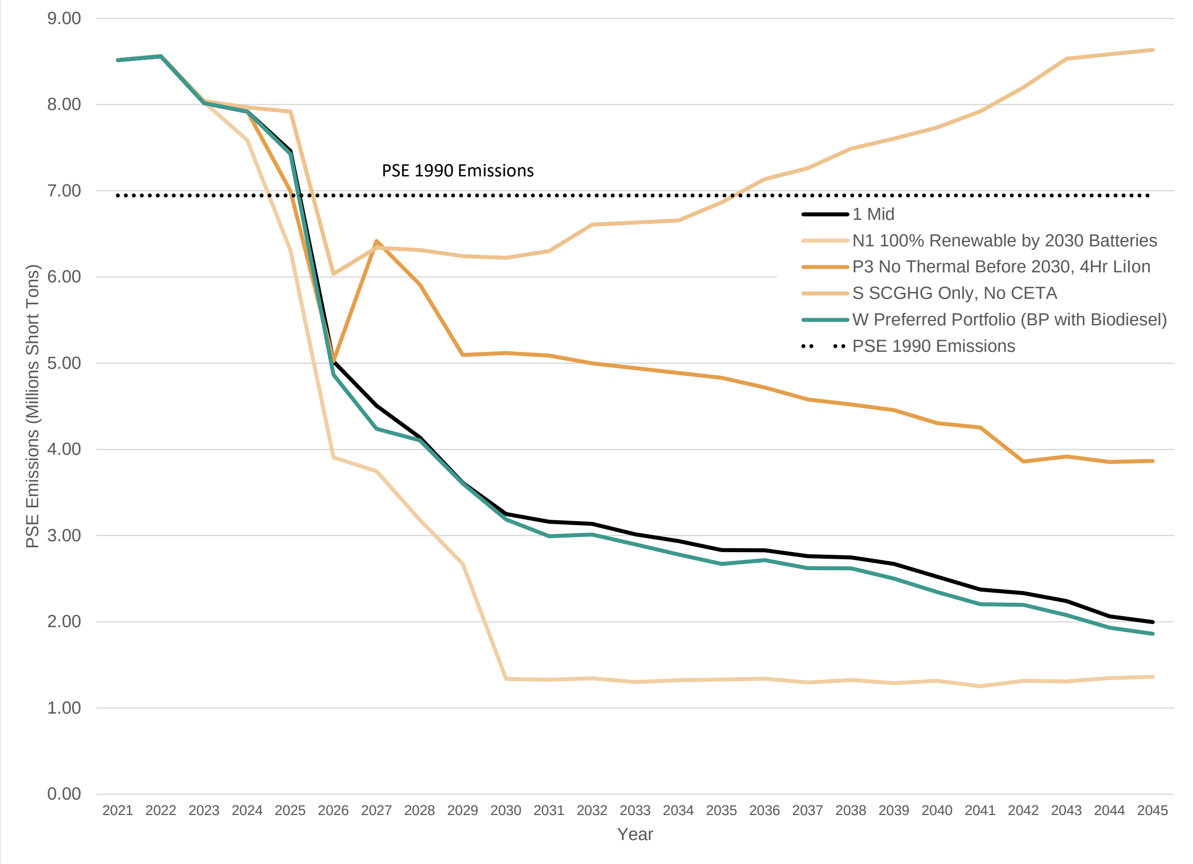
Portfolio Emissions

Significant emission reductions are achieved with the additions of non-emitting resources, retirement of coal resources and lower dispatch of existing resources.

Comparison of Direct CO2 Emissions & Upstream Emissions



Comparison of Direct CO2 Emissions, Upstream Emissions, & Market

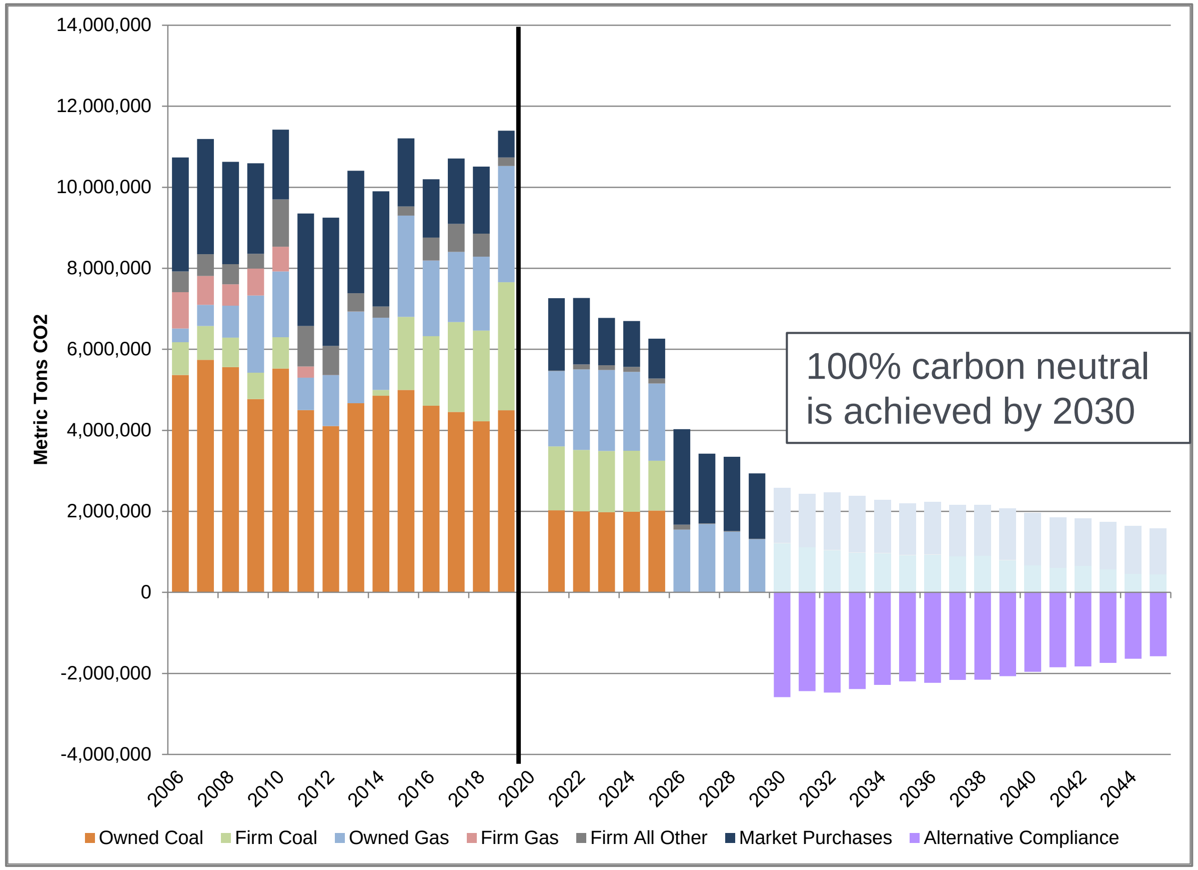


Projected emissions for the preferred portfolio

- The preferred portfolio achieves 100% carbon neutral by 2030 with a combination of
  - ➢ Coal plant retirement
  - ➢ Lower dispatch of natural gas resources
  - ➢ Alternative compliance

- Over 70% reduction in emissions from 2019 to 2029.

Historical Emissions and Projected Emissions for Draft Preferred Portfolio



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Customer Benefit Indicators

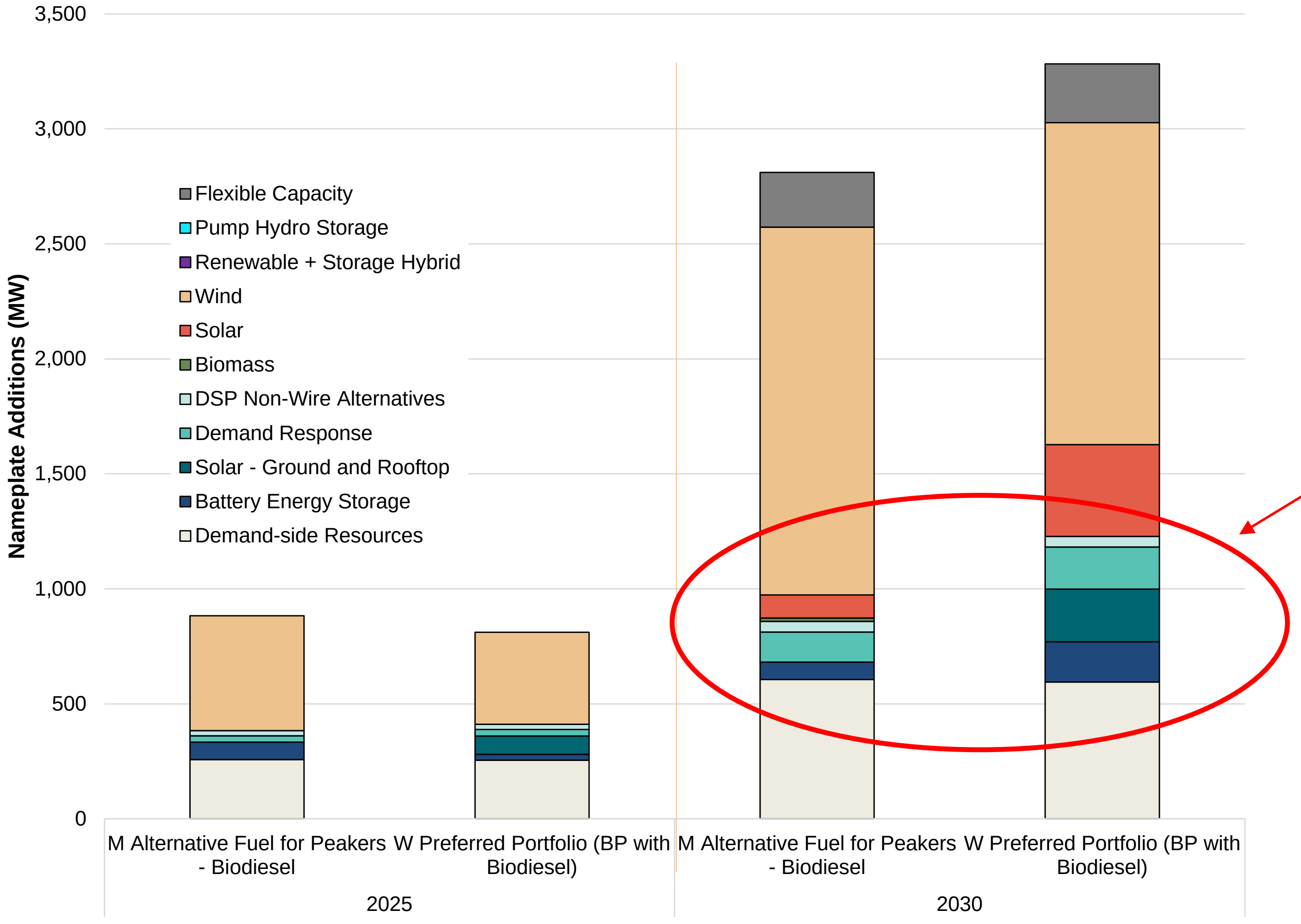
Sensitivity	Cost	Climate Change	Air Quality	Market Position	Environment	Resource Adequacy	Resiliency	Overall Rank
1 Mid	3	13	13	4	10	18	16	8
A Renewable Overgeneration	15	4	10	20	18	6	5	11
C Distributed Transmission	13	20	20	17	8	13	6	20
D Transmission/build constraints - time delayed (option 2)	5	12	8	15	10	12	13	7
F 6-Yr DSR Ramp	4	15	15	7	11	15	14	16
G NEI DSR	8	14	16	12	12	7	10	12
H Social Discount DSR	9	16	13	18	12	5	8	15
I SCGHG Dispatch Cost - LTCE Model	1	10	11	11	10	8	9	3
K AR5 Upstream Emissions	6	16	13	2	9	16	14	8
M Alternative Fuel for Peakers - Biodiesel	2	7	4	8	8	9	11	1
N1 100% Renewable by 2030 Batteries	19	2	1	16	8	21	1	5
N2 100% Renewable by 2030 PSH	22	1	1	1	13	21	21	13
O1 100% Renewable by 2045 Batteries	16	8	6	19	12	20	2	17
O2 100% Renewable by 2045 PSH	21	11	8	14	7	10	21	19
P1 No Thermal Before 2030, 2Hr LiIon	18	21	21	21	18	14	4	21
P2 No Thermal Before 2030, PHES	17	5	7	13	9	19	7	10
P3 No Thermal Before 2030, 4Hr LiIon	20	22	22	22	18	17	3	22
V1 Balanced portfolio	10	11	13	5	8	1	17	4
V2 Balanced portfolio + MT Wind and PSH	14	17	17	3	9	1	19	14
V3 Balanced portfolio + 6 Year DSR	12	13	18	6	9	1	12	6
W Preferred Portfolio (BP with Biodiesel)	11	5	5	9	8	1	17	2
AA MT Wind + PHSE	7	14	10	10	11	11	20	18

Sensitivities included in the CBI ranking:

- Ensure consistency across demand and electric price forecast
- Must meet CETA requirements
- Represent current carbon regulation

Portfolio W was selected as the preferred portfolio and is discussed on following slides.

Decisions driving the preferred portfolio



- Portfolio M: Alternative fuel for peakers was ranked #1 in the CBIs, but was not chosen as the preferred portfolio.
- Portfolio W, is a balanced portfolio that takes earlier action on DERs and includes more distributed solar and battery energy storage in the first 10 years of the plan.

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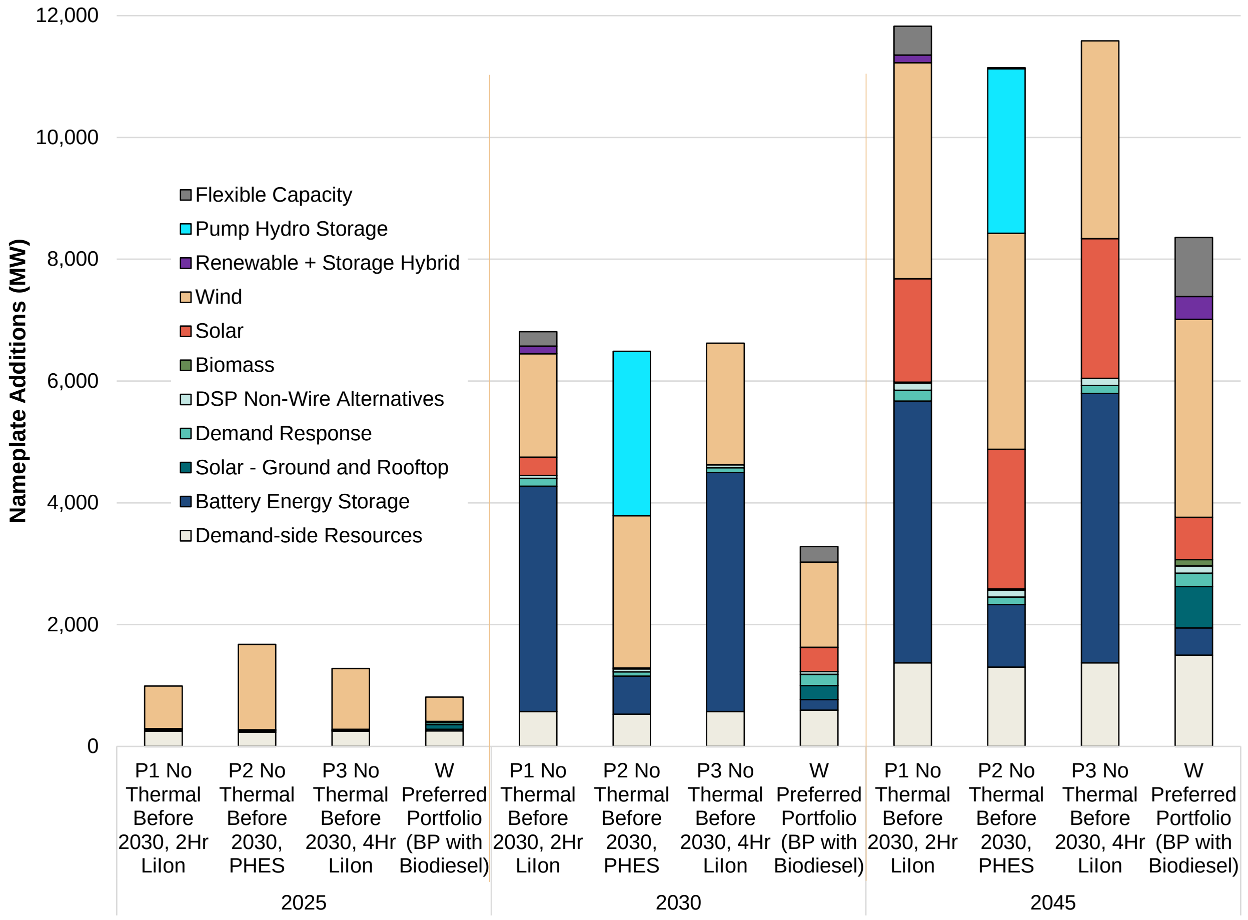
Decisions driving the preferred portfolio

Why does the preferred portfolio have flexible capacity instead of more energy storage?

- ➢ Portfolios P1, P2, and P3 optimize the portfolio builds with no peaker builds allowed before 2030.
- ➢ These portfolios are significantly higher cost that the preferred portfolio

Portfolio	Cost (NPV $Billions)	CBI rank
Preferred Portfolio	$16.11	2
P1: 2-hr Li-Ion	$30.84	21
P2: Pumped storage hydro	$22.85	10
P3: 4-hr Li-Ion	$39.01	22



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Clean Energy Action Plan

Clean Energy Transformation Standards are met in the Draft Preferred Portfolio.
Draft Preferred Portfolio achieves: 100% carbon neutral by 2030 and 100% carbon free by 2045

Incremental Resource Additions (Nameplate MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Distributed Energy Resources											
Demand-side Resources	74	64	61	57	63	66	82	75	75	81	696
Battery Energy Storage	-	-	-	25	25	25	25	25	50	25	200
Solar - ground and rooftop	-	-	-	80	30	30	30	30	30	30	260
Demand Response	-	5	6	18	27	34	41	27	26	13	195
DSP Non-Wire Alternatives	3	6	9	4	3	5	6	5	4	4	50
Total DERs	77	75	76	184	148	160	184	162	185	153	1,401
Renewable Resources											
Wind	-	-	-	400	200	400	-	200	200	100	1,500
Solar	-	-	-	-	-	100	-	100	199	-	398
Total Renewable Resources	-	-	-	400	200	500	-	300	399	100	1,898
Flexible Capacity	-	-	-	-	255	-	-	-	-	-	255

Overview of the Clean Energy Implementation Plan and Public Participation

Participation Objectives

- PSE will review elements of the Clean Energy Implementation Plan

  PSE will consult with stakeholders on the public participation plan for the CEIP

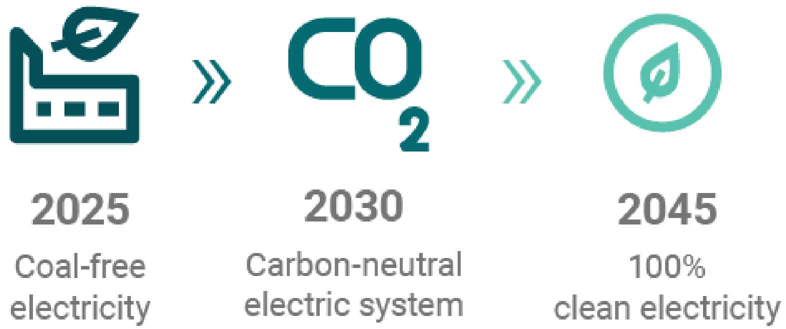
  IAP2 level of participation:

  INFORM & CONSULT

CETA and a better clean energy future

Washington's Clean Energy Transformation Act (CETA) focuses on:

Clean energy standards



Ensuring all customers benefit

- Equitable distribution of energy and non-energy benefits and reduction of burdens to vulnerable populations and highly impacted communities
- Public health and environmental benefits and reduction of costs and risk
- Energy security and resiliency

The new planning cycle

Identifies specific actions to phase out coal, meet GHG neutral standard by 2030 and clean energy standard by 2045.

Filed jointly as the IRP

IRP

Clean Energy Action Plan

Clean Energy Implementation Plan

Reporting

The IRP identifies PSE's energy, capacity, and renewable energy need ***through 2045***, potential options to meet those needs, and models the energy, capacity, and cost of meeting those needs.

The CEAP identifies the lowest reasonable cost resource plan PSE will pursue over the next ***10 years*** to meet the energy capacity, and renewable energy needs, considering risk and equity.

The CEIP identifies the specific and interim targets consistent with the CEAP, and the actions the company will take over the next ***4 years*** to achieve those targets and ensure equitable distribution of benefits.

Reporting identifies the actual progress the company makes and the cost incurred over the past year.

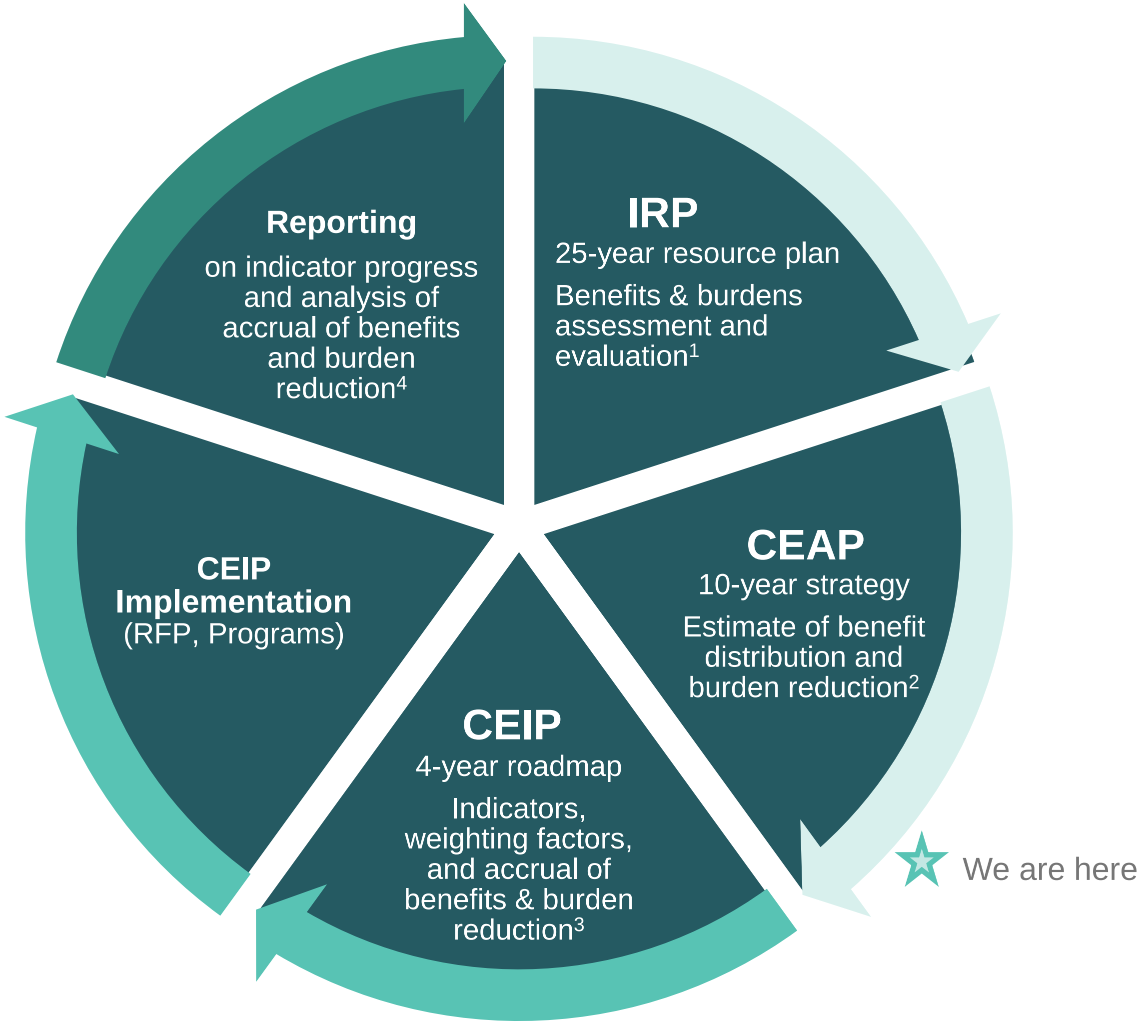
What is the **Clean Energy Implementation Plan**?

- Roadmap of targets, actions and programs for a 4-year period
- First plan covers calendar years 2022-2025
  - Draft CEIP due Aug. 15, 2021
  - Final CEIP due Oct. 1, 2021
- Clean Energy Implementation Plans establish:

1. Interim targets for the 4-year period: percentage of retail sales of electricity supplied by non-emitting and renewable resources
2. Specific targets for the 4-year period:
   - o Demand response
   - o Energy efficiency
   - o Renewable energy
3. Specific actions for the 4-year period, ***based on the Clean Energy Action Plan*** and interim and specific targets

- Embeds equity through: customer benefit indicators and weightings; understanding around highly impacted communities and vulnerable populations; barrier reductions; and public participation
- CEIP filed with the UTC, and the UTC will approve, deny, or can modify the plans

IRP, CEAP and CEIP lifecycle



- Continuous focus on:
  - Clean energy standards
  - Equitable distribution of benefits and burden reduction
- IRP and CEAP set a baseline carried through by CEIP
- Progress made with CEIP feeds next IRP

[1] IRP assessment and evaluation: WAC 480-100-620(9) and (11)(g)
[2] CEAP estimates: WAC 480-100-620(12)(c)(ii)
[3] CEIP indicators and weighting factors: WAC 480-100-640(4) and (5)(a)
[4] Reporting on indicator progress: WAC 480-100-650(1)(d)

PUGET SOUND ENERGY

Developing the CEIP: engaging advisory groups & customers

Equity Advisory Group – new!

WAC 480-100-655 (1)(b)

“The utility must maintain and regularly engage an **external equity advisory group to advise the utility on equity issues** including, but not limited to, vulnerable population designation, equity customer benefit indicator development, data support and development, and recommended approaches for the utility's compliance with WAC 480-100-610 (4)(c)(i). The utility must encourage and include the participation of environmental justice and public health advocates, tribes, and representatives from highly impacted communities and vulnerable populations in addition to other relevant groups;”

PSE’s existing advisory groups

- Low Income Advisory Committee
- Conservation Resources Advisory Group
- IRP participants

Customers, including:

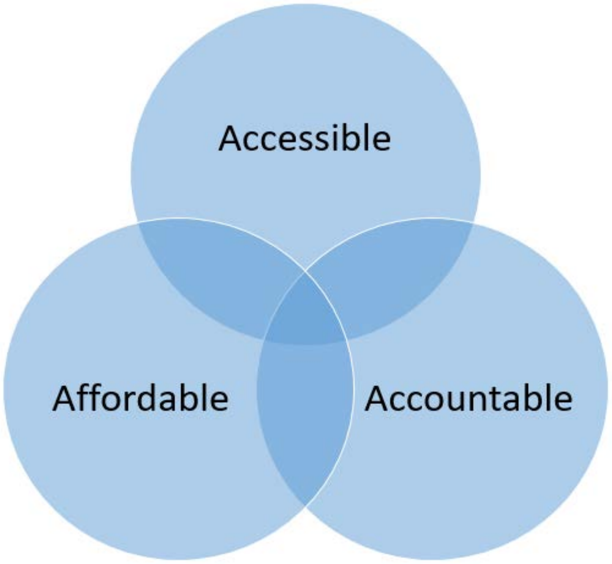
- Residential, commercial and industrial

EAG mission and framework

Mission: Provide advice to PSE on equity issues and broaden our engagement with frontline customers as we work to deliver a just and equitable clean energy future

2021 inaugural EAG will:

- Engage in developing metrics that help us measure equity in electric energy planning and decision-making for PSE's Clean Energy Implementation Plan
- Focus on paths to expanding equity, so our efforts are accessible, affordable and accountable
- Highlight and mitigate barriers to customer participation
- Provide advice on PSE's public participation plan
- Shape process for future EAG membership



Inaugural EAG sessions – draft

Mar. 2021

1 | **Orientation & clean energy**
Relationship building
Orientation on energy planning
Discussion on clean energy

2 | **Burdens, barriers & opportunities**
Discuss barriers and burdens
Discuss practices to address, mitigate

3 | **Measuring equity**
Refine HIC/VP definitions
Begin customer benefit indicators discussions

Jun. 2021: Modeling begins

4 | **Customer benefit indicators**
Small groups co-develop CBIs

5 | **Putting it all together**
Update on customer outreach
Finalize CBIs
Develop weightings
Portfolio discussion

6 | **Equity forum**
Invited speakers to share insights on equity issues

Aug. 15: Draft CEIP

Oct. 1: Final CEIP

Oct. 2021 – Mar. 2022

7 | **Progress update**
Discuss model outputs on draft targets and actions

Input on Draft CEIP
Comments to UTC

8-10 | **Implementation focus**
Establish membership selection process
Explore equity topics (TBD)

CEIP and public participation: goals

For the 2021 CEIP, we will:

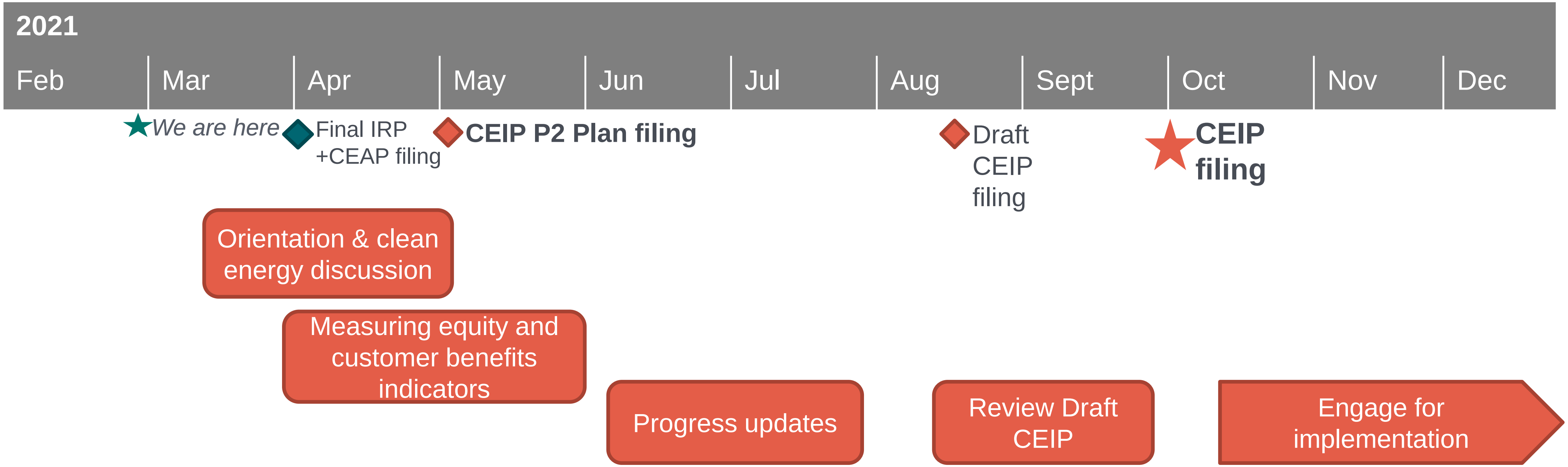
- Engage with the new Equity Advisory Group
- Inform and consult PSE's existing advisory groups (IRP, CRAG and LIAC)
- Inform and consult our customers, specifically highly impacted communities and vulnerable populations

Outcomes we're seeking for 2021:

- Durable CEIP
- Diverse, meaningful, and equitable engagement
- Accountable, repeatable process
- Create a foundation of community relationships and approaches for future engagement

PUGET SOUND ENERGY

CEIP and public participation schedule – draft



To stay up to date on the CEIP, sign up for our email list at ceip@pse.com

PUGET SOUND ENERGY

Questions and next steps

Public participation

- What methods do you suggest for engaging customers on developing the CEIP?
- What partnerships might help PSE connect with highly impacted communities and vulnerable populations?
- How do you suggest we engage customers through the CEIP's implementation phase?

Equity Advisory Group

- As you've gone through this year's IRP process, are there equity questions related to clean energy that we could share with the EAG?
- Are there any energy justice resources that could support the EAG's work?

Questions & Answers

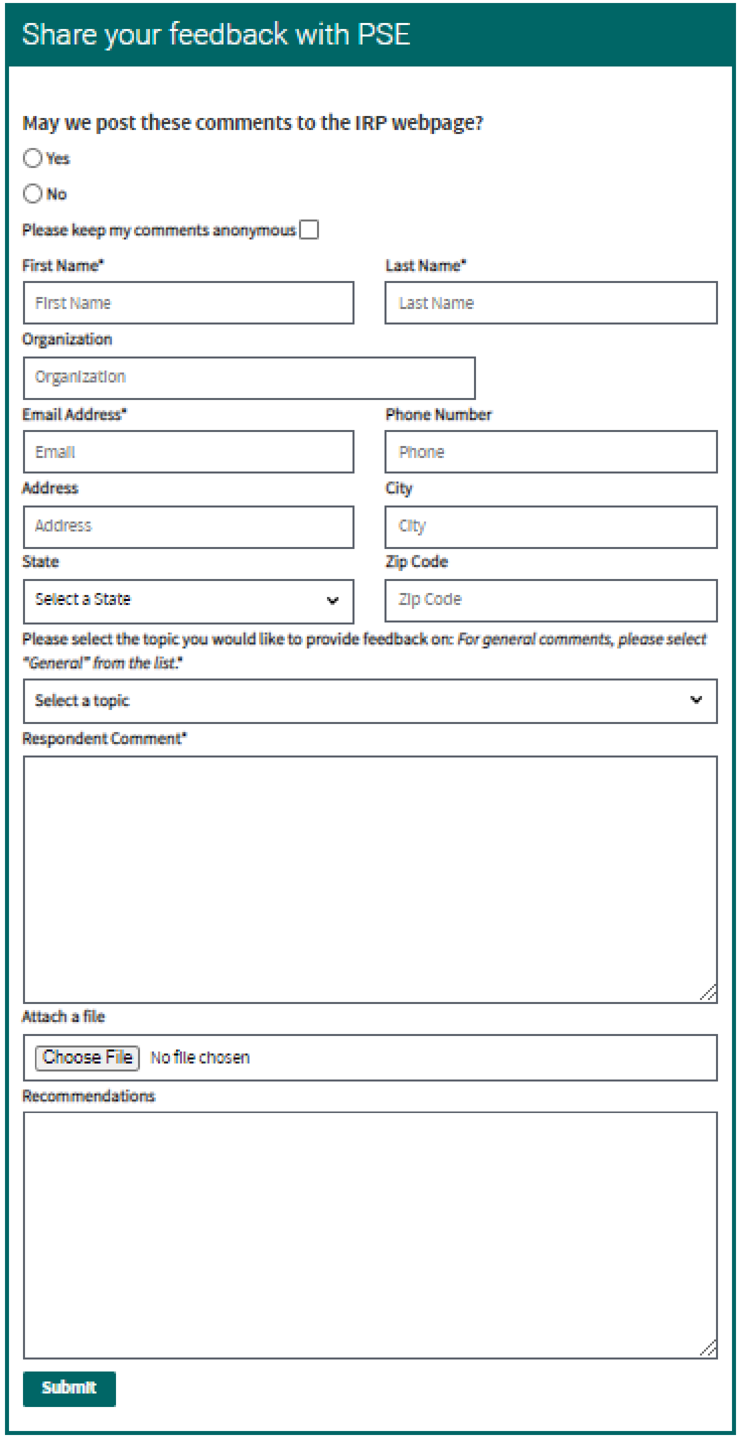
PUGET SOUND ENERGY

This session is being recorded by Puget Sound Energy.
Third-party recording is not permitted.

Feedback Form

- An important way to share your input
- Available on the website 24/7
- Comments, questions and data can be submitted throughout the year, but timely feedback supports the technical process
- Please submit your Feedback Form <u>within a week of the meeting topic</u>

Feedback Form → **Feedback Report** → **Consultation Update**


Share your feedback with PSE

May we post these comments to the IRP webpage?

Yes

No

Please keep my comments anonymous

First Name* | Last Name*

First Name | Last Name

Organization

Organization

Email Address* | Phone Number

Email | Phone

Address | City

Address | City

State | Zip Code

Select a State | Zip Code

Please select the topic you would like to provide feedback on: *For general comments, please select "General" from the list.**

Select a topic

Respondent Comment*

Attach a file

Choose File No file chosen

Recommendations

Submit

Next steps

- Submit Feedback Form to PSE by **March 12, 2021.**
- A recording and the chat from today's webinar will be posted to the website on **Monday, March 8, 2021.**
- PSE will include feedback from this webinar in the Final IRP scheduled to be filed on **April 1, 2021**.

Thank you for your attention and input.

Please complete your Feedback Form by March 12, 2021

Thank you for your participation in PSE’s 2021 IRP!

PUGET SOUND ENERGY

PORTFOLIO SUMMARY COMPARISON

EXCEL SPREADSHEET

Click this link to download the spreadsheet:

https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/March_5_webinar/Portfolio%20Summary_Comparison_clean.xlsx

Webinar #13: Market Risk Assessment, Stochastic Analysis, Preferred Portfolio and Clean Energy Action Plan, Overview of the CEIP and Public Participation

3/5/2021

Overview

On March 5, 2021 Puget Sound Energy hosted an online meeting with stakeholders to discuss the market risk assessment, stochastic analysis, preferred portfolio and clean energy action plan, overview of the CEIP and public participation. Additionally, participants were able to ask questions and make comments using a chat box provided by the Go2Meeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendee

A total of 75 stakeholders and PSE staff attended the webinar, plus another 4 attendees who called into the meeting and did not identify themselves (79 people total).

Attendees included: Alexandra Streamer, Anne Newcomb, Anthony O'Rourke, Ben Farrow, Bill Pascoe, Bill Westre, Bill Will, Brian Grunkemeyer, Brian Tyson, Bruce Boram, Carryn Vande Griend, Chad Ihrig, Charlie Inman, Christine Bunch, Colin Crowley, Corey Kupersmith, Court Olson, Cuong Nguyen, Dan Catchpole, David Mills, Diann Strom, Don Marsh, Don Vanney, Doug Howell, Elise Johnson, Elizabeth Hossner, Ellyn Murphy, Elyette Weinstein, Fred Heutte, Gurvinder Singh, Irena Netik, Jacob Hibbeln, Allison Jacobs, James Adcock, Jeff Kugel, Jennifer Magat, Jon Lange, Joni Bosh, Josh Jacobs, Kara Durbin, Kasey Curtis, Kate Maracas, Kelly Hall, Kelly Xu, Kendra White, Kevin Jones, Kyle Frankiewich, Leslie Almond, Loren Molander, Lori Elworth, Lucila Gamino, Marc Alberts, Mark Lenssen, Markus Virta, Marty Saldivar, Michele Kvam, Nate Moore, Paul Wetherbee, Pete Stoppani, Peter Brown, Renchang Dai, Robert Stolarski, Sarah Laycock, Stephanie Chase, Therese Miranda-Blackney, Tom Eckman, Tyler Tobin, Virginia Lohr, Weimin Dang, Wendy Gerlitz, Zac Yanez, and Zhi Chen.

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 1:00 PM PDT and ended at 5:00 PM PDT.

Name	Time Sent	Comment
Alexandra Streamer	**1:10 PM**	Good afternoon, stakeholders! Orienting anyone who is new to the 2021 IRP process to the chat box today
Kyle Frankiewich	**1:13 PM**	Hello all! The commission has posted a recording of last week's recessed open meeting. It can be found here: https://wutc.app.box.com/v/OpenMeetings
Doug Howell	**1:14 PM**	I would like to share a concern about the CEIP earlier rather than waiting to the end as I expect there will be lots of drop off
Alexandra Streamer	**1:16 PM**	Thanks, Doug. I've added you to the queue with a raised hand. We'll call on you during our next Q&A break
Doug Howell	**1:16 PM**	Slide 11 - How long is your firm transition and can it be renewed or expanded?
James Adcock	**1:17 PM**	Slide 12: Why isn't there a large amount of dispatchable hydro from BPA showing in the "PNW" part of the slide?
Jon Lange	**1:19 PM**	why is the solar and wind contribution going down over time. is there no plan to replace the solar and/or wind as the existing resources reach end of life? Solar and Wind have shown to be one of the most cost effective resource, correct?
Court Olson	**1:22 PM**	Agree with Doug Howell's request.
Kyle Frankiewich	**1:23 PM**	slide 14: this is a great comparison, appreciate the context. What did similar RA studies look like a few years ago? Was this dramatic drop-off in supply something that was forecast in 2016?
Elyette Weinstein	**1:24 PM**	I agree with Doug's comments about needed meaningful public participation.
Kate Maracas	**1:24 PM**	2nd Doug's recommendation for less presentation and more 2-way dialogue. PSE is helpful in providing full slide decks in advance; advocates can prpare questions and comments from those. I strongly agree we should use our consultative dialog time to address top ten or so issues during webinars.
Kyle Frankiewich	**1:29 PM**	Re: Doug's comment on public participation in the CEIP, I'd like to highlight the recently-adopted commission rules on this subject. https://apps.leg.wa.gov/wac/default.aspx?cite=480-100-655
Fred Heutte	**1:29 PM**	Hi, I will have some questions/comments when the presentation is done on slide 18.
Bill Westre	**1:32 PM**	S-18 raise hand
Kyle Frankiewich	**1:33 PM**	slide 17: how did CA export power to PSE during the state's own capacity shortage? Also, i'd appreciate a brief description of the stages of emergency, what triggers them and what options are made available when a utility declares an emergency.
James Adcock	**1:33 PM**	Slide 17: If PSE in practice keeps getting into trouble during the summer months, then why does PSE keep "modeling" that they will get into trouble during the winter months?
Jon Lange	**1:34 PM**	Slide 15 - is this graph representing volume of outgoing energy sales or incoming?
Doug Howell	**1:34 PM**	Slide 18 - what do you mean by "capacity" in the first bullet? Are you talking about flexible capacity i.e. peakers?
Kyle Frankiewich	**1:35 PM**	slide 18: What is the distinction between a 'capacity need' and a 'market risk adjusted capacity need'? Which of these needs will PSE's 2021 IRP preferred portfolio be tailored to meet?

Doug Howell	**1:35 PM**	slide 18 - You are adding 1,000 MW of new capacity need extremely late in this IRP process? Why? We knew this was a concern for months.
Joni Bosh	**1:36 PM**	Slide 18 - is the change from 1500 to 50 MW reflected in the preferred portfolio resource acquistions, say in slide 41?
Joni Bosh	**1:38 PM**	SLide 18 - typo in previous question - should be 1500 -500
Kyle Frankiewich	**1:38 PM**	Mr. Huette's comments are interesting. I also would appreciate more information regarding how the EIM interacts with securing capacity on a day-ahead and longer-term basis.
Kyle Frankiewich	**1:40 PM**	Potentially remedial follow-up for Mr. Weatherbee - what does procurement in the forwards mean? What does the 'spot market' mean, and how might that differ from forwards?
James Adcock	**1:40 PM**	Comment: When I compare the Mid-C "Evidence" vs. the Evidence from the California AC/DC Interties, the interties don't look bad yet, where 99.9% of the time the PNW is exporting to California, and only 0.01% of the time, during a cold winter snap, is the PNW importing a relatively small amount of power from California.
Elise Johnson	**1:40 PM**	Sharing questions from Jon Lange with all attendees: why is the solar and wind contribution going down over time. is there no plan to replace the solar and/or wind as the existing resources reach end of life? Solar and Wind have shown to be one of the most cost effective resource, correct?
Elise Johnson	**1:41 PM**	Slide 15 - is this graph representing volume of outgoing energy sales or incoming?
Kyle Frankiewich	**1:42 PM**	So the EIM pulled resources that were being bought and sold on a day-ahead basis into either the EIM or something more like a month-ahead market?
Charlie Black	**1:43 PM**	What did the market risk assessment assume about physical and financial attributes of forward purchases?
Kyle Frankiewich	**1:44 PM**	Like Mr. Black, I'm interested in the cost impacts of this evolution in how the wholesale markets have been operating.
Charlie Black	**1:45 PM**	For example, are all short-term purchases assumed to be fixed-price, firm physical power supply?
Charlie Black	**1:46 PM**	Make that short-term and forward purchase up to 3 years forward.
Doug Howell	**1:46 PM**	+++ to Bill Westre's comments. PSE could have reduced this risk with early action.
Court Olson	**1:47 PM**	I agree with Bill Westre. PSE is lagging in building capacity to replace Centralia and Colstrip closures, and not rely as much on market purchases which are dwindling.
Court Olson	**1:48 PM**	BTW, least cost (and cheaper) replacements for coal are wind and solar renewables.
Kyle Frankiewich	**1:49 PM**	Thanks, Paul, I'll carry the emergency stages question into the written comments.
Anne Newcomb	**1:50 PM**	I also agree with Bill W.
Joni Bosh	**1:54 PM**	Slide 18 Irena what kind of "feedback" on this market change are you looking for?
Irena Netik	**2:00 PM**	I'd like to respond to Joni's question about the kind of feedback we are looking for. Some questions that come to mind: Is it appropriate to decline to 500 MW in 2027? Or should PSE target a different number? Is this the appropriate pace (200MW reduction per year)? Or anything else that stakeholders can offer.

Court Olson	**2:02 PM**	Moving on without answering all questions is, once again, another example of the problem that Doug Howell mentioned earlier. Answering questions later outside of the webinar is not a friendly stakeholder engagement approach. PSE continues to overload these webinars with too much information and too many slides to cover and, consequently, doesn't allow dialogue and interaction. Not a healthy process.
Charlie Black	**2:04 PM**	Does each gas price stochastic draw cover the entire IRP planning period, or are the draws done separately for each year?
Joni Bosh	**2:05 PM**	+ C. Black
Charlie Black	**2:06 PM**	Repeat the same question for the time granularity of draws for the other stochastic inputs
Charlie Black	**2:08 PM**	If any of the draws cover the entire planning period, this does not adequately represent short-term variability (e.g., year-to-year and variability in prices, hydro conditions, temperature-dependent loads, etc.)
James Adcock	**2:10 PM**	Comment Slide 26: Not in this cycle, but in cycles moving forward I hope PSE will use BPA's new, recently released hydro modeling data including the effects of climate change.
Charlie Black	**2:13 PM**	Fo example, a draw that shows hydro conditions staying above or below normal for 20 years is not realistic
James Adcock	**2:13 PM**	Slide 28: Can we get access to the representative draws, given that NREL *IS* public data which should not be subject to any PSE's claims of be "proprietary data?"
Charlie Inman	**2:15 PM**	Hi James, the representative draws will be made available in Appendix H when the final IRP is published.
Doug Howell	**2:15 PM**	Slide 30. Would you please explain the recent outage at Colstrip Unit 4. It is our understanding is was not expected, related to boiler tubes, and remains a concern. Please clarify.
James Adcock	**2:16 PM**	Does that include explaining which geographical locations are associated with those draws -- so we can see if the "draws" modeling are "plausible" or not?
Charlie Black	**2:16 PM**	How will the results of the stochastic analysis be used to inform selection of PSE's preferred resource strategy
Charlie Inman	**2:18 PM**	James, the corresponding NREL site IDs are included with each dataset.
James Adcock	**2:18 PM**	Sorry -- my previous question was to Charlie Inman re "Appendix H" draws.
James Adcock	**2:29 PM**	Comment Slide 34: PSE continues their pattern of the last dozen years of exaggerating how cold plausibly coldest (hourly) winter days can be, with actual recent decades coldest winter day (hour) not being colder than 18 degrees F. In the case of this slide, where PSE is using average *daily* [not hourly] temperatures, then PSE's assumed winter temperature distributions are much too low compared to actual, real, historical daily temperatures from recent decades.
Joni Bosh	**2:39 PM**	Would you explain again why you can get results for the gas stochastic analysis (slide 36) now, but not the electric (slide 30) until april 1st? Also, will you be correcting the slides the Gurvinder has corrected verbally (31, 33)?
Doug Howell	**2:41 PM**	Big picture question - why is PSE expecting roughly the same load over 20 years when new state law calls for a 70% reduction of carbon?
Joni Bosh	**2:43 PM**	Thanks
Christine Bunch	**2:44 PM**	When do you expect to share the sensitivity analysis?

Charlie Black	**2:45 PM**	I am interested in hearing how the elecric stochastic analysis results will be used to inform the electric resource strategy
James Adcock	**2:46 PM**	Comment: It sounds like the "conclusion" is getting ahead of the analysis.
Christine Bunch	**2:47 PM**	are RNG prices included in the analysis for gas?
Anne Newcomb	**2:49 PM**	In your presentation to the UTC on Friday your new gas plant was expected to run on biofuel. How was this modeled and how does the price compare to NG?
Alexandra Streamer	**2:50 PM**	Thanks, Anne - if others have follow up questions for Gurvinder and Jennifer, we'll get to those after the break
Jon Lange	**3:03 PM**	no slide reference - there may be a more appropriate time for this question in the presentation so feel free to address it then: Snohomish PUD is currently piloting a V 2 G (vehicle to Grid) program to analyze the financial case for the offset of it's peak demand. Is PSE currently planning anything like this?
Don Marsh	**3:03 PM**	+++ on information regarding V2G!
James Adcock	**3:04 PM**	Slide 41: Raise Hand
Don Marsh	**3:04 PM**	Slide 41: Raise Hand
Court Olson	**3:06 PM**	On Slide #41 are the renewable resource figures added nameplate or net after capacty factors are applied.
Markus Virta	**3:07 PM**	Slide41: Why is PSE backloading DER addoption to 2031-2045? Solar, Demand response, Energy Storage, etc all are ready to deployable today. What is PSE's logic for the delay in deployment?
Markus Vita	**3:10 PM**	You are showing distributed solar's widespread adoption/growth happening between 2026-2045 likely after retail Net Metering has been ended by PSE. How do you forsee distributed solar growing in a market without Net Metering?
Court Olson	**3:14 PM**	Slide 41. With Centralia and Colstrip coal retiring by 2026, there should be about 1057 MW of new power replacing them. Why is PSE not planning to replace the coal with that much wind and solar, especiallly since current market costs are less than coal or gas (for baseload which is what coal was used for).
Don Marsh	**3:18 PM**	Slide 44: raise hand
Charlie Black	**3:18 PM**	Can you please repeat what type of fuel (e.g., RNG or biodiesel) and what fuel price is assumed for the peakers?
Joni Bosh	**3:19 PM**	Apprecite the detail on when new resources will be added year by year. Will you provide a year by year chart or schedule that shows how existing resources/contracts will be retired?
Katie Ware	**3:20 PM**	Slide 42 -- what updated assumptions resulted in a decrease of battery storage? And what replaced those procurements, if not renewables or "flexible capacity"?
James Adcock	**3:20 PM**	+1 Joni: Retirements *are part of IRP planning.
Court Olson	**3:26 PM**	we are getting echo from Elizabeth that makes her hard to hear.
Bill Westre	**3:27 PM**	s-41 +++Court , If you replaced all the coal resources you would need addition feible energy in 2026
Bill Westre	**3:30 PM**	s41 correction-If you replaced all the coal resources with (2450mw) renewable you wouldn't need the flexible energy.
Anne Newcomb	**3:35 PM**	In your 711 MW of flexible capacity can you please break this down? sorry if this is redundant

Charlie Black	**3:38 PM**	Following up on Joni's question about retirements of existing resources - what has PSE assumed about needs and costs for refurbishments of PSE's existing resources between now and 2045 (e.g., 1980s vintage peakers at Whitehorn, Fredonia and Frederickson)?
Katie Ware	**3:40 PM**	I still don't understand what updated assumptions resulted in reduced battery storage. And if 1500 MW market purchases are assumed, I don't understand how market purchases replaced storage. New question -- I presume you have completed your sensitivity analysis on the 2% cost threshold. How did that sensitivity inform these modified resource additions?
Court Olson	**3:46 PM**	Please show us the replacement costs that your are using for making retirement decisions. I've seen recent market cost data that show wind and solar resources are being purchased by western state utilities at rates lower than what we have heard for current coal and gas plant costs. How do you explain that these low costs don't promote early retirements of existing gas and coal plants?
Bill Westre	**3:48 PM**	s-41 If you replaced all the coal resources with (2450mw) renewable you wouldn't need the flexible energy.
Court Olson	**3:48 PM**	There is more to operational cost than just the initial capital purchase cost.
James Adcock	**3:48 PM**	Slide 46: Raise Hand
Don Marsh	**3:50 PM**	What does "BP with Biodiesel" mean? The "BP" part?
Kyle Frankiewich	**3:50 PM**	I think it means 'balanced portfolio'
Don Marsh	**3:51 PM**	That makes sense. Thanks, Kyle!
Kyle Frankiewich	**3:53 PM**	slide 47: it'll be interesting to see how this slide looks in the context of the market reliance adjusted system need.
Joni Bosh	**3:53 PM**	SLide 47 - Alternative compliance options allow for RECs, payments, Energy transformation projects and possibly Spokane burner electricity. What Carbon offsets are you referring to?
Irena Netik	**3:54 PM**	Thanks Kyle! That's correct. That was the internal naming convention before that became our preferred portfolio.
Bill Westre	**3:54 PM**	s-47 Explain the content of Alternative Compliance
Don Marsh	**3:55 PM**	Slide 48 - What is the difference between "Climate Change" and "Environment?" It seemed odd that Sensitivity A scored high on Climate Change, but really bad on Environment. That seems to be a tradeoff in many sensitivities.
Don Marsh	**3:56 PM**	Slide 48 – raise hand
Anne Newcomb	**3:57 PM**	Are you sure there will be a sufficient amount of biodiesel for all of these gas plants?
Kyle Frankiewich	**3:59 PM**	+1 for Anne's question on biodiesel availability. similar questions for RNG and renewable hydrogen, and how those prospective costs or limitations compare with other CETA compliance approaches
Katie Ware	**3:59 PM**	slide 50 - raise hand
Charlie Black	**4:01 PM**	What prices is PSE assuming for its intended purchases of GHG emissions allowances from the CARB auctions?
Charlie Black	**4:03 PM**	I am looking for PSE's forecast for $/metric ton prices . How fast are those prices forecasted to increase (e.g., average annual rate of increase)?
James Adcock	**4:12 PM**	Slide 48 Comment: N1 100% Renewables with Batteries has the highest Resiliency FWIW.

Kyle Frankiewich	**4:13 PM**	It could also be that the model was curtailing the overbuilt renewables, though you'd think that would be occurring in other runs too, and that other builds with fewer renewables would intuitively have lower utility-scale renewable MWhs generated. I really appreciate the company sharing the big spreadsheet, and anticipate that a lot of useful questions will pop up as stakeholders comb through it.
Don Marsh	**4:15 PM**	James, yes I noticed that. N1 would be great if it weren't for cost and Resource Adequacy. I think it's odd that Resiliency and Resource Adequacy seem to be at odds with each other. It doesn't seem like those would be opposed to each other.
Anne Newcomb	**4:18 PM**	Do you think it is possible the modeling tool could be favoring gas as well?
Joni Bosh	**4:24 PM**	Is there some reason the chart on slide 41 does not coordinate with the CEIP time periods? THe second time period covers 2026 through 2029, not 2030.
Kyle Frankiewich	**4:28 PM**	is there a public process set up for CEIP yet? or will this group get updated when there is on?
Kyle Frankiewich	**4:28 PM**	one*
Anne Newcomb	**4:33 PM**	Will you be reaching out to the tribes?
Don Marsh	**4:35 PM**	I like the idea of the Equity Advisory Group, but have two concerns. Will PSE really listen? And does this effort have credibility while PSE continues to build the Tacoma LNG plant, which seems to directly contradict tribal rights and equity issues?
Kyle Frankiewich	**4:38 PM**	slide 61: i worry that the inform and consult levels under IAP2 aren't the level of impact that customers should have under CETA.
Elyette Weinstein	**4:39 PM**	Will you travel to the impacted communities to have your meetings? This is critical
Kyle Frankiewich	**4:40 PM**	for example, the CBIs should be reflective of direct customer input. CBIs don't necessarily result in a specific action, but 't guarantee any specific action, but customers should be fully in control of defining what they value and how much they value it
Don Marsh	**4:44 PM**	raise hand
Court Olson	**4:44 PM**	Slide 62. The reference isn't a website link. How does one sign up?
Irena Netik	**4:46 PM**	Hi Court - you can email ceip@pse.com.
James Adcock	**4:46 PM**	SLide 62: Raise Hand
James Adcock	**4:48 PM**	Slide 63: Raise Hand.
Jon Lange	**4:53 PM**	one way you could easilly connect with folks is through your extensive mailing list of customers. a good quality one pager soliciting participation.
James Adcock	**4:54 PM**	Raise Hand in closing
James Adcock	**5:00 PM**	Why am I not surprised.

The following stakeholder input was gathered through the online Feedback Form, from February 26 through March 12, 2021. PSE's response to the feedback can be found in the far-right column. To understand how PSE incorporated this feedback into the 2021 IRP, feedback will be incorporated as practicable into the filing of the Final 2021 IRP. This Webinar 13 Feedback Report and the Consultation Update will be provided into the meeting record on pse.com/irp and included into Appendix A of the Final IRP.

Feedback Form Date	Stakeholder	Comment	PSE Response
3/5/2021	Elyette Weinstein	Per Diane's suggestion at today's meeting presentation regarding the CEIP's Equity Advisory Groupc (EAG), I am posting the following suggestion: Once the risk of Covid transmission is effectively "over" per health experts, I recommend that the EAG travel to highly impacted communities and areas with vulnerable populations to hear from their residents. I have heard directly from members of these communities (of various races and ethnicities) that they respect outside groups who come to the turf of these highly impacted, vulnerable populations. They consider it a sign of respect and that the outside group takes the concerns of such populations seriously. In return, such populations are likely to be more upfront and cooperative with the EAG.	Thank you for the comment. We agree that connecting with people where they reside provides valuable insights into local conditions and interests. We are taking this into consideration as we develop our public participation plan and Equity Advisory Group plan, and will continue to do so in the future. In light of the COVID-19 pandemic, we anticipate EAG meetings will be virtual through at least the summer. We will consider in-person discussions when it is safe to do so for community members, the facilitation team and PSE staff.
3/7/2021	Bill Westre, Union of Concerned Scientists	I believe the planned use of Biodiesel as a natural gas substitute is ill advised. Bio-Fuels are and will be increasingly scarce. They are critically needed to reduce emissions in the transportation sector - aviation, shipping, truck and train that have fewer options than utilities. As a retired aircraft designer, I am familiar with the airline industries work. They have been instrumental in developing bio-fuels beginning in the early 2000's. They have demonstrated successful flight with them but have not demonstrated how to source the supply for 20,000 commercial aircraft that together burn 73 million gallons of fuel per day. PSE should question whether it can successfully compete in the purchase market with these other industries that need this resource much more. PSE should consider the ethical issues in using this fuel when it has other renewable options. Will PSE take a second and more informed look at this?	Thank you for your comments on biofuel. PSE acknowledges that biofuels, in particular biodiesel, have a number of drawbacks for use as a fuel source including supply concerns, unique combustion characteristics and cost. PSE has modeled biodiesel as possible alternative fuel for the 2021 IRP because the company believes that there may be adequate supply in the region to maintain resource adequacy during times of peak demand. Biodiesel fueled frame peakers would be fired sparingly to provide flexible capacity, not as a baseload resource. That said, PSE is actively investigating other fuel sources such as renewable natural gas and green hydrogen. PSE looks forward to including these fuels in future IRP cycles.
3/11/2021	Renewable Northwest	The letter dated March 11, 2021 submitted in the feedback form is uploaded as part of the Feedback Report, and provided in Appendix A of the Final IRP. A brief summary of salient questions and recommendations are provided below.	Thank you for your letter. PSE inserted the recommendation and questions from the letter along with PSE's responses below.
3/11/2021	Renewable Northwest	What updated resource assumptions resulted in a decrease in battery storage between the draft IRP and the final preferred portfolio? What replaced those procurements, if not renewable resources or flexible capacity?	The summary statistics provided on slide 42 of the March 5 webinar obscure some nuance in the changes in the preferred portfolio between the draft and final IRP. Most notably is the addition of 375 MW of wind + storage hybrid present in the final preferred portfolio which was absent from the draft plan. These hybrid resources "replace" the storage between the draft and final plans. Regarding why these changes occurred, as explained in the Feb 10 Webinar, several updates were incorporated into the final portfolio model including: updates to the flexibility benefit, corrected transmission costs, addition of a transmission and distribution benefit for storage resources and biomass build limits. These changes were incorporated simultaneously, so determining specific outcomes from each change is difficult. Each of these changes has the potential to impact build decisions from the long-term capacity expansion model. Additional details describing PSE's portfolio model methodology are included in the Consultation Update.
3/11/2021	Renewable Northwest	There appear to be fundamental problems with the inputs and/or design of PSE's portfolio modeling tool such that nonemitting capacity resources cannot compete with flexible capacity, and we insist the company determine the source of this resource skewing so that its preferred resource strategy is truly resource agnostic.	Please refer to the Consultation Update for additional modeling details demonstrating that all resources are evaluated consistently

Feedback Form Date	Stakeholder	Comment	PSE Response
3/11/2021	Don Marsh, CENSE.org1	The letter dated March 11, 2021 and submitted in the feedback form and sent to PSE and the WUTC on March 12, 2021 is as part of the Feedback Report, and provided in Appendix A of the Final IRP. 1/ All signatories to the letter: Don Marsh, CENSE.org Doug Howell, Sierra Club Kevin Jones, Vashon Climate Action Group Court Olson, Green building consultant, member of Shift Zero, Chair of People for Climate Action Pete Stoppani, Indivisible Eastside David Perk, 350 Seattle Leadership Team Anne Newcomb Michael Laurie, sustainability consultant, owner of Watershed LLC Willard Westre, Union of Concerned Scientists Kate Maracas, Managing Director, Western Grid Group	Thank you for your letter. PSE inserted the recommendation and questions form the letter along with PSE's responses below.
3/11/2021	Don Marsh, CENSE.org1	The letter references slide 48 of the Webinar 13 presentation specifically and the excel Portfolio Summary Comparison. The letter states: "We commend PSE on increased transparency regarding these results. However, careful study of the spreadsheet has revealed significant flaws in the design and methodology of this study. These problems cast doubt on the conclusions."	PSE thanks you and the group for recognizing our improvements to the 2021 IRP stakeholder public participation process by providing additional data and increasing transparency.
3/11/2021	Don Marsh, CENSE.org1	Study flaw 1: Questionable metrics. The seven metrics shown in the above table determine the final score and overall ranking of each sensitivity. Some of the metrics are averages of rankings of other metrics. For example, "Environment" encompasses subcategories such as Utility Scale Renewable Generation, Energy Efficiency, Distribution Efficiency, Codes and Standards, DSP NWA, Rooftop Solar, Ground Solar, Customer net metering, and Customer Programs (Green Direct, Green Power, Qualifying Facilities). Some of these metrics matter more to customers and some less, but PSE weighs categories equally when calculating a final score for each sensitivity.	Thank you for your comments concerning the metrics used in the Customer Benefit Indicator Analysis. As PSE has stated previously, the customer benefit indicators selected for this analysis are preliminary and intended to open the discussion on which indicators are important to PSE's customers. PSE introduced this methodology in the February 10 webinar and incorporated stakeholder feedback following the webinar. The list of customer benefit indicators will be further developed and refined throughout the Clean Energy Implementation Plan process through public participation and insights from the Equity Advisory Group.
3/11/2021	Don Marsh, CENSE.org1	Study flaw 2: NOx emissions. Emissions of nitrogen oxides (NOx) are averaged with emissions of sulfur dioxide (SO2) and particulates (PM) to produce an "Air Quality" metric. Although NOx can combine with hydrocarbons to produce ground level ozone, this is not a major concern in the Puget Sound region. Puget Sound Clean Air Agency's Strategic Plan (https://www.pscleanair.gov/DocumentCenter/View/445/2014-to-2020-Strategic-PlanPDF?bidId=) states the most harmful pollutants in our region are fine particle pollution and air 2 toxics. When considering an IRP that strives to meet CETA targets, NOx emissions are not nearly as important as the Social Cost of Greenhouse Gases (SCGHG) and CO2 Emissions. Sulfur dioxide emissions may also be subcritical.	Thank you for your comments, see response above.
3/11/2021	Don Marsh, CENSE.org1	Study flaw 3: PSE ranks all the sensitivities with respect to a particular metric early in the analysis. This destroys meaningful distinctions between the sensitivities. For example, the cost difference between the two least expensive sensitivities is $34 million, while the difference between the two most expensive portfolios is $26 billion. Early ranking obscures the fact that the latter difference is 765 times larger than the former.	Thank you for your comments concerning the methodology used in the Customer Benefit Analysis. PSE will continue to work with customers and the Equity Advisory Group to refine the methodology used in the Customer Benefits Analysis. Your feedback will be taken under advisement during this process.
3/11/2021	Don Marsh, CENSE.org1	Study flaw 4: Averaging rank scores. After ranking is performed for each metric, all seven rank scores are averaged together to produce a composite score. Aside from the problem of treating each metric as equally important, the averaging process obscures another fact. Rank scores mean different things for different metrics. For example, the difference between rank 1 and rank 19 in the Customer Programs subcategory is 0.000004%. The difference between ranks 1 and 19 in Portfolio Cost is 208%. When the rank scores for these metrics are averaged together, the result is almost meaningless.	Thank you for your comments concerning the ranking of the Customer Programs indicator. PSE has revised the Customer Programs indicator to round to the nearest full MWh. Further methodological changes will be considered throughout the Clean Energy Implementation Plan process.
3/11/2021	Don Marsh, CENSE.org1	Study flaw 5: Puzzling data. We note that the Portfolio Cost for sensitivity M (Alternative Fuel for Peakers – Biodiesel) is the second least expensive sensitivity of this set. How can that be true, when the cost of biodiesel fuel was estimated	The contribution of a fuel to the revenue requirement of a portfolio is function of both the cost of the fuel and the quantity of fuel consumed. The frame peakers used to meet reliability (resource adequacy) in Sensitivity M (Alternative Fuel for Peakers) are fired with the relatively more

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		to be ten times higher than natural gas in the webinar? Is PSE assuming that natural gas is likely to be used instead of biodiesel for practical cost reasons.	expensive biodiesel, but at a much lower frequency than the equivalent frame peakers fired with natural gas in the Mid portfolio.
3/11/2021	Don Marsh, CENSE.org1	A better method: Stakeholders are developing a better method to score the sensitivities with the data PSE has provided in the spreadsheet. There has not been sufficient time to vet the new method before the deadline for comments, but we expect to publish the improved method soon. Initial results appear to produce a stronger preference for portfolios A and N1 compared to PSE's method. We believe it is possible to choose a portfolio that effectively meets CETA targets, avoids the uncertain availability and potential expense of biodiesel fuel, and keeps customer costs reasonable.	PSE looks forward to learning more about your improved Customer Benefit Analysis methodologies. Thank you for contributing your time and talents to this endeavor.
3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	The letter dated March 11, 2021 and submitted in the feedback form and sent to PSE and the WUTC on March 12, 2021 is as part of the Feedback Report, and provided in Appendix A of the Final IRP.	Thank you for your questions and comments. PSE inserted each item below along with PSE's responses.
3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 13: This slide is interesting but it is hard to understand whether what being compared connects to the assumption, which PSE is revisiting, that its access to the Mid-C market is limited by its transmission rights, rather than by the depth of the market itself. The differences could be explained by the fact that utilities have different service areas, different peak load needs, and different transmission rights to different market hubs. Do other utilities set the assumed market availability during seasonal peaks based on their transmission rights, or do they derate the assumed availability due to other factors?	PSE cannot speak to specific details associated with other utilities as each utility has its own unique resource adequacy methodology, resource procurement and hedging practices. However, the benchmarking provides a useful guide.
3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 16: We appreciate the context, and agree that price volatility is an important part of the evaluation of market reliance risk. We note that none of the three events shown here match with a capacity planning standard connected to the company's winter peak.	Thank you for your comment. PSE's resource adequacy analysis evaluates the loss of load events across 8760 hours for a model year and although most of the loss of load events occur in the winter, there are also events that occur in the summer. The details of the resource adequacy analysis including the market risk assessment are provided in Chapter 7 of the final IRP.
3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 17: The August 2020 event provides further evidence that PSE's winter system peak may not be the biggest reliability challenge in meeting load across the year. Does the graph on this slide represent PSE's market position in each hour? Are the purchases and sales not labeled "CAISO" all from Mid-C, or was PSE able to access other markets as well?	The graph represents the hourly sales/purchases for August 17, 2020. All bars not labeled CAISO represent energy sales or purchases at the Mid-C hub. The different colors show when the purchase or sale was made.
3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 17: The presence of CAISO on this graph is fascinating for multiple reasons. If I recall correctly, PSE's IRP tools model a market price for Mid-C, but do not include contemplation of other possible markets or bilateral trading partners in the WECC. This graph demonstrates that, on an operational level, PSE procures resources from sources other than Mid-C. Please describe these transactions. How common are they? What is a representative estimate of these transactions' size and frequency? Has PSE attempted to include these potential market resources in its modeling? Given that non-Mid-C market resources mitigated the need to escalate PSE's stage 1 emergency, this event illustrates that other market resources can be a critical option in maintaining system reliability.	PSE only trades power at the Mid-C bilateral trading hub. On August 17, 2020, PSE was able to self-schedule a small amount of power export from the CAISO Balancing Authority Area (BAA) to support reliability requirements because no offers were available at the Mid-C hub. This transaction was not a market award and PSE does not participate in the CAISO Day Ahead market. Self-scheduled exports are unusual because they expose PSE customers to price risk and PSE does not include self-scheduled imports as a resource in its modeling.
3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 18: What is the distinction between a 'capacity need' and a 'market risk adjusted capacity need'? Which of these needs will PSE's 2021 IRP preferred portfolio be tailored to meet?	PSE's preferred portfolio has been developed to meet all capacity, energy and renewable energy needs including market risk. PSE attempted to distinguish between the capacity need created by the market risk versus the resource adequacy analysis but recognizes that this new terminology created confusion. In the final IRP, PSE will use one capacity need view and not this new terminology presented at the webinar.

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3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 18: Mr. Wetherbee's presentation included a discussion of real-time, day-ahead, and "forward" market purchases. Which types of market transactions present outsized risk during periods of shallow market depth? How is this linked to PSE's resource procurement strategy?	PSE's recent experience at the Mid-C bilateral trading hub is that power price volatility is most pronounced in the Day Ahead market and in Hour Ahead trading at the Mid-C hub or between other utility real time desks. PSE's procurement strategy seeks to reduce price volatility impacts to PSE customers by efficient use of forward contracts and optimized economic dispatch of PSE resources.
3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 18: What does PSE mean by "market risk adjusted capacity need"? Why does PSE propose reducing its market reliance from 1500 MW to 500 MW, rather than some other value (800 MW, 200 MW, 0 MW)?	Please see the explanation of market risk adjusted capacity need above. Due to the confusion that this terminology has caused, PSE will not use it. PSE acknowledges that the wholesale electric market is experiencing tighter supply and increasing volatility and as a result we must change the way that we plan. PSE plans to reduce the market risk through the upcoming all-source RFP. The convergence of the RFP process and the development of the Northwest Power Pool (NWPP) resource adequacy program will provide additional useful guidance in the future.
3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 21: This slide could probably be its own webinar. We have many questions, though at this stage of the IRP process, it may be too late to revisit the analysis even if stakeholder review identifies significant concerns in methodology. We will some of the questions below, as a representative sample of the level of detail that we would encourage the company to provide when completing the narrative description of the stochastic analysis in the final IRP. ○ What datasets were used for each data input? ○ How did the company represent the probability of outliers for each data input? Did the company assume a normal distribution for any or all inputs? How is distribution modeled? ○ Does the modeling account for any correlations across variables? For example, if there is a relationship between hydro generation and Mid-C prices, does the outcome of one 'draw' get factored into the possible outcomes for a related draw? ○ As participant Charlie Black asked, do the stochastic draws cover the entire IRP planning period, or does the stochastic modeling include draws at a more frequent timeline? We agree that a model run which assumes, for example, very bad (or very good) hydro for all 24 years of the planning horizon is an inaccurate (or at least exceedingly unlikely) representation of the possible futures that should be modeled in the stochastic analysis. ○ How are 310 iterations looking out 24 yrs Slide 22: As with Slide 21, staff would appreciate more details regarding how, exactly, the modeling is done.	Thank you for the recommendations on clarifying information to include in the Final IRP. PSE will address these details in Appendix G, Electric Analysis Models, of the Final IRP.
3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 24: Do the 80 'draws' generated from the company's load forecast represent various percentiles of the main forecast, or was this done some other way? How did the company condense these key inputs into an aggregated 80 draws? We would like to explore whether boiling four important variables into one static 80-draw dataset might attenuate the variability that should be included in a robust stochastic analysis.	The Electric Price Forecast is an output of an AURORA simulation of the entire WECC, for more details on the Electric Price Forecast AURORA model see Chapter 8, Electric Analysis, and Appendix G, Electric Analysis Models, in the Final IRP. The 80 electric price forecast draws were generated through a stochastic analysis of the electric price model, where regional demand, fuel prices, hydro conditions and regional wind conditions were varied. In the Portfolio Model, these same inputs (and more) are varied at the PSE portfolio level of detail. Therefore, there was little risk of attenuating the variability of these inputs.
3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 26: As we have highlighted before, we are concerned with the continued use of historical data stretching back almost 100 years in view of our changing climate. A representation of climate and weather patterns based on distant historical data is unlikely to produce an accurate forecast of weather and climate conditions in the next 24 years.	The objective of stochastic analysis is to model a variety of input conditions to understand the range of possible conditions in the future. For largely variable, complex systems such as hydro storages, historical data provides a reasonable estimation of future events. Many years of historical data provide coverages for the wide variety of conditions which may exist. The Pacific Northwest Coordination Agreement Hydro Regulation data have long been used by the energy industry in the PNW to estimate hydro variability. PSE is not currently aware of any forecast hydro data which meet these needs, but would be open to evaluating any data sources suggested by stakeholders.

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3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 30: Does the frequency duration outage method in Aurora use historical outage rates for individual resources as an input? Are the outage rates adjusted for each plant based on historical performance, or based on recent maintenance or capital investment?	The frequency duration outage method in AURORA uses the most recent 4 years of historical outage data as an initial condition. The method also applies plant specific mean time to repair statistics.
3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 31: Please see our comments for slide 21. Our line of questioning for the electric stochastic analysis also applies to the company's natural gas stochastic analysis.	Thank you for the recommendation on content for the IRP. These components will be incorporated into Chapter 9, Natural Gas Analysis, and Appendix I, Natural Gas Analysis Results, of the Final IRP.
3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 35: We appreciate this interesting way to represent this comparison.	Thank you for your positive statement concerning slide 35.
3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 42: What assumptions regarding transmission to WY and MT resources were changed? What prompted these changes? Also, we echo participant Katie Ware's question: what updated assumptions resulted in a decrease of battery storage? What replaced those procurements, if not renewables or "flexible capacity"?	PSE would clarify that fixed transmission costs for Wyoming and Idaho resources were updated between the Draft and Final IRP. Montana fixed transmission costs have not adjusted. Fixed transmission costs for WY and ID were increased following new insights into transmission availability and costs for the region. Variable transmission costs were added for all resources, following solidification of methodologies for cost estimation. Please refer to the Consultation Update for additional modeling details demonstrating that all resources are evaluated consistently.
3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 46: For clarity, please describe the source of forecasted emissions associated with PSE's electric system in 2045, and describe the modeled approach to offsetting these emissions.	The emissions may be associated with market purchases and dispatch of thermal resources. PSE used the cost associated with the California carbon price as a proxy to reflect alternative compliance mechanisms, as this may align with the requirement for greenhouse gas neutral electricity. The forecasted prices start at over $34 per MWh in 2030 and increase to $59 per MWh in 2044.
3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 51: We appreciate the year-by-year breakout and the inclusion of flexible capacity in this chart. Do any of these resources make use of the 1500 MW of transmission capacity to Mid-C, effectively displacing market purchases?	The results of the market risk sensitivity will be available in Chapter 8, Electric Analysis,of the Final IRP.
3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Staff recommendation 1: **Market risk capacity need adjustment** – While we agree PSE that the company's reliance introduces price and reliability risk, the analysis provided in this presentation does not provide us with a quantification of this risk, nor does it particularly support the company's implicit proposal of 500 MW as a target which appropriately balances the risks and benefits that come with market reliance. We were also left with questions regarding whether the company's representation of the dwindling spot market connect directly with PSE's ability to procure energy and/or capacity through other contract arrangements. On slides 15 -17 the	Thank you for your comments. PSE recognizes that some elements of this IRP are completed late in the process. The implementation of CETA into PSE's IRP was a significant challenge. PSE will provide an expanded discussion of the market risk assessment along with an updated resource adequacy analysis and stochastic analysis results in the Final IRP to support the market risk recommendation.

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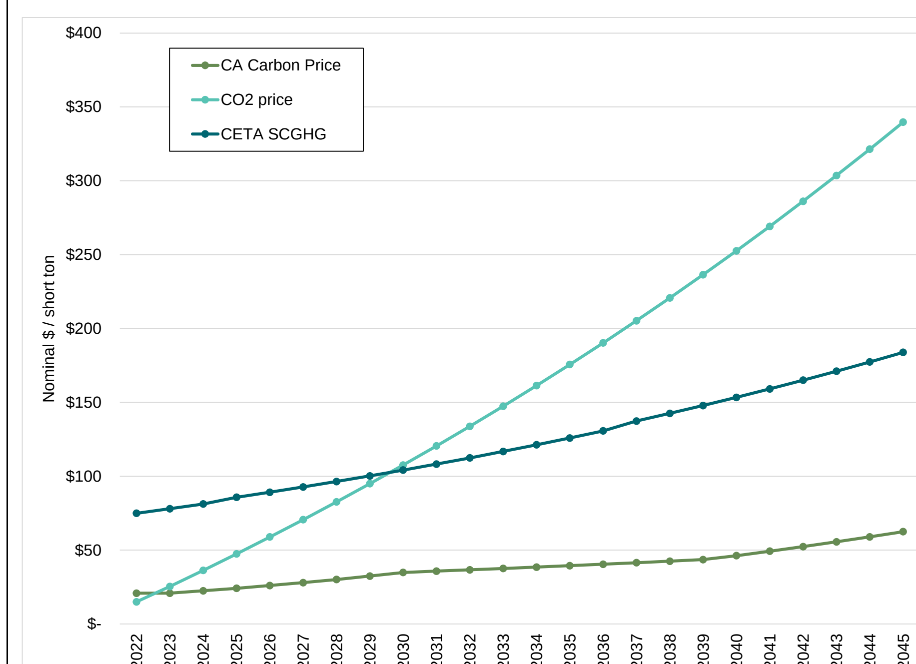
		company shows a reduction in trading volume and increasing price volatility for what we understand to be day-ahead markets, but the company does not provide similar data for the forward market, which we understand to be longer-duration contracts and which, if we understand correctly, comprises a large share of the 1500 MW of capacity the company assumes it can acquire. It is unfortunate that the market reliance analysis and the stochastic analysis will be seen for the first time by staff and other stakeholders in the final IRP. We encourage the company to include sufficient analysis demonstrating that the company's proposed market reliance target – whether it is 500 MW or some other number – reasonably balances the costs and benefits that come with market reliance.	
3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Staff recommendation 2: **Stochastic risk analysis -** Staff understands that PSE is letting AURORA stochastically select a single gas price, water year, market price, force outage rate, load growth rate, etc. for the entire planning period for each future it tests, rather than using the values for each of these variables that were used to develop the "optimized" portfolio. We believe that a much better approach is to let AURORA select a different value for each "variable" each year of the planning period. This is how the real world operates, and is consistent with the NWPCC's methodology. We recommend that the company investigate, in collaboration with staff and stakeholders, how to improve its approach to stochastic risk analysis for the next IRP. On the natural gas side, we appreciate PSE's comparisons across each optimized resource portfolio's composition to see how that might change across alternative futures. While it would be a heavy lift, and it is too late for this IRP cycle, we believe a similar analysis could be done for the electric line of business.	Thank you for the recommendation. PSE acknowledges that inputs which vary year-to-year as well as simulation-to-simulation would provide a more nuanced analysis. PSE will explore opportunities to incorporate these changes into future IRP cycles. For the 2021 IRP, PSE suggests that static inputs as modeled still provide meaningful results and adequately bracket the upper and lower bounds of expected results as well as insight into various possible futures.
3/12/2021	Kyle Frankiewich, Washington Utilities and Transportation Commission	Staff recommendation 3: **Comparative Cost of GHG Emissions Reduction -** While PSE provided multiple slides (43-47) on the level of emissions by resource portfolio, it would be very informative if it also reported a $/ton of reduction achieved by each portfolio. For example, slide 44 shows that the preferred portfolio has a NPV of $16.11 billion and produces emissions of around 0.6 million short tons in 2045 without counting market purchases and just about 1.8 million short tons with market emissions. The preferred portfolio has an NPV of roughly $580 million more than the M-1 portfolio and produces 200,000 short tons less emission in 2045. PSE should compare the cumulative emissions difference between the two portfolios over the entire 24 year planning period. The cost per ton of emissions reduction across each of the portfolios would provide the commission and stakeholders with a point of comparison with other options (i.e., securing other CETA-compliant credits or offsets, rather than building more renewables and storage or biodiesel fuel) for CETA compliance.	Thank you for the metric recommendation. PSE will include this information in the Final IRP. PSE will include a table of the cost of greenhouse gas emissions ($/ton) by sensitivity in Appendix H. This metric will also be discussed in related sensitivity analyses within Chapter 8.
3/17/2021	Orijit Ghoshal, Invenergy	The letter dated March 17, 2021 and submitted to Michele Kvam is as part of the Feedback Report, and provided in Appendix A of the Final IRP. A brief summary of salient questions and recommendations are provided below.	Thank you for your comments.
3/17/2021	Orijit Ghoshal, Invenergy	Market Risk Analysis – "…the late change in PSE's methodology has prevented stakeholders from assessing whether PSE's methodology is reasonable. PSE has not adequately demonstrated that it can prudently wait until 2027 to reach a level of 500 megawatts of market reliance by making reductions of 200 megawatts per year. Further, during Webinar #13, PSE did not present any information about how the resulting 1,000 MW increase in its need for new capacity will affect its preferred resource strategy. Instead, PSE stated that the impacts on its resource strategy will be included in the final IRP. This blocks meaningful review and comment by stakeholders and is simply unacceptable."	Thank you for your comments. PSE recognizes that some elements of this IRP are completed late in the process. The implementation of the Clean Energy Transformation Act (CETA) into PSE's IRP was a significant challenge. PSE will provide an expanded discussion of the market risk assessment along with an updated resource adequacy analysis and stochastic analysis results in the Final IRP to support the market risk recommendation.
3/17/2021	Orijit Ghoshal, Invenergy	Electric Stochastic Analysis – "…the purpose of stochastic analysis is to incorporate the effects of short-term variability in key inputs such as natural gas prices, hydroelectric electric conditions and electric loads, PSE's analysis does not adequately reflect the impacts of the stochastic variables. This is due to oversimplification of how the stochastic variables are input and used in PSE's model. As a result, the model's outputs do not accurately reflect the impacts of stochastic variabilities. …	Thank you for your comments. PSE acknowledges that inputs which vary year-to-year as well as simulation-to-simulation would provide a more nuanced analysis. PSE will explore opportunities to incorporate these changes into future IRP cycles. For the 2021 IRP, PSE suggests that static inputs as modeled still provide meaningful results and adequately bracket the upper and lower bounds of expected results as well as insight into various possible futures.

Feedback Form Date	Stakeholder	Comment	PSE Response
		Further, during Webinar #13, PSE did not present any results for its electric stochastic analysis. Instead, PSE stated that the results will be included in its 2021 IRP filing on April 1, 2021. This is another example of how PSE is not providing timely information for review and comment by stakeholders."	PSE recognizes that some elements of this IRP are completed late in the process. The implementation of CETA into PSE's IRP was a significant challenge. PSE will provide an expanded discussion of the stochastic analysis throughout the Final IRP.
Questions from the Webinar requiring follow-up			
3/5/2021	Joni Bosh	Slide 41 – Is there some reason the chart on slide 41 does not coordinate with the CEIP time periods? The second time period covers 2026 through 2029, not 2030.	PSE contacted Joni Bosh on March 10 to communicate the minor corrections to slides posted on March 9. The time periods on slide 41 represent key points along the CETA timeline including retirement of coal resources, the 2030 emissions target and the 2045 clean energy target.
3/5/2021	Katie Ware	Slide 42 - I still don't understand what updated assumptions resulted in reduced battery storage. And if 1500 MW market purchases are assumed, I don't understand how market purchases replaced storage. New question -- I presume you have completed your sensitivity analysis on the 2% cost threshold. How did that sensitivity inform these modified resource additions?	Please refer to the Consultation Update for additional modeling details. Based on stakeholder feedback received in response to Webinar #12, PSE will not use the 2% cost threshold to adjust the preferred portfolio.
3/5/2021	Charlie Black	Slide 48 – What prices is PSE assuming for its intended purchase of GHG emissions allowances from the CARB auctions?	PSE used the California carbon price as a proxy, as this may align with the requirement for greenhouse gas neutral electricity. The forecasted prices start at over $34 per MWh in 2030 and increase to $59 per MWh in 2045 , see green line on the graph below. The graph below is also included in Chapter 5 of the Final IRP. 
3/5/2021	Anne Newcomb	Slide 51 – Do you think it is possible the modeling tool could be favoring gas as well?	PSE attempts to model all resources as fairly and true to life as feasible. PSE's portfolio model appears to select 2-hr lithium ion batteries more often than other battery storage technologies, which led PSE to state that the model may favor this resource. As an emerging technology, battery storage resources pose unique challenges to the modeling process including accurate cost estimations, flexibility benefit assumptions and dispatch logic. PSE is actively working to ensure these factors and others are properly balanced between all resources.

Feedback Form Date	Stakeholder	Comment	PSE Response
			While still complex to model, thermal resources are a well-established technology, with established modeling practices, PSE is confident the assumptions for the thermal resource options are well designed and representative of real-world applications. PSE would not suggest that there is any bias toward selection of thermal resources. However, model constraints such as resource adequacy favor flexibility and reliability of thermal resources over non-dispatchable resources.

March 11, 2021

Puget Sound Energy
IRP Team

RE: Feedback of Renewable Northwest, 2021 IRP Webinar 13
Puget Sound Energy's March 5, 2021, Webinar Relating to the Stochastic Analysis, Resource Plan, and Clean Energy Action Plan for the 2021 Integrated Resource Plan.

I. INTRODUCTION

Renewable Northwest thanks Puget Sound Energy ("PSE") for this opportunity to provide feedback as a stakeholder in the company's effort to develop its 2021 Integrated Resource Plan ("IRP"). This feedback is in response to PSE's March 5, 2021, webinar and associated materials regarding various updates and draft results for the continued development of the 2021 IRP.

Renewable Northwest participated in the webinar and asked various clarifying questions throughout. Below, we first follow up on PSE's request for stakeholder feedback on the company's decision to incorporate a market risk adjusted capacity need in the resource procurement strategy for the final IRP. We also provide feedback on the stochastic analysis presentation and request more information on changes reflected in the slide deck for webinar 13 as compared to the information published in PSE's draft IRP.

II. FEEDBACK

A. Market Risk Assessment

For the final IRP, PSE will be incorporating a market risk adjusted capacity need with a gradually declining market purchase limit from 1500 MW to 500 MW by 2027. Given the potential capacity deficits forecasted by multiple sources, and given events of capacity shortage are likely to become more common as the effects of climate change are realized, Renewable Northwest appreciates the company's consideration of market risk. However, just as important as PSE's consideration of market risk is the consideration of regional resource adequacy and the interplay between the two.

PSE is an active participant in the regional resource adequacy program ("RAP") under development by the Northwest Power Pool ("NWPP") in consultation with the Southwest Power Pool ("SPP"). The potential of this program to unlock the geographical and resource diversity of the region should be considered for the final IRP, especially considering that the program's non-binding forward showing will launch in Q3 of this year -- around the time PSE will submit its final Clean Energy Implementation Plan ("CEIP").

While PSE states it will amend the preferred resource strategy to incorporate the market risk adjusted capacity need, it is not clear how PSE's model will compensate for the 1,000 MW market purchase reduction and how the actual availability at the market will inform PSE's procurement strategy. Renewable Northwest recommends PSE outline in the final IRP how incremental reductions (e.g. business as usual, 1,000 MW market purchases, 500 MW market purchases) in market reliance affect the preferred portfolio, as this will be most informative to stakeholders and the company itself as it balances potential market risk with improvements in the region's resource adequacy considerations.

We are also generally concerned that this reduction in market reliance will result in increased flexible capacity procurements, as PSE's model appears to favor that resource and not accurately value nonemitting capacity resources. Because PSE has not considered variability in biodiesel price, volatility of that market, or access to biodiesel, PSE cannot confidently claim that alternative fuel enabled combustion turbines are the most economic replacement of market reliance, yet PSE has made this claim in its draft IRP with regard to replacing retired coal-fired generation.[1] We strongly urge PSE to take a hard look at what is causing its model to prefer a flexible capacity resource, whether the resource assumptions informing its model align with current research and industry standards (see the recommendations of Renewable Northwest submitted to docket UE-200304),[2] and determine what characteristics or inputs of its model prevent it from outputting a portfolio of nonemitting capacity resources.[3]

B. Electric Stochastic Analysis

During the webinar, PSE requested stakeholder feedback on the granularity of the data the company should release as an appendix to the stochastic analysis published in the final IRP. Because PSE's stochastic analysis takes a static approach to analyzing conditions which may vary over the course of the planning horizon -- versus a year-to-year reflection of varied

[1] Puget Sound Energy's January 4, 2021 Draft IRP, p. 8-70.
[2] February 5, 2021 Comments of Renewable Northwest, Docket UE-200304, attached to these comments as Exhibit A.
[3] *See* slide 50, PSE 2021 IRP webinar 13.

conditions -- we request that PSE publish very detailed data in Appendix H so stakeholders can understand the extent to which the limitations of the company's modeling tool results in potentially diluted results.

C. Preferred Portfolio and Clean Energy Action Plan

In the two months since PSE filed its draft IRP with the Commission, the company performed additional sensitivity analyses resulting in changes in the preferred resource portfolio.[4] PSE notes that procurements in demand side resources, distributed solar, flexible capacity, and renewable resources have stayed the same.[5] However, battery storage procurements have decreased by 325 MW over the planning horizon. During the webinar, Renewable Northwest asked:

1. What updated resource assumptions resulted in a decrease in battery storage?
2. What replaced those procurements, if not renewable resources or flexible capacity?

Because PSE's model assumes 1,500 MW of market reliance, the company's initial response that market purchases replaced battery storage procurements would not align with the company's previous statements. Therefore, PSE committed to following up with the answers to the above questions. We look forward to understanding these altered resource preferences in greater detail.

Regarding PSE's modifications to Sensitivity P, the iterative analysis performed by the company continues to skew the cost and performance of nonemitting capacity resources to meet PSE's capacity need following coal closures. Renewable Northwest voiced during the webinar that the model should be allowed to choose from the full suite of storage resources -- at minimum, 2- and 4-hour lithium-ion batteries, pumped hydro storage, and hybrid resources -- in place of flexible capacity. PSE's response that the model always prefers one storage resource over another revealed the inability of the company's model to build a *portfolio* of nonemitting storage resources. There appear to be fundamental problems with the inputs and/or design of PSE's portfolio modeling tool such that nonemitting capacity resources cannot compete with flexible capacity, and we insist the company determine the source of this resource skewing so that its preferred resource strategy is truly resource agnostic.

[4] *See* slide 41, PSE 2021 IRP webinar 13.
[5] *See* slide 42, PSE 2021 IRP webinar 13.

III. CONCLUSION

Renewable Northwest thanks PSE for its consideration of this feedback. We look forward to continued engagement as a stakeholder in this 2021 IRP process.

Sincerely,

/s/ Katie Ware
Katie Ware
Washington Policy Manager
Renewable Northwest
katie@renewablenw.org

EXHIBIT A

February 5, 2021

Mark Johnson
Executive Director and Secretary
Washington Utilities and Transportation Commission
621 Woodland Square Loop SE
Lacey, WA 98504-7250

RE: Comments of Renewable Northwest, Docket UE-200304
Utilities and Transportation Commission's January 5, 2021, Notice of Opportunity to File Written Comments Relating to Puget Sound Energy's 2021 Draft Integrated Resource Plan for Electricity, Docket UE-200304.

I. INTRODUCTION

Renewable Northwest thanks the Washington Utilities and Transportation Commission ("the Commission") for this opportunity to comment in response to the Commission's January 5, 2021, Notice of Opportunity ("Notice") to File Written Comments relating to Puget Sound Energy's 2021 Draft Integrated Resource Plan ("Draft IRP") for Electricity, which Puget Sound Energy ("PSE" or "the Company") published January 4, 2021.

Renewable Northwest was an active stakeholder during the public participation process of PSE's Draft IRP development, including submission of written feedback on the Company's generic resource assumptions, transmission constraints, portfolio sensitivities, electric portfolio model, flexibility analysis, and draft portfolio results. We have noted in these comments various areas for improvement in the Draft IRP for PSE and the Commission to consider, bearing in mind the important role of this IRP to plan for compliance with the clean energy standards of Washington's Clean Energy Transformation Act ("CETA"), and as such, to inform PSE's first Clean Energy Implementation Plan ("CEIP"), set to be published later this year.[1]

In these comments, we identify areas where PSE's Draft IRP does not align with the most current resource costs and characteristics. We offer recommendations for revising PSE's key analytical assumptions, resource adequacy considerations, and various sensitivity analyses with the goal of nudging the Company toward a least-cost portfolio with the best likelihood of meeting CETA's clean energy standards.

[1] WAC 480-100-640

Finally, we appreciate the gesture of PSE's recent announcement of its "Beyond Net Zero Carbon" goal, which commits its electric operations to compliance with the standards mandated by CETA.[2] We think the Company is making strides in creating a path toward meeting those goals, but we urge PSE and the Commission to consider where the Draft IRP may be hindered by traditional resource planning assumptions not relevant to an energy transformation toward a dynamic mix of non-emitting resources. We look forward to continued participation in the development of PSE's 2021 IRP.

II. COMMENTS

A. Regulatory Context

CETA broadly requires Washington utilities to achieve greenhouse gas neutrality by 2030 and to serve Washington customers with one hundred percent non-emitting and renewable electricity by 2045.[3] Utilities must identify steps to achieve these standards using the new tool of Clean Energy Implementation Plans, and those CEIPs must in turn "identify specific actions to be taken by the investor-owned utility over the next four years, *consistent with the utility's long-range integrated resource plan* and resource adequacy requirements, that demonstrate progress toward meeting the standards under RCW 19.405.040(1) and 19.405.050(1)" as well as interim targets to ensure incremental progress.[4]

The Commission worked for months with many stakeholders, including Renewable Northwest, to craft new rules aligning utility IRPs with CEIPs and CETA's substantive requirements. These new rules point to some key downstream effects of IRPs: first, "[t]he commission will consider the information reported in the integrated resource plan when it evaluates the performance of the utility in rate and other proceedings"[5]; and second, a utility's "CEIP must describe how [its] specific actions ... [a]re consistent with the utility's integrated resource plan."[6] The main takeaway of this structure is that it is important to get as much correct as possible in the IRP, as analytical missteps could have repercussions both for utility cost recovery and for achieving CETA's critically important substantive standards.

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[2] PSE sets "Beyond Net Zero Carbon" goal (Jan. 21, 2021), *available at* https://www.pse.com/press-release/details/pse-sets-beyond-net-zero-carbon-goal?utm_source=Social&utm_medium=LINKEDIN&utm_campaign=TOGETHER.
[3] RCW 19.405.040(1) & 19.405.050(1) (emphasis added).
[4] RCW 19.405.060(1)(b)(iii).
[5] WAC 480-100-238(6).
[6] WAC 480-100-640(6)(d).

With that backdrop in mind, we offer the following comments on PSE's Draft IRP, assessing elements of the Draft IRP not only against specific provisions of the Commission's rules as appropriate, but also against the broader context of how the information in this IRP will be used in future planning, procurement, and ultimately cost recovery efforts.

B. Resource Plan Decisions

Renewable Northwest appreciates PSE's efforts to update its traditional resource planning tools and philosophies to fit with Washington's nation-leading clean energy goals, as set forth in CETA. The resulting portfolio of resources represented in PSE's Draft IRP, which includes 3,547 MW of distributed energy resources ("DERs") and 4,462 MW of incremental renewable resources over the 24-year planning horizon, is a strong step toward the Company's fulfillment of its recent commitment to have a 100% carbon-free electric supply by 2045 -- with one significant exception which will be discussed below.

For the final IRP, PSE will be testing its preferred resource mix against the two-percent cost threshold outlined by CETA (RCW 19.405.060(3)(a)), an alternative compliance mechanism.[7] We request that, if PSE proposes in the final IRP to rely on the two-percent cost threshold for alternative compliance, PSE make it clear how that proposal fits with its commitment to provide customers with 100% carbon-free electricity by 2045, and how the use of alternative compliance with CETA will be adjusted to achieve that goal. Further, in considering how the cost threshold may inform PSE's resource decisions, we have outlined in these comments areas where PSE's modeling assumptions or inputs should be clarified or revised for the Company to make the case that it has "maximized investments in renewable resources and nonemitting electric generation," a requirement for use of alternative compliance with CETA's clean energy standards.[8]

Moving now to the Company's preferred portfolio, we appreciate the extent to which DERs appear in PSE's planning horizon. However, the heavy back-end of these procurements, with 2,284 MW of DERs preferred from 2031-2045, may be a source of PSE's perceived need for flexible capacity by 2026. DERs have the ability to provide critical peak shaving and reduce capacity needs for the system at a much lower cost compared to building new centralized infrastructure. In fact, recent techno-economic optimization modeling shows that scenarios in which DER resources are included earlier in the portfolio leads to lower costs over the long run to the tune of multiple billion dollars with savings accruing at a much faster rate[9]. In addition, investing in DERs may allow PSE to utilize its transmission capacity to be fully utilized efficiently and lead to lower overall costs. We encourage PSE to consider ongoing pilot projects

[7] P. 3-16
[8] RCW 19.405.060(3)(b)
[9] Why Local Solar For All Costs Less: A New Roadmap for the Lowest Cost Grid. Vibrant Clean Energy, LLC.

for distributed energy management systems to ensure the grid-balancing value of these resources is captured in portfolio modeling.[10]

PSE's preference for flexible capacity to maintain resource adequacy is contrary to the clean energy standards mandated by CETA, and we still have questions about the Company's resource assumptions which informed the portfolio model to opt for flexible capacity following 2025 coal retirements. Though the Draft IRP claims that PSE's "current modeling results show alternative fuel enabled combustion turbines as the most cost-effective resource to meet capacity resource needs that cannot otherwise be met by demand-side resources and distributed and renewable energy resources," PSE's modeling of alternative fuel enabled combustion turbines -- limited to sensitivity W in the Draft IRP -- may not support the claim that this resource is least cost. Sensitivity W explores a ramped schedule of DER procurements with biofuel as the fuel source for new frame peaker resources. Because PSE assumes a *fixed* biofuel price of $30.53 per million British Thermal Units over the entire study period, the model does not consider volatility of that market, inflation, or limited access to the resource.[11] And while sensitivity M will be completed for the final IRP to explore hydrogen as an alternative fuel for peaker plants, broadly projecting the viability of flexible capacity -- considering the regulatory environment and the lack of supporting data -- makes it difficult not to question PSE's resource agnosticism.

Because PSE states in the Draft IRP that alternative fuel enabled combustion turbines are the least cost resource to meet the remaining capacity needs after maximum deployment of DERs and incremental renewables, it appears that an assumption of PSE's model may be that these new combustion turbines will operate with a null social cost of greenhouse gas ("SCGHG") and zero CETA-related penalties. At the very least, PSE should caveat its flexible capacity resource selections with "assuming availability of comparably-priced alternative fuels." It is not clear from the Draft IRP whether new procurements for gas enabled combustion turbines would still be least cost, considering the incorporation of the SCGHG -- ranging from $69 per ton in 2020 and $238 per ton in 2052 -- and CETA penalties into the model.[12] In any event, these questions regarding the analytical foundations of PSE's flexible capacity preference lead us to concerns regarding not only PSE's pending incremental cost calculation but also how the IRP will inform PSE's CEIP and downstream resource actions; to alleviate these concerns would likely require significant changes in the company's final IRP.

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[10] *See, e.g.,* "Opus One Tests 'Transactive Energy' for California Rooftop Solar, Behind-the-Meter Batteries," *available at* https://www.greentechmedia.com/articles/read/opus-one-tests-transactive-energy-for-california-rooftop-solar-behind-the-meter-batteries.
[11] P. 8-70
[12] P. 5-58

C. Key Analytical Assumptions

In the "Electric Resource Assumptions" section, PSE provides details on the type and operational characteristics of the resources considered in the 2021 IRP. We would like to suggest two recommendations that would provide a better understanding to how resources are operated historically:

1. **Pumped-hydro storage:** It is our understanding that PSE considers splitting up the nameplate capacity of the generic pumped hydro resource to account for reasonable joint ownership considerations. In doing so, the model assumes that PSE's share from the resource would be 50 MW. As PSE rightly mentions, pumped hydro storage resources can provide capacity as well as sub-hour flexibility, two key value streams that will be increasingly important in the future power system. Additionally, since the nameplate capacity of a typical pumped hydro storage resource ranges from 250 MW to 3 GW, a model that reflects less than 25% of the average capacity of a pumped hydro resource may not accurately reflect the costs and benefits of the resource. Thus, we suggest that PSE consider at least **100-150 MW** of nameplate capacity of pumped hydro with 8-, 10-, and 12-hour duration in their modeling to ensure the resource receives thorough consideration. Additional assessment is warranted because of pumped hydro's unique characteristics as a CETA-compliant resource, one that can integrate large shares of renewables into PSE's system, and one that can provide flexibility (valued at $10/kW-year in this IRP) and other reserve products required to balance the grid.

2. **Hybrid resources:** PSE has modeled three different combinations of hybrid resources: eastern Washington solar + 2-hour Lithium-ion battery, eastern Washington wind + 2-hour Lithium-ion battery, and Montana wind + pumped hydro. While we appreciate PSE's addition of these resources into this IRP cycle and the company's recognition of the emergence of hybrid projects as cost-effective, non-emitting resources, below we highlight some additional hybrid resource configurations that may enhance PSE's modeling of hybrids and provide better understanding for the current and future IRPs.

   First, hybrid resources can provide valuable energy during hours of peak demand or hours with highest probability of loss of load because they have the inherent ability to shift delivery of energy based on the needs of the grid. This means hybrids can provide **capacity and additional grid flexibility**, thereby helping to integrate large shares of renewable energy resources. While PV coupled with batteries is the most prevalent hybrid resource currently, utility innovations in this field have shown that concepts like triple-hybrids consisting of wind + solar + batteries are also techno-economically viable generation resources.[13] Second, typically solar or wind resources are coupled with a **4-hour duration** Li-ion battery system to ensure sufficient MWhs are shifted from the generating resource to the battery during low-demand hours to avoid curtailment and allow for discharge across high-demand hours, as well as to ensure that the additional capital cost of the battery is effectively utilized to the maximum extent.[14] Modeling 2-hour Li-ion batteries might not lead to complete realization of benefits that a 4-hour system can provide, a result that could skew the selection of hybrid and storage resources -- or lack thereof -- in a preferred portfolio. Finally, hybrid resources are also flexible in terms of the variety of operational **configurations** available. Apart from the generic AC-coupled systems, recent industry developments in DC-coupled systems have provided additional options to deploy hybrid resources. In these systems, batteries provide the extra benefit of recapturing "clipped" energy from oversized solar systems, and DC-coupled systems enable low-voltage harvesting periods when inverters cannot generate power from the solar system. Modeling different operational configurations could similarly unlock benefits that change the composition and costs of PSE's resource portfolios.

Renewable Northwest appreciates the additional sensitivities conducted by PSE, in particular pertaining to emission reduction pathways which are not only highly probable due to recent policy developments but can also be a cost-effective resource strategy over the long run if implemented efficiently. Since PSE's Mid-Case buildout includes 907 MW of "flexible capacity" resources that may not be consistent either with CETA's standards or with the company's emission-reduction goals, we recommend additional exploration of alternative resources. In particular, we recommend that PSE take a harder look at cost-effective resources such as storage, demand response, and hybrids to fill that capacity need. A portfolio approach similar to "Sensitivity P", considering a mixture of 4-hour standalone storage, 8-10 pumped hydro, solar/wind paired with 4-hour storage and demand response could likely meet early morning and evening peak needs during winter months that the company's loss of load heatmap matrix (Figure 3-14) has shown. Thus, we suggested in comments to PSE that it assess a modification to the Scenario P in order to prioritize selection of these resources before a new gas plant, which would not only threaten PSE's CETA compliance and emission goals but also create financial risks related to stranded assets in the future. We look forward to seeing the results of this modified sensitivity.

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[13] *See*, *e.g.*, Portland General Electric's December 2020 press release regarding the wind + solar + battery storage Wheatridge Renewable Energy Facility procured as a result of a 2018 competitive solicitation: https://portlandgeneral.com/news/2020-12-8-pges-and-nextera-energy-resources-leading-edge-renewable-energy.
[14] NREL Annual Technology Baseline, 2020, *available at* https://atb.nrel.gov/electricity/2020/index.php?t=st

In previous comments to PSE, we have also highlighted four key dimensions of a robust flexibility resource and subsequent analysis.[15] These are: first, absolute power output capacity range (in "MW"); second, the speed of power output change, or ramp rate (in "MW/min"); third, the duration of energy levels (in "MWh"); and finally the carbon intensity (in "CO2e/MWh"). Resources which have a larger range between their minimum and maximum "MW" output, such as pumped-hydro storage systems, can provide the flexibility to adjust to a wider range of power system conditions. Resources that can change their output quickly or can be easily turned on or off, including 2-, 4- & 6-hour Li-ion, flow battery storage systems, and demand response ("DR"), have a higher ramp rate and are more flexible because they adjust faster to changes in power system conditions. Resources that can deliver energy for longer durations increase flexibility because they can address prolonged disturbances or outages. Resources such as conventional and combined cycle combustion turbines can provide dispatchable power but by definition have low capacity utilization when used as peakers and are emission-intensive when ramped up or down rapidly. These different dimensions are important to consider in any holistic flexibility analysis and, thus, in calculating benefits, we recommend PSE consider not just the frequency of flex violations but their magnitude, speed, duration, and carbon intensity. Based on these dimensions, we anticipate that PSE may identify a different resource or resources to fill that flexible capacity need, and we recommend that PSE continue to study clean, non-emitting, and flexible capacity resources which meet all the required characteristics of each dimension.

D. <u>Resource Adequacy Analysis</u>

Renewable Northwest appreciates Draft IRP's detailed description of PSE's efforts to maintain a reliable and adequate system during all hours of the year using the multi-scenario probabilistic Resource Adequacy Model ("RAM"). Evaluating the capacity credit of individual resources is an integral part of this analysis, which informs the planning reserve margin ("PRM") to maintain the system under the standard of 5% loss of load probability ("LOLP"). Having taken a close look into the analysis provided, we have the following thoughts:

1. The LOLP matrix for 2027 and 2031 shows peak demand hours for winter months during mornings from (8 a.m. - 11 a.m.) and evenings from (6 p.m. to 10 p.m.); as noted above, the resource needs associated with these peaks can likely be met by a portfolio of flexible resources such as pumped hydro, standalone storage, hybrids, demand response, and market purchases at a lower cost than that associated with the flexible capacity resources that currently appear in PSE's preferred portfolio. The duration (assuming full discharge) for all storage resources combined contributes up to 16 hours, excluding demand response. PSE should consider this portfolio approach instead of investing in new gas

[15] Feedback of Renewable Northwest re: Flexibility Analysis & Portfolio Draft Results. Submitted December 21, 2020.

infrastructure which will likely end up being stranded, leading to financial losses for the company and its customers.

2. The Draft IRP's peak capacity credit for hybrid solar + storage resources appears to be skewed because coupling solar or wind with 2-hour Li-ion storage contributes much less to peak capacity than a similar resource paired with 4-hour storage. In fact, 4-hour storage is the industry standard for pairing with renewable resources due to their cheaper $/kW capital costs[16] as well as costs related to the balance-of-system ("BoS"), in addition to the ability to provide 4-hour dispatch during evening hours when the solar is ramped down and demand is high on the grid. Research has shown that hybrid solar + storage (4-hour duration) can deliver greater than 99% ELCC in the Western US at a lower cost than a combustion turbine peaker power plant in an analysis conducted using Strategic Energy and Risk Valuation Model (SERVM) by Astrape Consulting.[17]

3. PSE is an active participant in the regional resource adequacy program ("RAP") being developed by the Northwest Power Pool ("NWPP") in consultation with the Southwest Power Pool ("SPP"). This program has the ability to unlock the geographical and resource diversity of the region and allow utilities to share resources during stress hours instead of following the traditional "go-it alone" approach. The program is currently in the detailed design phase, and its non-binding forward showing will launch in Q3-2021, with the binding + operational program to be launched in 2024 -- two years before PSE's Draft IRP shows a need for new flexible capacity. Thus, it would be prudent for PSE to assess whether participation in the program could reduce or even eliminate the need for new flexible capacity assets, especially when combined with some set of the non-emitting resources discussed above.

E. <u>Electric Analysis</u>

PSE provides a levelized cost of capacity comparison for peakers, baseload gas plants, and energy storage resources in the Mid Scenario, illustrated by *Figure 8-12* in the Draft IRP:

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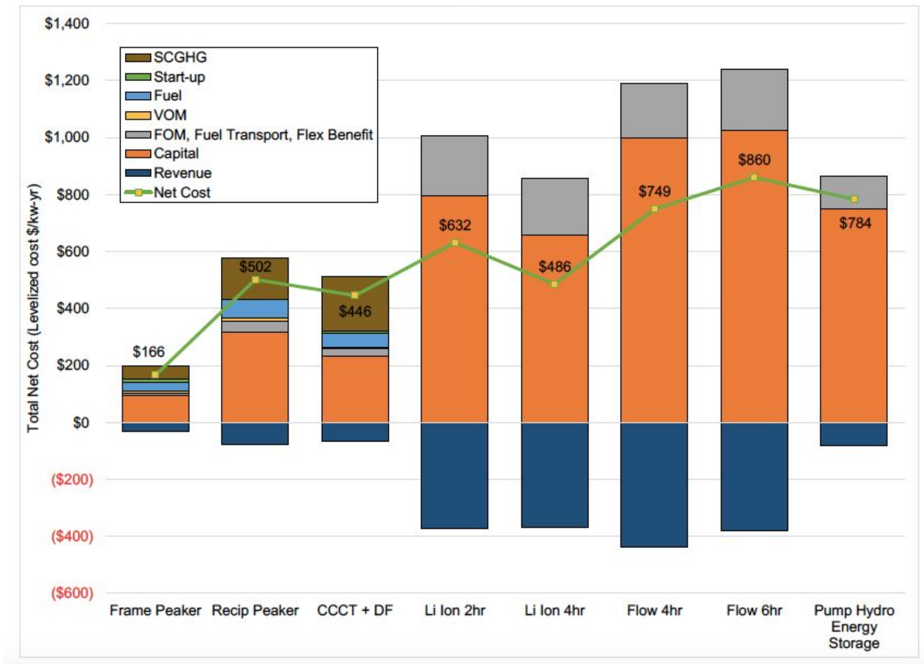
[16] See Figure 9. 2018 U.S. Utility-Scale PhotovoltaicsPlus-Energy Storage System Costs Benchmark. Fu et al. 2018. NREL. Available at: https://atb.nrel.gov/electricity/2020/index.php?t=st

[17] California Public Utility Commission. Joint IOU Study. August 2020. Available at: https://www.astrape.com/2020-joint-ca-iou-elcc-study-report-1/

Astrapé Consulting was contracted by the California Investor Owned Utilities to examine the annual marginal ELCC values for the resource classes and locations using the SERVM model which calibrates the reliability planning to loss of load expectation (LOLE) of 0.1 or 1 day in 10 years.

Figure 8-12: Net Cost of Capacity in the Portfolio Model



However, public data and other IRP filings support lower capital cost estimates ($/kW) than PSE has incorporated in their modeling. For example, the National Renewable Energy Laboratory's ("NREL") 2018 Annual Technology Baseline ("ATB") reports meaningfully lower costs for 2-hour and 4-hour lithium-ion batteries with mid-cost projections (shown in *Figure 1* below). The most recent cost estimates reflected in NREL's 2020 ATB are lower still at $1500/kW for a moderate-level projection (shown in *Figure 2* below). On the other hand, the 4-hour Li-ion battery capital cost assumed for the "Levelized Capacity Cost" (in PSE's Figure 8-12 reproduced above) calculation would produce a range of $2300-2400 kW/year, assuming a 15-year system lifecycle and a capacity credit of 25% -- a very conservative estimate. Battery storage costs are falling rapidly and efficiencies are increasing due to technological advancements and economies of scale. Battery storage systems are increasingly emerging as important assets for the future grid -- and even the present grid -- to integrate increasing penetrations of non-emitting resources. Thus, evaluating their cost and operating parameters appropriately in the current IRP cycle would not only meet the company's obligations this IRP cycle but also lay important groundwork for future resource planning.

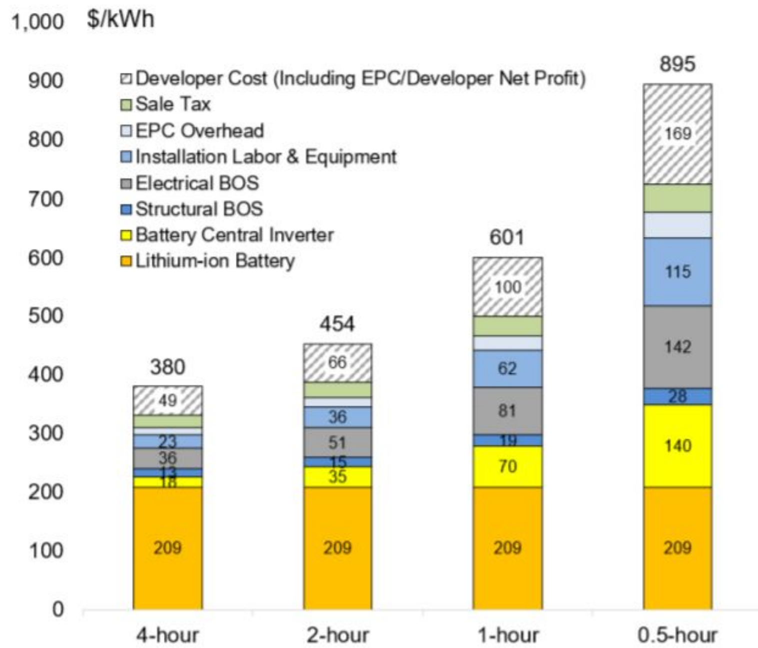


Figure 1. 2018 U.S. utility-scale lithium-ion standalone storage costs for durations of 0.5-4 hours (60 MW_{DC}), NREL's 2018 Annual Technology Baseline.[18]

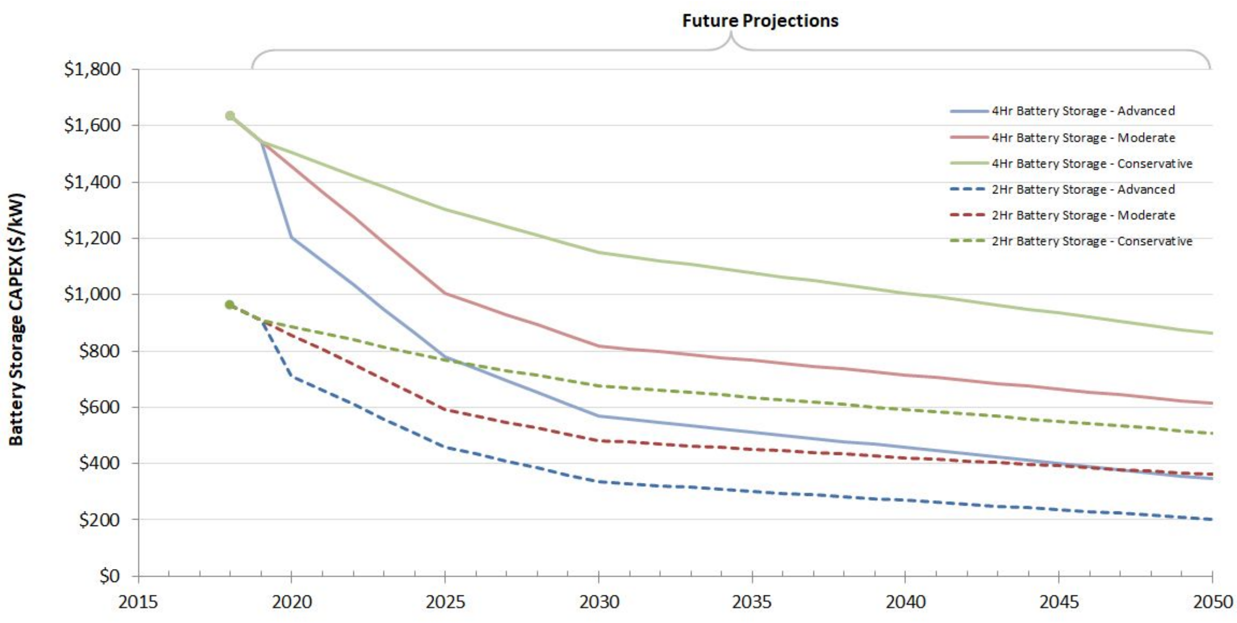


Figure 2. Li-ion battery storage projection (in $/kW) from NREL's Annual Technology Baseline 2020.[19]

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[18] NREL Annual Technology Baseline, 2020, *available at* https://atb.nrel.gov/electricity/2020/index.php?t=st.

[19] Battery Storage cost values from W. Cole and A. W. Frazier, "Cost Projections for Utility-scale Battery Storage: 2020 Update," NREL/TP-6A20-75385. Golden, CO: National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy20osti/75385.pdf.

We appreciate PSE's solicitation of stakeholder feedback during the development of a list of sensitivities to inform the IRP. We provided written feedback on some of these sensitivities to PSE in December, and the Company generally seems open to some adjustment for the final IRP. Below, we outline how various sensitivities could be improved to better inform PSE's preferred portfolio.

1. Sensitivity A -- Renewable Overgeneration Test
   This sensitivity explores the importance of market sales by preventing excess renewable generation from being sold to the Mid-C market. The 24-year levelized costs are only slightly higher than those of the Mid Scenario, and the model successfully minimizes overgeneration of renewables by selecting biogas and battery storage and likely curtailing any excess renewable generation. These details make sensitivity A an attractive option, especially considering the decreased peaking capacity compared to the Mid Scenario. However, because this sensitivity is relevant to discussions occurring at the state agencies regarding the definition of "use" in RCW 19.405.040(1)(a)(ii), it may be informative for PSE to explore how market availability would be affected if all Washington utilities operated within a CETA compliance structure such that renewable overgeneration was minimized. This would be difficult to model, as the sudden drop in Washington market sales may alter the way other utilities in the region participate in the market. Regardless, it may be worth PSE addressing in the final IRP that selection of sensitivity A's portfolio would imply other utilities would have similar resource planning strategies, and thus, the impact to market availability would be difficult to forecast.

2. Sensitivity B -- Reduced Market Reliance at Peak Hours
   This sensitivity restricts PSE's reliance on market purchases to meet peak load. This analysis will be completed for the final IRP. However, the context PSE provides for this sensitivity is problematic: "PSE currently uses market purchases of energy in order to meet demand at peak demand hours. As CETA pushes the generation mix of the Pacific Northwest to become increasingly renewable, energy may not be available for purchase on the Mid-C market."[20] Because there is meaningful variability in the generation profiles of renewable resources across the region, and because storage technologies -- especially as costs continue to fall -- will improve the flexibility of the grid, this narrative presents an overly narrow and arguably incorrect view of the cause of potential limits in the market at peak hours. If peak-hour market availability does decrease over the planning

[20] P. 5-45

horizon, it will likely be in part because of the more extreme weather events, a consequence of the global climate shift, making region-wide events of high energy demand more common.

3. Sensitivity E -- Firm Transmission as a Percentage of Resource Nameplate
This sensitivity explores the cost savings associated with securing firm transmission as a percentage of resource nameplate capacity, given renewable resources often generate below their maximum outputs. While PSE's results indicate there may be some cost savings associated with securing firm transmission as a percentage of nameplate capacity PSE does not feel the savings would "add materially to the IRP portfolio development process."[21] However, we recommend PSE continue exploring solutions to transmission underutilization both in future IRP efforts and upcoming resource acquisition decisions. In fact, we are hoping to meet with PSE transmission planning staff in upcoming months to explore additional possibilities for unlocking flexibility in the existing transmission system. We also look forward to seeing PSE's future modeling of co-located wind and solar with shared, limited transmission capacity due to the complementary relationship between the generation profiles of these resources.[22]

4. Sensitivity O -- Natural Gas Generation Out by 2045
This sensitivity forces the model to retire all emitting resources by 2045 as opposed to at the end of their economic life. Renewable Northwest requested in December that PSE model a new sensitivity for its final IRP, building on sensitivity O. Sensitivity O still opts for new gas but forces the model to retire existing fossil resources by 2045. A new or revised sensitivity forcing the model to select from the full suite of non-emitting resources -- including 4-hour lithium-ion batteries, pumped hydro storage, and hybrid resources -- to meet all capacity needs and allowing existing fossil resources to economically retire would be more informative, especially if the conservation measures of the Mid Scenario were applied on the front end to reduce capacity need over the planning horizon.

5. Sensitivity P -- Must-take Battery and Must-take Pumped Hydro Energy Storage
This sensitivity is split into two analyses: 1) batteries as must-take resources following coal retirements in 2025, and 2) pumped hydro storage as must-take resources following coal retirements in 2025. As follow-up to our December 15 feedback to PSE on its draft portfolio results, PSE agreed to modify sensitivity P to better illustrate the resource mix and portfolio costs of diverse storage options that align better with the portfolios that are emerging by other utilities in the region.

[21] P. 8-46
[22] P. 8-47

Sensitivity P currently explores a forced delay of peaking capacity additions to determine the portfolio cost impacts associated with earlier procurements of battery storage and demand response. Battery storage in this sensitivity is represented by 2-hour lithium-ion batteries, which PSE chose because they are least cost. However, while these duration-limited batteries may be least cost up front, the incrementally more expensive 4-hour lithium-ion battery would contribute more to resource adequacy and flexibility while also reducing the amount of storage procurements required to replace peaking capacity resources. Moreover, PSE's Mid Scenario considers 4-hour lithium-ion batteries, likely because this appears to be the industry standard,[23] so changing sensitivity P in this way would better fit with PSE's portfolio comparisons.

PSE has agreed to run a sensitivity allowing the model to select from a *mix* of storage options, notably 4-hour lithium-ion batteries and 8-hour pumped hydro storage. We look forward to seeing how this additional storage resource diversification may influence PSE's final resource strategy.

III. CONCLUSION

Renewable Northwest thanks PSE and the Commission for their consideration of this feedback. We are optimistic that the changes and additional analysis we have recommended above will help PSE to identify a least-cost portfolio that also puts the Company on a path to achieving CETA's clean energy standards and the Company's own emission reduction goals. We look forward to continued engagement as a stakeholder in this 2021 IRP process.

Sincerely,

/s/ Katie Ware	*/s/ Sashwat Roy*	*/s/ Max Greene*
Katie Ware	Sashwat Roy	Max Greene
Washington Policy Manager	Technology & Policy Analyst	Regulatory & Policy Director
Renewable Northwest	Renewable Northwest	Renewable Northwest
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[23] *See, e.g.*, Avista's Draft 2021 Electric IRP (Jan. 4, 2021), at 9-13, *available at* https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/avista-2021-draft-electric-irp.pdf.

March 11, 2021

Dear IRP team and Commissioners,

At the final stakeholder webinar for PSE's 2021 IRP, PSE presented a table comparing the costs and benefits of 22 portfolio sensitivities (see slide 48 at https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/March_5_webinar/webinar13_FINAL.pdf):

Sensitivity	Cost	Climate Change	Air Quality	Market Position	Environment	Resource Adequacy	Resiliency	Overall Rank
1 Mid	3	13	13	4	10	18	16	8
A Renewable Overgeneration	15	4	10	20	18	6	5	11
C Distributed Transmission	13	20	20	17	8	13	6	20
D Transmission/build constraints - time delayed (option 2)	5	12	8	15	10	12	13	7
F 6-Yr DSR Ramp	4	15	15	7	11	15	14	16
G NEI DSR	8	14	16	12	12	7	10	12
H Social Discount DSR	9	16	13	18	12	5	8	15
I SCGHG Dispatch Cost - LTCE Model	1	10	11	11	10	8	9	3
K AR5 Upstream Emissions	6	16	13	2	9	16	14	8
M Alternative Fuel for Peakers - Biodiesel	2	7	4	8	8	9	11	1
N1 100% Renewable by 2030 Batteries	19	2	1	16	8	21	1	5
N2 100% Renewable by 2030 PSH	22	1	1	1	13	21	21	13
O1 100% Renewable by 2045 Batteries	16	8	6	19	12	20	2	17
O2 100% Renewable by 2045 PSH	21	11	8	14	7	10	21	19
P1 No Thermal Before 2030, 2Hr LiIon	18	21	21	21	18	14	4	21
P2 No Thermal Before 2030, PHES	17	5	7	13	9	19	7	10
P3 No Thermal Before 2030, 4Hr LiIon	20	22	22	22	18	17	3	22
V1 Balanced portfolio	10	11	13	5	8	1	17	4
V2 Balanced portfolio + MT Wind and PSH	14	17	17	3	9	1	19	14
V3 Balanced portfolio + 6 Year DSR	12	13	18	6	9	1	12	6
W Preferred Portfolio (BP with Biodiesel)	11	5	5	9	8	1	17	2
AA MT Wind + PHSE	7	14	10	10	11	11	20	18

PSE also provided a spreadsheet (https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/March_5_webinar/Portfolio%20Summary_Comparison_clean.xlsx) that shows the data and methodology used to calculate the overall ranking of these sensitivities.

We commend PSE on increased transparency regarding these results. However, careful study of the spreadsheet has revealed significant flaws in the design and methodology of this study. These problems cast doubt on the conclusions.

Study flaws

Some of our concerns are as follows:

1. **Questionable metrics.** The seven metrics shown in the above table determine the final score and overall ranking of each sensitivity. Some of the metrics are averages of rankings of other metrics. For example, "Environment" encompasses subcategories such as Utility Scale Renewable Generation, Energy Efficiency, Distribution Efficiency, Codes and Standards, DSP NWA, Rooftop Solar, Ground Solar, Customer net metering, and Customer Programs (Green Direct, Green Power, Qualifying Facilities). Some of these metrics matter more to customers and some less, but PSE weighs categories equally when calculating a final score for each sensitivity.

2. **NOx emissions.** Emissions of nitrogen oxides (NOx) are averaged with emissions of sulfur dioxide (SO2) and particulates (PM) to produce an "Air Quality" metric. Although NOx can combine with hydrocarbons to produce ground level ozone, this is not a major concern in the Puget Sound region. Puget Sound Clean Air Agency's Strategic Plan (https://www.pscleanair.gov/DocumentCenter/View/445/2014-to-2020-Strategic-Plan-PDF?bidId=) states the most harmful pollutants in our region are fine particle pollution and air

toxics. When considering an IRP that strives to meet CETA targets, NOx emissions are not nearly as important as the Social Cost of Greenhouse Gases (SCGHG) and CO2 Emissions. Sulfur dioxide emissions may also be subcritical.

3. **Premature ranking.** PSE ranks all the sensitivities with respect to a particular metric early in the analysis. This destroys meaningful distinctions between the sensitivities. For example, the cost difference between the two least expensive sensitivities is $34 million, while the difference between the two most expensive portfolios is $26 **billion**. Early ranking obscures the fact that the latter difference is 765 times larger than the former.

4. **Averaging rank scores.** After ranking is performed for each metric, all seven rank scores are averaged together to produce a composite score. Aside from the problem of treating each metric as equally important, the averaging process obscures another fact. Rank scores mean different things for different metrics. For example, the difference between rank 1 and rank 19 in the Customer Programs subcategory is 0.000004%. The difference between ranks 1 and 19 in Portfolio Cost is 208%. When the rank scores for these metrics are averaged together, the result is almost meaningless.

5. **Puzzling data.** We note that the Portfolio Cost for sensitivity M (Alternative Fuel for Peakers – Biodiesel) is the second least expensive sensitivity of this set. How can that be true, when the cost of biodiesel fuel was estimated to be ten times higher than natural gas in the webinar? Is PSE assuming that natural gas is likely to be used instead of biodiesel for practical cost reasons?

A better method

Stakeholders are developing a better method to score the sensitivities with the data PSE has provided in the spreadsheet. There has not been sufficient time to vet the new method before the deadline for comments, but we expect to publish the improved method soon. Initial results appear to produce a stronger preference for portfolios A and N1 compared to PSE's method. We believe it is possible to choose a portfolio that effectively meets CETA targets, avoids the uncertain availability and potential expense of biodiesel fuel, and keeps customer costs reasonable.

Respectfully,

Don Marsh, CENSE.org
Doug Howell, Sierra Club
Kevin Jones, Vashon Climate Action Group
Court Olson, Green building consultant, member of Shift Zero, Chair of People for Climate Action
Pete Stoppani, Indivisible Eastside
David Perk, 350 Seattle Leadership Team
Anne Newcomb
Michael Laurie, sustainability consultant, owner of Watershed LLC
Willard Westre, Union of Concerned Scientists
Kate Maracas, Managing Director, Western Grid Group

Commission Staff Feedback for Puget Sound Energy 2021 IRP
Webinar #13: Market risk assessment, stochastic analysis, preferred portfolio, Clean Energy Action Plan and overview of the CEIP and public participation – March 5, 2021

Questions and comments from presentation:

- Slide 13: This slide is interesting but it is hard to understand whether what being compared connects to the assumption, which PSE is revisiting, that its access to the Mid-C market is limited by its transmission rights, rather than by the depth of the market itself. The differences could be explained by the fact that utilities have different service areas, different peak load needs, and different transmission rights to different market hubs. Do other utilities set the assumed market availability during seasonal peaks based on their transmission rights, or do they derate the assumed availability due to other factors?
- Slide 16: We appreciate the context, and agree that price volatility is an important part of the evaluation of market reliance risk. We note that none of the three events shown here match with a capacity planning standard connected to the company's winter peak.
- Slide 17: The August 2020 event provides further evidence that PSE's winter system peak may not be the biggest reliability challenge in meeting load across the year. Does the graph on this slide represent PSE's market position in each hour? Are the purchases and sales not labeled "CAISO" all from Mid-C, or was PSE able to access other markets as well?
- Slide 17: The presence of CAISO on this graph is fascinating for multiple reasons. If I recall correctly, PSE's IRP tools model a market price for Mid-C, but do not include contemplation of other possible markets or bilateral trading partners in the WECC. This graph demonstrates that, on an operational level, PSE procures resources from sources other than Mid-C. Please describe these transactions. How common are they? What is a representative estimate of these transactions' size and frequency? Has PSE attempted to include these potential market resources in its modeling? Given that non-Mid-C market resources mitigated the need to escalate PSE's stage 1 emergency, this event illustrates that other market resources can be a critical option in maintaining system reliability.
- Slide 18: What is the distinction between a 'capacity need' and a 'market risk adjusted capacity need'? Which of these needs will PSE's 2021 IRP preferred portfolio be tailored to meet?
- Slide 18: Mr. Wetherbee's presentation included a discussion of real-time, day-ahead, and "forward" market purchases. Which types of market transactions present outsized risk during periods of shallow market depth? How is this linked to PSE's resource procurement strategy?
- Slide 18: What does PSE mean by "market risk adjusted capacity need"? Why does PSE propose reducing its market reliance from 1500 MW to 500 MW, rather than some other value (800 MW, 200 MW, 0 MW)?
- Slide 21: This slide could probably be its own webinar. We have many questions, though at this stage of the IRP process, it may be too late to revisit the analysis even if stakeholder review identifies significant concerns in methodology. We will some of the questions below, as a representative sample of the level of detail that we would encourage the company to provide when completing the narrative description of the stochastic analysis in the final IRP.
    - What datasets were used for each data input?

- How did the company represent the probability of outliers for each data input? Did the company assume a normal distribution for any or all inputs? How is distribution modeled?
    - Does the modeling account for any correlations across variables? For example, if there is a relationship between hydro generation and Mid-C prices, does the outcome of one ‘draw’ get factored into the possible outcomes for a related draw?
    - As participant Charlie Black asked, do the stochastic draws cover the entire IRP planning period, or does the stochastic modeling include draws at a more frequent timeline? We agree that a model run which assumes, for example, very bad (or very good) hydro for all 24 years of the planning horizon is an inaccurate (or at least exceedingly unlikely) representation of the possible futures that should be modeled in the stochastic analysis.
    - How are 310 iterations looking out 24 yrs
- Slide 22: As with Slide 21, staff would appreciate more details regarding how, exactly, the modeling is done.
- Slide 24: Do the 80 ‘draws’ generated from the company’s load forecast represent various percentiles of the main forecast, or was this done some other way? How did the company condense these key inputs into an aggregated 80 draws? We would like to explore whether boiling four important variables into one static 80-draw dataset might attenuate the variability that should be included in a robust stochastic analysis.
- Slide 26: As we have highlighted before, we are concerned with the continued use of historical data stretching back almost 100 years in view of our changing climate. A representation of climate and weather patterns based on distant historical data is unlikely to produce an accurate forecast of weather and climate conditions in the next 24 years.
- Slide 30: Does the frequency duration outage method in Aurora use historical outage rates for individual resources as an input? Are the outage rates adjusted for each plant based on historical performance, or based on recent maintenance or capital investment?
- Slide 31: Please see our comments for slide 21. Our line of questioning for the electric stochastic analysis also applies to the company’s natural gas stochastic analysis.
- Slide 35: We appreciate this interesting way to represent this comparison.
- Slide 42: What assumptions regarding transmission to WY and MT resources were changed? What prompted these changes? Also, we echo participant Katie Ware’s question: what updated assumptions resulted in a decrease of battery storage? What replaced those procurements, if not renewables or "flexible capacity"?
- Slide 46: For clarity, please describe the source of forecasted emissions associated with PSE’s electric system in 2045, and describe the modeled approach to offsetting these emissions.
- Slide 51: We appreciate the year-by-year breakout and the inclusion of flexible capacity in this chart. Do any of these resources make use of the 1500 MW of transmission capacity to Mid-C, effectively displacing market purchases?

Staff recommendations:

1. **Market risk capacity need adjustment** – While we agree PSE that the company’s reliance introduces price and reliability risk, the analysis provided in this presentation does not provide us with a quantification of this risk, nor does it particularly support the company’s implicit proposal of 500 MW as a target which appropriately balances the risks and benefits that come with market reliance.

We were also left with questions regarding whether the company's representation of the dwindling spot market connect directly with PSE's ability to procure energy and/or capacity through other contract arrangements. On slides 15 -17 the company shows a reduction in trading volume and increasing price volatility for what we understand to be day-ahead markets, but the company does not provide similar data for the forward market, which we understand to be longer-duration contracts and which, if we understand correctly, comprises a large share of the 1500 MW of capacity the company assumes it can acquire.

It is unfortunate that the market reliance analysis and the stochastic analysis will be seen for the first time by staff and other stakeholders in the final IRP. We encourage the company to include sufficient analysis demonstrating that the company's proposed market reliance target – whether it is 500 MW or some other number – reasonably balances the costs and benefits that come with market reliance.

2. **Stochastic risk analysis** –Staff understands that PSE is letting AURORA stochastically select a single gas price, water year, market price, force outage rate, load growth rate, etc. for the entire planning period for each future it tests, rather than using the values for each of these variables that were used to develop the "optimized" portfolio. We believe that a much better approach is to let AURORA select a different value for each "variable" each year of the planning period. This is how the real world operates, and is consistent with the NWPCC's methodology. We recommend that the company investigate, in collaboration with staff and stakeholders, how to improve its approach to stochastic risk analysis for the next IRP. On the natural gas side, we appreciate PSE's comparisons across each optimized resource portfolio's composition to see how that might change across alternative futures. While it would be a heavy lift, and it is too late for this IRP cycle, we believe a similar analysis could be done for the electric line of business.

3. **Comparative Cost of GHG Emissions Reduction:** While PSE provided multiple slides (43-47) on the level of emissions by resource portfolio, it would be very informative if it also reported a $/ton of reduction achieved by each portfolio. For example, slide 44 shows that the preferred portfolio has a NPV of $16.11 billion and produces emissions of around 0.6 million short tons in 2045 without counting market purchases and just about 1.8 million short tons with market emissions. The preferred portfolio has an NPV of roughly $580 million more than the M-1 portfolio and produces 200,000 short tons less emission in 2045. PSE should compare the cumulative emissions difference between the two portfolios over the entire 24 year planning period. The cost per ton of emissions reduction across each of the portfolios would provide the commission and stakeholders with a point of comparison with other options (i.e., securing other CETA-compliant credits or offsets, rather than building more renewables and storage or biodiesel fuel) for CETA compliance.

Invenergy Comments on Puget Sound Energy (PSE) 2021 Integrated Resource Plan (IRP) Webinar #13
Comments Submitted March 17, 2021

General Comments

Invenergy's comments on previous webinars have expressed ongoing concerns that PSE is not providing timely, unambiguous, and detailed information about its assumptions, analyses, and results for the 2021 IRP. These concerns were further reinforced during Webinar #13. Unfortunately, PSE has continued to be unwilling or unable to share meaningful information on a timely basis or constructively respond to stakeholder questions and comments.

PSE is required to file a completed IRP with the Washington Utilities and Transportation Commission by April 1, 2021. The IRP must comply with the Commission's IRP rules. At this late stage in the 2021 IRP process, it appears highly unlikely that PSE's IRP will satisfy Commission requirements for analysis or for stakeholder involvement.

Specific Comments on Webinar #13

Market Risk Assessment

During Webinar #13, PSE presented major, last-minute changes to its need for new electric capacity. The changes involve switching to a fundamentally different market risk assessment methodology that would significantly decrease PSE's reliance on market purchases from 1,500 megawatts to 500 megawatts.

In PSE's last several IRP processes, Invenergy has consistently emphasized that PSE under-estimated the risks associated with PSE's excessive reliance on short-term market purchases of electricity to serve firm retail customer needs. Invenergy agrees that PSE's market reliance should be significantly reduced from the current level of 1,500 megawatts.

However, the late change in PSE's methodology has prevented stakeholders from assessing whether PSE's methodology is reasonable. PSE has not adequately demonstrated that it can prudently wait until 2027 to reach a level of 500 megawatts of market reliance by making reductions of 200 megawatts per year.

Further, during Webinar #13, PSE did not present any information about how the resulting 1,000 MW increase in its need for new capacity will affect its preferred resource strategy. Instead, PSE stated that the impacts on its resource strategy will be included in the final IRP. This blocks meaningful review and comment by stakeholders and is simply unacceptable.

Electric Stochastic Analysis

During Webinar #13, PSE presented information on its methodology and assumptions for electric stochastic analysis. While the purpose of stochastic analysis is to incorporate the effects of short-term variability in key inputs such as natural gas prices, hydroelectric electric conditions and electric loads, PSE's analysis does not adequately reflect the impacts of the stochastic variables. This is due to oversimplification of how the stochastic variables are input and used in PSE's model. As a result, the model's outputs do not accurately reflect the impacts of stochastic variabilities.

For example, in PSE's presentation Slide 25 (Electric price charts), deviations in wholesale electricity prices from average are shown as persisting throughout the entire resource planning period, rather than deviating from year to year as actually occurs. In other words, PSE's analysis treats variabilities more as scenarios than as stochastics. As a result, the analysis under-represents the impacts of stochastic variability and introduces hidden, systemic bias in PSE's evaluation of alternate resource strategies.

Further, during Webinar #13, PSE did not present any results for its electric stochastic analysis. Instead, PSE stated that the results will be included in its 2021 IRP filing on April 1, 2021. This is another example of how PSE is not providing timely information for review and comment by stakeholders.

03/23/2021

The following consultation update is the result of stakeholder suggestions gathered through an online Feedback Form, collected between March 5 and March 12, 2021 and summarized in the Feedback Report dated March 19, 2021. PSE has elected to release both the Feedback Report and Consultation Update at the same time because the typical feedback cycle timeline would overlap with publication of the Final IRP on April 1, 2021.

PSE thanks the IRP stakeholder group for the valuable questions and recommendations following the March 5 Webinar. PSE believes many of these questions and recommendations will be reflected in the Final IRP. However, feedback which cannot be added to the Final IRP will be considered for future IRP cycles, as noted in specific responses in the Feedback Report.

Several stakeholders raised questions that could benefit from further explanation of PSE's portfolio modeling process and those details are included below.

PSE portfolio model

During the three years since the last IRP was filed, the 2017 IRP, PSE has made significant improvements to their portfolio modeling process, in particular how energy storage is modeled. During the 2017 IRP, PSE used an Excel based model called the Portfolio Screening Model (PSM). This is an annual model that relied on AURORA to dispatch the resources, and then the data was pulled into PSM where a solver was added to Excel for the linear programming (LP) optimization model. By moving the LP optimization model directly into AURORA, PSE is able to evaluate economic retirement of resources, increase the selection of new generic resources, access the ability to model energy storage resources and hybrid resources, and a utilize a more robust solver engine.

PSE expanded how energy storage resources are modeled in the IRP to include:

1. A full dispatch in the AURORA model to see how the resource charged and discharged and was able to benefit the portfolio from hour to hour.
2. A full dispatch in the PLEXOS model to see how the resource was able to benefit the portfolio in the subhourly, 15-minute re-dispatch of resources for the flexibility needs.
3. Transmission and distribution benefits from adding the battery energy storage as a distributed resource the will also benefit PSE's system.

The AURORA Long-Term Capacity Expansion simulation (LTCE) is used to forecast the installation and retirement of resources over a long period of time. Over the study period of an LTCE simulation, existing resources are retired and new resources are added to the resource portfolio.

The LTCE model begins the resource planning process by taking into account the current fleet of resources available to PSE, the options available to fill resource needs, and the necessary planning margins required for fulfilling resource adequacy needs. The resource need is calculated dynamically as the simulation is performed using demand forecasts. The LTCE model has the discretion to optimize the additions and retirements of new resources based on resource need, economic conditions, resource lifetime, and competitive procurement of new resources. The new resources that are available to the model to acquire are established prior to the execution of the model. The PSE Resource Planning team along with IRP stakeholders worked to identify potential new resources, and compiled the relevant information to these resources such as capital costs, variable costs, transmission needs, and output performance.

The AURORA LTCE model is a mixed integer linear programing optimization model. Optimization Modeling is the process of finding the optimal minimum or maximum value of a specific relationship, called the objective function. The objective function in PSE's LTCE model seeks to minimize the revenue requirement of the total portfolio, or, in other words, the cost to operate the fleet of generating resources.

When solving for each time step of the LTCE model, AURORA considers the needs of the portfolio and the resources that are available to fill those needs. The needs of the portfolio include capacity need, reserve margins, effective load carrying capacity (ELCC), and other relevant parameters that dictate the utility's ability to provide power. If a need must be addressed, the model will select a subset of resources that are able to fill that need.

At that time step, each resource will undergo a small simulation to forecast how it will fare in the portfolio. This miniature forecast takes into account the operating life, capacity output, and scheduled availability of the resource. Resources that are best able to fulfill the needs of the portfolio are then considered on the merits of their costs.

Resource costs include the cost of capital to invest in the resource, fixed operation and maintenance (O&M) costs, and variable O&M costs. Capital costs include the price of the property, physical equipment, transmission connections, and other investments that must be made to acquire the physical resource. Fixed O&M costs include the costs of staffing and scheduled maintenance of the resource under normal conditions. Variable O&M costs include costs that are incurred by running the resource, such as fuel costs and maintenance issues that accompany use.

Once the costs of operating each resource are forecasted, they are compared to find which has the least cost while serving the needs of PSE. The goal of the LTCE model, an optimization model, is to provide a portfolio of resources that minimizes the cost of the portfolio.

The capital cost of a resource plays a large role in its consideration for acquisition by the model. The frame peakers are added to the portfolio because they are the lowest cost resource that satisfies the constraints of the model, including the social cost of greenhouse gases. PSE tested this by running sensitivity P where the new frame peakers were removed from the model and the model was forced to optimize without the thermal resources (P is named: “no new thermal resources before 2030” in the Final IRP). In this sensitivity, P1, the first resource it optimized was the 2-hour lithium ion battery (P1 detail: “This portfolio limited peaker builds before 230 so that the model must meet peak capacity with alternative resourves” in the Final IRP). When the 2-hour lithium-ion battery was removed, P2, the portfolio optimized to a mix of pumped storage hydro and 4-hour lithium ion batteries at a lower cost than P2. The question is, why did P1 choose the 2-hour lithium-ion battery instead of the pumped storage hydro and 4-hour lithium-ion batteries? This question is something that PSE will continue to explore. The question on why the model chooses the frame peaker instead of the pumped storage hydro and 4-hour lithium ion battery is because the frame peaker is the lowest cost option to meet the resource adequacy needs. This can been seen in the table below that compares the costs of the different portfolios. The portfolio with the frame peakers costs $16.11 billion whereas the portfolio with the pumped storage hydro and lithium ion batteries costs $22.85 billion, $6.7 billion more than the preferred portfolio.

Portfolio	Cost (NPV $Billions)
Preferred Portfolio	$16.11
P1: 2-hr Li-Ion	$30.84
P2: Pumped storage hydro	$22.85
P3: 4-hr Li-Ion	$39.01

A complete discussion of the portfolio results will be in Chapter 8, Electric Analysis, of the 2021 IRP and a discussion of the portfolio model will be in Appendix G, Electric Analysis Models, of the Final IRP.

PSE stochastic model

Deterministic analysis is a type of analysis where all assumptions remain static. Given the same set of inputs, a deterministic model will produce the same outputs. In PSE’s IRP process, deterministic analysis identifies the least-cost mix of demand-side and supply-side resources that will meet need, given the set of static assumptions defined in the scenario or sensitivity.

Stochastic risk analysis deliberately varies the static inputs to a deterministic analysis, to test how a portfolio developed in the deterministic analysis performs with regard to cost and risk across a wide range of potential future power prices, gas prices, hydro generation, wind generation, loads and plant forced outages. By simulating the same portfolio under different conditions, more information can be gathered about how a portfolio will perform in an uncertain future. The stochastic portfolio analysis is performed in AURORA.

The goal of the stochastic modeling process is to understand the risks of alternative portfolios in terms of costs and revenue requirements. This process involves identifying and characterizing the likelihood of bad events and the likely adverse impacts of their occurrence for any given portfolio. The modeling process used to develop the stochastic inputs is a Monte Carlo approach. Monte Carlo simulations are used to generate a distribution of resource energy output (dispatched to prices and must-take), costs and revenues from AURORA. The stochastic inputs considered in this IRP are Mid-C power price, gas prices for the Sumas and Stanfield hubs, PSE loads, hydropower generation, wind generation, solar generation, and thermal plant forced outages. This section describes how PSE developed these stochastic inputs.

Hydro Draws: Monte Carlo simulations for each of PSE’s hydro projects were obtained using the 80-year historical Pacific Northwest Coordination Agreement Hydro Regulation data (1929-2008). PSE uses the same hydro data that was developed by the Bonneville Power Administration and used in BPA’s rate cases. It is also the same hydro data that is used by the Northwest Power and Conservation council along with all the other utilities in the pacific northwest. It is important to stay consistent with the other entities since we are all modeling that same hydro power projects. PSE is particular does not have a large dependence on owned or contracted hydro resources, so variations have a smaller effect on PSE’s ability to meet loads. The hydro variations have a larger effect on the available market for short term purchases which is captured in the market risk assessment.

Thermal plant forced outages: In AURORA, each thermal plant is assigned a forced outage rate based on the average of the last 5 years. This value represents the percentage of hours in a year where the thermal plant is unable to produce power due to unforeseen outages and equipment failure. This value does not include scheduled maintenance. In the stochastic modeling process the forced outage rate is used to randomly disable thermal generating plants, subject to the minimum down time and other maintenance characteristics of the resource. Over the course of a stochastic iteration, the total time of the forced outage events will converge on the forced outage rate.

PSE is very conscious of model limitations and computer run times. We have discussed the idea of the varying hydro, wind and solar for each of each draw, but we need to ask ourselves, what is the benefit? What are we trying to model? PSE is trying to model the robustness of the portfolio. If we commit to a certain set of builds and the future is different than expected, will there be enough resources to meet needs? Avista's stochastic model takes about 2 weeks to complete one run. PSE's current stochastic model takes about 1 hour per draw to run the simulation, so that is 310 hours to do the current simulations. By dividing the computer cores and sharing out between multiple machines, it takes about 2 days complete one portfolio simulation by keeping the portfolio static and not changing the hydro, wind and solar draws for each year.

The LTCE model described above takes about 18 – 24 hours to run one complete simulation for a portfolio. If PSE were to run the LTCE for each stochastic draw, then that would take 18 hours * 310 draws = 5,580 hours / 24 = 232 days to complete a portfolio simulation for each draw. PSE is working Energy Exemplar on model run times. At most, we might be able to decrease run times by half. This is why PSE does the sensitivity model, to isolate out several of the variables to see how that would effect portfolio builds.

For CETA compliance, the hydro is averaged over 4 years to try to smooth out any variation. So building to an average hydro estimate is the most prudent.

A description of the stochastic model will be included in the Appendix G of the Final 2021 IRP.