
# 4 Planning Environment

*This chapter reviews the conditions that defined the planning context for the 2021 IRP.*

## Contents

# 1. CLEAN ENERGY TRANSFORMATION ACT RULEMAKINGS

Since the passage of the Clean Energy Transformation Act (CETA) in 2019, several state agencies have been engaged in rulemakings to implement key provisions of the statute. These include the following.

1. The Washington Utilities and Transportation Commission (WUTC) – multiple topics, including the IRP, Clean Energy Implementation Plan (CEIP), and Purchase of Electricity rulemakings
2. The Department of Commerce (Commerce) – CETA rulemaking primarily for consumer-owned utilities
3. The Department of Health (DOH) – cumulative impact analysis
4. The Department of Ecology (Ecology) – unspecified emissions rate and energy transformation projects.

Each of these rulemaking efforts is summarized below. At the time of this writing, some topics remain unresolved in rulemaking and await further discussion and development in 2021.

## WUTC CETA Rulemakings

The WUTC completed three rulemakings at the end of 2020 to implement CETA: the Energy Independence Act (EIA) Rulemaking, the IRP/CEIP Rulemaking, and the Purchase of Electricity Rulemaking.

**EIA RULEMAKING*.*** The EIA rulemaking revises certain provisions of existing EIA rules to align with CETA and defines key terms related to the low-income provisions of CETA in RCW 19.405.120, including “low income,” “energy assistance need” and “energy burden.”

**IRP/CEIP RULEMAKING.** The IRP/CEIP Rulemaking outlines the timing and processes associated with filing an IRP, a Clean Energy Action Plan (CEAP) and a Clean Energy Implementation Plan (CEIP). Among many other new requirements, utilities are directed to establish equity advisory groups to advise utilities on equity issues, including vulnerable population designation, equity customer benefit indicator development and recommended approaches for compliance with RCW 19.405.040(8) as codified in the rule.

**PURCHASE OF ELECTRICITY RULEMAKING.** The Purchase of Electricity Rulemaking outlines the timing and expectations for utilities when acquiring resources that are identified as a resource need in the IRP.

In addition, the WUTC anticipates further discussions and policy development in 2021 regarding the following issues through a subsequent Markets Work Group rulemaking as required in RCW 19.405.130 or other rulemakings or policy statements.

- Non-energy benefits and the cost-effectiveness test
- No-coal attestation under CETA
- Natural gas IRP rulemaking per HB 1257
- Policy guidance for implementing Section 12 low-income provisions of CETA
- Interpreting a utility's "use" of electricity to serve customers
- Incorporating DOH's Cumulative Impact Analysis (CIA) into utility planning processes

## Department of Commerce CETA Rulemaking

The Department of Commerce (Commerce) is charged with developing rules for implementation of CETA for consumer-owned utilities. Additionally, Commerce is responsible for developing reporting procedures for all utilities, investor-owned and consumer-owned. Commerce published the final rules at the end of 2020.

## Department of Commerce CETA Low-income Draft Guidelines and WUTC Low-income Policy Development

In early 2020, the Department of Commerce released draft guidelines to support the low-income reporting requirements that utilities must meet under RCW 19.405.120 (Section 12 of CETA). Utilities provided data related to energy assistance to Commerce pursuant to the guidelines issued on November 13, 2020.

Beginning July 31, 2021, utilities must provide to Commerce a biennial assessment of the following.

- Programs and mechanisms to reduce energy burden, including the effectiveness of those programs and mechanisms for both short-term and sustained energy burden reduction.
- Outreach strategies used to encourage participation of eligible households.
- A cumulative assessment of previous funding levels for energy assistance compared to funding levels needed to meet 60 percent of the current energy assistance need or increasing energy assistance by 15 percent over the amount provided in 2018, whichever is greater, by 2030; and 90 percent of the current energy assistance need by 2050.

This assessment also must include a plan to improve the effectiveness of the assessment mechanisms and strategies towards meeting the energy assistance need.

PSE anticipates that this biennial low-income energy assistance report to Commerce will be used to inform any energy assistance potential assessment that may be required in future IRP cycles.[1]

## Department of Health Cumulative Impact Analysis

CETA directs DOH to develop a CIA of the impacts of both climate change and fossil fuels on population health, in order to designate highly impacted communities. The results of the CIA will be used to inform power utilities' planning in the transition towards cleaner energy. While DOH set out to carry out this work collaboratively with robust input from stakeholders through work group meetings and subcommittees, DOH's plans for stakeholder engagement were scaled back in 2020 after the onset of the COVID-19 pandemic. DOH released a final CIA tool in February 2021.

Under CETA, the CIA is an important tool for informing a utility's equity-related assessment in its IRP, as well as informing its Clean Energy Implementation Plans.

*1 / See Draft WAC 480-100-620(3)(b)(iii), included as part of the UTC's IRP/CEIP Final Proposed Draft Rules published on December 4, 2020.*

## Department of Ecology Rulemaking

The Department of Ecology is responsible for adopting rules that provide methods for assigning greenhouse gas emission factors for electricity and establishing a process for determining what types of projects may be eligible as "energy transformation projects" under CETA.

Ecology adopted a new rule on January 6, 2021 that establishes: 1) the default unspecified emissions factor in CETA; 2) a general process for determining eligible energy transformation projects; and 3) a process and requirements for developing standards, methodologies and procedures to evaluate energy transformation projects.

# 2. TECHNOLOGY CHANGES

## Convergence of Delivery System Planning and Resource Planning

Traditionally, the focus of an integrated resource planning process has been to determine the lowest reasonable cost mix of demand- and supply-side resources needed to meet the total projected load and peak needs of its customers with an adequate reserve margin. In Washington state, the planning process is prepared under rules or requirements for an IRP and reviewed by state utility commissions.

The IRP process includes the cost of transmission and distribution infrastructure needed to connect and transmit the power from potential new generation sources; however, planning for the transmission and distribution delivery systems that ensure power can be delivered to end-use customers has traditionally been separate from the IRP process.

A variety of economic, technological and societal factors are changing the electric utility planning process and blurring the historical division between delivery system planning (DSP) and integrated resource planning. These include the increasing affordability of solar generation (including rooftop solar), the maturing of battery storage technology, electric vehicle adoption, advancements in customer management and information about electricity use, and advancements in the management and data systems used to integrate and control distributed energy technologies.

In the future, continued growth of customer solar generation and other distributed energy resources will contribute to meeting the overall resource need but will also lead to power being pushed back to a distribution feeder that was not designed for two-way power flows. This will require PSE to plan and build a grid that is different than today to capture the resource benefit effectively. The grid of the future needs to be safe, reliable, resilient, smart, clean and flexible.

Washington State's Clean Energy Transformation Act is also driving change. It recognizes that transforming the state's energy supply requires the modernization of its electricity system and that clean energy action planning must include any need to develop new, or expand or upgrade existing, bulk transmission and distribution facilities. Additionally RCW 19.280.100, resulting from House Bill 1126, furthers this connection as energy supply needs are met through distributed energy resources (DERs). It established a policy that guides how distributed energy resource planning processes are to occur in order to illuminate the interdependencies among customer-sited energy and capacity resources.

With this backdrop, PSE is in the process of increasing the coordination of delivery system planning with resource planning, as it provides benefits by bringing together solutions to address delivery system challenges while meeting resource needs. With the increasing maturity and feasibility of DERs, delivery system needs may be solved using these non-traditional solutions at local points or in certain areas of the delivery system. If these non-traditional resources decrease load (such as demand response programs) or provide a generation source (such as rooftop solar), they may also provide benefit to the overall energy supply resource portfolio. This creates a natural connection between DSP and energy supply resource planning.

Historically, the two planning processes have occurred on separate timelines. However, DERs installed in sufficient quantity to solve delivery system needs may change the results in the resource planning process, so coordinating the two benefits both processes and analyses.

A coordinated process must accommodate:

- customer-owned resources and electric vehicles
- programs such as distribution automation and demand response
- distributed energy resources
- energy storage
- energy efficiency strategies

In addition to incorporating the cost of transmission and distribution infrastructure, the IRP and DSP processes use some of the same core information in different ways. Data flows from one process to the other at different steps as shown in Figures 4-1 and 4-2.

The confluence of technology, customer adoption, grid integration capability and solution effectiveness will drive the pace of interconnecting the DSP and IRP processes.

*Figure 4-1: Data Flows between Delivery System Planning and Integrated Resource Planning*

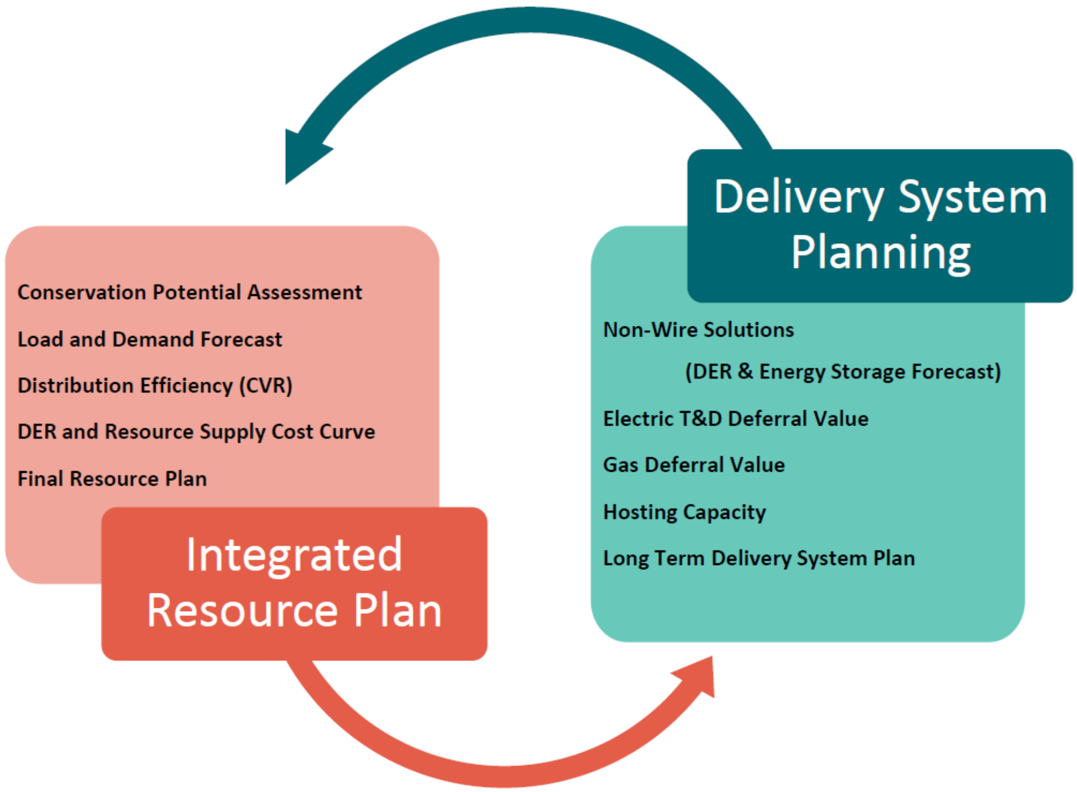

*Figure 4-2: Data Flows between Delivery System Planning and Integrated Resource Planning (Table)*

| | | |
|---|---|---|
| IRP Outputs in the DSP | Conservation Potential Assessment | Decreases county-level system capacity needs |
| | Load and Demand Forecast | Decreases county-level system capacity needs |
| | Distribution Efficiency (CVR) | Decreases capacity needs where implementable and may be a solution alternative |
| | DER and Resource Supply Cost Curve | Cost supply curve including different types of DER resources which could be used as non-wire solution alternatives if located appropriately |
| | Final Resource Plan (including DER's) | Insight for participation in resource acquisition process for DERs to enhance locational value opportunities and informs enabling grid modernization requirements |
| DSP Outputs in the IRP | Non-wire Solutions (DER & Energy Storage Forecast) | Decreases overall resource need by identifying must-take DER resources to meet specific transmission and distribution delivery needs |
| | Electric T&D Deferral Value | Provides a quantitative value of past T&D investments to use in the conservation potential assessment |
| | Gas Deferral Value | Provides a quantitative value of past investments to use in the conservation potential assessment |
| | Hosting Capacity (future) | Future input for economic opportunities |
| | Long-term System Delivery Plan | Future input for opportunities and constraints that should be considered |

## New Fuel Technologies

### Renewable Natural Gas

Renewable natural gas (RNG) is pipeline quality biogas that can be used as a substitute for conventional natural gas streams. Renewable natural gas is gas captured from sources like dairy waste, wastewater treatment facilities and landfills. The American Biogas Council ranks Washington 22nd in the nation for methane production potential from biogas sources, with the potential to develop 128 new biogas projects within the state. RNG is significantly higher cost than conventional natural gas; however, it provides greenhouse gas benefits in two ways: 1) by reducing $CO_2e$ emissions that might otherwise occur if the methane and/or $CO_2$ is not captured and brought to market, and 2) by avoiding the upstream emissions related to the production of the conventional natural gas that it replaces.

RNG is not yet produced at utility-scale in this region and will require developing both supply sources and an infrastructure to deliver that supply to utilities. RNG will most likely be directed toward natural gas utilities before being used as a generation fuel. The electric sector has access to a more mature set of renewable options than the natural gas sector; these include hydro, wind, solar, geothermal and energy storage systems that can capture surplus energy. Natural gas utilities have very few options to decarbonize, so as natural gas utilities begin decarbonizing their systems in earnest, markets will probably pull RNG to natural gas utilities before it is used broadly as generation fuel. Costs remain high to upgrade RNG to gas pipeline specifications and bring it to market. Another obstacle is that RNG currently generated in the U.S. is mostly used as a transportation fuel because of federal and state programs such as the EPA's Renewable Fuel Standard (RFS) and California's Low Carbon Fuel Standard (LCFS), which provide more value through generating credits than when it is used for end-use consumption or to generate electricity. However, the existing natural gas distribution network can be used to deliver renewable fuel.

HB 1257 became effective in July, 2019, and PSE is working with the WUTC and other stakeholders to develop guidelines to implement its requirements. However, recognizing the competitive nature of the existing RNG market, PSE concluded that there would be an advantage to be a first-mover. To that end, PSE conducted a RFP to determine availability and pricing of RNG supplies. After analysis and negotiation, PSE acquired a long-term supply of RNG from a recently completed and operational landfill project in Washington at a competitive price. PSE is in final design of Tariff provisions and IT enhancements to facilitate availability of a voluntary RNG program for PSE customers to take effect in the first half of 2021. RNG supply not utilized in

PSE's voluntary RNG program(s) will be incorporated into PSE's supply portfolio, displacing natural gas purchases as provided for in HB 1257.

In addition, PSE has a current offering called Carbon Balance which provides residential natural gas customers the choice to purchase blocks of carbon offsets for a fixed price. The program provides customers with a way to reduce their carbon footprint through the purchase of third-party verified carbon offsets from local projects that work to reduce or capture greenhouse gases.

This IRP does not analyze hypothetical RNG projects that would connect to NWP or to PSE's system and displace conventional natural gas that would otherwise flow on NWP pipeline capacity. Because of RNG's significantly higher cost, the very limited availability of sources, and the unique nature of each individual project, RNG is not suitable for generic analysis. The benefits of RNG are measured primarily in terms of $CO_2e$ reduction, which are unique to each project. The incremental costs of new pipeline infrastructure to connect the RNG projects to the NWP or PSE system are also unique to each project. Avoided pipeline charges realized by connection of acquired RNG directly to the PSE system will be considered, but are not significant, relative to the cost of the RNG commodity. Contract RNG purchases present known costs, however, many projects may not materialize absent a capital investment by PSE. Due to the very competitive RNG development market, including competition from the California compliance markets, PSE is not prepared to discuss specific potential RNG projects in a public environment. Individual projects will be analyzed and documented as PSE pursues additional supplies.

The aforementioned contract acquisition of landfill RNG will, within a few years, provide RNG equal to approximately 2 percent of PSE's current supply portfolio and as much as a 1.5 percent reduction in the carbon footprint of PSE's gas system, annually. PSE is planning significant further investments in cost-effective RNG supplies and continues to believe there is value in being a proactive RNG buyer and/or producer in the region. PSE is confident that it can acquire sufficient RNG volumes to meet the needs of its future Voluntary RNG Program participants and even exceed the 5 percent cost limitation related to the RNG incorporated into the supply portfolio. In order to meet the expectations within the WUTC RNG Policy Statement, PSE will utilize staggered RNG supply contracts and project development timelines, resales in compliance markets and other techniques to manage RNG costs while maximizing the availability of RNG in its portfolio and achieving meaningful carbon reductions.

## Biodiesel

Biodiesel is defined as a renewable resource under section 2 (34) of CETA. To be considered renewable, biodiesel must not be derived from crops raised on land cleared from old growth or first-growth forests. Biodiesel is chemically similar to petroleum diesel but is derived from waste cooking oil or from dedicated crops. According to the U.S. Energy Information Administration, there are two facilities in Washington state that make biodiesel, which together can manufacture upwards of 100 million gallons of biodiesel a year.[2] Biodiesel may become crucial in the future as a fuel supply for combustion turbines. These units would be the same basic generator as a natural gas combustion turbine, but instead of burning natural gas with petroleum diesel as a backup fuel, the generator would burn renewable natural gas with biodiesel as the backup fuel. Biodiesel may also serve as a primary fuel for combustion turbines intended for strictly peak need events. At full capacity, a 237 MW frame peaker would require approximately 25,000 gallons of biodiesel per hour. At this fuel feed rate, a facility would require about 1.2 million gallons of biodiesel storage to continuously fire for a 48-hour peak event. Existing Washington state biodiesel production could plausibly supply several combustion turbines intended to supply reliable capacity during critical hours. This technology may be crucial to maintaining a reliable, renewable electric system during low hydro conditions.

Biodiesel use in simple-cycle combustion turbines is explored in this IRP. An analysis of the amount of fuel needed is in Chapter 7, Resource Adequacy Analysis, and the results of the portfolio optimization are in Chapter 8, Electric Analysis.

## Hydrogen

Renewable hydrogen, also known as power-to-gas, is a process by which excess renewable electricity can be transformed (by splitting hydrogen from water) into hydrogen, or, if combined with carbon, synthetic natural gas. These fuels can then be stored utilizing existing natural gas pipeline infrastructure to more cost effectively shift seasonal supply when mismatched with demand.

PSE is a founding member of the Renewable Hydrogen Alliance (RHA). The RHA promotes using renewable electricity to produce climate-neutral hydrogen and other energy-intensive products to supplant fossil fuel consumption. This group is instrumental in keeping PSE up to date on industry developments.

Hydrogen or its derivatives can be used to reduce the GHG content of gas for gas utilities. Renewable hydrogen can be injected into the existing pipeline infrastructure. The amount of hydrogen that can be blended into the pipeline system with natural gas is limited, because hydrogen is less energy dense than current standards for pipeline quality gas. That means a cubic foot of hydrogen has less energy than a cubic foot of natural gas. Pipeline systems are required to maintain heat content within predetermined ranges for safety reasons. Natural gas-consuming equipment and appliances are designed to use a certain amount of gas per unit of

2 / *https://www.eia.gov/biofuels/biodiesel/capacity/*

time, so the gas feeding that equipment needs to maintain these standards. Currently, it appears the ratio of hydrogen that could be injected into the system is about 20 percent.

Hydrogen can also be used as a fuel in gas combustion turbines – both simple-cycle and combined-cycle plants. The hydrogen can be blended into the upstream natural gas supply and delivered on existing infrastructure, based on the physical safety limits described above for gas utilities. Hydrogen can also be injected directly into combustion turbines or blended in higher ratios than 20 percent, if the hydrogen manufacturing, storage and delivery infrastructure is built.

A significant challenge for hydrogen is cost. Today, gray hydrogen (hydrogen manufactured with fossil fuel energy) sells for about $2 per kilogram delivered to a few key chemical market hubs, which translates to about $17.6 per MMBtu for natural gas.[3] While green hydrogen may use surplus renewable electricity that may cost less on a dollars per MWh basis, the output of a hydrogen manufacturing facility using only surplus renewable energy will be less, which will drive up the average cost per unit.

For this IRP, PSE explored hydrogen as an alternative fuel source for the combustion turbines. Though manufacturers have done extensive development for a hydrogen-fueled combustion turbine, it was difficult to get a price forecast for the fuel. Also, the modeling techniques are not available to model hydrogen as both a storage for renewable energy and a fuel for the combustion turbines. PSE will continue to explore hydrogen as a fuel source for combustion turbines and new modeling techniques for future IRPs.

*3 / See S&P Global at: https://www.spglobal.com/ratings/en/research/articles/201119-how-hydrogen-can-fuel-the-energy-transition-11740867#:~:text=S%26P%20Global%20Ratings%20believes%20hydrogen,and%20massive%20growth%20of%20renewables.&text=A%20Hydrogen%20Council%20report%20suggests,primary%20energy%20supply%20by%202050*

# 3. WHOLESALE MARKET CHANGES

## Prices, Volatility and Liquidity / August 2020 Supply Event

Wholesale electricity prices in the Pacific Northwest remain, on average, relatively low. In recent years, however, these relatively low prices have been punctuated by periods of high volatility and limited market liquidity.

On August 17, 2020, in the middle of a heat wave affecting the western U.S., the region's reliability coordinator declared an Energy Emergency Alert for PSE and four other grid operators in the WECC, indicating these entities risked not having sufficient energy supply to meet their load and reliability obligations. Wholesale market dynamics and reliance on energy transfers from neighboring entities were key factors in how this event developed in the Northwest. In the day-ahead market, power prices at the Mid C hub spiked to more than five times what they were just days earlier. Offers to sell power at Mid C disappeared as available supply flowed to even higher priced delivery points in California and the desert southwest. By Monday August 17, 2020, forecasted load had increased with higher temperatures, but additional supply in the Mid C real-time market was extremely scarce. For the highest load hours of the day PSE was unable to procure power at any price. In California, the situation was even more severe, and in the days leading up to August 17, 2020, CAISO implemented rolling black-outs in order to maintain grid stability.

In its report on the August 2020 event, CAISO identifies extreme heat resulting from climate change and the evolving mix of generation resources as primary factors leading to insufficient supply conditions. As extreme temperatures become more common and traditional thermal resources continue to be replaced with variable renewable resources, high price volatility and the risk of unavailable supply are likely to be more prevalent in western U.S. wholesale power markets.

## Market Developments / CAISO EDAM

In late 2018, CAISO engaged stakeholders to examine the feasibility of extending participation in its day-ahead market to entities already participating in the energy imbalance market (EIM). Potential benefits of an extended day-ahead market (EDAM) include production cost savings through more efficient use of available transmission, more efficient day-ahead unit commitment, and the creation of day-ahead base schedules at hourly granularity; diversity of imbalance reserves; and environmental benefits including reduced curtailment of renewable resources. EDAM would operate in a framework similar to EIM's approach to the real-time market, which does not require full integration into the California ISO balancing area. Participating entities and their regulatory authorities would remain responsible for transmission planning, resource adequacy and balancing area control performance.

A feasibility assessment completed near the end of 2019 identified significant benefits associated with the EDAM proposal, and stakeholder entities have since started work on more specific market design criteria. Evaluation of topics including governance, resource sufficiency requirements and the distribution of market benefits has been ongoing throughout 2020, and a final market design proposal is expected in late 2021.

# 4. REGIONAL RESOURCE ADEQUACY

Utilities across the Northwest have partnered to explore a potential regional resource adequacy program. Resource planning in the Northwest is currently done on a utility-by-utility basis, typically through integrated resource planning processes. This utility-by-utility planning framework has worked well for the region during times when the region was surplus capacity. As large amounts of firm generators retire and several regional studies point to a capacity deficit in the next decade, utilities have growing concerns about whether the new capacity needed to maintain regional reliability can be procured in a timely manner. A Northwest resource adequacy program would offer two key benefits: reliability and cost savings. First, a regional resource adequacy program would ensure that sufficient generation is available to reliably serve demand during periods of grid stress. Resource adequacy programs do this by establishing transparent processes to assess, allocate and procure a region’s resource needs. Second, a regional resource adequacy program would enable cost savings. By planning for the peak demand of the entire region (the coincident peak demand) instead of each utility’s individual (non-coincident) peak demand, a regional approach would produce an overall lower capacity need and therefore a reduced level of investment. Furthermore, larger systems tend to require lower reserve margins because they are less vulnerable to single contingencies and variation in supply and demand.

Resource adequacy programs deliver these benefits by establishing transparent, coordinated calculations of required capacity and offering mechanisms for sharing resources among participants. A resource adequacy program in the Northwest would help the region navigate reliability and cost challenges given its evolving resource mix.

In late 2019, NWPP members initiated a resource adequacy program design development process. In mid-2020, the NWPP Resource Adequacy Program Conceptual Design was completed and Southwest Power Pool (SPP) was hired to lead the detailed design in partnership with the NWPP members. At the time of this writing, the detailed design is underway, and the process is expected to conclude in mid-2021. The timeline for the overall resource adequacy program implementation is estimated to be in 2024. PSE is actively involved in the design development process and looks to leverage program benefits. Future IRPs will need to incorporate the RA program into its resource adequacy analysis and overall planning process.

# 5. FUTURE DEMAND UNCERTAINTY FACTORS

## Electric Vehicles

Electric vehicles (EVs) are rapidly gaining a presence in PSE's service territory and taking hold in every vehicle market. These EVs include light-duty vehicles, medium-duty vehicles, and heavy-duty vehicles, both cars and trucks, and they are operated by individuals and as members of fleets. EVs create new electric load, and the pace and scale of EV adoption is key to the magnitude of these impacts on utility demand. PSE contracted for an EV sales and load forecast, which was then incorporated into the 2021 IRP Demand Forecast. This forecast revealed new opportunities to manage EV load and improve customer experience, which PSE is investigating through a suite of EV pilot programs.

The 2021 IRP Base Demand Forecast incorporates GuideHouse's incremental EV energy forecast by excluding demand from existing vehicles. See Chapter 6, Demand Forecasts, for a discussion of base energy demand and peak impacts.

### Demand Impacts

The Electric Vehicle Charger Incentive (EVCI) Pilot Program, which went into effect on May 1, 2014, allowed PSE to offer a $500 rebate to customers who purchase their own Level 2 electric vehicle charger.[4] Using data gathered through this pilot, PSE created an "Electric Vehicle Household and Charger Load Profiling" study with a study period set for 12 months ending June 2017. At the time, there were an estimated 13,140 EVs registered in PSE's electric service territory, of which 9,480 were 100 percent battery-operated (BEV) and 3,660 were plug-in hybrid vehicles (PHEV).[5]

The key findings of the study were as follows:

- On a typical weekday, hourly load per Level 2 EV charger varied between 0.1 kW and 0.9 kW while hourly load per Level 1 charger ranged between 0.06 kW and 0.6 kW.[6]
- On a typical weekend day, hourly load per Level 2 charger ranged between 0.08 kW and 0.6 kW while the range of hourly load per Level 1 charger was 0.04 kW to 0.5 kW.

*4 / Docket UE-131585*
*5 / A list of EV's registered through the end of June 2017 was provided by Washington State Department of Licensing.*
*6 / The average hourly load per EV charger should not be interpreted as the hourly energy use by a typical EV charger. For example, a typical Level 2 charger uses between 1.1 kW and 2.6 kW while in use and close to zero while not in use. An individual L2 charger load shape would be characterized by a flat load at nearly zero kW for most of the day interrupted by one or more charging events which last a few hours or so per event.*

- Daily peak of EV charger load occurred mostly in the early evening hours of 6:00 PM to 8:00 PM, as does monthly system peak demand.
- Monthly load factor and system coincidence factor of EV charger loads are fairly low for most months. During the study period, all of the monthly load factors were below 0.29 while 8 of 12 monthly system coincidence factors were lower than 0.40. However, the system coincidence factor will become very high if monthly system peak and EV charger peak loads occur on the same day, as happened in March 2017 when the system coincidence factor was 0.91.

Although at the time of this study EVs represented a very small portion of the residential class load, PSE predicts that by 2032 there will be more than 250,000 Light Duty EVs in PSE's service territory.

To study the implications of this growing load that can be added anywhere and potentially coincident with peak, PSE's Up & Go Electric programs are actively working to develop load shapes for additional charging use cases that are specific to PSE's electric service territory. This suite of pilot programs is expanding to include workplace charging, multi-unit dwellings, public charging, many unique low-income use cases, a more refined load profile for single-unit dwelling charging, and to capture a broader audience for each of these use cases. The programs will also develop load profiles for prominent medium and heavy duty vehicle charging use cases.

In addition to developing load shapes, a key goal of PSE's Up & Go Electric program is to investigate the most effective and efficient ways of encouraging and enabling EV customers to shift charging to off-peak hours in a way that minimizes demand-side impacts. These programs are ongoing and final results are not yet available, but PSE has already applied some of the early lessons learned to the design of future programs to ensure that customer load is managed not only to reduce coincidence with system peak, but also to minimize the coincidence of charging between EV chargers.

## Energy Efficiency Technology, Codes and Standards and Electrification

Changing codes and standards and energy efficiency technology are impacting both customer choices and energy efficiency programs.

In terms of energy efficiency programs for example, when federal minimum lighting performance standards included screw-in LED lighting, this removed LEDs from energy efficiency program offerings; while LEDs continue to achieve savings, they could no longer be included in incentive programs.

The two energy codes that impact PSE customers, the Washington State Energy Code (WSEC) and the Seattle Energy Code, are transitioning to include a focus on carbon emissions in addition to energy efficiency, and these changes emphasize electrification of systems formerly fueled by natural gas. Since 2018, the WSEC no longer gives builders efficiency credits for new single family homes that install natural gas space heating or water heating, instead giving them credits for installing heat pumps for space and water. In 2021, the Seattle Energy Code put significant barriers on using natural gas for space and water heating in new commercial and multi-family buildings. With few exceptions, new buildings will be using various types of heat pump technology to attempt to meet the loads of these systems.

While technology continues to provide innovation in how loads are met in customer homes and buildings, it takes time for these changes to gain significant market penetration. Heat pump water heaters, for example, have been on the market for nearly a decade, but they are largely limited to the new home market rather than the much larger existing home market. When code changes move quickly, adoption issues arise and may include: the lack of robust examples/applications that have validated particular approaches (such as the sole use of heat pumps to serve both space and water heating in large-demand applications, essentially new building electrification); the complexity of the design, operation and maintenance of systems that have been largely hands-off traditionally; and the installer community not being fully prepared to transition to installing and maintaining these systems. Time is required to work out design flaws, build trust in the installer/trades community, and drive down costs so that consumers will pay reasonable costs to make these changes.

Despite how quickly changes are taking place in the areas of technology and codes and standards, PSE remains committed to ensuring its customers are made aware of the opportunities to reduce energy use and carbon footprints, advocating for smart changes to codes and standards and working with our trade allies to understand and mitigate barriers to new technology adoption.

## Distributed Energy Resources

DER-based generation, such as rooftop solar panels, has seen price declines and increases in customer adoption. The technology and its rate of adoption are still evolving, and therefore future demand can be significantly impacted by policy, including incentives, and technological advances, including further price declines.

While PSE customer adoption of DER is low when compared to states like California and Hawaii, PSE residential solar is increasing by about 2,000 customers annually. Additionally, the average capacity of residential solar is increasing. In 2009, the average residential capacity was 4.7 kW, while the current average system generating capacity is 10 kW. As of the end of 2020, PSE's system hosted 85 MW of net metered solar, with over 10,100, or about 1 percent, of customers participating. In comparison, solar represents about 25 percent of Hawaii's generation capacity and over 10 percent of its residential customers have solar generation.

Adding increasing volumes of DERs to the distribution system, whether they are generating technologies such as solar, storage technologies such as batteries, or load management tools, requires rethinking how the distribution system operates and what standards and controls are needed to maintain the safety and reliability of the system. Demand will be impacted by when and how these technologies operate, whether dependably and reliably decreasing load or intentionally increasing load if charging is allowed during peak hours.

Additionally, most customers pursing DER solutions today do not consume all of the energy they generate on-site in real time, making demand and power flow more variable on the local distribution system and resource management overall. Storage and control systems promise improvement in managing DERs' benefits and impacts on demand, and over 4 percent of PSE's net metered solar installations include battery storage today. These emerging capabilities are maturing, and as monitoring, control, communications, delivery infrastructure and energy storage systems are modernized, opportunities to understand real demand impacts will increase.

For this IRP, PSE explored and modeled numerous future DER options; these are documented in Chapters 5 and 8.

# 6. NATURAL GAS SUPPLY AND PIPELINE TRANSPORTATION

## Risks to Natural Gas Supply

Natural gas is imported to the Pacific Northwest, primarily from British Columbia and the Rocky Mountain region. Disruptions to natural gas transportation infrastructure, therefore, present a risk to reliable gas supply in the region.

In October 2018 the Westcoast Pipeline, a major pipeline that brings natural gas from British Columbia south to the U.S. border, ruptured, severely limiting the supply of natural gas to the Pacific Northwest. Through a combination of immediate conservation efforts, the shutdown of natural gas fired power plants, and curtailment of service to select industrial customers, the region only narrowly avoided destabilization of the natural gas transportation system and curtailment of service to large swaths of natural gas customers.

Capacity restrictions on the Westcoast Pipeline continued well into 2019 causing a dramatic increase to wholesale natural gas prices in the region. By late 2019, the pipeline had been restored to normal full capacity, and while average gas prices have generally returned to pre-event levels, prices remain significantly more volatile compared to recent historical periods.

The lessons learned from the October 2018 event were applied in the restructured Northwest Mutual Assistance Agreement (NWMAA). The Agreement is made among entities that utilize, operate and control natural gas transportation and/or storage facilities in the Pacific Northwest (British Columbia, Alberta, Washington, Oregon, Nevada and Idaho). The Agreement[7] is intended to define the terms and conditions for cooperation and/or assistance between the parties in an emergency if such aid is volunteered. Another objective is to maintain and improve communication linkages between the members as they pertain to emergency planning and incident response.

*7 / https://www.westernenergy.org/nwmaa/*

# 7. PURCHASING VERSUS OWNING ELECTRIC RESOURCES

The IRP determines the supply-side capacity, renewable energy and energy need which set the supply-side targets for future detailed planning in the Clean Energy Implementation Plan, as well as the acquisition process. The formal Request for Proposal (RFP) processes for demand-side and supply-side resources are just one source of information for making acquisition decisions. Market opportunities outside the RFP and resource build decisions should also be considered when making prudent resource acquisition decisions.

In Build versus Buy, “Build” refers to resource acquisitions that involve PSE ownership of an asset. Ownership could occur anywhere along the development life cycle of a project. PSE could complete development activities from the beginning or buy the asset anywhere from early stage development to Commercial Operation Date (COD) or after. “Buy” refers to purchase of the output of a project through a Power Purchase Agreement (PPA).

In general, quantitative and qualitative evaluations for Build and Buy proposals are conducted similarly in an RFP, consistent with WAC 480-107, solving for the lowest cost options for customers. Qualitative project risks are evaluated in the same way for both kinds of acquisitions. Quantitative evaluations for Build options include costs of ownership such as operating expenses and depreciation. These are typically embedded in the MWh price for PPAs. Build proposals include the allowable rate of return on capital assets as a cost to customers, while Buy proposals include a return on the PPA costs as allowed by the Clean Energy Transformation Act. Project designs also need to be more carefully scrutinized for projects that PSE would own and operate. Equipment selection and design specifications must meet PSE standards for ownership.

In the 2018 RFP, PSE received a large number of ownership proposals. These proposals included offers for PSE to take ownership of projects before COD, at COD and after COD. Primarily because of the fact that PSE cannot monetize federal tax incentives for renewable projects, these proposals were not competitive relative to PPAs.