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2017 PSE Integrated Resource Plan

Electric Resources and Alternatives

This appendix describes PSE's existing electric resources; current electric resource alternatives and the viability and availability of each; and estimated ranges for capital and operating costs.[1]

Contents

1 / Operating costs are defined as operation and maintenance costs, insurance and property taxes. Capital costs are defined as depreciation and carrying costs on capital expenditures.

1. RESOURCE TYPES

It is helpful to understand some of the distinctions used to classify electric resources.

Supply-side and Demand-side

Both of these types of resources are capable of enabling PSE to meet customer loads. Supply-side resources provide electricity to meet load, and these resources originate on the utility side of the meter. Demand-side resources reduce load and originate on the customer side of the meter. An “integrated” resource plan includes both supply- and demand-side resources.

SUPPLY-SIDE RESOURCES for PSE include:

- PSE’s generating plants, including baseload gas, peakers, coal, water and wind plants
- Long-term contracts with independent producers to supply electricity to PSE (these have a variety of fuel sources)
- Transmission contracts with Bonneville Power Administration (BPA) to carry electricity from short-term wholesale market purchases to PSE’s service territory

DEMAND-SIDE RESOURCES for PSE include:

- Energy efficiency programs
- Customer programs

The contribution that demand-side programs make to meeting resource need is accounted for as a reduction in demand for the IRP analysis.

Thermal and Renewable

These supply-side resources are distinguished by the type of fuel they use.

THERMAL RESOURCES use fossil or other fuels to generate electricity (gas, oil, coal, uranium). PSE’s gas-fired and coal-fired generating facilities are thermal resources.

RENEWABLE RESOURCES use renewable fuels such as water, wind, sunlight and biomass to generate electricity. Hydroelectricity and wind generation are PSE’s primary renewable resources.

Baseload, Peaking, Intermittent and Storage

These distinctions refer to how the resource functions within the system.

BASELOAD RESOURCES produce energy at a constant rate over long periods at a lower cost relative to other production facilities available to the system. They are typically used to meet some or all of a region's continuous energy demand. Baseload resources usually have a high fixed cost but low marginal cost and thus could be characterized as the most efficient units of the fleet.

For PSE, baseload resources can be divided into two categories: thermal and hydro. These have different dispatching capabilities. Thermal baseload plants can take up to several hours to start and have limited ability to ramp up and down quickly, so they are not very flexible. Hydro plants, on the other hand, are very flexible and are typically the preferred resource to use to balance the system.

PSE's three sources of baseload energy are baseload gas plants, hydroelectric generation and coal-fired generation.

PEAKING RESOURCES are quick-starting units that can ramp up and down quickly in order to meet short-term spikes in need. They also provide flexibility needed for load following, wind integration and spinning reserves. Peaking resources generally have a lower fixed cost but are less efficient than baseload plants. Historically, gas-fueled peaking units have low capacity factors because they are often not economical to operate compared to market purchases.

The flexibility of peaking resources will become more important in the future as new renewable resources are added to the system and as PSE participates in the Energy Imbalance Market.

PSE's peaking resources include simple-cycle combustion turbines and hydroelectric plants that can perform peaking functions in addition to baseload functions.

INTERMITTENT RESOURCES provide power that offers the company limited discretion in the timing of delivery. Renewable resources like wind and solar are intermittent resources because their generating patterns vary as a result of uncontrollable environmental factors, so the timing of delivery from these resources doesn't necessarily align with customer demand in the Puget Sound area. As a result, additional resources are required to back up intermittent resources in case the wind dies down or the sun goes behind a cloud.

PSE's largest intermittent resource is wind generation, and to a lesser extent, rooftop solar generation, which has achieved some market penetration within PSE's system. Smaller intermittent resources include small power production within the system and the 10 aMW of energy PSE is required to take from co-generation.

For planning purposes, PSE includes the randomness, forced outage rates and curtailments of each particular type of technology in its analysis.

ENERGY STORAGE has the potential to provide multiple services to the system, including efficiency, reliability, capacity arbitrage, ancillary services and backup power for intermittent renewable generation. It is capable of benefiting all parts of the system – generation, transmission, distribution and end-use customers; however, these benefits vary by location and the specific application of the product. For instance, a battery in one location could be installed to relieve transmission congestion and thereby defer the cost of transmission upgrades, while a battery at another location might be used to back up intermittent wind generation and reduce integration costs. The drawbacks to energy storage are that it operates with a limited duration and requires generation from other sources. Detailed modeling is required to fully evaluate the value of energy storage at the sub-hourly level.

Capacity Values

The tables on the following pages describe PSE's existing electric resources using the net maximum capacity of each plant in megawatts (MW). Net maximum capacity is the capacity a unit can sustain over a specified period of time – in this case 60 minutes – when not restricted by ambient conditions or de-ratings, less the losses associated with auxiliary loads and before the losses incurred in transmitting energy over transmission and distribution lines. This is consistent with the way plant capacities are described in the annual 10K report[2] that PSE files with the U.S. Securities and Exchange Commission and the Form 1 report filed with the Federal Energy Regulatory Commission (FERC).

Different plant capacity values are referenced in other PSE publications because plant output varies depending upon a variety of factors, among them ambient temperature, fuel supply, whether a natural gas plant is using duct firing, whether a combined-cycle facility is delivering steam to a steam host, outages, upgrades and expansions. To describe the relative size of resources, it is necessary to select a single reference point based on a consistent set of assumptions. Depending on the nature and timing of the discussion, these assumptions – and thus the expected capacity – may vary.

2 / PSE's most recent 10K report was filed with the U.S. Securities and Exchange Commission in March 2017 for the year ending December 31, 2016. See http://www.pugetenergy.com/pages/filings.html.

2. EXISTING RESOURCES INVENTORY

Supply-side Thermal Resources

Coal

Reliable, low-cost electricity from the Colstrip generating plant currently supplies 18 percent of PSE's baseload energy needs.

THE COLSTRIP GENERATING PLANT. Located in eastern Montana about 120 miles southeast of Billings, the plant consists of four coal-fired steam electric plant units. PSE owns 50 percent each of Units 1 & 2 and 25 percent each of Units 3 & 4. PSE's total ownership in Colstrip contributes 677 MW net maximum capacity to the existing portfolio.

Baseload Gas

PSE's six baseload gas plants (combined-cycle combustion turbines or CCCTs) have a combined net maximum capacity of 1,293 MW and supply 19 to 27 percent of PSE's baseload energy needs, depending on market heat rates and plant availabilities. In a CCCT, the heat that a simple-cycle combustion turbine produces when it generates power is captured and used to create additional energy. This makes it a more efficient means of generating power than the peakers (simple-cycle turbines) listed below. PSE's baseload gas fleet includes the following.

MINT FARM is located in Cowlitz County, Wash.

FREDERICKSON 1 is located in Pierce County, Wash. (PSE owns 49.85 percent of this plant; the remainder of the plant is owned by Atlantic Power Corporation.)

GOLDENDALE is located in Klickitat County, Wash.

ENCOGEN, FERNDALE and **SUMAS** are located in Whatcom County, Wash.

Figure D-1: PSE's Owned Baseload Coal and Gas Resources

POWER TYPE	UNITS	PSE OWNERSHIP	NET MAXIMUM CAPACITY (MW)[1]
Coal	Colstrip 1 & 2[2]	50%	307
Coal	Colstrip 3 & 4	25%	370
Total Coal			**677**
CCCT	Encogen	100%	165
CCCT	Ferndale[3]	100%	253
CCCT	Frederickson 1[3,4]	49.85%	136
CCCT	Goldendale[3]	100%	315
CCCT	Mint Farm[3]	100%	297
CCCT	Sumas	100%	127
Total CCCT			**1,293**

NOTES
1. Net maximum capacity reflects PSE's share only.
2. In July 2016, PSE reached a settlement with the Sierra Club to retire Colstrip Units 1 and 2 no later than July 1, 2022.
3. Maximum capacity of Ferndale, Frederickson 1, Goldendale and Mint Farm includes duct firing capacity.
4. Frederickson 1 CCCT unit is co-owned with Atlantic Power Corporation - USA.

Peakers

These gas-fired simple-cycle combustion turbines (SCCTs) provide important peaking capability and help us to meet operating reserve requirements. The company displaces these resources when their energy is not needed to serve load or when lower-cost energy is available for purchase. PSE's four peakers contribute a net maximum capacity of 612 MW. When pipeline capacity is not available to supply them with natural gas fuel, these units are capable of operating on distillate fuel oil.

FREDONIA Units 1, 2, 3 and 4 are located near Mount Vernon, Wash., in Skagit County.

WHITEHORN Units 2 and 3 are located in northwestern Whatcom County, Wash.

FREDERICKSON Units 1 and 2 are located south of Seattle in east Pierce County, Wash.

Ownership and net maximum capacity are shown in Figure D-2 below.

Figure D-2: PSE's Owned Peakers (Simple-cycle Combustion Turbines)

NAME	PSE OWNERSHIP	NET MAXIMUM CAPACITY (MW)
Fredonia 1 & 2	100%	207
Fredonia 3 & 4	100%	107
Whitehorn 2 & 3	100%	149
Frederickson 1 & 2	100%	149
Total SCCT		**612**

Supply-side Renewable Resources

Hydroelectricity

Hydroelectricity supplies between 19 and 24 percent of PSE's baseload energy needs. Even though restrictions to protect endangered species limit the operational flexibility of hydroelectric resources, these generating assets are valuable because of their ability to instantly follow customer load and because of their low cost relative to other power resources. High precipitation and snowpack levels generally allow more power to be generated, while low-water years produce less power. During low-water years, the utility must rely on other, more expensive, self-generated power or market resources to meet load. The analysis conducted for this IRP accounts for both seasonality and year-to-year variations in hydroelectric generation. PSE owns hydroelectric projects in western Washington and has long-term purchased-power contracts with three public utility districts (PUDs) that own and operate large dams on the Columbia River in central Washington. In addition, we contract with smaller hydroelectric generators located within PSE's service territory.

Figure D-3: PSE Owned and Contracted Hydroelectric

PLANT	OWNER	PSE SHARE %	NET MAXIMUM CAPACITY (MW)[1]	CONTRACT EXPIRATION DATE
Upper Baker River	PSE	100	91	None
Lower Baker River	PSE	100	109	None
Snoqualmie Falls	PSE	100	48[2]	None
Total PSE-owned			**248**	
Wells	Douglas Co. PUD	29.89	231[3]	8/31/18[3]
Rocky Reach	Chelan Co. PUD	25.0	325	10/31/31
Rock Island I & II	Chelan Co. PUD	25.0	156	10/31/31
Wanapum	Grant Co. PUD	0.64	9	03/31/52
Priest Rapids	Grant Co. PUD	0.64	8	03/31/52
Mid-Columbia Total			**725**	
Total Hydro			**973**	

NOTES
1. Net maximum capacity reflects PSE's share only.
2. FERC license authorizes the full 54.4 MW; however, the project's water right, issued by the state Department of Ecology, limits flow to 2,500 cfs, and therefore output, to 47.7 MW.
3. Wells has one turbine out for the next many years. This reduces its total peaking capability from 840 MW to 774 MW and PSE's share to 231 MW. PSE has entered into a new agreement to purchase Wells project output through 2028 following expiration of the current agreement; additional details provided in the text below. For the purposes of this IRP, PSE assumes this contract will terminate.

BAKER RIVER HYDROELECTRIC PROJECT. This facility is located in Washington's north Cascade Mountains. It consists of two dams and is the largest of PSE's hydroelectric power facilities. The project contains modern fish-enhancement systems including a "floating surface collector" (FSC) to safely capture juvenile salmon in Baker Lake for downstream transport around both dams, and a second, newer FSC on Lake Shannon for moving young salmon around Lower Baker Dam. In addition to generating electricity, the project provides public access for recreation and significant flood-control storage for people and property in the Skagit Valley. Hydroelectric projects require a license from FERC for construction and operation. These licenses normally are for periods of 30 to 50 years, and then they must be renewed to continue operations. In October 2008, after a lengthy renewal process, FERC issued a 50-year license allowing PSE to generate approximately 710,000 MWh per year (average annual output) from the Baker River project. PSE also completed construction of a new powerhouse and 30 MW generating unit at Lower Baker dam in July 2013. The new unit improves river flows for fish downstream of the dam while producing more than 100,000 additional MWh of energy from the facility each year. This incremental energy qualifies as a renewable resource under the State of Washington Energy Independence Act, RCW 19.285.

SNOQUALMIE FALLS HYDROELECTRIC PROJECT. Located east of Seattle on the Cascade Mountains' western slope, the Snoqualmie Falls Hydroelectric Project consists of a small diversion dam just upstream from Snoqualmie Falls and two powerhouses. The first powerhouse, which is encased in bedrock 270 feet beneath the surface, was the world's first completely underground power plant. Built in 1898-99, it was also the Northwest's first large hydroelectric power plant. FERC issued PSE a 40-year license for the Snoqualmie Falls Hydroelectric Project in 2004. The terms and conditions of the license allow PSE to generate an estimated 275,000 MWh per year (average annual output). The facility recently underwent a major redevelopment project which included substantial upgrades and enhancements to the power-generating infrastructure and public recreational facilities. Efficiency improvements completed as part of the redevelopment will increase annual output by over 22,000 MWh. This incremental energy qualifies as a renewable resource under the State of Washington Energy Independence Act, RCW 19.285.

MID-COLUMBIA LONG-TERM PURCHASED POWER CONTRACTS. Under long-term purchased-power agreements with three PUDs, PSE purchases a percentage of the output of five hydroelectric projects located on the Columbia River in central Washington. PSE pays the PUDs a proportionate share of the cost of operating these hydroelectric projects. The current agreement with Douglas County PUD for the purchase of 29.89 percent of the output of the Wells project expires in 2018. In March 2017, PSE entered into a new power purchase agreement with Douglas County PUD that begins upon expiration of the current agreement and has a 10-year term. Under this new agreement PSE will continue to purchase a percentage of the output from the Wells project. The actual percentage available to PSE will be calculated annually and based primarily on Douglas PUD's retail load requirements – as Douglas PUD's retail load grows, they will reserve a greater share of Wells project output for their customers and the percentage PSE purchases will decline. PSE expects to purchase approximately 30 percent of Wells output (232 MW) beginning at the end of 2018 with that share declining to approximately 22 percent (170 MW) by the end of the contract term.[3] PSE has a 20-year agreement with Chelan County PUD for the purchase of 25 percent of the output of the Rocky Reach and Rock Island projects that extends through October 2031. PSE has an agreement with Grant County PUD for a 0.64 percent share of the combined output of the Wanapum and Priest Rapids developments. The agreement with Grant County PUD will continue through the term of the project's FERC license, which ends March 31, 2052.

Wind Energy

PSE is the largest utility owner and operator of wind-power facilities in the Northwest. Combined, the maximum capacity of the company's three wind farms is 773 MW. They are forecast to produce on average, more than 2 million MWhs of power per year, which is about 8 to 9 percent PSE's energy needs. These resources are integral to meeting renewable resource commitments.

HOPKINS RIDGE. Located in Columbia County, Wash., Hopkins Ridge has an approximate maximum capacity of 157 MW. It began commercial operation in November 2005.

WILD HORSE. Located in Kittitas County near Ellensburg, Wash., Wild Horse has an approximate maximum capacity of 273 MW. It came online in December 2006 at 229 MW and was expanded by 44 MW in 2010.

LOWER SNAKE RIVER. PSE brought online its third and largest wind farm in February 2012. The 343 MW facility is located in Garfield County, Wash.

3 / The percentages referenced here are annual averages. Under the new agreement the percentage available to PSE will vary by season with a higher percentage available during the spring and summer months and a lower percentage available during the winter months. During the peak winter months (December through February), PSE's expected share of the output begins at about 26 percent (206 MW) and declines to about 14 percent (108 MW) by the end of the contract term.

Solar Energy

The Wild Horse facility contains 2,723 photovoltaic solar panels, including the first made-in-Washington solar panels.[4] The array can produce up to 0.5 MW of electricity with full sun. Panels can also produce power under cloudy skies – 50 to 70 percent of peak output with bright overcast and 5 to 10 percent with dark overcast. The site receives approximately 300 days of sunshine per year, roughly the same as Houston, Tex. On average this site generates 780 MWhs of power per year.

Energy Storage

The Glacier Battery Demonstration Project was installed in early 2017. The 2 MW / 4.4 MWh lithium-ion battery storage system is located in Whatcom County, Wash. The Glacier battery will serve as a short-term backup power source (up to 2.2 hours at capacity with a full charge) to a core "island" of businesses and residences during outages, reduce system load during periods of high demand, and help balance energy supply and demand. The project was funded in part by a $3.8 million Smart Grid Grant from the State of Washington Department of Commerce. Under the terms of the grant, Pacific Northwest National Laboratories is performing a study to evaluate the battery's capability.

Figure D-4 presents details about the company's wind, solar and energy storage resources.

Figure D-4: PSE's Owned Renewable Resources

POWER TYPE	UNITS	PSE OWNERSHIP	NET MAXIMUM CAPACITY (MW)
Wind	Hopkins Ridge	100%	157
Wind	Lower Snake River, Phase 1	100%	343
Wind	Wild Horse	100%	273
Total Wind			**773**
Solar	Wild Horse Solar Demonstration Project	100%	0.5
Energy Storage	Glacier Battery Demonstration Project	100%	2.0
Total Other Renewables			**2.5**
Total Renewables			**775.5**

4 / Outback Power Systems (now Silicon Energy) in Arlington produced the first solar panels in Washington. The Wild Horse Facility was Outback Power Systems' launch facility, utilizing 315 of their panels. The remaining panels were produced by Sharp Electronics in Tennessee.

Supply-side Contract Resources

Long-term contracts consist of agreements with independent producers and other utilities to supply electricity to PSE. Fuel sources include hydropower, gas, coal, waste products and system deliveries without a designated supply resource. These contracts are summarized in Figure D-5. Short-term wholesale market purchases negotiated by PSE's energy trading group are not included in this listing.

POINT ROBERTS PPA. This contract provides for power deliveries to PSE's retail customers in Point Roberts, Wash. The Point Roberts load, which is physically isolated from PSE's transmission system, connects to British Columbia Hydro's electric distribution facilities. We pay a fixed price for the energy during the term of the contract.

BAKER REPLACEMENT. Under a 20-year agreement signed with the U.S. Army Corps of Engineers (COE) PSE provides flood control for the Skagit River Valley. Early in the flood control period, we draft water from the Upper Baker reservoir at the request of the COE. Then, during periods of high precipitation and runoff between October 15 and March 1, we store water in the Upper Baker reservoir and release it in a controlled manner to reduce downstream flooding. In return, PSE receives a total of 7,000 MWhs of power and 7 MW of net maximum capacity from BPA in equal increments per month for the months of November through February to compensate for the lower generating capability caused by reduced head due to the early drafting at the plant during the flood control months.

ELECTRON HYDROELECTRIC PROJECT PPA. In November 2014, PSE sold the Electron Project and associated water rights to an independent power producer. PSE will purchase the output of the Electron Project under a power purchase agreement with the new owner that extends through 2026.

PACIFIC GAS & ELECTRIC COMPANY (PG&E) SEASONAL EXCHANGE. Each calendar year PSE exchanges with PG&E 300 MW of seasonal capacity, together with 413,000 MWh of energy, on a one-for-one basis, under this system-delivery power exchange contract. PSE is a winter-peaking utility and PG&E is a summer-peaking utility, so PG&E has the right to call for the power in the months of June through September, and PSE has the right to call for the power in the months of November through February.

CANADIAN ENTITLEMENT RETURN. Under a treaty between the United States and Canada, one-half of the firm power benefits produced by additional storage capability on the Columbia River in Canada accrue to Canada. PSE's benefits and obligations from this storage are based on the percentage of our participation in the Columbia River projects. Agreements with the Mid-Columbia PUDs specify PSE's share of the obligation is to return one-half of the firm power benefits to Canada during peak hours until the expiration of the PUD contracts or expiration of the Columbia River Treaty, whichever occurs first. The Columbia River Treaty will not expire prior to 2024. This is energy that PSE provides rather than receives, so it is a negative number. The energy returned during 2016 was approximately 19.6 aMW with a peak capacity return of 34.9 MW.

COAL TRANSITION PPA. Under the terms of this agreement, PSE began to purchase 180 MW of firm, baseload coal transition power from TransAlta's Centralia coal plant in December 2014. On December 1, 2015, the contract increased to 280 MW. From December 2016 to December 2024 the contract is for 380 MW, and in the last year the contract volume drops to 300 MW. This contract advances a separate TransAlta agreement with state government and the environmental community to phase out coal-fired power generation in Washington by 2025. In 2011, the state Legislature passed a bill codifying a collaborative agreement between TransAlta, lawmakers, environmentalists and labor representatives. The timelines agreed to by the parties enable the state to make the transition to cleaner fuels, while preserving the family-wage jobs and economic benefits associated with the low-cost, reliable power provided by the Centralia plant. The legislation allows long-term contracts, through 2025, for sales of coal transition power associated with the 1,340 MW Centralia facility, Washington's only coal-fired plant.

KLONDIKE III PPA. PSE's wind portfolio includes a power purchase agreement with Iberdrola Renewables for a 50 MW share of electricity generated at the Klondike III wind farm in Sherman County, Ore. The wind farm has 125 turbines with a project capacity of nearly 224 MW. This agreement remains in effect until November 2026.

SKOOKUMCHUCK WIND PPA. PSE has recently executed a 20-year power purchase agreement with RES to purchase the output from the Skookumchuck Wind Project. The wind project is currently in development in Thurston and Lewis counties, and it is expected to be in service by the end of 2018. The output from the facility will be used to serve subscribers to PSE's new Green Direct program, which is described in the Demand-side Customer Programs section of this appendix.

HYDROELECTRIC PPAs. Among PSE's power purchase agreements are several long-term contracts for the output of production from hydroelectric projects within its balancing area. These contracts were established through PSE's RFP process and are shown in Figure D-5 below. The projects are run-of-river and do not provide any flexible capacity.

SCHEDULE 91 CONTRACTS. PSE's portfolio includes a number of electric power contracts (included in Figure D-5) with small power producers in PSE's electric service area. These Qualifying Facilities offer output pursuant to WAC-107-095. Part one of this statute states that "A utility must purchase electric energy, electric capacity, or both from a qualifying facility on terms that do not exceed the utility's avoided costs for such electric energy, electric capacity, or both." A qualifying facility is defined by WAC 480-107-007 as a generating facility "that meet(s) the criteria specified by the FERC in 18 C.F.R. Part 292 Subpart B."

Figure D-5: Long-term Contracts for Electric Power Generation (continued next page)

NAME	POWER TYPE	CONTRACT EXPIRATION	CONTRACT CAPACITY (MW)[1]
Pt. Roberts[2]	System	9/30/2019, but ongoing	8
Baker Replacement	Hydro	9/30/2029	7
Electron PPA	Hydro	12/31/2026	23.8
PG&E Seasonal Exchange-PSE	Thermal	Ongoing	300
Canadian EA	Hydro	09/15/2024	(34.9)
Coal Transition PPA	Transition Coal	12/31/2025	380[3]
Klondike III PPA	Wind	11/30/2027	50
Skookumchuck Wind	Wind	12/31/2038	130[4]
Twin Falls PPA	Hydro-QF	2/28/2025	15.3
Koma Kulshan PPA	Hydro-QF	3/31/2037	10.9
Weeks Falls PPA	Hydro-QF	11/30/2022	4.6
Farm Power Lynden	Schedule 91 - Biogas	12/31/2019	0.75
Farm Power Rexville	Schedule 91 - Biogas	12/31/2019	0.75
Rainier Biogas	Schedule 91 – Biogas	12/31/2020	1.0
Vanderhaak Dairy	Schedule 91 – Biogas	12/31/2019	0.60[5]
Edaleen Dairy	Schedule 91 – Biogas	12/31/2021	0.75
Van Dyk - Holsteins Dairy	Schedule 91 – Biogas	12/31/2020	0.47
Blocks Evergreen Dairy	Schedule 91 – Biogas	12/31/2031	.019
Bio Energy Washington[6]	Schedule 91 - Biogas	12/31/2021	4.88
Emerald City Renewables[7]	Schedule 91 – Biogas	12/31/2026	4.50
Skookumchuck Hydro	Schedule 91 – Hydro	12/31/2020	1.0
Smith Creek	Schedule 91 – Hydro	12/31/2020	0.12
Black Creek	Schedule 91 – Hydro	3/25/2021	4.2
Nooksack Hydro	Schedule 91 – Hydro	12/31/2021	3.5
Sygitowicz – Kingdom Energy	Schedule 91 – Hydro	12/31/2030	.45
Island Solar	Schedule 91 – Solar	5/09/2021	0.075
Finn Hill Solar (Lake Wash SD)	Schedule 91 – Solar	12/31/2021	0.355
CC Solar #1, LLC and CC Solar #2, LLC (combined)	Schedule 91 – Solar	1/1/2021	0.026
IKEA	Schedule 91 – Solar	12/31/2031	0.331
Knudson Wind	Schedule 91 – Wind	12/31/2019	0.108
3 Bar-G Wind	Schedule 91 – Wind	12/31/2019	1.395
Swauk Wind	Schedule 91 – Wind	12/31/2021	4.25
Total			**794.2**

NOTES
1. Capacity reflects PSE share only.
2. The contract to provide power to PSE's Point Roberts customers expires 9/30/2017, but is expected to be renegotiated and continue past that date as Point Roberts is not physically interconnected to PSE's system.
3. 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.
4. PSE is currently anticipating that contract capacity will be approximately 130 MW; however, actual capacity may be slightly higher.
5. VanderHaak has two generators with a combined capacity of .60 MW. However, VanderHaak primarily runs only the larger generator, which has a capacity of .45 MW.
6. Schedule 91 contract is a power purchase from Bio Energy, which provides gas under the Cedar Hills contract. When Bio Energy is producing gas, it will not be producing power to sell to PSE under Schedule 91. As gas is currently being produced at Cedar Hills, the Schedule 91 contract volume is considered to be zero.
7. Emerald City Renewables was formerly known as BioFuels Washington.

Supply-side Transmission Resources

Mid-C Transmission Resources

Transmission capacity to the Mid-Columbia (Mid-C) market hub gives PSE access to the principal electricity market hub in the Northwest, which is one of the major trading hubs in the Western Electricity Coordinating Council (WECC). It is the central market for northwest hydroelectric generation. The majority of PSE's transmission to the Mid-C market is contracted from BPA on a long-term basis; in addition to these contracts, PSE also owns 450 MW of transmission capacity to Mid-C.[5]

PSE's Mid-C transmission capacity is detailed in Figure D-6 below; 1,600 MW of this capacity to the Mid-C wholesale market comprises a significant portion of the capacity required to meet PSE's peak need.[6]

EIM Transmission Resources

Starting in October 2016, 300 MW of Mid-C transmission capacity contracted from BPA on a long-term basis has been redirected for the use of Energy Imbalance Market (EIM) trades. Although these redirects reduce transmission capacity available to support PSE's peak need, PSE still maintains sufficient capacity to meet the winter peak. The 300 MW of redirected Mid-C transmission will need to be renewed on an annual basis, and this will allow PSE to reevaluate its EIM transfer capacity needs in light of future winter peak needs. Figure D-7 details the transmission capacity currently redirected for EIM.

5 / PSE also owns transmission and transmission contracts to other markets, in addition to the Mid-C market transmission detailed here.
6 / See Chapter 6, Electric Analysis, for a more detailed discussion of PSE reliance on wholesale market capacity to meet peak need.

Figure D-6: Mid-C Hub Transmission Resources

NAME	EFFECTIVE DATE	TERMINATION DATE	TRANSMISSION DEMAND (MW)
BPA Mid-C Transmission			
Midway	11/1/2017	11/1/2022	100
Midway	4/1/2008	11/1/2035	5
Rock Island	7/1/2007	7/1/2037	400
Rocky Reach	11/1/2017	11/1/2022	100
Rocky Reach	11/1/2017	11/1/2022	100
Rocky Reach	11/1/2014	11/1/2019	40
Rocky Reach	11/1/2014	11/1/2019	40
Rocky Reach	11/1/2014	11/1/2019	40
Rocky Reach	11/1/2014	11/1/2019	5
Rocky Reach	11/1/2014	11/1/2019	55
Rocky Reach	9/1/2014	11/1/2031	160
Vantage	11/1/2017	11/1/2022	100
Vantage	12/1/2014	12/1/2019	19
Vantage	11/1/2014	3/1/2025	3
Vantage	11/1/2014	11/1/2019	27
Vantage	11/1/2014	11/1/2019	27
Vantage	11/1/2014	11/1/2019	27
Vantage	11/1/2014	11/1/2019	3
Vantage	11/1/2014	11/1/2019	36
Vantage	10/1/2013	11/1/2019	5
Wells	1/24/1966	9/1/2018	266
NWE Purchase IR Conversion	10/01/2016	10/1/2021	94
Vantage	3/1/2016	2/28/2021	23
Total BPA Mid-C Transmission			**1,675**
PSE Owned Mid-C Transmission			
McKenzie to Beverly	-	-	50
Rocky Reach to White River	-	-	400
Total PSE Mid-C Transmission			**450**
Total Mid-C Transmission			**2,125**

As shown, PSE has a total of 2,125 MW of capacity to the Mid-C market hub: 1,675 MW in BPA contracts and 450 MW of owned capacity. Figure D-6 also shows the BPA contract periods.

Figure D-7: Mid-C Hub Transmission Resources Redirected for EIM as of 8/4/17

NAME	EFFECTIVE DATE	TERMINATION DATE	TRANSMISSION DEMAND (MW)
BPA Mid-C Transmission Redirected for EIM			
Midway	10/1/2013	10/1/2018	115
Midway	3/1/2014	3/1/2019	35
Vantage	12/1/2014	12/1/2019	150
Total BPA Mid-C Transmission Redirected for EIM			**300**

Demand-side Energy Efficiency Resources

Existing demand-side resource (DSR) programs consist of:

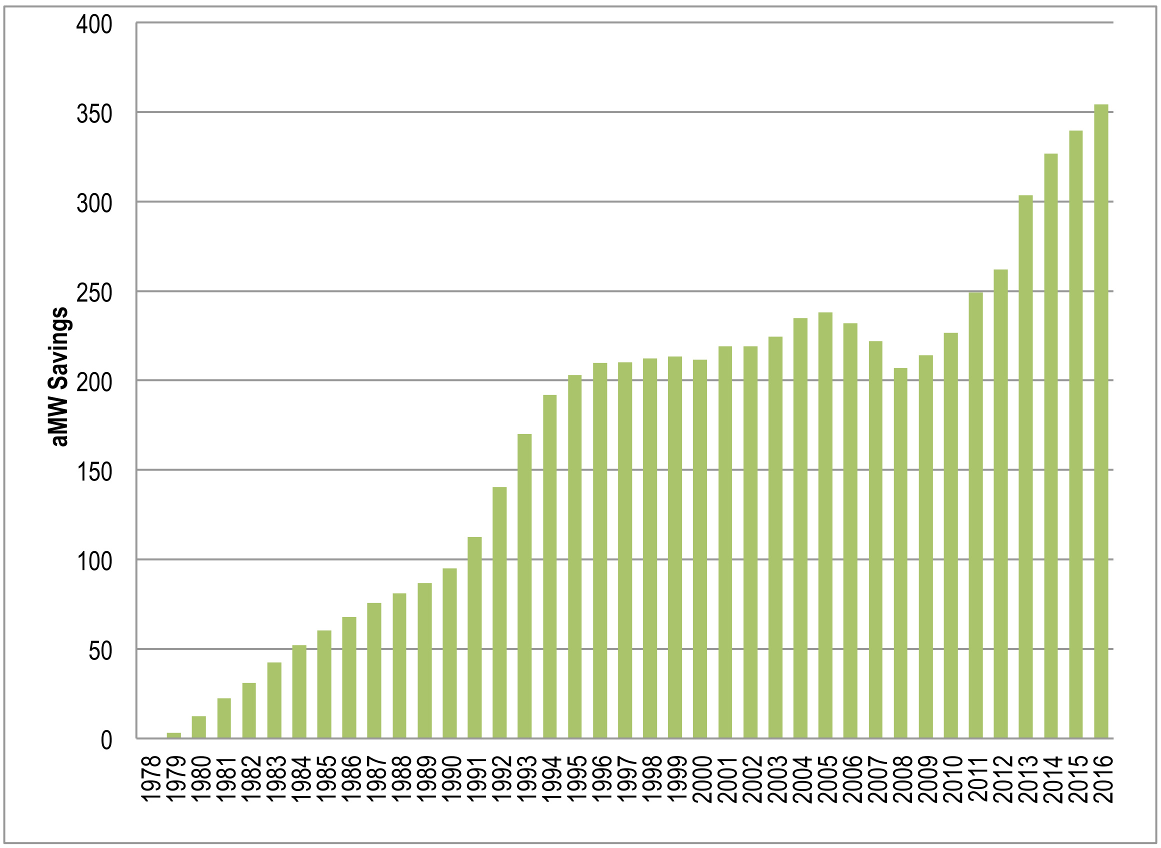
- **ENERGY EFFICIENCY**, implemented by PSE's Customer Energy Management group
- **FUEL CONVERSION**, implemented by PSE's Customer Energy Management group
- **DISTRIBUTION EFFICIENCY**, managed by the System Planning department
- **GENERATION EFFICIENCY**, evaluated by PSE's Customer Energy Management group. (This represents energy efficiency opportunities at PSE generating facilities.)
- **DISTRIBUTED GENERATION**, overseen by the Customer Renewable Energy Programs group.

Energy efficiency is by far PSE's largest electric demand-side resource. Energy efficiency programs serve all types of customers – residential, low-income, commercial and industrial. Program savings targets are established every two years in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group (CRAG) and Integrated Resource Plan Advisory Group (IRPAG). The majority of electric energy efficiency programs are funded using electric "conservation rider" funds collected from all customer classes.[7]

7 / See Electric Rate Schedule 120, Electricity Conservation Service Rider, for more information.

Since 1978, annual first-year savings (as reported at the customer meter) have increased more than 400 percent, from 9 aMW in 1978 to 38 aMW in 2016. The cumulative investment and power savings from 1978 through 2016 are approximately $1.3 billion and 354 aMW. The savings are adjusted for measure life, so that savings are retired at the end of the measure's life and no longer counted towards the cumulative savings. Figure D-8 shows the cumulative savings from 1978 through 2016. By 2016, those savings represented enough electrical energy to serve more than 250,000 homes for a year.

Figure D-8: Cumulative Electric Energy Savings from DSR, 1978 through 2016



In the most recently completed program cycle, the 2014-15 tariff period, energy efficiency (including fuel conversion) achieved a total savings of 75 aMW; the target for the current 2016-17 program cycle is 69.1 aMW. The savings impact from the successive program cycles is mitigated somewhat by earlier programs reaching the end of their productive lives, causing the net savings increase to be less than the program cycle savings in a given year (see Figure D-8).

Electric Energy Efficiency Programs

The savings are generally evenly split between PSE's Residential Energy Management (REM) and Business Energy Management (BEM) sectors. In the 2014-15 program cycle, REM contributed 33 aMW while BEM provided 30 aMW. Similarly, in the 2016-17 program plan, the REM target is 30 aMW and the BEM target is 34 aMW. The two largest programs within the REM and BEM sectors are the Single Family Residential Lighting Program and the Commercial and Industrial Retrofit Program.

THE SINGLE FAMILY RESIDENTIAL LIGHTING PROGRAM. This program offers rebates to single-family residential customers and builders who purchase Energy Star fixtures and compact fluorescent light bulbs. The program is delivered through various channels. The retail channel is by far the largest delivery mechanism; rebates are provided upstream to the retail stores to reduce the cost of energy efficient lighting products sold to consumers. The lighting products are also delivered using direct-install programs. In the 2014-15 program cycle, lighting in the residential sector accounted for approximately 18 aMW of the 33 aMW in REM program savings.

THE COMMERCIAL AND INDUSTRIAL RETROFIT PROGRAM. This program offers expert assistance and grants to help existing commercial and industrial customers use electricity more efficiently via cost-effective and energy efficient equipment, designs and operations. The program is not limited to any given technology or end use and allows the customers to engage in deep retrofits. In the 2014-15 program cycle, the retrofit grant program in the commercial and industrial sector accounted for approximately 15 aMW of the 30 aMW in BEM program savings.

While lighting savings have been a mainstay of the program in the past, this may change as LEDs saturate the market due to declining costs and as minimum federal lighting standards make the LED a baseline technology. Behavioral programs and technologies that use learning software will offer new ways to save energy.

Figure D-9: PSE 2014-15 Electric Energy Efficiency Program Savings – Targeted versus Actual[8]

	2014			2015		
	Savings (MWh)	Goal (MWh)	Savings (% of goal)	Savings (MWh)	Goal (MWh)	Savings (% of goal)
Residential	151,259	133,388	113%	135,855	131,922	103%
Business	148,830	130,962	114%	116,210	112,127	104%
Pilots	26,759	26,760	100%	8,220	8,219	100%
Regional	51,691	53,295	97%	22,338	25,388	88%
Total	**378,539**	**344,405**	**110%**	**282,623**	**277,656**	**102%**

Figure D-9 shows the performance of the REM and BEM sector programs compared to two-year savings goals for the biennial 2014-2015 electric energy efficiency programs. PSE's electric energy efficiency programs saved a total of 76 aMW of electricity at a cost of $190 million during 2014-15, surpassing energy savings goals while operating under budget.

The 2016-2017 electric energy efficiency programs are targeted to save 69.1 aMW of electricity at a cost of $199 million.

Distribution Efficiency

This energy efficiency measure is accomplished through conservation voltage reduction (CVR) accompanied by load phase balancing. PSE began implementing distribution efficiency in 2013. Two substations were adapted in 2013, another two in 2014, and work on four more substations was completed in 2015. Five more substations were targeted for completion by the end of 2015. However, the work has been postponed due to the work that was being done to transition to the advanced metering infrastructure (AMI) upgrade. Since AMI technology is needed to monitor the CVR measures once in place, the work is anticipated to resume in 2018 in this IRP, and its rollout will be closely coordinated with the AMI deployment under way to reduce cost.

8 / Source: PSE 2014-15 BECAR Final Report

Generation Efficiency

In 2014, PSE worked with the CRAG to refine the boundaries of what to include as savings under generation efficiency. It was determined that only parasitic loads[9] served directly by a generator would be included in the savings calculations as available for generation efficiency upgrades; generators whose parasitic loads are served externally – from the grid – would not be included. Using this definition, PSE completed site assessments in 2015 and the assessments did not yield any cost-effective measures. Most of the opportunities were in lighting, and the issue was very low operating hours making them not cost effective. Currently there is an approach to replace the existing lamps on burnout with more efficient ones.

Demand-side Customer Programs

PSE's customer renewable energy programs remain popular options. The Green Power Program serves customers who want to purchase additional renewable energy, and Net Metering and Local Energy Development programs serve customers who generate renewable energy on a small scale. Our customers find value as well as social benefits in these programs, and PSE embraces and encourages their use.

Green Power Program

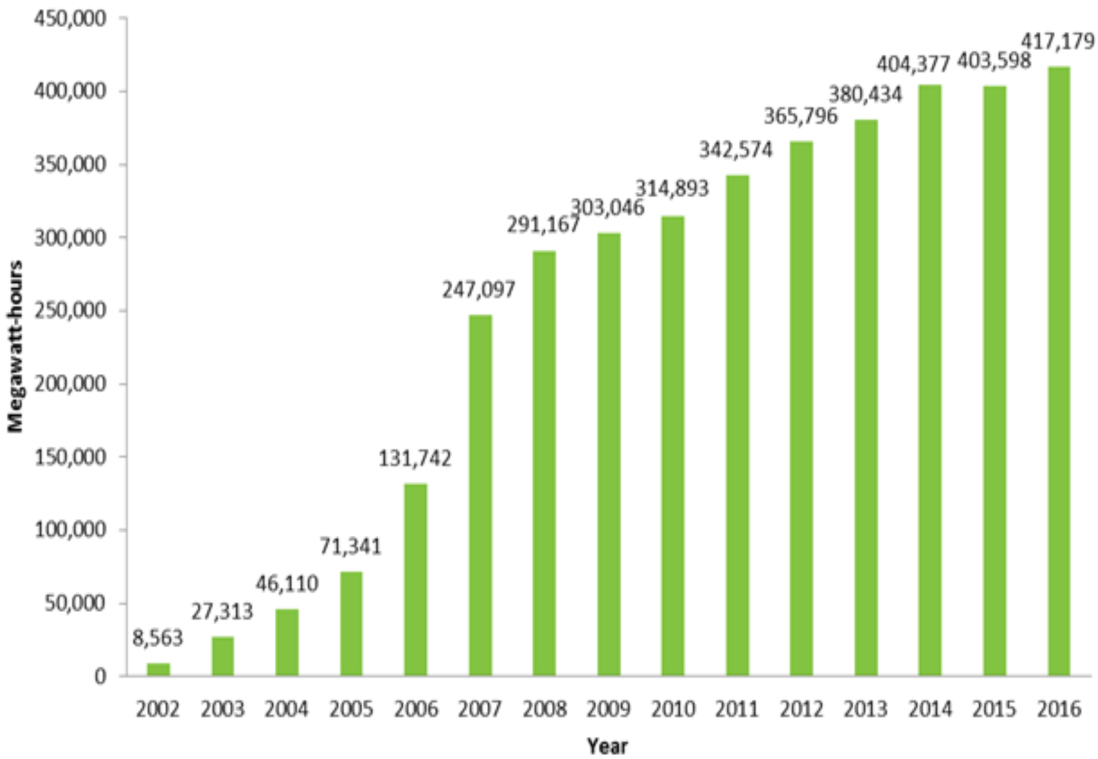
Launched in 2001, PSE's Green Power Program allows customers to voluntarily purchase retail electric energy from qualified renewable energy resources. In 2009, we began working to increase participation in the program with 3Degrees, a third-party renewable energy credits (REC) broker that has developed and refined education and outreach techniques while working with other utility partners across the country. While customer participation since 2014 has remained relatively stable, the number of MWh sold continues to grow. In that time, the number of megawatt-hours purchased increased by approximately 3 percent, from 404,377 to 417,773.

Top 10

PSE has been recognized as one of the country's top 10 utilities for Renewable Energy Sales and Total Number of Green Power Participants by the National Renewable Energy Laboratory since 2005.

9 / *Electric generation units need power to operate the unit, including auxiliary pumps, fans, electric motors and pollution control equipment. Some generating plants may receive this power externally, from the grid; however, many use a portion of the gross electric energy generated by the unit for operations – this is referred to as the "parasitic load."*

Figure D-10: Green Power Megawatt-hours Sold, 2002-2016



To supply green power, the program purchases RECs from a variety of sources. In the past two years, the majority of RECs have come from the Bonneville Environmental Foundation (BEF), a nonprofit environmental organization in Portland, Ore., and 3Degrees, a REC broker based in San Francisco, Calif. These suppliers provide PSE's Green Power Program with RECs primarily from Pacific Northwest wind facilities. In addition, the Green Power Program currently purchases RECs directly from eighteen small, local and regional producers in order to support the development of new small renewable resources. These include FPE Renewables, Farm Power Rexville, Farm Power Lynden, Edaleen Cow Power, Van Dyk-S Holsteins, Rainier Biogas, Port of Tillamook Bay, 3Bar G Community Wind, First Up! Knudson Community Wind, Swauk Wind, Ellensburg Community Solar, Skagit Community Solar, APSB Community Solar, Maple Hall Community Solar, Anacortes Library Community Solar, Greenbank Community Solar, LRI Landfill Gas and the Nooksack Hydro Facility – many of these entities also provide power to PSE under the Schedule 91 contracts discussed above.

Over the last nine years, the Green Power Program has also committed over $400,000 in grant funding to 15 cities for solar demonstration projects located on municipal facilities. For example, In 2016, the City of Bellingham completed its second successful Green Power Community Challenge by meeting its goal for increased enrollment in the Green Power Program, and in recognition PSE provided the city with a $50,000 grant towards a solar project in the community. A similar campaign in Bellevue resulted in a $50,000 grant that the city used to install a 20 kW system at the Crossroads Community Center. Other projects have been installed throughout PSE's service territory in Whidbey Island, Snoqualmie, Vashon and Olympia.

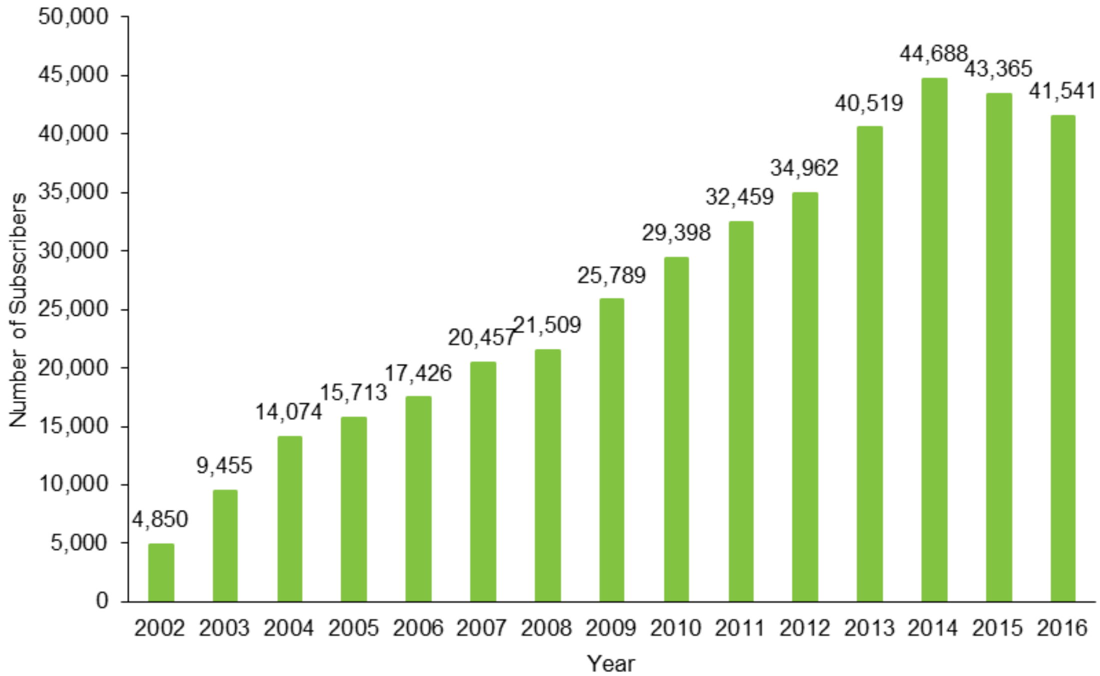
In 2015, PSE issued a RFQ that resulted in competitively awarding REC contracts to the Bonneville Environmental Foundation, Port of Tillamook Bay and 3Degrees to help supply the balance of our Green Power Program portfolio needs for up to two years, beginning in 2016. Pricing for these Pacific Northwest REC contracts was relatively low, largely due to a generous supply of renewable energy and the region's utilities having met their initial compliance targets. As a result, the Green Power Program has been able to focus on building a portfolio of RECs generated from wind, solar, biogas and low-impact hydro located primarily in Washington, with some additional supply from Oregon and Idaho. However, indications are that Pacific Northwest REC prices have increased as RPS compliance targets have stepped up to the next level in the region; Washington state's target increased from 3 percent to 9 percent in 2016. PSE plans to issue another RFQ in mid-2017.

GREEN POWER RATES. In September 2016, PSE received approval from the WUTC to reduce Green Power rates. The standard rate for green power now drops from $0.0125 per kWh to $0.01 per kWh. Customers can now purchase 200 kWh blocks for $2.00 per block with a two-block minimum, or they can choose to participate in the "100% Green Power Option." Introduced in 2007, this option adjusts the amount of the customer's monthly green power purchase to match their monthly electric usage. The large-volume green power rate dropped from $0.006 per kWh to $0.0035 per kWh for customers who purchase more than 1,000,000 kWh annually. This product has attracted approximately 30 customers since it was introduced in 2005.

In 2016, the average residential customer purchase was 640 kWh per month, and the average commercial customer purchase was 2,050 kWh. The average 2016 large-volume purchase under Schedule 136, by account, was 12,200 kWh per month.

Figure D-11 illustrates the number of subscribers by year. Of our 41,541 Green Power subscribers at the end of 2016, 40,403 were residential customers, 698 were commercial accounts, and 440 accounts were assigned under the large-volume commercial agreement. Cities with the most residential and commercial participants include Bellingham with 5,511, Olympia with 5,177 and Bellevue with 3,183.

Figure D-11: Green Power Subscribers, 2002-2016



Solar Choice

In September, 2016, the WUTC approved the addition of the Solar Choice program, a new renewable energy product offering for residential and small to mid-size commercial customers. Similar to the Green Power program, Solar Choice allows customers to voluntarily purchase retail electric energy from qualified renewable energy resources; but in this case, all of the resources supplied are solar energy facilities located in Washington and Idaho. Customers can elect to purchase solar in $5.00 blocks for 150 kilowatt-hours. Their purchase is added to their monthly bill. The program was officially launched to customers in April 2017.

Green Direct

Green Direct was approved by the Washington Utilities and Transportation Commission (WUTC) and became effective on September 30, 2016. Like the Green Power program and Solar Choice, Green Direct falls under the rules governing utility green pricing options found in Washington RCW 19.29A, Voluntary Option to Purchase Qualified Alternative Energy Resources. Green Direct is a product that allows the utility to procure and sell fully bundled renewable energy to large (10,000 MWh per year or more of load in PSE's service area) commercial and municipal customers from a specified wind resource, and within the Washington regulatory framework. For Phase I, PSE has signed a 20-year power purchase agreement for the output from the Skookumchuck Wind project, under development in Thurston and Lewis Counties. Customers can elect to enroll for terms of 10,15 or 20 years. The customer will continue to receive and pay for all of the standard utility services for safety and reliability. Customers will be charged for the total cost of the energy from the new plant, but receive a credit for the energy-related power costs from the company.

Green Direct held its first open enrollment period in November and December 2016, followed by a second open enrollment period that opened on May 1, 2017. As of June 30, 21 customers had fully-subscribed to a 130 MW wind facility, which is under contract with PSE for 20 years. Enrollees include companies like Starbucks, Target Corporation and REI; and government entities like King County and the City of Olympia. PSE will issue a Request for Proposals to identify a new resource (or resources) for Phase II.

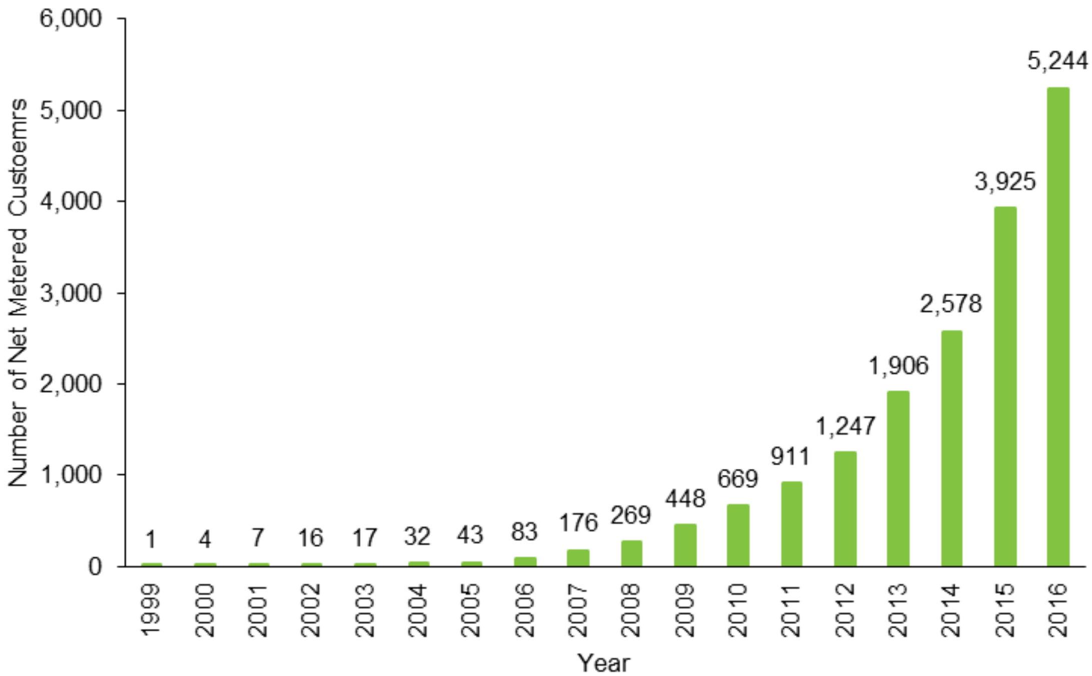
Customer Renewables Programs

PSE offers two customer renewables programs, a net metering program and a renewable energy cost recovery program.

The **NET METERING PROGRAM**, which began in 1999, provides a way for customers who generate their own renewable electricity to offset the electricity provided by PSE. The amount of electricity that the customer generates and sends back to the grid is subtracted from the amount of electricity provided by PSE, and the net difference is what the customer pays on a monthly basis. A kWh credit is carried over to the next month if the customer generates more electricity than PSE supplies over the course of a month. The "banked" energy can be carried over until every April 30, when the account is reset to zero according to state law. The interconnection capacity allowed under net metering is 100 kW.

Customer interest in small-scale renewables has increased significantly over the past seventeen years, as Figure D-12 shows. For 2016, PSE added 1,319 new net metered customers for a total of 5,244.

Figure D-12: Net Metered Customers, 1999-2016



The vast majority of customer systems (99 percent) are solar photovoltaic (PV) installations with an average generating capacity of 6.9 kW, but there are also small-scale hydroelectric generators and wind turbines. These small-scale renewable systems are distributed over a wide area of PSE's service territory. The median generating capacity of all net metered systems is 6.16 kW. Overall, the program was capable of producing more than 36.9 MW of nameplate capacity at the end of 2016.

Customer preference along with state and federal incentives continues to drive customer solar PV adoption. Residential customers were 94 percent of all solar PV by number and 87 percent by nameplate capacity. In 2016, PSE contracted with Clean Power Research to implement their PowerClerk software tool – a new online solar application. PSE continues to examine our processes to allow for continued growth in customer generation.

Figure D-13: Interconnected System Capacity by Type of System

SYSTEM TYPE	NUMBER OF SYSTEMS	AVERAGE CAPACITY PER SYSTEM TYPE (kW)	SUM OF ALL SYSTEMS BY TYPE (kW)
Hybrid: solar/wind	19	5.90	106.2
Micro hydro	5	6.07	38.2
Solar array	5,185	7.03	3,433.0
Wind turbine	35	3.23	117.7
Total	**5,244**	**6.13**	**3,695.1**

Figure D-14: Net Metered Systems by County

COUNTY	NUMBER OF NET METERS
Whatcom	1,041
King	1,781
Skagit	454
Island	278
Kitsap	582
Thurston	604
Kittitas	269
Pierce	235
Total	**5,244**

RENEWABLE ENERGY COST RECOVERY. In 2005, in response to Washington Administrative Code (WAC) 458-20-273, PSE launched a renewable energy production incentive payment program under tariff Schedule 151. The program is voluntary for Washington state utilities, but we embraced the opportunity to participate because we have such a large and committed group of interconnected customers. Under this program, PSE makes payments to interconnected electric customers who own and operate eligible renewable energy systems which include solar PV, wind or anaerobic digesters. The annual credits ranged from \$0.12 to \$1.08 per kWh of energy produced by their system. PSE receives a state tax credit equal to the payments made to customers, up to 0.5 percent of PSE's taxable electric sales for the previous year. For the incentive year that ended with the state fiscal year on June 30, 2016, production exceeded the allowable funds. In order to bring payments under the cap, PSE lowered the base rate by one cent – from \$0.15 to \$0.14 – before applying the appropriate multipliers. In 2016, PSE paid approximately \$9.7 Million to over 4,300 eligible customers.

3. ELECTRIC RESOURCE ALTERNATIVES

This overview of technology alternatives for electric power generation describes both mature technologies and new methods of power generation, including those with near- and mid-term commercial viability. Within each section, resources are listed alphabetically. PSE continues to explore emerging resources.

Thermal Resource Costs and Characteristics

PSE modeled two types of thermal resources in the 2017 IRP, baseload gas plants and peakers.

Generic Gas Resource Cost Assumptions

Figure D-15 summarizes the cost assumptions used in the analysis for baseload gas plants and peakers. All costs are in 2016 dollars.

PSE worked with Black and Veatch to produce a report on gas-fired generation characteristics and costs. The table below is a summary of the numbers needed for modeling; the full report can be found in Appendix P, Gas-fired Resource Costs.

Figure D-15: Generic Gas Resource Cost Assumptions

GENERIC GAS RESOURCES		BASELOAD GAS		PEAKERS					
2016 $	UNITS	CCCT - A	CCCT - B	FRAME PEAKER	FRAME PEAKER W/ OIL	AERO PEAKER	AERO PEAKER W/ OIL	RECIP ENGINE	RECIP ENGINE W/OIL
ISO Capacity Primary	MW	359	405	239	239	227	227	222	202
Capacity DF	MW	54	61						
Capital Cost + Duct Fire	$/kW	$1,267	$1,299	$571	$634	$1,004	$1,070	$1,277	$1,477
O&M Fixed	$/kW-yr	$8.10	$7.30	$6.40	$11.23	$6.50	$10.92	$6.50	$10.70
O&M Variable (1)	$/MWh	$2.50	$2.40	$0.95	$0.95	$10.20	$10.10	$7.80	$7.80
Start Up Costs	$/Start	$2.78	$2.69	$9,250	$9,250				
Capacity Credit	%	100%	100%	100%	100%	100%	100%	100%	100%
Operating Reserves	%	3%	3%	3%	3%	3%	3%	3%	3%
Forced Outage Rate		3%	3%	3%	3%	3% per unit	3% per unit	1% per unit	1% per unit
Heat Rate – Baseload (HHV) (2)	Btu/KWh	6,650	6,515	9,823	9,823	8,986	8,986	8,425	8,527
Heat Rate – Turndown (HHV) (2)	Btu/kWh	7,339	7,473	12,750	12,750	14,464	14,464	10,924	11,026
Heat Rate – DF	Btu/kWh	8,500	8,500						
Min Capacity	%	50%	42%	45%	45%	13% (25% per unit)	13% (25% per unit)	2% (25% per unit)	2% (25% per unit)
Start Time (3)	minutes	150	150	12	12	8	8	5	5
Location		PSE	PSE	PSE	PSE	PSE	PSE	PSE	PSE
Fixed Gas Transport	$/Dth/Day	$0.78	$0.78	$0.78	$0.01	$0.78	$0.01	$0.78	$0.01
Fixed Gas Transport	$/kW-yr	$45.44	$44.51	$67.11	$0.70	$61.40	$0.64	$57.56	$0.61
Variable Gas Transport	$/MMBtu	$0.01	$0.01	$0.01	$0.25	$0.01	$0.25	$0.01	$0.25
Fixed Transmission	$/kW-yr	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Variable Transmission	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Flexibility Benefit (4)	$/kw-yr	$0.00	$0.00	($0.91)	($0.91)	($6.34)	($6.34)	($9.97)	($9.97)
Emissions:									
CO_2 (5) - Natural Gas	lbs/MMBtu	117	117	117	117	117	117	117	117
CO_2 (5) - Distillate Fuel Oil	lbs/MMBtu				153		153		153
Nox - Natural Gas	lbs/MMBtu	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
Nox - Distillate Fuel Oil	lbs/MMBtu				0.077		0.077		0.077
First Year Available		2022	2022	2021	2021	2021	2021	2021	2021
Economic Life	Years	35	35	35	35	35	35	35	35
Greenfield Dev. & Const. Lead-time	Years	4	4	3	3	3	3	3	3

NOTES
1. Variable costs reflect the operating costs and major maintenance for all technologies except for the frame peaker, for which major maintenance is included in startup costs.
2. Includes two percent for degradation.
3. Start time for all technologies reflects the warm start on all units. The hot start follows a shutdown period of less than 8 hours.
4. Flexibility benefit based on report by E3 as commissioned by PSE.
5. CO_2 emissions reflect natural gas as the main source of fuel under normal operating conditions. In the event that the gas pipeline is constrained, the CO_2 emissions would be higher for plants that can run on oil backup as the secondary fuel source. The minimal amount of diesel fuel required by the duel fueled reciprocating engines when operating with natural gas as the primary fuel is not captured in the emission rates.

GAS TRANSPORTATION COSTS MODELED. Fixed and variable gas transportation cost assumptions for the gas plants assume that gas is purchased at the Sumas Hub. Gas transportation costs for resources without oil backup assume the need for 100 percent firm gas pipeline transportation capacity plus firm storage withdrawal rights equal to 13.4 percent of the plant's full fuel requirements. This applies to the baseload CCCT, frame peaker without oil, Aero peaker without oil, and the reciprocating engine without oil. The analysis assumes that the gas transportation needs for these resources will be met with 100 percent firm gas transportation on a Williams Northwest Pipeline (NWP) expansion to Sumas plus 100 percent firm gas transportation on a Westcoast Energy Inc. (Westcoast) gas pipeline expansion to Station 2. The plants are dispatched to Sumas prices, so a basis differential between Sumas and Station 2 is added back to the cost. For the peaker resources, we are assuming oil backup with no firm gas transportation.

Figure D-16 below shows the gas transport assumptions for resources with and without oil backup.

Figure D-16: Gas Transportation Costs for Western Washington Baseload Gas Plants and Peakers without Oil Backup – 100% Sumas on NWP + 100% Station 2 on Westcoast

PIPELINE/RESOURCE	FIXED DEMAND ($/DTH/DAY)	VARIABLE COMMODITY ($/DTH)	ACA CHARGE ($/DTH)	FUEL USE (%)	UTILITY TAXES (%)[5]
NWP Expansion[1]	0.5500	0.0083	0.0013	1.41%	-
Westcoast Expansion[2]	0.5000	-	-	-	-
Basis Gain[3]	(0.2781)				
Gas Storage[4]	0.0081	-	-	-	-
Total	**0.7800**	**0.0083**	**0.0013**	**5.5%**	**3.852%**

NOTES
1. Estimated NWP Sumas to PSE Expansion
2. Estimated Westcoast Expansion Fixed Demand
3. Basis gain represents the average of the Station 2 to Sumas price spread, net of fuel losses and variable costs over the 20-year forecast period. Variable Commodity Charge includes B.C. carbon tax and motor fuel tax of $0.0476 per Dth per day and fuel losses are 2.91 percent per Dth.
4. Storage requirements are based on current storage withdrawal capacity to peak plant demand for the gas for power portfolio (approx. 13.4 percent).
5. Utility taxes are charged by the state on fuel used at the plant.

Figure D-17: Gas Transportation Costs for Western Washington Peakers with Oil Backup – No Firm Gas Pipeline

PIPELINE/ RESOURCE	FIXED DEMAND ($/DTH/DAY)	WEIGHTED AVERAGE "VARIABLE" DEMAND ($/DTH)	VARIABLE COMMODITY ($/DTH)	ACA CHARGE ($/DTH)	FUEL USE (%)	UTILITY TAXES (%)[2]
NWP Demand	0.0000	0.2438	0.0083	0.0013	1.41%	-
Gas Storage[1]	0.0081	-	-	-	-	-
Total	**0.0081**	**0.2438**	**0.0083**	**0.0013**	**1.41%**	**3.852%**

NOTES
1.Storage requirements are based on current storage withdrawal capacity to peak plant demand for the gas for power portfolio (approx. 13.4 percent).
2. Utility taxes are charged by the state on fuel used at the plant.

Figure D-18: Gas Transportation Costs for Eastern Washington Baseload Gas Plants and Peakers without Oil Backup, 100% AECO on GTN/NOVA/Foothills

PIPELINE/ RESOURCE	FIXED DEMAND ($/DTH/DAY)	VARIABLE COMMODITY ($/DTH)	ACA CHARGE ($/DTH)	FUEL USE (%)	UTILITY TAXES (%)
NOVA	0.145	-	-	0%	-
Foothills	0.076	0.0	-	1.00%	-
GTN	0.155	0.004	0.0013	0.89%	-
Gas Storage	0.008	-	-	-	-
Total	**0.384**	**0.004**	**0.0013**	**1.89%**	**3.852%**

Natural Gas Characteristics

Natural gas generation is extensively modeled in this IRP analysis due to the following characteristics.

- **Proximity.** Gas-fired generators can often be located within or adjacent to PSE's service area, thereby avoiding costly transmission investments required for long-distance resources like coal or wind.
- **Timeliness.** Gas-fired resources are dispatchable, meaning they can be turned on when needed to meet loads, unlike "intermittent" resources that generate power sporadically such as wind, solar and run-of-the-river hydropower.
- **Versatility.** Gas-fired generators have varying degrees of ability to ramp up and down quickly in response to variations in load and/or wind generation.
- **Environmental Burden.** Natural gas resources produce significantly lower emissions than coal resources (approximately half the CO_2).

Gas storage and fuel supply become increasingly important considerations as reliance on natural gas grows, so the analysis also includes gas storage for some resources. The gas-fired baseload and peaking resources modeled in this analysis are described below.

Baseload Gas

Baseload gas plants – combined-cycle combustion turbines or CCCTs – produce energy at a constant rate over long periods at a lower cost relative to other production facilities available to the system. They are typically used to meet some or all of a region's continuous energy demand.

COMBINED-CYCLE COMBUSTION TURBINES (CCCTs). These baseload gas plants consist of one or more combustion turbine generators equipped with heat recovery steam generators that capture heat from the combustion turbine (CT) exhaust. This otherwise wasted heat is then used to produce additional electricity via a steam turbine generator. Many plants also feature "duct firing." Heat rates range between 6,400 and 6,500 BTU per kWh depending on the size, because of their high thermal efficiency and reliability, relatively low initial cost and low air emissions. Duct firing can produce additional capacity from the steam turbine generator, although with less efficiency than the primary unit. CCCTs have been a popular source of baseload electric power and process steam generation since the 1960s.

In this analysis, natural gas supply is assumed to be firm year-round at projected incremental gas pipeline firm rates. This analysis assumes 13.4 percent of gas storage is available to the baseload gas plants modeled to accommodate mid-day startups or shutdowns. The unit is assumed to be connected to the PSE transmission system and as such does not incur any direct transmission cost.

This technology is commercially available. Greenfield development requires approximately four years.

Peakers

Peakers are quick-starting units that can ramp up and down rapidly in order to meet spikes in need. They also provide flexibility needed for load following, wind integration and spinning reserves. PSE modeled three types of peakers; each brings particular strengths to the overall portfolio.

SIMPLE-CYCLE COMBUSTION TURBINES (SCCT). There are two principal types of simple-cycle combustion turbines for “peaking” applications: frame and aeroderivative (aero) engines.

Frame Peakers. Frame CT peakers are also known as “industrial” or “heavy-duty” CTs; these are generally larger in capacity and feature frames, bearings and blading of heavier construction. Conventional frame CTs are a mature technology. They can be fueled by natural gas, distillate oil or a combination of fuels (dual fuel). The turndown capability of the units is 45 percent. The assumed heat rate is 9,800 BTU per kWh depending on the size. They also have slower ramp rates, on the order of 40 MW per minute for 239 MW facilities, and some can achieve full load in eleven minutes.

Frame CT peakers are commercially available. Greenfield development requires approximately three years.

AERO Peakers (Aeroderivative Combustion Turbines). Aeroderivative combustion turbines are a mature technology, however, new aeroderivative features and designs are continually being introduced. They can be fueled by natural gas, oil or a combination of fuels (dual fuel). The heat rate is 8,810 BTU per kWh. Aero units are typically more flexible than their frame counterparts, and many can reduce output to nearly 25 percent. Most can start and achieve full output in less than eight minutes and start multiple times per day without maintenance penalties. Ramp rates are 50 MW per minute for a 227 MW facility. Another key difference between aero and frame units is size. Aero CTs are typically smaller in size, from 5 to 100 MW each. This small scale allows for modularity, but it also tends to reduce economies of scale.

This technology is commercially available. Greenfield development requires approximately three years.

RECIP PEAKERS (RECIPROCATING ENGINES). The reciprocating engine technology evaluated is based on a four-stroke, spark-ignited gas engine which uses a lean burn method to generate power. The lean burn technology uses a relatively higher ratio of oxygen to fuel, which allows the reciprocating engine to generate power more efficiently. Ramp rates are 168 MW per minute for a 228 MW facility. The heat rate is 8,260 BTU per kWh. However, reciprocating engines are constrained by their size. The largest commercially available reciprocating engine for electric power generation produces 18 MW, which is less than the typical frame or Aero turbine. Larger-sized generation projects would require a greater number of reciprocating units compared to an equivalent-sized project implementing either an Aero or frame turbine, reducing economies of scale. A greater number of generating units increases the overall project availability and reduces the impact of a single unit out of service for maintenance. Reciprocating engines are more efficient than simple-cycle combustion turbines, but have a higher capital cost. Their small size allows a better match with peak loads, thus increasing operating flexibility relative to simple-cycle combustion turbine peakers.

This technology is commercially available. Greenfield development requires approximately three years.

OIL BACKUP. For peakers with oil backup, natural gas supply is assumed to be available on an interruptible basis at projected gas pipeline seasonal interruptible rates for much of the year. The oil backup is assumed to provide fuel during peak periods. For units without oil backup, natural gas supply is assumed to be firm year-round at projected incremental gas pipeline firm rates. In either case, the analysis assumes 13.4 percent of gas storage is available to the peaking gas plants modeled to accommodate mid-day startups or shutdowns. The peaker unit is assumed to be connected to the PSE transmission system and as such does not incur any direct transmission cost.

Thermal Resources Not Modeled

As discussed below, other potential thermal resource alternatives are constrained by law, practical obstacles and cost. Long-term coal-fired generation is not a resource alternative because RCW 80.80 precludes utilities in Washington from entering into new long-term agreements for coal, and new nuclear generation is neither practical nor feasible.

COAL. Coal fuels a significant portion of the electricity generated in the United States. Most coal-fired electric generating plants combust the coal in a boiler to produce steam that drives a turbine-generator. A small number of plants gasify coal to produce a synthetic gas that fuels a combustion turbine. Of the fuels commonly used to produce electricity, coal produces the most greenhouse gases (GHGs) per MWh of electricity. Technologies for reducing or capturing some of the GHGs produced are currently in the research and development phase.

Commercial availability. New coal-fired generation is not a resource alternative for PSE, because RCW 80.80 sets a generation performance standard for electric generating plants that prohibits Washington utilities from building plants or entering into long-term electricity purchase contracts from units that emit more than 970 pounds of GHGs per MWh.[10] With currently available technology, coal-fired generating plants produce GHGs (primarily carbon dioxide) at a level two or more times greater than the performance standard, and carbon capture and sequestration technology is not yet effective or affordable enough to significantly reduce those levels.

There are no new coal-fired power plants under construction or development in the Pacific Northwest.

NUCLEAR. Capital and operating costs for nuclear power plants are so much higher than most conventional and renewable technologies that only a handful of the largest capitalized utilities can realistically consider this option. In addition, nuclear power also carries significant technology, credit, permitting, policy and waste disposal risks.

Cost assumptions. There is little reliable data on recent U.S. nuclear developments from which reasonable and supportable cost estimates can be made. The construction cost and schedule track record for nuclear plants built in the U.S. during the 1980s, 1990s, and 2000s has been poor. Actual costs have been far higher than projected, construction schedules have been subject to long delays, and interest rate increases have resulted in high financing charges. The Fukushima incident in 2011 has also motivated changing technical and regulatory requirements and public controversy that have contributed to project cost increases.

10 / To support a long-term plan to shut down the only coal-fired generating plant in Washington state, state government has made an exception for transition contracts with the Centralia generating plant through 2025.

Plant closings. An extensive discussion of then-existing U.S. nuclear facilities, decommissioning activities, new construction projects, and policy considerations was provided in Appendix D of PSE's 2013 IRP. Since then, facility owners have announced plans to permanently retire almost 8,500 MW of nuclear generating capacity in the next 10 years. Vermont Yankee, Fort Calhoun, Fitzpatrick, Clinton, Pilgrim, Quad Cities, Oyster Creek and Diablo Canyon will all be permanently closed by 2025 for economic reasons.

New construction. New nuclear facilities have been moving forward very slowly after many years of delays and cost overruns, with 5 units in various stages of construction. The 1,165 MW Watts Bar 2 plant finally entered commercial service in October 2016 after starting construction in the 1980s – the first new nuclear plant completed in the U.S. since 1996. The remaining units, Vogtle 3 & 4 and Summer 2 & 3, have been delayed again and are not expected to enter service until 2020 at the earliest.

With other energy options to choose from, the demonstrated high cost, poor completion track record, lack of a comprehensive waste storage/disposal solution and the uncertainty of current technology make nuclear energy an unnecessary risk for PSE at this time.

Energy Storage Resource Costs and Characteristics

PSE modeled three energy storage alternatives in the 2017 IRP: lithium-ion batteries, flow batteries and pumped hydro.

Generic Energy Storage Resource Cost Assumptions

Figure D-19 summarizes the generic costs assumptions used in the analysis for energy storage resources. All costs are in 2016 dollars.

Figure D-19: Generic Energy Storage Cost Assumptions

2016 $	Units	Li-Ion Battery 2-hr	Li-Ion Battery 4-hr	Flow Battery 4-hr	Flow Battery 6-hr	Pumped Storage
Nameplate Capacity	MW	25	25	25	25	25
Winter Capacity	MW	15	22	19	20	25
Capacity Credit	%	60%	88%	76%	80%	100%
Operating Reserves	%	3%	3%	3%	3%	3%
Capital Cost	$/kW	$1,514	$2,439	$2,324	$3,042	$2,400
O&M Fixed	$/kW-yr	$23.68	$36.49	$26.82	$23.40	$15.00
O&M Variable	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00
Forced Outage Rate	%	0.5%	0.5%	0.5%	0.5%	0.0%
Degradation	%/year	2.0%	2.0%	0.0%	0.0%	0.0%
Operating Range	%	10%-90%	10%-90%	0%-100%	0%-100%	0%-100%
R/T Efficiency[1]	%	85%	85%	75%	75%	81%
Discharge at Nominal Power	Hours	2	4	4	6	10
Location		PSE	PSE	PSE	PSE	PNW
Fixed Transmission	$/kW-yr	$0.00	$0.00	$0.00	$0.00	$21.48
Variable Transmission	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.33
Flexibility Benefit	$/KW-yr	($119)	($131)	($117)	($128)	($144)
First Year Available		2019	2019	2019	2019	2030
Economic Life	Years	10	10	20	20	60
Greenfield Dev. & Const. Leadtime	Years	1	1	1	1	15

NOTES
1. Round-trip efficiency means the percentage of energy input that is available for output.

Energy Storage Characteristics

Energy storage encompasses a wide range of technologies that are capable of shifting energy usage from one time period to another. These technologies could deliver important benefits to electric utilities and their customers, since the electric system currently operates on "just-in-time" delivery. Generation and load must be perfectly balanced at all times to ensure power quality and reliability. Strategically placed energy storage resources have the potential to increase efficiency and reliability, to balance supply and demand, to provide backup power when primary sources are interrupted and to assist with the integration of intermittent renewable generation. Energy storage technologies are rapidly improving and are capable of benefiting all parts of the system – generation, transmission and distribution – as well as customers. The drawbacks to energy storage are that it operates with a limited duration and requires generation from other sources.

Battery Storage

Unlike conventional generation resources such as combustion turbines, battery storage resources are modular, scalable and expandable. They can be sized from 20 kW to 1,000 MW and sited at a customer's location or interconnected to the transmission system. It is possible to build the infrastructure for a large storage system and install storage capacity in increments over time as needs grow. This flexibility is a valuable feature of the technology.

Within the battery category, there are many promising chemistries, each with its own performance characteristics, commercial availability and costs. PSE chose to model lithium-ion and flow batteries as the generic battery resources in this IRP because both technologies are commercially available, there are successful projects in operation, and cost estimates and data are available on a spectrum of system configurations and sizes. Other advantages are described below.[11] A detailed discussion of battery technologies is available in Appendix L to PSE's 2015 IRP.

11 / In an actual RFP solicitation, PSE would evaluate all proposed technologies based on least-cost and best-fit criteria, including technical and commercial considerations such as warranties, performance guarantees and counterparty credit, etc.

LITHIUM-ION BATTERIES have emerged as the leader in utility-scale applications because they offer the best mix of performance specifications for most energy storage applications. Advantages include high energy density, high power, high efficiency, low self-discharge, lack of cell "memory" and fast response time. Challenges include short cycle life, high cost, heat management issues, flammability and narrow operating temperatures. Battery degradation is dependent on the number of cycles and state of the battery's charge. Deep discharge will hasten the degradation of a lithium-ion battery. Lithium-ion batteries can be configured for varying durations (i.e., 0.5 to 6 hours), but the longer the duration, the more expensive the battery. Lithium-ion storage is ideally suited for ancillary applications benefitted by high power (MW), low energy solutions (MWh), and to a lesser extent, for supplying capacity.

FLOW BATTERIES are a type of rechargeable battery in which recharge ability is provided by two chemical components dissolved in liquids contained within the system. The two components are separated by a membrane, and ion exchange occurs through the membrane while both liquids circulate in their respective spaces. The ion exchange provides the flow of electric current. Flow batteries can provide the same services as lithium-ion batteries, but they can be used with more flexibility because they do not degrade over time. Flow batteries have very limited market penetration at this time.

Commercial availability. The U.S. installed 221 MW of battery energy storage resources in 2016, down three percent from 2015. Lithium-ion batteries continued to dominate the energy storage market with a market share of 97 percent in each quarter of 2016.[12]

In the "Energy Storage" sensitivity, this IRP tests the cost difference between a portfolio that includes battery storage and one that does not.

12 / GTM Research, U.S. Energy Storage Monitor, 2016 Year in Review and Q1 2017 Executive Summary. The 221 MW of deployments represents residential, non-residential and utility solar installations in 2016.

Pumped Hydroelectric Storage

Pumped hydroelectric storage ("pumped storage" or "pumped hydro") plants provide the bulk of utility-scale energy storage in the United States. These facilities store energy in the form of water, which is pumped to an upper reservoir from a second reservoir at a lower elevation. During periods of high electricity demand, the stored water is released through turbines to generate power in the same manner as a conventional hydropower station. Load shifting over a number of hours requires a large volume of energy storage capacity, and a storage device like pumped hydro is well suited for this type of application. During periods of low demand (usually nights or weekends when electricity costs less), the upper reservoir is "recharged" by using lower-cost electricity from the grid to pump the water back to the upper reservoir.

Reversible pump-turbine and motor-generator assemblies can act as both pumps and turbines. Pumped storage facilities can be very economical due to peak and off-peak price differentials and because they can provide critical ancillary grid services. Pumped storage projects are typically large, at 300 MW or more. Due to environmental impacts, permitting for these projects can take many years. Pumped storage can be designed to provide 6 to 20 hours of storage with 80 percent roundtrip efficiency.

Commercial availability. According to the Department of Energy's most recent *Hydropower Market Report*, there are 42 plants with a capacity of 21.6 GW. Most of this capacity was installed between 1960 and 1990, and three-quarters of it is located at very large (>500 MW) plants. At the time the report was published in April 2015, there were 51 pumped storage projects with a potential capacity of 39 GW in the FERC development pipeline.[13]

13 / Source: U.S. Department of Energy 2014 Hydropower Market Report, published April 2015: https://www.energy.gov/sites/prod/files/2015/04/f22/2014%20Hydropower%20Market%20Report_20150424.pdf

Energy Storage Not Modeled

LIQUID AIR ENERGY STORAGE (LAES). LAES converts energy from a variety of sources, such as natural gas or wind, and stores it as thermal energy. To charge the energy, air is cooled and compressed into a liquid state using electricity (i.e., liquefied air or liquefied nitrogen) and stored in tanks. To dispatch electrical energy back to the grid, the liquid air is heated and pressurized, bringing it back to a gaseous state. The gas is used to turn a turbine to generate electricity.

Potential benefits include the technology's suitability to deliver large-scale power for utility and distributed power applications; its suitability for long-duration energy storage; and its ability to use waste heat and cold from its own processes to enhance its efficiency. Also, LAES systems can be large in scale without requiring a large footprint, giving them greater geographical flexibility.

Commercial Availability. LAES systems combine three existing technologies: industrial gas production, cryogenic liquid storage and expansion of pressurized gasses. While the components are based on proven technology currently used in industrial processes and available from large OEMs, no commercial LAES systems are currently in operation. However, in March 2014, Highview Power Storage, a small U.K. company developing utility-scale LAES systems, signed an exclusive global licensing deal with GE to explore the potential to integrate their LAES technology into GE's natural gas peaker plants.[14] Since then, both Mitsubishi Hitachi Power Systems Europe[15] and The Linde Group[16] have indicated that they are currently developing LAES storage solutions on their websites.

Renewable Resource Costs and Characteristics

PSE modeled wind, biomass and solar renewable resources in the 2017 IRP.

Generic Renewable Resource Cost Assumptions

Figure D-20 summarizes the generic renewable resource cost assumptions used in the analysis. All costs are in 2016 dollars.

14 / Greentech Media website. Retrieved from https://www.greentechmedia.com/articles/read/ge-partners-with-highview-for-liquid-air-energy-storage, March 2014.
15 / Mitsubishi Hitachi Power Systems Europe website. Retrieved from http://www.eu.mhps.com/en/storage-technologies.html, December 2016.
16 / The Linde Group website. Retrieved from http://www.the-linde-group.com/en/clean_technology/clean_technology_portfolio/energy_storage/liquid_air_energy_storage/index.html, December 2016.

Figure D-20: Generic Renewable Resource Cost Assumptions

2016 $	UNITS	WA WIND	MT WIND	BIOMASS	SOLAR	OFFSHORE WIND
ISO Capacity Primary	MW	100	300	15	25	100
Winter Capacity Primary	MW	9	192	0	0	
Capacity Credit	%	9%	64%	0%	1%	
Operating Reserves	%	3%	3%	3%	3%	3%
Capacity Factor	%	30%	46%	85%	27%	35%
Capital Cost[1]	$/kW	$1,936	$3,950[6]	$7,150	$2,171	$7,150[7]
O&M Fixed	$/kW-yr	$27.12	$33.79	$113.70	$10.00	$77.30
O&M Variable[2]	$/MWh	$3.15	$3.50	$5.66	$0.00	$3.15
Degradation	%/year				0.5%	
Location		SE WA	Montana	Western WA	PSE - Central WA	Coast of WA
Fixed Transmission[3]	$/kW-yr	$35.88	$72.94	$21.48	$0.00	$35.88
Variable Transmission[4]	$/MWh	$1.85	$1.85	$0.35	$0.00	$1.85
Loss Factor to PSE	%	1.9%	7.3%	1.9%	0.0%	1.95%
Heat Rate – Baseload (HHV)	Btu/kWh			13,500		
Emissions:						
NO_x	lbs/MMBtu			0.00		
SO_2	lbs/MMBtu			3.152		
CO_2	lbs/MMBtu			195.0		
First Year Available[5]		2020	2022	2021	2020	2022
Economic Life	Years	25	25	35	25	25
Greenfield Dev. & Const. Leadtime	years	3	3	4	3	5

NOTES
1. Solar PV cost for AC installed
2. Idaho Solar includes Spin and Supplemental from Idaho Power. WA Wind includes wind integration cost from BPA. MT Wind includes wind integration cost from NWMT. WA solar includes a solar integration charge from BPA as a placeholder.
3. BPAT variable cost includes spin, supplemental and imbalance. Idaho solar includes solar integration cost form Idaho Power.
4. MT wind includes generation tax and WET tax.
5. First year available for MT wind is 2022 to correspond to retirement of Colstrip 1 & 2.
6. Includes $52 Million of transmission upgrades. If the resource were only 100 MW, then the capital cost would be higher since the transmission upgrades are $52 million regardless of size of plant.
7. Offshore wind capital cost does not include the cost of the marine cable.

Biomass Characteristics

Biomass in this context refers to the burning of woody biomass in boilers. Most existing biomass in the Northwest is tied to steam hosts (also known as “cogeneration” or “combined heat and power”). It is found mostly in the timber, pulp and paper industries. This dynamic has limited the amount of power available to date. The typical plant size we have observed is 10 MW to 50 MW. One major advantage of biomass plants is that they can operate as a baseload resource, since they do not impose generation variability on the grid, unlike wind and solar. Municipal solid waste, landfill and wastewater treatment plant gas are discussed in the section on waste-to-energy technologies.

Commercial availability. This technology is commercially available. Greenfield development of a new biomass facility requires approximately four years. The costs modeled in Figure D-22 above are from the biomass section of the U.S. Energy Information Administration report, *Capital Cost for Electricity Plants* (http://www.eia.gov/forecasts/capitalcost/).

Solar Characteristics

Solar energy uses the light and radiation from the sun to directly generate electricity with photovoltaic (PV) technology, or to capture the heat energy of the sun for either heating water or for creating steam to drive electric generating turbines. The solar energy resource modeled in this IRP portfolio sensitivity uses central station tracking PV technology.

PHOTOVOLTAICS are semiconductors that generate direct electric currents. The current then typically runs through an inverter to create alternating current, which can be tied into the grid. Most photovoltaic solar cells are made from silicon imprinted with electric contacts; however, other technologies, notably several chemistries of thin-film photovoltaics, have gained substantial market share. Significant ongoing research efforts continue for all photovoltaic technologies, which has helped to increase conversion efficiencies and decrease costs. Photovoltaics are installed in arrays that range from a few watts for sensor or communication applications, up to hundreds of megawatts for utility-scale power generation. PV systems can be installed on a stationary frame at a tilt to best capture the sun (fixed-tilt) or on a frame than can track the sun from sunrise to sunset.

CONCENTRATING PHOTOVOLTAICS use lenses to focus the sun’s light onto special, high-efficiency photovoltaics, which creates higher amounts of generation for the given photovoltaic cell size. The use of concentrating lenses requires that these technologies be precisely oriented towards the sun, so they typically require active tracking systems.

SOLAR THERMAL PLANTS focus the direct irradiance of the sun to generate heat to produce steam, which in turn drives a conventional turbine generator. Two general types are in use or development today, trough-based plants and tower-based plants. Trough plants use horizontally mounted parabolic mirrors or Fresnel mirrors to focus the sun onto a horizontal pipe that carries water or a heat transfer fluid. Tower plants use a field of mirrors that focus sunlight onto a central receiver. A heat transfer fluid is used to collect the heat and transfer it to make steam.

Commercial availability. Currently, renewable portfolio standards (RPS) drive most utility-scale solar development in the United States. Decreased prices and tax incentives have helped to fuel explosive solar growth in 2016 and this trend is expected to continue. Cumulative solar PV capacity in the U.S. reached 31.1 gigawatts (GW) by mid-2016, and 10 GW_{dc}[17] of utility-scale solar is slated for construction in the second half of 2016 and first half of 2017 at the time of this writing.[18]

With less sunlight than other areas of the country and incentive structures that limit development to smaller systems, photovoltaic development has been relatively slow in the Northwest. California continues to be the U.S. leader with 13.8 MW_{dc} of combined residential, non-residential and utility-scale solar PV installations as of September 2016.[19]

Likewise, concentrating PV and concentrating solar thermal systems have not been developed in the Northwest, primarily because of the relatively low irradiance and low market power prices. While there are no customer or utility-scale solar thermal installations in Washington state, such facilities have proven reliable over time; thermal solar energy generating systems have been operating successfully in California since the 1980s.

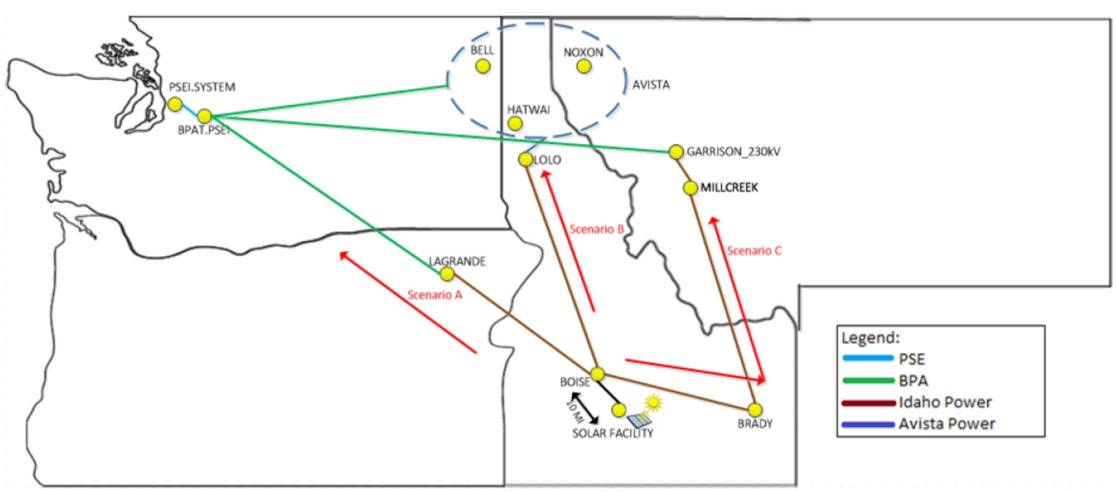
17 / Solar is installed at direct current (dc).
18 / Solar Electric Industry Association (SEIA), Q2 2016, http://www.seia.org/research-resources/solar-industry-data.
19 / Ibid.

Cost and performance assumptions. Since PSE built the Wild Horse Solar Demonstration Project in 2007, installed costs for PV solar systems have declined considerably. According to the Solar Electric Industry Association, by the second quarter of 2016, utility fixed-tilt and tracking projects saw an average price of $1.17 and $1.30 per Watt_{dc}, respectively, and had reached approximately $3.14 per Watt_{dc} for residential systems and $2.19 per Watt_{dc} for commercial systems.[20]

The EIA's *Annual Energy Outlook 2017* estimates capital costs for utility-scale PV solar systems to be approximately $2,169 per kW_{ac}[21] and solar thermal plants to be approximately $3,908 per kW_{ac}.

For PSE's generic solar resource, we assumed it is located in eastern Washington and either connected to PSE's BA or connected to BPA and would only require one wheel. Washington solar has an estimated capacity factor of 27 percent, but a solar resource in Idaho has an estimated capacity factor of 30 percent; however, a solar resource located in Idaho would have to go through additional transmission to get to PSE. The solar in Idaho would interconnect to Idaho power, through BPA, then to PSE. This additional transmission will cost $49.35/kw-yr with lines losses of 5.5 percent. Figure D-21 below is a description of the different transmission path options to get solar from Idaho to PSE.

Figure D-21: Washington Solar vs. Idaho Solar



20 / http://www.seia.org/research-resources/solar-market-insight-report-2016-q3
21 / PSE models generic solar resources as alternating current (ac) to recognize the cost of the conversion from dc to ac.

Wind Characteristics

Wind energy is the primary renewable resource that qualifies to meet RPS requirements in our region due to wind's technical maturity, reasonable lifecycle cost, acceptance in various regulatory jurisdictions and large "utility" scale compared to other technologies. However, it also poses challenges. Because of its variability, wind's daily and hourly power generation patterns don't necessarily correlate with customer demand; therefore, more flexible thermal and hydroelectric resources must be standing by to fill the gaps. This variability also makes wind power challenging to integrate into transmission systems. Finally, because wind projects are often located in remote areas, they frequently require long-haul transmission on a system that is already crowded and strained.

WASHINGTON, MONTANA AND OFFSHORE WIND. For this IRP, wind was modeled in three locations, eastern Washington, central Montana and offshore. Washington wind is located in BPA's balancing authority, so this wind only requires one transmission wheel through BPA to PSE. Montana wind, however, is outside BPA's balancing authority and will require four transmission wheels plus various system upgrades to deliver the power to PSE's service territory. The Judith Gap location was chosen because PSE was able to obtain data from that wind project for use in the analysis. Offshore wind would likely be located 22 miles off the coast of Washington near Grays Harbor. Offshore wind would require a marine cable to interconnect all the turbines and bring the power back to land. Once on land, it would require a transmission wheel through BPA to PSE.

Montana Wind Assumptions. The four scenarios PSE developed to determine the appropriate Montana wind costs to model in the IRP are labeled A through C in Figure D-24 and summarized in the table below it. Scenario A was modeled as the baseline. Scenario A looks at the cost to interconnect a 300 MW wind project at the Broadview substation using available transmission capacity from the retirement of Colstrip Units 1 & 2. Scenario B is the cost to interconnect a 300 MW wind project at the Colstrip substation using available transmission capacity from the retirement of Colstrip Units 1 & 2. Scenario C is the cost to interconnect 600 MW at the Broadview substation; 300 MW would use available transmission capacity from the retirement of Colstrip Units 1 & 2, the additional 300 MW would require constructing increased transmission capacity at the Broadview substation.

Figure D-22: Washington vs. Montana Wind, PSE Baseline Assumptions

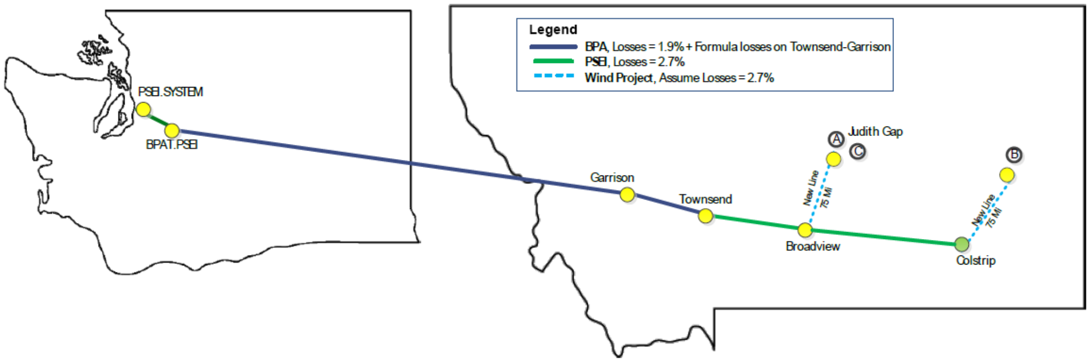


Figure D-23: Estimates of Interconnection Costs and Transmission Rates

	OPTION	INTERCONNECTION COSTS (Millions $)	TRANSMISSION RATES ($/kW-yr)
A	**Colstrip 1 & 2 Retired, 300 MW, 75 miles from Broadview Substation**	$52.2	$72.94
B	**Colstrip 1 & 2 Retired, 300 MW, 75 miles from Colstrip Substation**	$51.8	$72.94
C	**Colstrip 1 & 2 Retired, 600 MW, 75 miles from Broadview Substation**	$52.2	$72.94 + Impact of Capacity Increase on Rate

NOTES
1. Interconnection cost is added to the total capcital cost ($/kw) of the wind project. See table D-22 for total cost of MT wind with interconnection costs.
2. Breakdowns of costs are listed below in table D-26.

There are many unknowns with the Montana transmission system. The shutdown of Colstrip units 1 & 2 will open up 300 MW of transmission to Washington. However, there could be transmission issues if the baseload resource is replaced with an intermittent resource. To count as a qualifying renewable resource under Washington's RPS, wind outside the BPA footprint would have to be dynamically scheduled to match load. The assumptions for the scope and estimates of this study are listed below.

1. Transmission capacity available from the retirement of Colstrip Units 1 & 2 is currently unknown.
2. Costs to mitigate transmission impacts of retiring Colstrip Units 1 & 2 are currently unknown.
3. Interconnection costs and transmission facilities costs are estimates based on previous NorthWestern Energy (NWE) studies that assume Colstrip Units 1 & 2 are not retired.
4. Costs exclude costs to build generation.
5. Costs exclude overheads.

Figure D-24: New Montana Wind Plant,

Breakdown of Esimates for Interconnection and Transmission Capital Costs

Assumptions for New Montana Wind Plant	Estimated Interconnection Costs (Millions)	Estimated Transmission Costs (Millions)
Scenario A: Colstrip 1 & 2 are retired, 300 MW Wind Plant (Broadview Substation)		
New 75 mile 230kV line from Judith Gap to Broadview Substation (wood frame poles)	$44.7	
Broadview Substation upgrades to accommodate new 230kV line bay, assuming existing step-up transformer capacity is available[1]	$1.8	
Fiber communication between Judith Gap and Broadview Substation	$5.7	
Other potential costs: Voltage support equipment, overdutied equipment, RAS, relay upgrades, communication upgrades, etc.[3]	Uncertain	Uncertain
Total Scenario A:	**$52.2**	**-**
Scenario B: Colstrip 1 & 2 are retired, 300 MW Wind Plant (Colstrip Substation)		
New 75 mile 230kV line from Wind Farm to existing Colstrip Substation (Wood Frame Poles)	$44.7	
Colstrip Substation upgrades to accommodate new 230kV line bay, assuming existing step-up transformer capacity is available[2]	$1.4	
Fiber for communications between Wind Farm and Colstrip Substation	$5.7	
Other Potential Costs: Voltage support equipment, overdutied equipment, RAS, relay upgrades, communication upgrades, etc.[3]	Uncertain	Uncertain
Total Scenario B:	**$51.8**	**-**
Scenario C: Colstrip 1 & 2 are retired, 600 MW Wind Plant (Broadview Substation)		
New 75 mile 230kV line from Judith Gap to Broadview Substation (wood frame poles)	$44.7	
Broadview Substation upgrades to accommodate new 230kV line bay, assuming existing step-up transformer capacity is available[1]	$1.8	
Fiber communication between Judith Gap and Broadview Substation	$5.7	
NWE Facility Study - Upgrades required from Broadview to Garrison to increase line capacity[4]	-	$73
Other potential costs: Voltage support equipment, overdutied equipment, RAS, relay upgrades, communication upgrades, etc.[3]	Uncertain	Uncertain
Total Scenario C:	**$52.2**	**$73**

NOTES

1. Refer to NWE Facilities Interconnection Study for Project #207 completed in August 2016. This study assumes Colstrip 1 & 2 are not retired.

2. Refer to NWE Revised System Impact Study Report for Project #164 completed in January 2016. This study assumes Colstrip 1 & 2 are not retired.

3. Additional costs may be identified in an interconnection study or transmission service request that are currently unpredictable.

4. Refer to NWMT Transmission Service Request Facilities Study Report completed for Gaelectric LLC in January 2014 for additional 550 MW of capacity.

Figure D-25: Montana Wind Site Statistics

ESTIMATED WIND CAPACITY	PERCENTAGE
MT Wind Capacity Factor	46.00%
Loss Factor	7.30%
Wind Capacity Net of Losses	**42.64%**

Figure D-26: Montana Wind Transmission Rate Breakdown

TRANSMISSION RATES	PERCENTAGE
Colstrip to Townsend (PSEI)	$31.83
Townsend to Garrison (BPA)	$7.36
Garrison to PSEI (BPA)[1]	$21.62
Estimated Wind Integration Costs[2]	$12.12
Impact of Capacity Increase on Rate	Uncertain
Total Transmission Rate	**$72.94**

NOTES
1. BP-18 initial proposal, point-to-point (PTP) transmission plus scheduling
2. BP-18 initital proposal, Balancing Reserve rates

Land-based Wind

Wind turbine generator technology is mature and the dominant form of new renewable energy generation in the Pacific Northwest. While the basic concept of a wind turbine has remained generally constant over the last several decades, the technology continues to evolve, yielding larger towers, wider rotor diameters, greater nameplate capacity and increased wind capture (efficiency). Commercially available machines are in the 2.0 to 3.0 MW range with hub heights of 80 to 100[22] meters and blade diameters topping out around 110 meters. These changes have come about largely because development of premium high-wind sites has pushed new development into less-energetic wind sites. The current generation of turbines is pushing the physical limits of existing transportation infrastructure. In addition, if nameplate capacity and turbine size continue to increase, the industry must explore creative solutions, such as concrete tower foundations poured on site.

Commercial availability. Recent tax law changes to provide incentives will drive demand in the short term. Greenfield development of a new wind facility requires approximately three to five years and consists of the following activities at a minimum: one to two years for development, permitting and major equipment lead-time, and one year for construction.

22 / One hundred meters is equivalent to 328 feet which is equivalent to a 30-story building.

Cost and performance assumptions. The cost for installing a wind turbine includes the turbine, foundation, roads and electrical infrastructure. Installed cost for a typical facility in the Northwest region is approximately $2,000 per kW. The levelized cost of energy for wind power is a function of the installed cost and the performance of the equipment at a specific site, as measured by the capacity factor. The all-in levelized cost of energy ranges from $43.0 to $78.5 per MWh, which is very dependent on the quality of wind at the location.[23]

Offshore Wind

Offshore winds tend to blow harder and more uniformly than on land. The potential energy produced from wind is directly proportional to the cube of the wind speed. As a result, increased wind speeds of only a few miles per hour can produce a significantly larger amount of electricity. For instance, a turbine at a site with an average wind speed of 16 mph would produce 50 percent more electricity than at a site with the same turbine and average wind speeds of 14 mph.

The wind turbine generators used in offshore environments include modifications to prevent corrosion. Additionally, their foundations must be designed to withstand the harsh environment of the ocean, including storm waves, hurricane-force winds, and even ice floes. The engineering and design of offshore wind facilities depends on site-specific conditions, particularly water depth, geology of the seabed and wave loading. Foundations for offshore wind fall into two major categories, fixed and floating, with a variety styles for each category. The fixed foundation is a proven technology that is used throughout Europe. Monopiles are the preferred foundation type, which are steel piles driven into the seabed to support the tower and shell. Fixed foundations can be installed to a depth of 60 meters.

Roughly 90 percent of the U.S. wind energy resource occurs in waters too deep for current turbine technology, particularly on the West Coast. Engineers are working on new technologies, such as innovative floating wind turbines, that will transition wind power development to the harsher conditions associated with deeper waters.

All power generated by offshore wind turbines must be transmitted to shore and connected to the power grid. Each turbine is connected to an electric service platform (ESP) by a power cable. High voltage cables, typically buried beneath the sea bed, transmit the power collected from the wind turbines from the ESP to an onshore substation where the power is integrated into the grid.

23 / *Source: http://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf*

Cost and performance assumptions. Offshore wind installations have higher capital costs than land-based installations per unit of generating capacity, largely because of turbine upgrades required for operation at sea and increased costs related to turbine foundations, balance of system infrastructure, interconnection and installation. In addition, one-time costs are incurred with the development of the infrastructure to support the offshore industry, such as vessels for turbine installation.

Currently in the United States, there are no large-scale, commercially operational offshore wind projects, and the first demonstration project was only recently installed in December 2016. As a result, capital cost estimates for large-scale U.S. installations are pure conjecture. Offshore wind would benefit from federal and state government mandates, renewable portfolio standards, subsidies and tax incentives to help jump-start the market. As the market develops, costs should decrease dramatically as experience is gained. In addition, as the technology develops, bigger units should be able to capture more wind and achieve greater economies of scale.[24]

Commercial Availability. In Europe, offshore wind is a proven technology; there, 11 GW have been installed since 1991 and costs continue to decrease. On the other hand, the U.S. is just beginning the process of developing offshore wind. The first offshore wind installation in the U.S., the 30-MW Block Island demonstration project in Rhode Island, became operational in December 2016. However, thousands of megawatts of future development are currently in the planning stages, mostly in the Northeast and Mid-Atlantic regions. Projects are also being considered along the Great Lakes, the Gulf of Mexico and the Pacific Coast. The floating platforms required for deep water offshore wind are yet not commercially available.

24 / http://www1.eere.energy.gov/wind/pdfs/national_offshore_wind_strategy.pdf; http://www.nrel.gov/wind/offshore-energy-analysis.html; https://energy.gov/sites/prod/files/2015/09/f26/2014-2015-offshore-wind-technologies-market-report-FINAL.pdf

Renewable Resources Not Modeled

FUEL CELLS. Fuel cells combine fuel and oxygen to create electricity, heat, water and other byproducts through a chemical process. Fuel cells have high conversion efficiencies from fuel to electricity compared to many traditional combustion technologies, on the order of 25 to 60 percent. In some cases, conversion rates can be boosted using heat recovery and reuse. Fuel cells operate and are being developed at sizes that range from watts to megawatts. Smaller fuel cells power items like portable electric equipment, larger ones can be used to power equipment, buildings or provide backup power. Fuel cells differ in the membrane materials used to separate fuels, the electrode and electrolyte materials used, operating temperatures and scale (size). Reducing cost and improving durability are the two most significant challenges to fuel cell commercialization. To be economical, fuel cell systems must be cost-competitive with, and perform as well as, traditional power technologies over the life of the system.[25]

Provided that feedstocks are kept clean of impurities, fuel cell performance can be very reliable. They are often used as backup power sources for telecommunications and data centers, which require very high reliability. In addition, fuel cells are starting to be used for commercial combined heat and power applications, though mostly in states with significant subsidies or incentives for fuel cell deployment.

Commercial availability. Fuel cells have been growing in both number and scale, but they do not yet operate at large scale. According to the Department of Energy's report *State of the States: Fuel Cells in America 2016*,[26] there are fuel cell installations in 43 states, and more than 235 MW of large stationary (100 kW to multi-megawatt) fuel cells are currently operating in the U.S. The report further states that while California has the greatest number of stationary fuel cells, Connecticut (14.9 MW) and Delaware (30 MW) are home to the largest installations. In some states, incentives are driving fuel cell pricing economics to be competitive with retail electric prices, especially where additional value can be captured from waste heat. Currently, Washington state offers no incentives specific to fuel cells. The EIA's *Annual Energy Outlook 2017* estimates fuel cell capital costs to be approximately $6,252 per kW.

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25 / U.S. Department of Energy, Energy Efficiency and Renewable Energy, Fuel Cell Technologies Program.
26 / Source: U.S. Department of Energy's report, "State of the States: Fuel Cells in America 2016," dated November 2016 (https://energy.gov/eere/fuelcells/downloads/state-states-fuel-cells-america-2016).

GEOTHERMAL. Geothermal generation technologies use the natural heat under the surface of the earth to provide energy to drive turbine generators for electric power production. Geothermal energy production falls into four major types.

> **Dry Steam Plants** use hydrothermal steam from the earth to power turbines directly. This was the first type of geothermal power generation technology developed.[27]
>
> **Flash Steam Plants** operate similarly to dry steam plants, but they use low-pressure tanks to vaporize hydrothermal liquids into steam. Like dry steam plants, this technology is best suited to high-temperature geothermal sources (greater than 182 degrees Celsius).[28]
>
> **Binary-cycle Power Plants** can use lower temperature hydrothermal fluids to transfer energy through a heat exchanger to a fluid with a lower boiling point. This system is completely closed-loop, no steam emissions from the hydrothermal fluids are released at all. The majority of new geothermal installations are likely to be binary-cycle systems due to the limited emissions and the greater number of potential sites with lower temperatures.[29]
>
> **Enhanced Geothermal** or “hot dry rock” technologies involve drilling deep wells into hot dry or nearly dry rock formations and injecting water to develop the hydrothermal working fluid. The heated water is then extracted and used for generation.[30]

Geothermal plants typically run with high uptime, often exceeding 85 percent. However, plants sometimes do not reach their full output capacity due to lower than anticipated production from the geothermal resource.

Commercial availability. At the end of 2015, approximately 3.7 GW of geothermal generating capacity was online in the United States. Operating geothermal plants in the Northwest include the 28.5 MW Neal Hot Springs plant and the 15.8 MW Raft River plant in Idaho. An estimated 110 MW of planned capacity additions are in some stage of development in the Northwest, in Oregon and Idaho.[31]

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27 / http://energy.gov/eere/geothermal/electricity-generation
28 / Ibid.
29 / Ibid.
30 / http://energy.gov/sites/prod/files/2014/02/f7/egs_factsheet.pdf
31 / Geothermal Energy Association, 2016 Annual US & Global Geothermal Power Production Report. (http://www.geo-energy.org/reports/2016/2016 Annual US Global Geothermal Power Production.pdf).

The EIA's *Annual Energy Outlook 2017* estimates capital costs for geothermal resources to be approximately $2,586. Because geothermal cost and performance characteristics are specific for each site, this represents the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located. Overall, site-specific factors including resource size, depth and temperature can significantly affect costs.

WASTE-TO-ENERGY TECHNOLOGIES. Converting wastes to energy is a means of capturing the inherent energy locked into wastes. Generally, these plants take one of the following forms.

> **Waste Combustion Facilities.** These facilities combust waste in a boiler and use the heat to generate steam to power a turbine that generates electricity. This is a well-established technology, with 86 plants operating in the United States, representing 2,720 MW in generating capacity.[32]
>
> **Waste Thermal Processing Facilities.** This includes gasification, pyrolysis and reverse polymerization. These facilities add heat energy to waste and control the oxygen available to break down the waste into components without combusting it. Typically, a syngas is generated, which can be combusted for heat or to produce electricity. A number of pilot facilities once operated in the United States, but only a few remain today.
>
> **Landfill Gas And Municipal Wastewater Treatment Facilities.** Most landfills in the United States collect methane from the decomposition of wastes in the landfill. Many larger municipal wastewater plants also operate anaerobic systems to produce gas from their organic solids. Both of these processes produce a low-quality gas with approximately half the methane content of natural gas. This low-quality gas can be collected and scrubbed to remove impurities or improve the heat quality of the gas. The gas can then be used to fuel a boiler for heat recovery, or a turbine or reciprocating engine to generate electricity. There were 650 landfill gas energy projects operating in 49 U.S. states in 2015. According to the U.S. EPA, these facilities, combined, were capable of providing 16 billion kWh of electricity and 99 billion cubic feet of landfill gas to end users, or enough energy to power nearly 1.3 million homes that year.[33]

Commercial availability. Washington's RPS initially included landfill gas as a qualifying renewable energy resource, but excluded municipal solid waste. The passage of ESSB 5575 later expanded the definitions of wastes and biomass to allow some new wastes, such as food and yard wastes, to qualify as renewable energy sources.

32 / U.S. Environmental Protection Agency website. Retrieved from http://www.epa.gov/waste/nonhaz/municipal/wte/, January 2015.
33 / U.S. Environmental Protection Agency website. Retrieved from https://www.epa.gov/sites/production/files/2016-08/documents/green_power_from_landfill_gas.pdf, December 2016.

Currently, several waste-to-energy facilities are operating in or near PSE's electric service area. Three waste facilities – the H.W. Hill Landfill Gas Project, the Spokane Waste-to-Energy Plant and the Emerald City facility – use landfill gas for electric generation in Washington state; combined, they produce up to 67 MW of electrical output. The H.W. Hill facility in Klickitat County is fed from the Roosevelt Regional Landfill and capable of producing a maximum capacity of 36.5 MW.[34] The Spokane Waste-to-Energy Plant processes up to 800 tons per day of municipal solid waste from Spokane County and is capable of producing up to 26 MW of electric capacity.[35] Emerald City uses landfill gas produced at the LRI Landfill in Pierce County to generate up to 4.5 MW of electricity. The facility became commercially operational in December 2013.[36] PSE purchases the electricity produced by the facility through a power purchase agreement under a Schedule 91 contract, which is discussed above.

The largest landfill in PSE's service territory, the Cedar Hills landfill, currently purifies its gas to meet pipeline natural gas quality; then they sell that gas to PSE rather than using it to generate electricity.

Cost and performance assumptions. Relatively few new waste combustion and landfill gas-to-energy facilities have been built since 2010, making it difficult to obtain reliable cost data. The EIA's *Annual Energy Outlook 2017* estimates municipal solid waste-to-energy costs to be approximately $8,059 per kW.

In general, waste-to-energy facilities are highly reliable. They have used proven generation technologies and gained considerable operating experience over the past 30 years. Some variation of output from landfill gas facilities and municipal wastewater plants is expected due to uncontrollable variations in gas production. For waste combustion facilities, output is typically more stable, as the amount of input waste and heat content can be more easily controlled.

34 / Phase 1 of the H.W. Hill facility consists of five reciprocating engines, which combined produce 10.5 MW. Phase 2, completed in 2011, adds two 10-MW combustion turbines, and a heat recovery steam generator and steam turbine for an additional 6 MW. Source: Klickitat PUD website. Retrieved from http://www.klickitatpud.com/topicalMenu/about/powerResources/hwHillGasProject.aspx, December 2016.
35 / Spokane Waste to Energy website. Retrieved from http://www.spokanewastetoenergy.com/WastetoEnergy.htm, December 2016.
36 / BioFuels Washington, LLC landfill gas to energy facility (later sold to Emerald City Renewables, LLC) solid waste permit (2014-2015) and permit application (2013), as posted to the Tacoma – Pierce County Health Department website. Retrieved from http://www.tpchd.org/environment/waste-management/lri-landfill/, December 2016.

WAVE AND TIDAL. The natural movement of water can be used to generate energy through the flow of tides or the rise and fall of waves.

Tidal Generation technology uses tidal flow to spin rotors that turn a generator. Two major plant layouts exist: barrages, which use artificial or natural dam structures to accelerate flow through a small area, and in-stream turbines, which are placed in natural channels. The Rance Tidal Power barrage system in France was the world's first large-scale tidal power plant. It became operational in 1966 and has a generating capacity of approximately 240 MW. The Sihwa Lake Tidal Power Station in South Korea is currently the world's largest tidal power facility. The plant was opened in late 2011 and has a generating capacity of approximately 254 MW. Other notably large tidal facilities include the 240 MW Swansea Bay Tidal Lagoon in the United Kingdom, the 86 MW MeyGen Tidal Energy Project in Scotland and the 20 MW Annapolis Royal Generating Station in Nova Scotia, Canada.[37]

Wave Generation technology uses the rise and fall of waves to drive hydraulic systems, which in turn fuel generators. Technologies tested include floating devices such as the Pelamis and bottom-mounted devices such as the Oyster. The largest wave power plant in the world was the 2.25 MW Agucadoura Wave Farm off the coast of Portugal, which opened in 2008.[38] It has since been shut down because of the developer's financial difficulties.

In 2015, a prototype wave energy device developed by Northwest Energy Innovations was successfully launched and installed for grid-connected, open-sea pilot testing at the Navy's Wave Energy Test Site in Kaneohe Bay on the island of Oahu, Hawaii. According to the U.S. Department of Energy's web site, the 20-kilowatt Azura device is the nation's first grid-connected wave energy converter device.[39]

Commercial availability. Since mid-2013, a number of significant wave and tidal projects and programs have slowed, stalled or shut down altogether. In general, wave and tidal resource development in the U.S. continues to face limiting factors such as funding constraints, long and complex permitting process timelines, relatively little experience with siting and the early-stage of the technology's development. FERC oversees permitting processes for tidal power projects, but

37 / Power Technology website. Retrieved from http://www.power-technology.com/features/featuretidal-giants---the-worlds-five-biggest-tidal-power-plants-4211218, April 2014.
38 / CNN website. Retrieved from http://www.cnn.com/2010/TECH/02/24/wave.power.buoys/index.html, February 2010.
39 / The U.S. Department of Energy website. Retrieved from https://www.energy.gov/eere/articles/innovative-wave-power-device-starts-producing-clean-power-hawaii, July 2015.

state and local stakeholders can also be involved. After permits are obtained, studies of the site's water resource and aquatic habitat must be made prior to installation of test equipment.

Currently, there are no operating tidal or wave energy projects on the West Coast. In late 2014, Snohomish PUD abandoned plans to develop a 1 MW tidal energy installation at the Admiralty Inlet.[40] Several years ago, Tacoma Power considered and later abandoned plans to pursue a project in the Tacoma Narrows.

Tidal and wave generation technologies are very early in development, making cost estimates difficult. Most developers have not produced more than one full-scale device, and many have not even reached that point. Few wave and tidal technologies have been in operation for more than a few years and their production volumes are limited, so costs remain high and the durability of the equipment over time is uncertain.

Demand-side Resource Costs and Characteristics

The demand-side resource alternatives considered include the following.

ENERGY EFFICIENCY MEASURES. This label is used for a wide variety of measures that result in a smaller amount of energy being used to do a given amount of work. Among them are building codes and standards that make new construction more energy efficient; retrofitting programs; appliance upgrades; and heating, ventilation and air conditioning (HVAC) and lighting changes.

DEMAND RESPONSE (DR). Demand response resources are comprised of flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.

DISTRIBUTED GENERATION. Distributed generation refers to small-scale electricity generators located close to the source of the customer's load.[41]

DISTRIBUTION EFFICIENCY (DE). This involves voltage reduction and phase balancing. Voltage reduction is the practice of reducing the voltage on distribution circuits to reduce energy

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40 / The Seattle Times website. Retrieved from http://www.seattletimes.com/seattle-news/snohomish-county-pud-drops-tidal-energy-project/, October 2014.
41 / In this IRP distributed solar PV is not included in the demand-side resources. Instead, it is handled as a direct no-cost reduction to the customer load. Solar PV subsidies are driving implementation and the subsidies are not fully captured with by the Total Resource Cost (TRC) approach that is used to determine the cost-effectiveness of DSR measures. Under the TRC approach, distributed solar PV is not cost effective and so is not selected in the portfolio analysis. Treating solar as a no-cost load reduction captures the adoption of this distributed generation resource by customers and its impact on loads more accurately.

consumption, as many appliances and motors can perform properly while consuming less energy. Phase balancing eliminates total current flow losses that can reduce energy loss.

GENERATION EFFICIENCY. This involves energy efficiency improvements at the facilities that house PSE generating plant equipment, and where the loads that serve the facility itself are drawn directly from the generator and not the grid. These loads are also called parasitic loads. Typical measures target HVAC, lighting, plug loads and building envelope end-uses.

CODES AND STANDARDS (C&S). No-cost energy efficiency measures that work their way to the market via new efficiency standards that originate from federal and state codes and standards.

Treatment of Demand-side Resource Alternatives

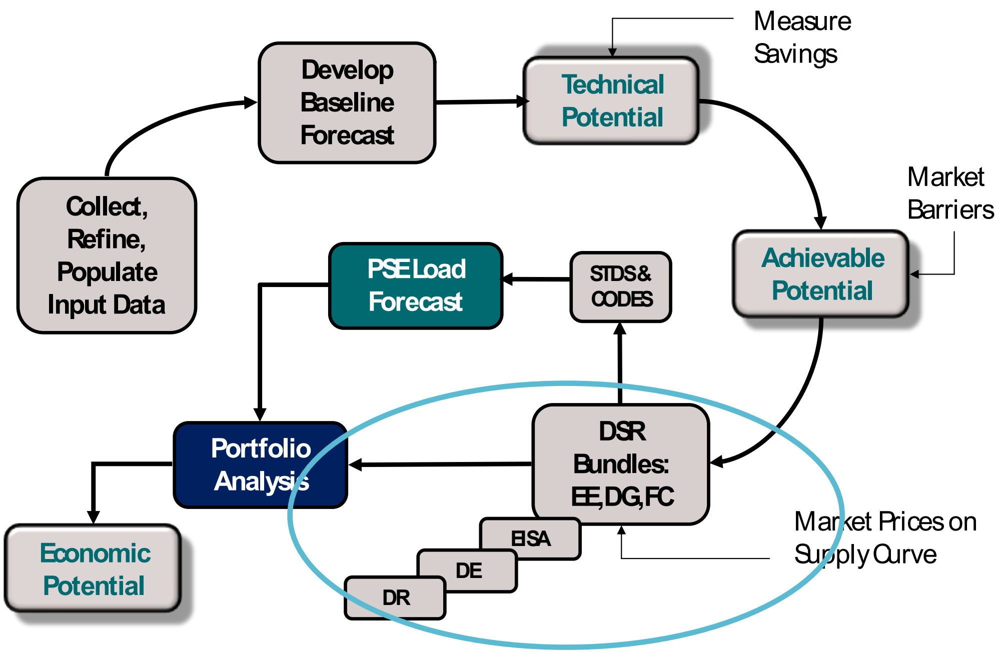
First, each demand-side measure was screened for technical potential. Screening for technical potential assumed that all energy and demand-saving opportunities could be captured regardless of cost or market barriers, so the full spectrum of technologies, load impacts and markets could be surveyed.

Second, market constraints were applied to estimate the achievable potential. To gauge achievability, we relied on customer response to past PSE energy programs, the experience of other utilities offering similar programs and the Northwest Power and Conservation Council's most recent energy efficiency potential assessment. For this IRP, PSE assumed achievable electric energy efficiency potentials of 85 percent in existing buildings and 65 percent in new construction.

Finally, the measures were combined into bundles based on levelized cost for inclusion in the portfolio optimization analysis. This methodology is consistent with the methodology used by the Northwest Power and Conservation Council.

Figure D-27 illustrates the methodology PSE used to assess demand-side resource potential in the IRP. Appendix J, Conservation Potential Assessment, contains a detailed discussion of the demand-side resource evaluation and development of the DSR bundles performed for PSE by Navigant.

Figure D-27: General Methodology for Assessing Demand-side Resource Potential



The following tables and charts summarize the results of the Navigant analysis of demand-side resources presented in Appendix J, Conservation Potential Assessment. Bundles 1 through 10 include energy efficiency, fuel conversion and distributed generation. Each bundle adds measures to the bundle that preceded it.

The savings potential for Bundles 1 through 10 consists of both discretionary and lost opportunity measures. Figure D-28 shows the proportion of discretionary versus lost opportunity measures in the bundles.

Figure D-28: Discretionary versus Lost Opportunity Measures in Bundles 1 to 10

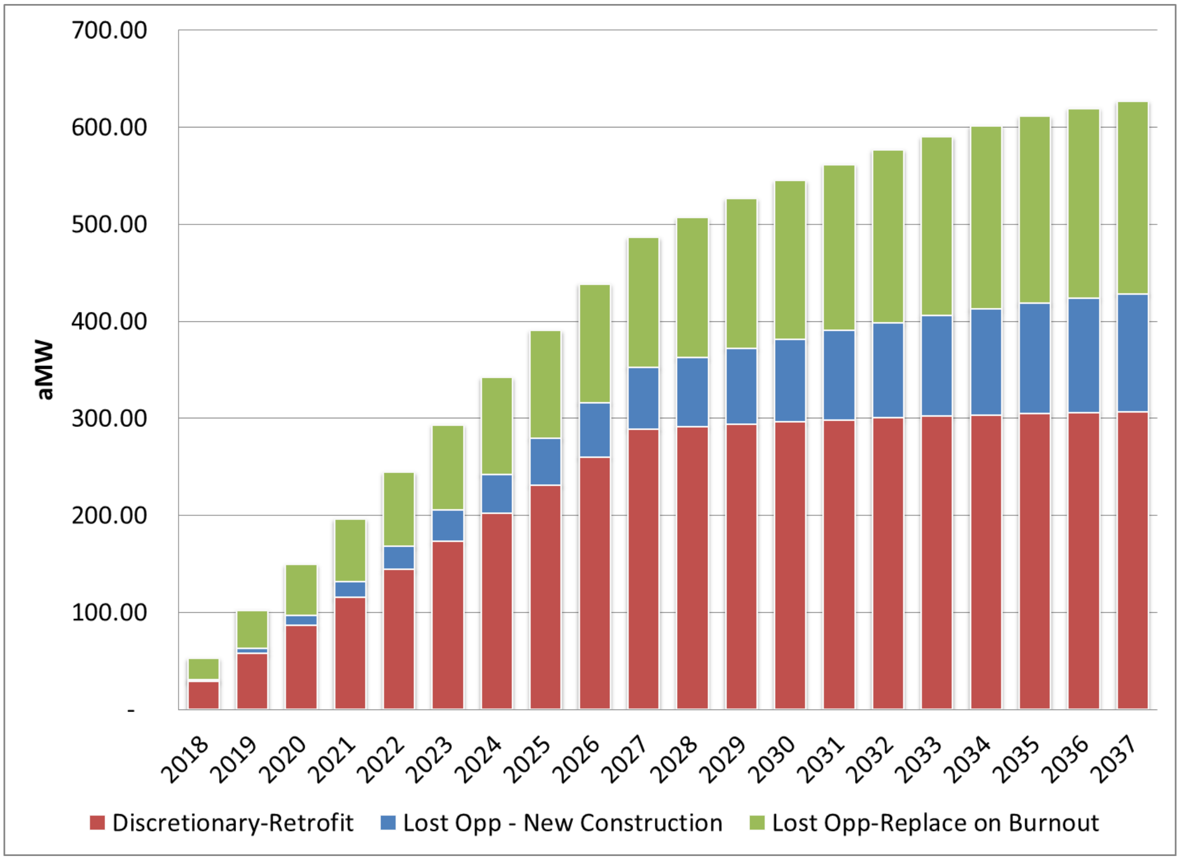


Figure D-29: Annual Energy Savings (aMW)

	Bundles (aMW)											
	1	2	3	4	5	6	7	8	9	10	DE	C&S
2018	12.62	15.73	20.09	20.59	23.00	23.77	24.64	28.70	29.95	68.03	0.31	2.65
2019	35.90	45.23	58.06	59.55	66.83	69.13	71.75	84.08	87.83	203.64	0.93	10.05
2020	55.39	70.93	91.81	94.29	106.56	110.37	114.73	135.60	141.88	338.53	1.55	47.73
2021	72.34	94.08	122.80	126.28	143.65	148.96	155.04	184.84	193.66	474.11	2.18	84.77
2022	88.40	116.38	152.91	157.38	179.96	186.76	194.55	233.72	245.08	612.37	2.82	91.83
2023	103.93	138.16	182.32	187.80	215.68	223.92	233.34	281.81	295.67	749.69	3.45	97.21
2024	118.36	158.60	209.61	216.10	249.30	258.85	269.62	326.26	342.35	872.95	4.09	101.92
2025	131.74	177.85	235.12	242.63	281.14	291.90	303.78	367.76	385.87	985.30	4.73	106.35
2026	144.29	196.20	259.31	267.84	311.66	323.56	336.40	407.17	427.16	1,090.40	5.39	110.41
2027	155.90	213.49	281.78	291.33	340.46	353.39	366.98	443.56	465.23	1,183.85	6.07	114.68
2028	164.66	226.14	298.33	308.41	360.61	374.12	388.27	469.63	492.37	1,255.84	6.94	118.96
2029	170.70	234.34	309.32	319.45	372.48	386.12	400.72	486.07	509.36	1,310.00	7.93	122.42
2030	176.08	241.84	319.24	329.42	383.25	397.01	411.97	500.83	524.62	1,359.06	8.97	126.01
2031	180.66	248.35	327.60	337.82	392.43	406.23	421.43	512.99	537.11	1,398.32	9.95	130.86
2032	184.79	254.33	335.29	345.55	400.86	414.71	430.12	524.32	548.77	1,436.15	10.99	136.54
2033	188.48	259.75	342.29	352.57	408.53	422.42	438.02	534.77	559.55	1,472.34	12.04	142.10
2034	191.45	264.13	347.73	358.03	414.54	428.42	444.06	542.51	567.46	1,497.92	13.16	147.07
2035	193.89	267.75	352.13	362.44	419.42	433.26	448.86	548.52	573.57	1,517.34	14.21	152.01
2036	196.01	270.94	356.01	366.34	423.71	437.51	453.06	553.89	579.02	1,535.33	15.33	157.60
2037	197.86	273.75	359.48	369.82	427.51	441.27	456.77	558.75	583.94	1,552.18	16.45	163.34

Figure D-30: Total December Peak Reduction (MW)

	Bundles (MW)											
	1	2	3	4	5	6	7	8	9	10	DE	C&S
2018	19.34	4.98	5.31	0.50	3.29	1.18	0.85	4.23	2.02	46.88	0.96	3.57
2019	52.89	14.08	13.15	1.50	9.93	3.18	1.95	9.23	5.29	106.24	1.93	13.52
2020	79.77	23.18	20.17	2.50	16.70	5.17	3.05	14.40	8.57	168.65	2.92	77.58
2021	102.34	32.31	26.76	3.50	23.61	7.14	4.15	19.97	11.82	234.33	3.92	142.53
2022	123.27	41.53	33.21	4.51	30.66	9.10	5.25	25.86	15.09	303.51	4.90	154.65
2023	143.27	50.80	39.44	5.52	37.84	11.02	6.28	31.73	18.28	372.34	5.90	163.31
2024	161.87	60.00	45.03	6.54	45.09	12.84	7.09	36.84	21.24	432.62	6.91	170.50
2025	179.44	69.40	50.62	7.56	52.40	14.64	7.84	42.23	24.19	494.52	7.92	177.30
2026	195.83	78.85	55.75	8.59	59.77	16.37	8.44	47.07	26.99	550.52	8.95	183.69
2027	211.28	88.43	60.60	9.62	67.19	18.07	8.96	51.63	29.71	603.92	10.12	190.11
2028	223.12	95.33	64.17	10.17	71.61	18.93	9.35	55.28	31.15	645.99	11.64	196.30
2029	231.47	99.57	66.62	10.22	73.00	19.00	9.68	58.29	31.40	680.14	13.20	201.54
2030	238.86	103.79	68.68	10.28	74.39	19.04	9.94	60.74	31.58	709.95	14.80	207.14
2031	245.33	107.87	70.34	10.32	75.73	19.05	10.12	62.63	31.68	734.88	16.46	214.19
2032	251.23	111.87	72.02	10.35	76.96	19.09	10.33	64.70	31.86	762.24	18.10	222.12
2033	256.25	115.54	73.34	10.38	78.04	19.10	10.46	66.21	31.97	783.98	19.76	230.08
2034	260.43	118.83	74.32	10.40	78.95	19.08	10.50	67.16	32.00	799.78	21.39	237.43
2035	263.99	121.81	75.19	10.42	79.67	19.06	10.50	67.99	32.04	813.75	23.14	244.51
2036	267.01	124.52	75.98	10.43	80.24	19.04	10.49	68.74	32.07	826.10	24.91	252.21
2037	269.60	127.01	76.70	10.45	80.68	19.02	10.47	69.42	32.11	837.20	26.77	260.33

The DSR December peak reduction is based on the average of the very heavy load hours (VHLH). The VHLH method takes the average of the five-hour morning peak from hour ending 7 a.m. to hour ending 11 a.m. and the five-hour evening peak from hour ending 6 p.m. to hour ending 10 p.m. Monday through Friday. The system demand peaked during the evening hours and correspondingly the demand-side resource peaks were chosen to be coincident with those evening system peak hours.

Figure D-31: Annual Costs (dollars in thousands)
(Codes and Standards has no cost and is considered a must-take bundle.)

	Bundles ($'000)										
	1	2	3	4	5	6	7	8	9	10	DE
2018	$13,617	$11,412	$24,380	$3,711	$25,096	$8,306	$10,447	$52,921	$19,392	$1,301,079	$467
2019	$23,349	$22,777	$47,179	$7,376	$49,369	$16,595	$20,820	$108,060	$38,877	$2,672,556	$467
2020	$110,203	$22,680	$44,324	$7,286	$47,919	$16,386	$20,634	$111,613	$39,152	$2,807,015	$467
2021	$119,200	$22,545	$42,551	$7,208	$47,330	$16,077	$20,418	$116,458	$39,054	$2,915,158	$467
2022	$33,207	$22,456	$41,758	$7,122	$46,933	$15,777	$20,183	$121,515	$38,852	$3,007,757	$467
2023	$25,668	$22,213	$40,169	$7,079	$45,935	$15,119	$19,192	$119,891	$37,815	$3,003,981	$467
2024	$19,873	$21,341	$35,632	$7,046	$44,531	$13,596	$15,896	$104,615	$33,496	$2,724,910	$467
2025	$15,827	$20,646	$32,029	$6,931	$42,870	$12,352	$12,857	$93,158	$29,974	$2,482,786	$467
2026	$12,764	$20,030	$29,264	$6,750	$41,155	$11,402	$10,728	$84,817	$27,341	$2,294,636	$467
2027	$10,501	$19,092	$25,293	$6,511	$39,378	$10,172	$8,278	$70,946	$23,601	$2,014,905	$545
2028	$7,290	$12,655	$18,444	$3,375	$22,356	$5,429	$6,096	$56,169	$14,552	$1,500,646	$701
2029	$4,576	$6,534	$12,562	$344	$6,067	$1,124	$4,554	$44,503	$6,847	$1,062,385	$701
2030	$3,979	$6,074	$10,499	$286	$5,661	$828	$3,579	$37,230	$5,736	$926,492	$701
2031	$3,283	$5,221	$7,689	$224	$5,052	$347	$2,277	$26,797	$3,766	$717,827	$701
2032	$2,791	$4,547	$6,395	$167	$4,296	$291	$1,799	$23,453	$3,349	$627,176	$701
2033	$2,312	$3,781	$5,326	$119	$3,445	$273	$1,427	$20,501	$3,003	$542,497	$701
2034	$1,689	$2,745	$3,287	$81	$2,576	$44	$594	$12,178	$1,511	$359,098	$701
2035	$1,195	$1,924	$2,045	$53	$1,789	$2	$212	$7,348	$769	$238,035	$701
2036	$814	$1,289	$1,423	$33	$1,129	$1	$115	$5,298	$534	$168,487	$701
2037	$472	$731	$846	$18	$600	$0	$51	$3,254	$312	$100,859	$701

Demand response programs are organized into 5 categories. These include:

1. Direct Load Control (DLC)
2. Commercial and Industrial (C&I) Curtailment
3. Economic Demand Response
4. Residential Dynamic Pricing
5. C&I Dynamic Pricing

Figure D-32 describes the total December peak reduction achieved by each program, and Figure D-33 describes the costs for each program.

Figure D-32: Demand Response Programs, Total December Peak Reduction (MW)

	Programs				
	1	2	3	4	5
2018	9	5	2	-	-
2019	26	13	6	-	-
2020	52	26	10	-	-
2021	77	39	14	-	-
2022	85	42	15	-	-
2023	84	42	14	4	1
2024	85	42	14	12	2
2025	84	41	14	24	5
2026	84	41	14	36	7
2027	85	42	14	40	8
2028	85	41	14	40	8
2029	85	42	14	40	8
2030	86	42	15	40	8
2031	86	43	15	41	8
2032	87	43	15	41	8
2033	87	44	15	41	8
2034	88	44	15	41	9
2035	89	45	16	41	9
2036	90	46	16	42	9
2037	90	46	16	42	9

Figure D-33: Demand Response Annual Costs (dollars in thousands)

	Programs ($0'000)				
	1	**2**	**3**	**4**	**5**
2018	$1,945	$306	$390	$-	$-
2019	$4,567	$1,077	$836	$-	$-
2020	$7,007	$1,911	$868	$-	$-
2021	$7,743	$2,872	$634	$-	$-
2022	$4,129	$3,218	$44	$-	$-
2023	$2,136	$3,253	$(168)	$909	$509
2024	$2,357	$3,309	$(150)	$1,566	$778
2025	$2,295	$3,364	$(149)	$2,126	$1,143
2026	$2,511	$3,463	$(123)	$1,800	$1,138
2027	$2,648	$3,562	$(132)	$(229)	$324
2028	$4,809	$3,628	$379	$(1,272)	$(103)
2029	$7,462	$3,847	$972	$(1,330)	$(93)
2030	$10,261	$3,891	$1,124	$(1,284)	$(95)
2031	$10,847	$4,038	$911	$(1,333)	$(100)
2032	$6,663	$4,189	$183	$(1,353)	$(107)
2033	$4,193	$4,346	$(89)	$(979)	$393
2034	$4,557	$4,508	$(71)	$(533)	$720
2035	$4,523	$4,683	$(63)	$(44)	$1,207
2036	$4,949	$4,866	$(30)	$52	$1,303
2037	$4,965	$5,035	$(59)	$(1,007)	$453