ELECTRIC RESOURCES AND ALTERNATIVES

Contents

This appendix describes the different types of electric resources available to PSE. It presents an inventory of PSE's existing electric resources and then describes current electric resource alternatives, including information about the viability and availability of each resource for PSE and estimated ranges for capital and operating costs.[1]

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.*

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. They are different, however, and they originate on different sides of the meter. Supply-side resources provide electricity to meet load and 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:

- All of PSE's generating plants, regardless of how they are fueled (by natural gas, coal, water or wind)
- Long-term contracts with independent producers to supply electricity to PSE (these also 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 and Intermittent. These distinctions refer to how the resource functions within the system.

BASELOAD RESOURCES are capable of generating electricity economically over long periods of time. They can often "follow load," which means they are capable of increasing output when demand is high and decreasing output when demand is low (but they cannot respond as quickly as peaking resources).

PSE's three sources of baseload energy are natural-gas fired combined-cycle combustion engines, hydroelectric generation and coal-fired generation.

PEAKING RESOURCES are generators that can ramp up and down quickly in order to meet spikes in need. They are typically not deployed for long periods of time because they are not as economical to operate as baseload resources.

Peaking resources can also provide flexibility to the portfolio by providing load following, wind integration and spinning reserves.

Simple-cycle combustion turbines are PSE's main peaking resource; some hydro-electric plants can also perform peaking functions.

INTERMITTENT RESOURCES experience big fluctuations in their generating patterns because their fuel sources are not constant – such as wind and solar. Since those fluctuations don't necessarily correspond to the fluctuations in customer demand, other resources need to be standing by to fill in when the wind dies down or the sun goes behind a cloud.

PSE's largest intermittent resource is wind generation; rooftop solar generation is also an intermittent resource. PSE has several smaller intermittent resources represented by co-generation and small power production which provide about 10 aMW of annual energy.

All generation and market purchases, whether baseload, peaking or intermittent, are subject to random and unforeseen curtailment and forced outage events, so for planning purposes, PSE cannot rely upon these resources 100 percent of the time to meet loads.

Capacity Values. The tables in 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 2015 for the year ending December 31, 2014. See http://www.pugetenergy.com/pages/filings.html.

EXISTING RESOURCES INVENTORY

Within each of the following sections, resources are listed in alphabetical order.

Supply-side Thermal Resources

Coal. Reliable, low-cost electricity from the Colstrip generating plant currently supplies 18 to 20 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. Appendix K, Colstrip, delivers a detailed description of the facility and its operations, ownership, history and applicable environmental regulations.

Gas-fired Combined-cycle Combustion Turbines (CCCTs). PSE's six CCCT resources have a combined net maximum capacity of 1,276 MW and supply 19 to 24 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 simple-cycle turbines listed below. PSE's CCCT 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 Coal and CCCT Resources

POWER TYPE	UNITS	PSE OWNERSHIP	NET MAXIMUM CAPACITY (MW)[1]
Coal	Colstrip 1 & 2	50%	307
Coal	Colstrip 3 & 4	25%	370
Total Coal			**677**
CCCT	Encogen	100%	165
CCCT	Ferndale[3]	100%	273
CCCT	Frederickson 1[2,3]	49.85%	136
CCCT	Goldendale[3]	100%	278
CCCT	Mint Farm[3]	100%	297
CCCT	Sumas	100%	127
Total CCCT			**1,276**

NOTES
1 Net maximum capacity reflects PSE's share only.
2 Frederickson 1 CCCT unit is co-owned with Atlantic Power Corporation - USA.
3 Maximum capacity of Ferndale, Frederickson 1, Goldendale and Mint Farm includes the capacity of duct firing.

Gas-fired Simple-cycle Combustion Turbines (SCCTs). These resources provide important peaking capability and help us to meet operating reserve requirements. The company displaces these resources when the energy is not needed to serve load or lower-cost energy is available for purchase. PSE's four simple-cycle combustion turbine plants 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 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 Resources

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.	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	7	04/04/52
Priest Rapids	Grant Co. PUD	0.64	6	04/04/52
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 which reduces its peaking capability in total from 840 MW to 774 MW and PSE's share of this to 231 MW. For the purposes of this IRP, PSE assumes the Wells hydroelectric contract is renegotiated at a lower share through the end of the IRP time horizon (2035).

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 Washington State's 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 Washington State's 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 agreement with Douglas County PUD for the purchase of 29.89 percent of the output of the Wells project expires in 2018 and PSE is in the process of negotiating an extension to this contract which has been included in the resource assumptions for this IRP. 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 April 4, 2052.

Wind Energy. PSE is the largest utility owner and operator of wind-power facilities in the Northwest. Combined, the company's three wind farms maximum capacity 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.

Figure D-4 presents details about the company's wind resources.

Figure D-4: PSE's Owned Wind 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 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.

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.

BPA – WNP-3 BONNEVILLE EXCHANGE POWER. This is a system-delivery, not a unit-specific, purchased power contract. The agreement resulted from PSE and others claims against the Bonneville Power Administration (BPA) regarding its action to halt construction on nuclear project WNP-3 in 1984, in which PSE had a 5 percent interest. Under the agreement, in effect until June 2017, PSE receives power during the winter months from BPA according to a formula based on the average equivalent annual availability and cost factors of surrogate nuclear plants similar in design to WNP-3. In exchange, PSE provides power to BPA from its combustion turbines, if requested and warranted under the contract terms, except during the month of May.

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.

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.

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 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.

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 2014 was approximately 20.4 aMW with a peak capacity return of 37.4 MW.

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.

COAL TRANSITION PPA. Under the terms of this agreement, PSE will buy 180 MW of firm, baseload coal transition power from TransAlta's Centralia coal plant starting in December 2014. On December 1, 2015, the contract increases 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. The state Legislature in 2011 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-megawatt (MW) Centralia facility, Washington's only coal-fired plant.

KLAMATH PEAKER TOLL. This tolling contract between PSE and Iberdrola Renewables is designed to help PSE meet its customers' peak winter electricity demand. During winter months (November through February) through February 2016, PSE can call upon 100 MW of energy from the Klamath natural gas-fired peaking facility in Klamath Falls, Ore.

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 224 MW. This agreement remains in effect until November 2026.

HYDROELECTRIC PPAs. Among PSE’s power purchase agreements are four long-term contracts for the output of production from hydroelectric projects within its balancing area. These contracts were establish 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	CAPACITY (MW)[1]
BPA- WNP-3 Exchange	System	6/30/2017	82
Pt. Roberts[2]	System	9/30/2019, but ongoing	8
Baker Replacement	Hydro	9/30/2029	7
Electron PPA	Hydro	12/31/2026	12.5[3]
PG&E Seasonal Exchange-PSE	Thermal	Ongoing	300
Canadian EA	Hydro	09/15/2024	(40.5)
Coal Transition PPA	Transition Coal	12/31/2025	180[4]
Klamath Peaker Toll	Natural Gas	2/29/2016	100
Klondike III PPA	Wind	11/30/2027	50
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
Hutchinson Creek PPA	Hydro-QF	9/30/2016	0.9
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
Van Dyk - Holsteins Dairy	Schedule 91 – Biogas	12/31/2020	0.472
Bio Energy Washington	Schedule 91 - Biogas	12/31/2021	1.20
Edaleen Dairy	Schedule 91 – Biogas	12/31/2021	0.75
BioFuels Washington	Schedule 91 – Biogas	12/31/2021	4.50
Skookumchuck	Schedule 91 – Hydro	12/31/2020	1.0
Smith Creek	Schedule 91 – Hydro	12/31/2020	0.12
Black Creek	Schedule 91 – Hydro	3/24/2021	4.2
Nooksack Hydro	Schedule 91 – Hydro	12/31/2021	3.5
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	Schedule 91 – Solar	12/31/2026	0.026
Knudson Wind	Schedule 91 – Wind	12/31/2019	0.108
3 Bar-G Wind	Schedule 91 – Wind	12/31/2019	0.12
Swauk Wind	Schedule 91 – Wind	12/31/2021	4.25
Total			**755**

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 reflects contract before May 2016. The capacity increases to 23.8MW after Nov. 2016.
4 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 180 MW from 12/1/2014 to 11/30/2015, 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.

Supply-side 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 of capacity required to meet PSE's peak need.[6]

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 as of 8/1/2015

NAME	EFFECTIVE DATE	TERMINATION DATE	TRANSMISSION DEMAND (MW)
BPA Mid-C Transmission			
Midway	11/1/2012	11/1/2017	100
Midway	10/1/2013	10/1/2018	115
Midway	3/1/2014	3/1/2019	35
Midway	4/1/2008	11/1/2035	5
Rock Island	7/1/2007	7/1/2037	400
Rocky Reach	11/1/2012	11/1/2017	100
Rocky Reach	11/1/2012	11/1/2017	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	12/1/2014	11/30/2031	160
Vantage	11/1/2012	11/1/2017	100
Vantage	12/1/2014	12/1/2019	169
Vantage	10/1/2013	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	11/1/2014	11/1/2019	5
Wells	1/24/1966	9/1/2018	266
NWE Purchase IR Conversion	10/1/2011	10/1/2016	94
Vantage	5/1/2014	3/1/2021	23
Total BPA Mid-C Transmission			**1,975**
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			**2,425**

As shown, PSE has a total of 2,425 MW of capacity to the Mid-C market hub: 1,975 MW in BPA contracts and 450 MW of owned capacity. Figure D-6 also shows the BPA contract periods. The NWE Purchase IR Conversion will not be renewed when it expires in October 2016; this will reduce BPA contracted Mid-C transmission to 1,881 MW beginning October 1, 2016.

Demand-side Energy Efficiency Resources

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

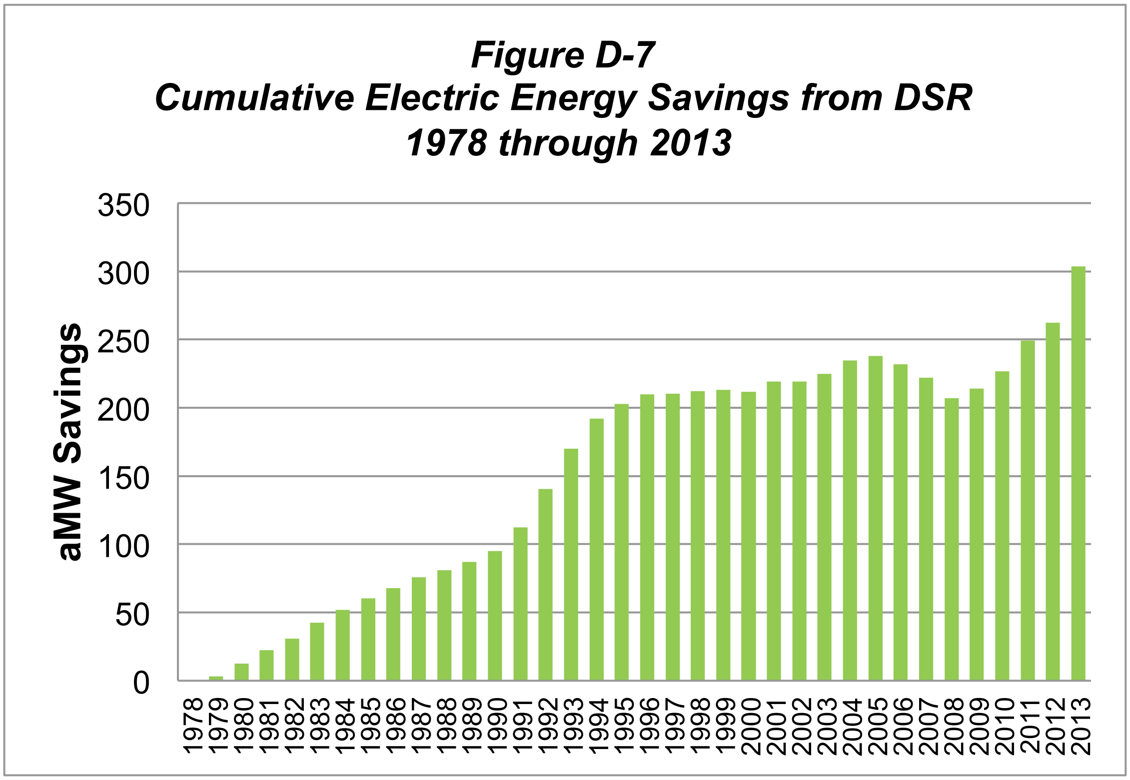
- **ENERGY EFFICIENCY**, implemented by PSE's Customer Energy Management (CEM) group
- **FUEL CONVERSION**, implemented by PSE's Customer Energy Management (CEM) group
- **DISTRIBUTION EFFICIENCY**, managed by the System Planning department
- **GENERATION EFFICIENCY**, evaluated by PSE's Customer Energy Management (CEM) 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 the 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]

Since 1978, annual first-year savings (as reported at the customer meter) have increased more than 450 percent, from 9 aMW in 1978 to 43 aMW in 2014. The cumulative investment and power savings from 1978 through 2014 are approximately $1.1 billion and 350 aMW respectively. The savings are adjusted for measure life, so that savings from very early programs that are past the measure life are not counted. Figure D-7 shows the cumulative savings from 1978 through 2014. By 2014, those savings represented enough electrical energy to serve more than 250,000 homes for a year.

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

Figure D-7: Cumulative Electric Energy Savings from DSR, 1978 through 2014



In the most recently completed program cycle, the 2012-13 tariff period, energy efficiency (including fuel conversion) achieved a total savings of 80 aMW; the target for the current 2014-15 program cycle is 70.9 aMW. The savings impact from the most recent program cycles is mitigated somewhat by earlier programs reaching the end of their productive lives, causing those savings "drop off" the chart in Figure D-7.

Electric Energy Efficiency Programs. The two largest programs offered by PSE to customers are the Commercial and Industrial Retrofit program and the Single Family Residential Lighting program.

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 spent more than $17 million (mostly in grants) to over 520 business customers in 2014 to achieve savings of over 74,000 MWh.

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 to the retail stores to reduce the cost of energy efficient lighting products. With a budget totaling more than $17 million, the program captured savings of over 103,000 MWh in 2014.

Figure D-8: Annual Energy Efficiency Program Summary, 2012-2014

Program	2012 - 2013 Actual	’12-’13 2-Year Budget/ Goal	‘12/’13 Actual vs. Budget % Total	2014 Actual	’14-’15 2-Year Budget/ Goal	’14 Actual vs. ‘14-15 % Total
Electric Program Costs	$ 190	$ 193	98.0%	$99	$ 188	53%
Megawatt Hour Savings	701,000	666,000	105%	378,540	621,000	61%
aMW Savings	80	76	105%	43	71	61%

Figure D-8 shows the combined performance of these two programs compared to two-year budget and savings goals for the biennial 2012-2013 electric energy efficiency programs; it also records 2014 progress against 2014-2015 budget and savings goals.

PSE’s electric energy efficiency programs saved a total of 80 aMW of electricity at a cost of $190 million during 2012-2013, surpassing energy savings goals while operating under budget. Through 2014, the 2014-2015 electric energy efficiency programs have saved 43 aMW of electricity at a cost of $99 million.

Fuel Conversion. The Fuel Conversion Program has been growing, albeit slowly, since its inception in 2010. In the most recent years, an average of 260 customers have participated in the program. See Figure D-9 below.

Figure D-9: Fuel Conversion Program 2012-2014

Year	Savings (kWh)	Budget Spent	Total Incentives $	Total Customers (rebates paid)
2012	1,531,500	$540,306.00	$339,879.00	250
2013	1,622,750	$649,666.00	$404,909.00	263
2014	1,741,000	$655,950.00	$456,970.00	270

PSE gas and electric customers and Cascade Natural Gas service territory customers are eligible to convert. Currently there is a minimum average requirement of 19,000 kWh to qualify for all incentives (with the exception of water-heat only). The kWh requirement and gas availability are barriers to participation.

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 and two substations were adapted in that year and another two in 2014. Work started on another four substations in 2014 and was completed in the third quarter of 2015. Five more substations are targeted for completion by the end of 2015. Figure D-10 summarizes the savings to date for the completed substations and estimates savings for those still to be completed in 2015.

Figure D-10: Distribution Efficiency Savings thru 2015

Substation	Year Completed	Annual kWh Savings	Notes
South Mercer	2013	607,569	Completed
Mercerwood	2013	357,240	Completed
Mercer Island	2014	859,586	Completed
Britton	2014	636,197	Completed
Panther Lake	2015	484,183	Completed 2015 Q3
Hazelwood	2015	546,003	Completed 2015 Q3
Inglewood	2015	533,607	Completed 2015 Q3
Pine Lakes	2015	627,167	Completed 2015 Q3
Cambridge	2015	403,044	Scheduled for end of 2015
Cresecent Harbor	2015	218,932	Scheduled for end of 2015
Lakota	2015	456,900	Scheduled for end of 2015
Rhodes Lake	2015	562,393	Scheduled for end of 2015
Vashon	2015	403,594	Scheduled for end of 2015
Total Estimated Savings		**6,696,415**	

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[8] 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 has been conducting site assessments and expects that they will be completed in 2015. To date, the assessments have not yielded any cost effective measures. Figure D-11 summarizes the assessments to date.

Figure D-11: Summary of Generation Efficiency Assessment

PSE Generation Facilities	Measures Description	Measure Cost	Annual Energy Savings (kWh)	TRC[4]
Encogen[1]	Lighting Upgrade	$51,720	35,662	0.41
	VFDs: Make-up water pumps	TBD	0	
	VFDs: Condensate pumps	TBD	0	
	VFDs: Boiler feedwater pumps	TBD	0	
	VFDs: Cooling tower fans	TBD	0	
Ferndale	Lighting Upgrade	$56,800	38,899	0.41
Fredonia	Lighting Upgrade	$30,200	10,449	0.21
Fredrickson[2]	TBD	TBD	0	TBD
Goldendale[3]	Not eligible	0	0	
Lower Baker	TBD	0	0	TBD
Upper Baker	TBD	0	0	TBD
Mint Farm	Lighting Upgrade	$88,881	85,020	0.66
Sumas	Lighting Upgrade	$38,352	30,269	0.55
	VFDs: HP Pump	$360,000	189,216	0.4
	VFDs: IP Pump	$90,000	23,126	0.19
	VFDs: RW pumps	$120,000	59,568	0.38
Whitehorn	Lighting Upgrade	$35,215	3,848	0.07
Colstrip	**TBD**	$0	0	TBD
Totals			**476,057**	

NOTES
1 Encogen has variable frequency drive (VFD) projects that have been identified as energy efficient opportunities, but they have not been assessed for cost-effectiveness or potential savings.
2 Fredrickson is being evaluated by PSE Energy Management Engineering at this time. Potential savings estimate is to be determined.
3 Production facilities are not eligible as all equipment is powered by the grid.
4 TRC is total resource cost test.

8 / 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 – which is referred to as the "parasitic load."

Demand-side Customer Programs

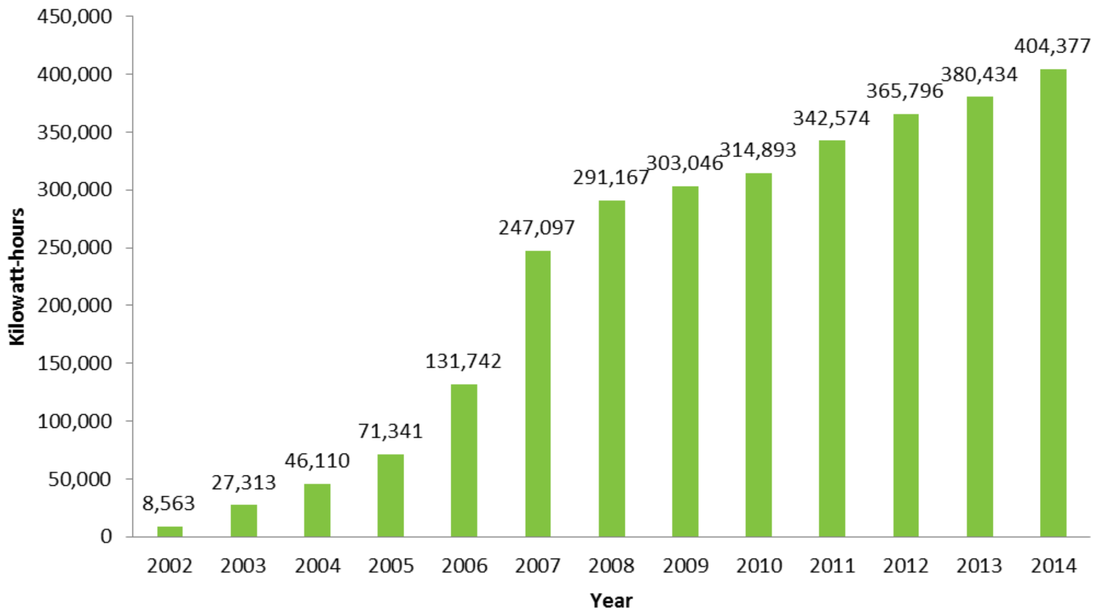
PSE's customer renewable energy programs continue to grow. The Green Power Program serves customers who want to purchase additional renewable energy, and the Customer Renewables Program serves customers who generate renewable energy on a small scale. Our customers find value as well as social benefits in both 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. Customer growth has more than doubled since the original 3Degrees contract was initiated in January 2009. Participation increased by 16 percent and 10 percent in 2013 and 2014, respectively. As of December 31, 2014, over 4 percent of PSE electric customers are participating in the program. Between 2012 and 2014, the number of subscribers increased nearly 28 percent – from 34,962 to 44,688 – and the number of megawatt-hours purchased increased over ten percent, from 365,796 to 404,377.

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.

Figure D-12: Green Power Kilowatt-hours Sold, 2002-2014



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.; EDF Energy Services, a national REC broker; 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 thirteen small, local 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, 3Bar G community wind, and First Up! Knudson community wind, Swauk Wind, Ellensburg Community Solar, Skagit Community Solar, BioFuels Washington and the Nooksack Hydro Facility – many of which also provide power to PSE under Schedule 91 contracts discussed above.

Over the last 9 years, the Green Power Program has also committed over $350,000 in grant funding to 14 cities for solar demonstration projects located on municipal facilities. For example, in 2013, the City of Mercer Island, Wash. installed a 4.4 KW system at their community center with $30,000 in grant funding from PSE. Some of the other projects have been installed throughout PSE's service territory, in Bellingham, Whidbey Island, Vashon and Olympia.

In 2013, the cities of Anacortes, Bainbridge Island, Kirkland and Tumwater were each awarded $20,000 grants for solar projects in their communities, and the City of Snoqualmie was awarded a $40,000 grant. The grants were in recognition of a successful multi-city Green Power Community Challenge campaign in which the five cities met individual goals for increased enrollment in the Green Power Program. The City of Snoqualmie received an additional $20,000 in recognition of achieving the highest percentage of new enrollments among available accounts during the 12-month challenge period. In 2014, a similar multi-city challenge was held with the cities of Redmond, Issaquah and Puyallup. All met their individual goals and each earned a $20,000 grant.

In 2013, PSE competitively awarded three-year REC contracts to the Bonneville Environmental Foundation and 3Degrees to help supply the balance of our Green Power Program portfolio needs in those three years. Pricing has remained relatively low, largely due to an increasing 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.

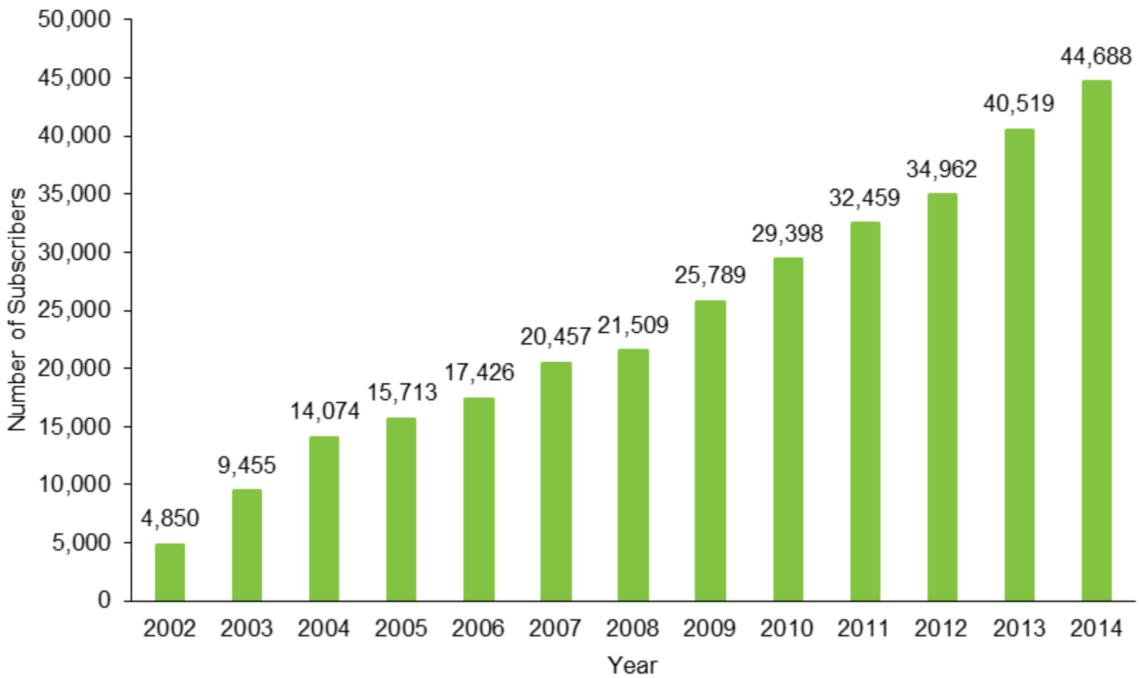
GREEN POWER RATES. The standard rate for green power is $0.0125 per kWh. Customers can purchase 160 kWh blocks for $2.00 per block with a two-block minimum, or they can choose to participate in the "100% Green Power Option." Introduced in 2007, this option adjusts the amount of the customer's monthly green power purchase to match their monthly electric usage.

The large-volume green power rate – $0.006 cent per kWh for customers who purchase more than 1,000,000 kWh annually – has attracted 27 customers since it was introduced in 2005.

In 2014, the average residential customer purchase was 640 kWh per month, and the average commercial customer purchase was 1,902 kWh. The average 2014 large-volume purchase, by account, under Schedule 136 was 14,390 kWh per month.

Figure D-13 illustrates the number of subscribers by year. Of our 44,688 Green Power subscribers at the end of 2014, 43,629 were residential customers, 790 accounts were commercial accounts, and 269 accounts were assigned under the large-volume commercial agreement. Cities with the most residential and commercial participants include Olympia with 5,348, Bellingham with 5,080, and Bellevue with 2,944.

Figure D-13: Green Power Subscribers, 2002-2014

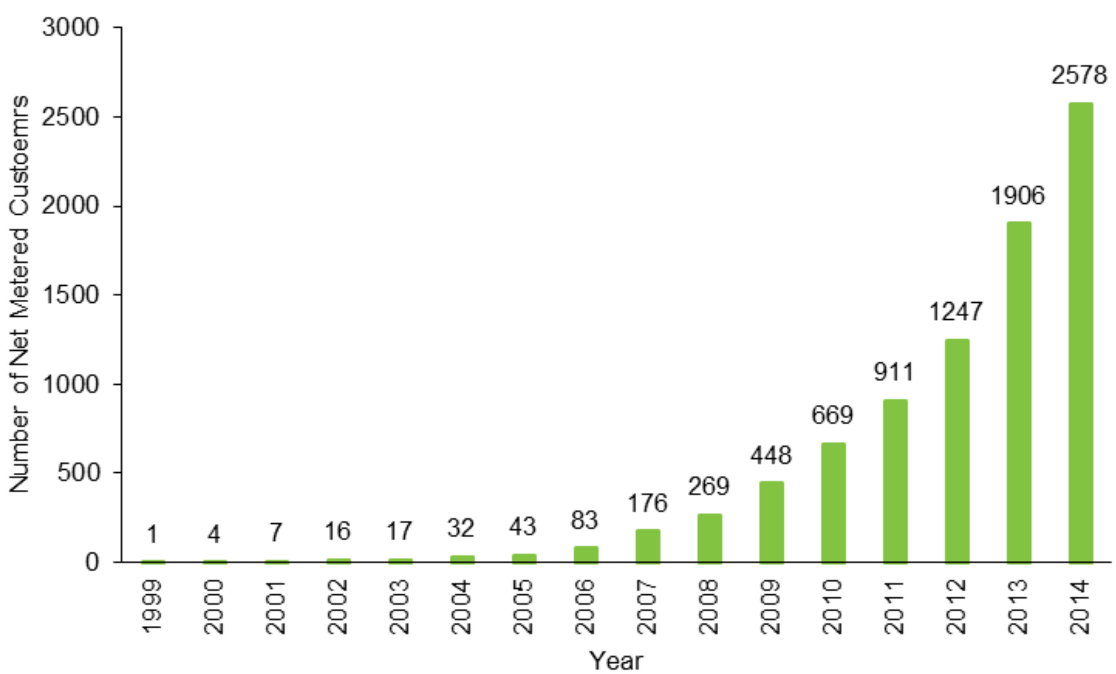


Customer Renewables Programs. PSE offers two customer renewables programs.

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 fifteen years, as Figure D-14 shows. For 2014, PSE added 672 new net metered customers for a total of 2,578.

Figure D-14: Net Metered Customers, 1999-2014



The vast majority of customer systems (98 percent) are solar photovoltaic (PV) installations with an average generating capacity of 6.25 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 5.17 KW. Overall, the program was capable of producing more than 15.8 MW of nameplate capacity at the end of 2014.

Customer preference along with state and federal incentives continues to drive customer solar PV adoption. Residential customers were 92 percent of all solar PV by number and 82 percent by nameplate capacity. PSE introduced a new streamlined solar application in 2014 and continues to prepare for growth in customer generation.

Figure D-15: 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	12	8.76	105.07
Micro hydro	4	3.30	13.20
Solar array	2,530	6.16	15,575.61
Wind turbine	32	3.23	103.30
Total	**2,578**	**6.13**	**15,797.18**

Figure D-16: Net Metered Systems by County

County	Number of Net Meters
Whatcom	482
King	822
Skagit	238
Island	174
Kitsap	353
Thurston	340
Kittitas	73
Pierce	96
Total	**2,578**

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. Average annual credits range 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. By the end of 2014, PSE had paid $3,130,000 to 2,000 customers eligible for production payments.

ELECTRIC RESOURCE ALTERNATIVES

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

PSE continues to explore emerging resources. This IRP includes an analysis of battery and pumped energy storage (see Appendix L, Electric Energy Storage), an analysis of the impact of high levels of rooftop solar generation at the circuit level and an analysis of the maximum amount of rooftop solar PV that could be installed in PSE's service territory (see Appendix M, Distributed Solar).

Generic Resource Costs and Characteristics

Figure D-17, next page, summarizes the generic thermal resources modeled by PSE. All costs are in 2014 dollars.

Figure D-17: Generic Resource Thermal Assumptions Modeled

2014 dollars	Units	CCCT	Frame Peaker w/ Oil	Frame Peaker w/o Oil	Aero Peaker w/ Oil	Aero Peaker w/o Oil	Recip Peaker
ISO Capacity[1]	MW	317	224	224	207	207	220
Winter Capacity[2]	MW	335	228	228	203	203	220
Capacity Duct Fired unit	MW	50					
Capital Cost	$/kW	$1,256	$896	$830	$1,342	$1,273	$1,599
O&M Fixed	$/kW-yr	$10.55	$17.05	$7.25	$16.23	$7.24	$5.31
O&M Variable	$/MWh	$2.96	$2.69	$2.69	$3.50	$3.50	$8.63
Forced Outage Rate	%	3%	3%	3%	3%	3%	3%
Operating Reserves	%	3%	3%	3%	3%	3%	3%
Heat Rate – Baseload HHV	Btu/kWh	6,798	10,046	10,046	9,156	9,156	8,538
Heat Rate – Turndown HHV	Btu/kWh	7,396	14,115	14,115	11,122	11,122	9,431
Heat Rate Duct Fired unit	Btu/kWh	8,670					
Minimum Capacity[3]	%	50%	40%	40%	25%	25%	4%
Start Time	Minutes	60	29	29	10	10	10
Location[4]		PSE	PSE	PSE	PSE	PSE	PSE
Fixed Gas Transport	$/kW-yr	$63.35	$48.74	$93.62	$44.42	$85.32	$79.57
Variable Gas Transport	$/MMBtu	$0.04	$0.28	$0.04	$0.28	$0.04	$0.04
Fixed Transmission[4]	$/kW-yr	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Variable Transmission[4]	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Emissions[5]							
NO_x	lbs/MMBtu	0.01	0.01	0.01	0.01	0.01	0.02
SO_2	lbs/MMBtu	0.006	0.006	0.006	0.006	0.006	0.03
CO_2	lbs/MMBtu	116.0	112.5	112.5	116.0	116.0	114.7
First Year Available		2020	2019	2019	2019	2019	2019
Economic Life	Years	35	35	35	35	35	35
Greenfield Development[6] & Construction Lead time	Years	4	3	3	3	3	3

NOTES
1 "ISO" capacities represent the operational capacities at International Standard Organization conditions.
2 Winter capacity represents the operational capacity at 23 degrees Fahrenheit.
3 An aeroderivative turbine may run at a minimum capacity of 50%. The generic resource includes two turbines, so the minimum capacity is one unit at 50%, which is equivalent to 25% of two units. Reciprocating turbines may also run at a minimum capacity of 50%. The generic resource includes 12 turbines, which is equivalent to 4% of the capacity of twelve turbines.
4 The location "PSE" means that the plants are located in the PSE service territory with no fixed or variable transmission costs.
5 Emission rates for natural gas only.
6 New power plant built from scratch on undeveloped land.

The fixed and variable gas transport costs for the gas plants are based on purchasing gas at the Sumas Hub. The transport costs for a resource without oil backup are based on needing 100 percent firm gas pipeline transport capacity plus 20 percent in gas storage. This applies to the CCCT, frame peaker without oil, Aero peaker without oil and the reciprocating engine. We are assuming 100 percent firm gas pipeline on a Williams Northwest Pipeline (NWP) expansion to Sumas, plus 100 percent firm gas pipeline on a Westcoast Energy Inc. (Westcoast) gas pipeline expansion to Station 2, and 20 percent of the daily need in gas storage. For the resources with oil backup, the frame and Aero peakers, we are assuming we need 50 percent firm gas pipeline transport on a NWP expansion to Sumas and 50 percent firm gas pipeline transport on a Westcoast pipeline expansion to Station 2, plus 20 percent in gas storage.

Figure D-18 below shows the gas transport assumptions for resources with and without oil backup.

Figure D-18: Gas Transport Costs

CCCT & 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 (%)
NWP Expansion	0.560	0.030	0.0018	1.9%	3.852%
Westcoast Expansion	0.460	0.010	-	1.6%	3.852%
Gas Storage	0.044	-	-	2.0%	3.852%
Total	**1.064**	**0.040**	**0.0018**	**5.5%**	**3.852%**

Peakers with Oil Backup – 50% Sumas on NWP + 50% Station 2 on Westcoast

Pipeline/ Resource	Fixed Demand ($/Dth/Day)	Variable Demand ($/Dth)	Variable Commodity ($/Dth)	ACA Charge ($/Dth)	Fuel Use (%)	Utility Taxes (%)
NWP Expansion	0.280	0.131	0.030	0.0018	1.9%	3.852%
Westcoast Expansion	0.230	0.110	0.010	-	1.6%	3.852%
Gas Storage	0.044	-	-	-	2.0%	3.852%
Total	**0.554**	**0.242**	**0.040**	**0.0018**	**5.5%**	**3.852%**

As discussed in Chapter 4, one of the sensitives for the electric portfolio is to test the location of the natural gas plants. The baseline assumption is that the plants are located in the PSE service territory and therefore have zero transmission costs. The "gas plant location" sensitivity is that the plants will be located in eastern Washington, within BPA's Balancing Authority (BA) and will therefore, require BPA firm Point-to-Point transmission service at a cost of $17.75 per kW per year in 2014 dollars. The plants will also get natural gas from AECO, via the NOVA, Foothills and GTN pipelines. Figure D-19 below displays the gas pipeline costs for a plant in eastern Washington.

Figure D-19: Gas Transport Costs for Eastern Washington

CCCT & Peakers with No 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	0.170	-	-	1.10%	3.852%
Foothills	0.097	0.0	-	1.39%	3.852%
GTN	0.160	0.004	0.0018	2.00%	3.852%
Gas Storage	0.044	-	-	-	3.852%
Total	**0.470**	**0.004**	**0.0018**	**4.49%**	**3.852%**

Peakers with Oil Backup – 50% AECO on GTN/NOVA/Foothills

Pipeline/ Resource	Fixed Demand ($/Dth/Day)	Variable Demand ($/Dth)	Variable Commodity ($/Dth)	ACA Charge ($/Dth)	Fuel Use (%)	Utility Taxes (%)
NOVA	0.085	0.050	-	-	1.10%	3.852%
Foothills	0.049	0.026	-	-	1.39%	3.852%
GTN	0.080	0.048	0.004	0.0018	2.00%	3.852%
Gas Storage	0.044	-	-	-	-	3.852%
Total	**0.257**	**0.124**	**0.004**	**0.0018**	**4.49%**	**3.852%**

Thermal Resources Modeled

Natural Gas. Additional 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. New large-scale hydro projects are not practical to develop today, as discussed below. New nuclear generation is neither practical nor feasible. Therefore, 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 three types of gas-fired generators modeled in this analysis are described below. Each brings particular strengths into the overall portfolio.

COMBINED-CYCLE COMBUSTION TURBINES (CCCT). Combined-cycle combustion turbine power 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." Duct firing can produce additional capacity from the steam turbine generator, although at less efficiency than the primary unit. CCCT plants currently entering service can convert about 60 percent (HHV[9]) of the chemical energy of natural gas into electricity. Because of their high thermal efficiency and reliability, relatively low initial cost and low air emissions, CCCTs have been a popular source of electric power and process steam generation since the 1960s.

9 / Higher Heating Value (HHV) is determined at a standard temperature of 59 degrees Fahrenheit.

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

Natural gas supply is assumed to be firm year-round and based on projected gas pipeline firm rates. The unit is assumed to be connected to the PSE transmission system and as such does not incur any direct transmission cost. This analysis assumes 20 percent of gas storage is available to the CCCT plants modeled.

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

Frame CT 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). Typical units have efficiencies in the range of 30 percent to 40 percent (HHV) at full load. These units are typically less flexible than aeroderivative turbines and reciprocating engines, meaning they cannot reduce output beyond about 40 percent. They also have slower ramp rates (on the order of 20 MW/minute), and though some can start in ten minutes, the output achieved in ten minutes is typically not baseload and incurs a significant maintenance penalty for each ten-minute start.

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

Aeroderivative (Aero) Peakers. 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). Typical aero units have efficiencies in the range of 25 percent to 38 percent (HHV) at full load. Aero units are typically more flexible than their frame counterparts and many can reduce output to nearly 50 percent. Most can start and achieve full output in less than ten minutes and start multiple times per day without maintenance penalties. Ramp rates range from 20 to 90 MW per minute. 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.

RECIPROCATING ENGINES (RECIP PEAKERS). 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. Lean burn reciprocating engines typically show HHV efficiencies in the range of 30 percent to 40 percent while some newer units claim efficiencies as high as nearly 50 percent. 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 turbines.

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

Thermal Resources Not Modeled

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 hard data on recent U.S. nuclear developments from which reasonable cost estimates can be made. The construction costs track record for nuclear plants completed in the U.S. during the 1980s and 1990s was certainly poor. Actual costs were far higher than projected, construction schedules experienced long delays, and interest rate increases resulted in high financing charges. Changing regulatory requirements also contributed to project cost increases, and in some instances public controversy contributed to construction delays and cost overruns.

The high cost and high uncertainty of nuclear technology make it an undue risk for PSE at this time.

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.

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.

Energy Storage Resources Modeled

Figure D-20: Energy Storage Assumptions Modeled

2014 dollars	Units	Battery	Pumped Hydro
Power	MW	80	200
Energy	MWh	160	2000
Discharge at Nominal Power	Hours	2	10
Round-trip Efficiency[1]	%	85%	81%
Recharge at Nominal Power	Hours	2.35	12.42
Station Footprint	Acres	1.5	Big
Capital Cost	$000	$121,277	$480,000
Capital Cost per kW	$/kW	$1,516	$2,400
Capital Cost per kWh	$/kWh	$758	$240
Fixed O&M	$/kW-yr	$7.71	$15.00
Variable O&M	$/MWh	-	-
Forced Outage Rate	%	0.5%	-
Capacity Credit	%	100%	100%
Book Life	Years	20	60
Greenfield Development & Construction Lead time	Years	3	15

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

Electric energy storage technologies are improving rapidly, and this IRP includes a portfolio sensitivity that tests the cost difference between a portfolio that includes battery storage and one that does not. In addition, PSE has designed a pilot project of battery storage to more fully assess the multiple values that storage systems may provide. The study is being done in partnership with the Washington State Department of Commerce and Pacific Northwest National Laboratories. Appendix L, Electric Energy Storage, describes the project in Glacier, Wash.

Renewable Resources Modeled

Figure D-21: Generic Resource Renewable Assumptions Modeled

2014 dollars	Units	Wind	MT Wind	Biomass	Solar
Nameplate Capacity	MW	100	100	15	20
Winter Capacity	MW	8	55	0	0
Capital Cost	$/kW	$1,968	$4,659	$4,322	$2,535
O&M Fixed	$/kW-yr	$27.12	$27.12	$110.98	$17.47
O&M Variable	$/MWh	$3.15	$3.15	$5.53	$0.00
Capacity Factor	%	34%	41%	85%	20%
Capacity Credit	%	8%	55%[11]	0%	0%
Location		SE WA	Central MT	West WA	Central WA
Fixed Transmission	$/kW-yr	$35.23	$55.05	$20.83	$23.35
Variable Transmission	$/MWh	$1.84	$1.84	$0.34	$1.84
First Year Available		2019	2020	2019	2019
Economic Life	Years	25	25	35	25
Greenfield Development & Construction Lead time	Years	3	3	3	3

Biomass. 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 size 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. Also, 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 would require approximately four years. The costs modeled in Figure D-21 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/).

11 / This highly optimistic capacity contribution is based on a limited data set. A more comprehensive analysis of an actual wind farm/contract in an acquisition analysis would probably illustrate a lower capacity contribution, but PSE used this value in its analysis.

Solar. 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 fixed tilt PV technology. For this IRP, PSE has also studied the impact of large amounts of solar energy at the circuit level; see Appendix M, Distributed Solar, for a description of the study and its results.

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.

As of the third quarter of 2014, cumulative solar PV capacity reached 16.1 gigawatts and cumulative concentrating solar power capacity reached 1.4 GW.[12]

12 / Solar Electric Industry Association (SEIA), Q3 2014 Solar Market Insight Report, December 17, 2014.

Commercial availability. Currently, renewable portfolio standards (RPS) drive most utility-scale solar development in the United States. 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 642 MW_{dc}[13] of combined residential, non-residential and utility-scale solar PV installations as of September 2014.[14]

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. However, several thermal solar facilities have become operational in California in recent years, including the Ivanpah Solar Electric Generating System, a $2.2 billion project in California's Mojave Desert. In September 2013, NRG Solar announced that Unit 1 of Ivanpah's planned three-unit system had successfully synchronized to the power grid for the first time, producing the facility's first energy output. When all three units are online, the 377 MW facility jointly owned by NRG Energy, BrightSource Energy and Google will be the largest solar thermal facility in the world. It is expected to nearly double the amount of commercial solar thermal capacity now operating in the U.S.[15]

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.

Cost and performance assumptions. With a service area that crosses the Cascade Mountains, PSE saw a large range of customer solar production in 2014. Customer average PV production west of the Cascade Mountains was 982 kWh per KW. Systems in Kittitas County produced roughly 50 percent more, for a total of 1,473 kWh per KW for the year, meaning that PV systems in western Washington had a capacity factor of approximately 11 percent, while those in eastern Washington performed at 17 percent.

Since PSE built the Wild Horse Solar Demonstration Project in 2007, installed costs for PV solar systems have declined considerably. The Solar Electric Industry Association reported that by the third quarter of 2014, national averages had reached approximately $3.60 per $Watt_{dc}$ for residential systems, $2.27 per $Watt_{dc}$ for commercial systems and $1.88 per $Watt_{dc}$ for utility-scale single-axis tracking systems.[16]

13 / Solar is installed at direct current (dc).
14 / Solar Electric Industry Association (SEIA), Q3 2014 Solar Market Insight Report, December 17, 2014.
15 / Brightsource Energy website. Retrieved from http://www.ivanpahsolar.com/news-releases, September 2013.
16 / Solar Electric Industry Association (SEIA), Q3 2014 Solar Market Insight Report, December 17, 2014.

The EIA in its *Annual Energy Outlook 2014* estimates capital costs for utility-scale PV solar systems to be approximately \$3,564 per KW_{ac}[17] and solar thermal plants to be approximately \$5,045 per KW_{ac}. This is on the higher end of cost estimates. Many resources in the western United States are seeing costs around \$2,600 per KW_{ac}.

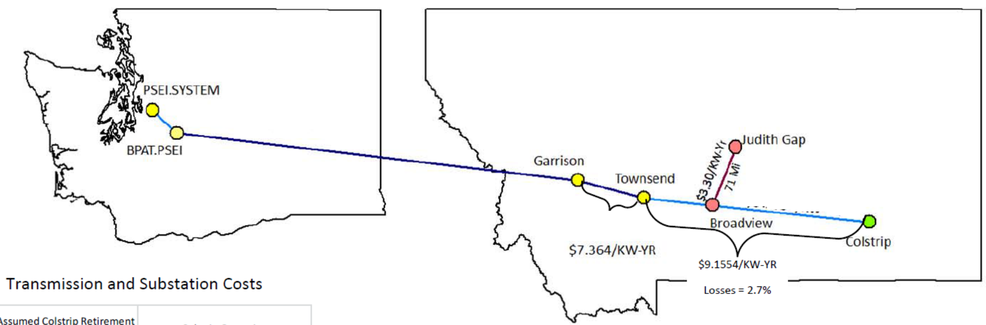
Wind. Wind energy is the primary renewable resource that qualifies to meet RPS requirements in our region due to wind's technical maturity, reasonable lifecycle cost, acceptance in various regulatory jurisdictions and large "utility" scale compared to other technologies. However, it also poses challenges. 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 it 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 WIND VS. MONTANA WIND. For this IRP, wind was modeled in two locations, southeast Washington and central Montana. Washington wind is located in BPA's BA, so this wind only requires one transmission wheel through BPA to PSE. Montana wind, however, is outside BPA's BA and will require four transmission wheels plus various system upgrades to deliver the power to PSE service territory; the Judith Gap location was chosen because PSE was able to obtain data from that wind project for use in the analysis.

Figures D-22 through D-25 explain the two sets of costs and assumptions used in this IRP analysis to examine Washington vs. Montana wind resources. PSE's original baseline assumptions are presented in Figures D-22 and D-23. When this material was discussed in the IRPAG, the group made a number of suggestions intended to help reduce the cost of Montana wind. PSE worked with an IRPAG member to create the second set of assumptions and scenarios summarized in Figures D-24 and D-25.

17 / PSE models generic solar resources as alternating current (ac) to recognize the cost of the conversion from dc to ac.

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



Transmission and Substation Costs

Assumed Colstrip Retirement Colstrip Operating	Colstrip Operating
A) $32.4 Million- Upgrade JG-Broadview Line	C) $662 Million- Upgrade JG-Broadview Line + Expand Broadview Sub + New Broadview-Garrison Line + Expand Garrison Sub
B) $94.2 Million- New JG-Broadview Line + Broadview Sub. Upgrade	D) $724 Million- New JG-Broadview Line + Expand Broadview Sub + New Broadview-Garrison Line + Expand Garrison Sub

*Right Of Way costs are not included in estimate of new transmission lines
*Assuming plant size of 265 MWs
*Costs only reflect additional substation/transmission equipment does not include transmission wheeling or cost to build wind facility
*Overheads not included

Legend
BPA
NWMT
PSEI

Wind Capacity	Percentage
MT Wind Capacity Factor	41.00%
Loss Factor	6.70%
Wind Capacity Net of Losses	38.30%
Transmission Costs	**$/KW-Year**
Judith Gap to Broadview	$ 3.3000
Broadview to Townsend	$ 9.1550
Townsend to Garrison	$ 7.3640
Total	**$ 19.8190**
$/MWh	**$ 5.5200**

The baseline costs for transmission of wind power from Montana can be broken down into two main categories.

1. Colstrip retires, making capacity available on the existing Colstrip transmission line.
2. Colstrip does not retire, and various lines and systems will need to be upgraded to provide the additional capacity required for wind transmission.

Figure D-23: PSE Wind Scenarios, 2015 IRP

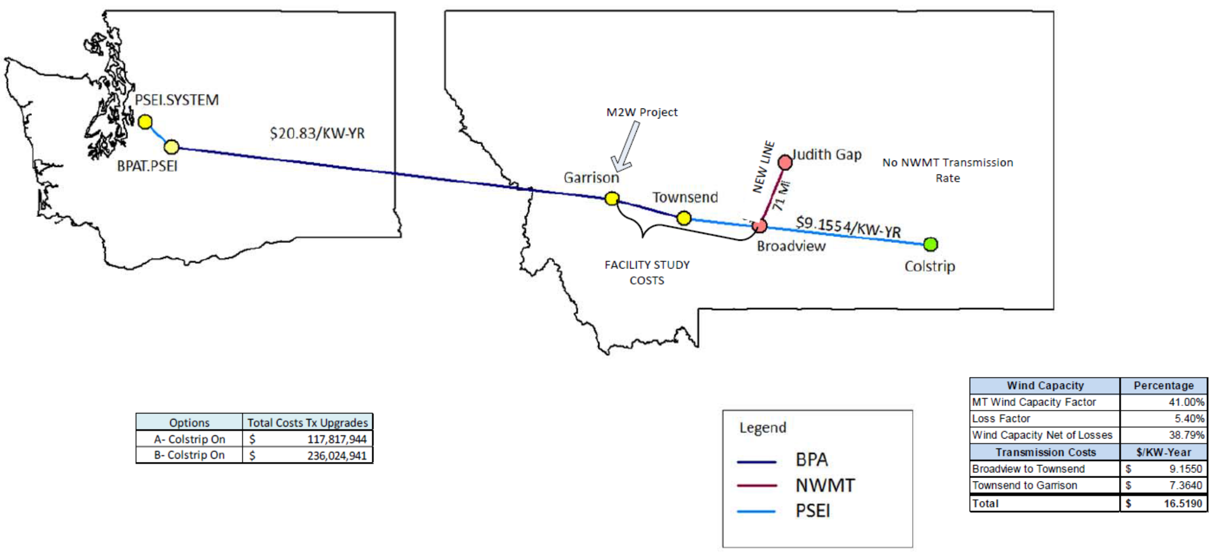
Name	Total Cost	Assumptions	Cost Breakdown Per Assumption
PSE Scenario A	$32.4 million	1. Colstrip is retired	
		2. Upgrade transmission line from Judith Gap to Broadview	$ 32,453,878
		Total PSE A:	*$ 32,453,878*
PSE Scenario B	$94.2 million	1. Colstrip is retired	
		2. Build new transmission line from Judith Gap to Broadview	$ 92,725,365
		3. Upgrade Broadview substation	$ 1,492,903
		Total PSE B:	*$ 94,218,268*
PSE Scenario C	$662 million	1. Colstrip is operating	
		2. Upgrade transmission line from Judith Gap to Broadview	$ 32,453,878
		3. Upgrade Broadview substation	$ 10,889,286
		4. New line required from Broadview to Garrison	$ 604,625,490
		5. Garrison substation expansion required	$ 14,512,836
		Total PSE C:	*$ 662,481,489*
PSE Scenario D	$723 million	1. Colstrip is operating	
		2. Build new transmission line from Judith Gap to Broadview	$ 92,725,365
		3. Upgrade Broadview substation	$ 10,889,286
		4. New line required from Broadview to Garrison	$ 604,625,490
		5. Garrison substation expansion required	$ 14,512,836
		Total PSE D:	*$ 722,752,976*

Wind Capacity	Percentage
MT Wind Capacity Factor	41.00%
Loss Factor	5.70%
Wind Capacity Net of Losses	35.30%
Transmission Costs	**$/KW-Year**
Broadview to Townsend	$ 9.1550
Townsend to Garrison	$ 7.3640
Total	**$ 16.5190**

To determine the appropriate costs to model in the IRP, PSE developed four different scenarios. These are labeled A through D on Figure D-22 above, and summarized in the table below.

For the purposes of this IRP, PSE Scenario C was modeled as the baseline. Scenario A was modeled under the Colstrip retirement scenario.

Figure D-24: Washington vs. Montana Wind Assumptions, per IRPAG Input



Options	Total Costs Tx Upgrades
A- Colstrip On	$ 117,817,944
B- Colstrip On	$ 236,024,941

Wind Capacity	Percentage
MT Wind Capacity Factor	41.00%
Loss Factor	5.40%
Wind Capacity Net of Losses	38.79%
Transmission Costs	**$/KW-Year**
Broadview to Townsend	$ 9.1550
Townsend to Garrison	$ 7.3640
Total	**$ 16.5190**

Per Figure D-24, two scenarios were developed using the IRPAG inputs.

Figure D-25: IRPAG Wind Scenarios

Name	Cost	Assumptions	Cost Breakdown Per Assumption
IRPAG Scenario A	$117 million	1. Colstrip is operating	
		2. New line from Judith Gap to Broadview substation (wood poles)	$ 37,995,039
		3. Broadview substation upgrades to accommodate additional line	*$ 1,492,903*
		4. Fiber for communications	$ 5,317,512
		5. NWMT Facility Study – Upgrades required from Broadview to Garrison (provided by Bill Pascoe)	$ 73,012,490
		6. BPA recovers in transmission rate the Montana to Washington project (totally $153 Million dollars, this scenario assumes $0)	$ -
		Total IRPAG Scenario A:	*$ 117,817,944*
IRPAG Scenario B	$236 million	1. Colstrip is operating	
		2. New line from Judith Gap to Broadview substation (wood poles)	$ 37,995,039
		3. Broadview substation upgraded to accommodate additional line	$ 1,492,903
		4. Fiber for communications	$ 5,317,512
		5. NWMT Facility Study – Upgrades required from Broadview to Garrison (provided by Bill Pascoe)	$ 73,012,490
		6. PSE would have to cover 77.26% of the Montana to Washington project (if PSE placed their transmission requests into the BPA queue today, this is the percentage of the total amount of MWs forcing the project to be built that would be PSE's portion).	$ 118,206,997
		Total IRPAG Scenario B:	*$ 236,024,941*

Wind Capacity	Percentage
MT Wind Capacity Factor	41.00%
Loss Factor	5.40%
Wind Capacity Net of Losses	38.79%
Transmission Costs	**$/KW-Year**
Broadview to Townsend	$ 9.1550
Townsend to Garrison	$ 7.3640
Total	**$ 16.5190**

The Montana transmission estimates that the IRPAG helped provide input on were used as a sensitivity, since the cost anaylsis was completed too late to be used in portfolio modeling. There are many unknowns with the Montana transmission system. Because a majority of the constrained paths are owned and operated by either BPA or Northwestern Energy, PSE's visibility is limited, which makes cost estimating difficult to complete. From various BPA meetings and PSE's experience with the West of Garrison flowgate, the transmission system to the west of the Garrison substation is currently at its capacity limit, and any additional capacity would require some type of upgrade to the transmission system. If these scenarios proved to be cost effective in the portfolio anaylsis and PSE wished to pursue the venture further, PSE would begin working with BPA and NWMT to refine the transmission cost estimates.

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[18] 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. The market for turbines appears to be in favor of buyers at the moment. 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.

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. Including operation and maintenance (O&M) costs, the levelized cost of energy ranges from $60 to $100 per MWh.[19] PSE's most recent wind project, the Lower Snake River facility, which was placed in service in February 2012, fits in the high end of this range.

18 / One hundred meters is equivalent to 328 feet which is equivalent to a 30-story building.
19 / Source: 2013 Wind Technologies Market Report, U.S. Department of Energy.

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. Fuel cell systems must be cost-competitive with, and perform as well as, traditional power technologies over the life of the system.[20]

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. Several megawatt-scale installations are operating in Connecticut, Delaware and California. The two largest fuel cell installations in the United States today are located on the East Coast. One is a 14.9 MW plant, owned by Dominion, located in Bridgeport, Connecticut. The other project consists of blocks of fuel cells installed at two Delmarva Power substations in Delaware that are capable of distributing a combined total of up to 30 MW of electric capacity. 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 2014 estimates fuel cell capital costs to be approximately $7,044 per KW.

20 / *U.S. Department of Energy, Energy Efficiency and Renewable Energy, Fuel Cell Technologies Program.*

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.[21]

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).[22]

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.[23]

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.[24]

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 2014 approximately 3.5 GW of geothermal generating capacity was online in the United States,[25] with 96 percent of that capacity in California or Nevada.[26] 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 160 MW of planned capacity additions are in some stage of development in the Northwest.[27] These include an expansion of the Raft River project in Idaho and Crump Geyser in Oregon. There are other projects in very early development that have not yet proven their output.

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21 / *http://energy.gov/eere/geothermal/electricity-generation*
22 / *Ibid.*
23 / *Ibid.*
24 / *http://energy.gov/sites/prod/files/2014/02/f7/egs_factsheet.pdf*
25 / *Geothermal Energy Association, 2015 Annual US & Global Geothermal Power Production Report.*
26 / *Geothermal Energy Association, 2013 Annual US Geothermal Power Production and Development Report*
27 / *Ibid.*

Geothermal energy plants are capital intensive, with estimated capital costs of approximately $6,200 per KW for traditional dual flash geothermal steam plants.[28] Other large-scale technologies, including binary plants, are similar in cost. 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.[29]

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.

28 / U.S. Energy Information Administration, Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, April 2013.
29 / U.S. Environmental Protection Agency website. Retrieved from http://www.epa.gov/waste/nonhaz/municipal/wte/, January 2015.

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 636 landfill gas energy projects operating in 48 U.S. states in 2014. According to the U.S. EPA, these facilities combined were capable of providing 15 billion kWh of electricity and 116 billion cubic feet of landfill gas to end users, or enough energy to power more than 1.6 million homes that year.[30]

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.

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 BioFuels Washington 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.[31] 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.[32] BioFuels Washington 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.[33] PSE purchases the electricity produced by the facility through a power purchase agreement under a Schedule 91 contract, which is discussed above.

30 / U.S. Environmental Protection Agency website. Retrieved from http://www.epa.gov/lmop/documents/pdfs/green_power_from_landfill_gas.pdf, September 2014.
31 / 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, January 2015.
32 / Spokane Waste to Energy website. Retrieved from http://www.spokanewastetoenergy.com/WastetoEnergy.htm, January 2015.
33 / BioFuels Washington, LLC landfill gas to energy facility 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/biofuels/, January 2015.

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. The only waste thermal processing facility known in the Northwest is a test facility operated by InEnTec in Richland, Wash. Several wastewater treatment plants in PSE's electric service area use gas from their digestion processes to generate electricity for their facility operations, but typically not enough to make surpluses available to PSE.

No waste-to-energy facilities are currently planned or under construction in the Northwest. However, a third waste combustion facility has been operational in the Northwest since 1987. Covanta's Marion County facility in Brooks, Ore. generates up to 13.1 MW of electricity from a single steam generator. Covanta sells this output to Portland General Electric Company.[34]

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 2014 estimates municipal solid waste-to-energy costs to be approximately $8,300 per KW.

In general, waste-to-energy facilities are highly reliable, as they've 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 / Covanta website. Retrieved from http://www.covanta.com/facilities/facility-by-location/marion.aspx,January 2015.

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. In-stream turbines up to 1.2 MW in size have been tested in Canada, Scotland and South Korea.[35]

In 2014, the U.S. Navy awarded $8 million to the University of Washington to develop marine energy from tides, currents and waves to help the Navy fulfill its commitment to obtain half of its energy from renewable sources by 2020. According to the university website, this project is in the early stages of exploration and development, with plans to begin testing prototypes and larger scale models over the next couple of years.[36]

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.[37] It has since been shut down because of the developer's financial difficulties. Significant testing has occurred off of Scotland's coast, and developments are underway in Scotland, Australia and England.

35 / Power Technology website. Retrieved from http://www.power-technology.com/features/featuretidal-giants---the-worlds-five-biggest-tidal-power-plants-4211218, April 2014.
36 / University of Washington website. Retrieved from http://www.washington.edu/news/2014/10/24/u-s-navy-awards-8-million-to-develop-wave-tidal-energy-technology/, October 2014.
37 / CNN website. Retrieved from http://www.cnn.com/2010/TECH/02/24/wave.power.buoys/index.html, February 2010.

Commercial availability. Since mid-2013, a number of significant wave and tidal projects and programs have slowed, stalled or shutdown altogether. Bloomberg New Energy Finance reported in August 2014 that Oceanlinx and Wavebob had gone out of business, Wavegen had been absorbed back into its parent company Voith, and both AWS Ocean Energy and Ocean Power Technologies had scaled back activities.[38] In November 2014, Scottish wave power developer Pelamis announced its intention to cease development due to lack of funding.[39] Soon after, energy and technology giant Siemens decided to sell its tidal power business, Marine Current Turbines Ltd., and to close its ocean energy division due to lack of development of the market and supply chain.[40] This was quickly followed in December 2014 by an announcement from Scotland's Aquamarine Power (developer of the Oyster wave machine) that it had decided to significantly downsize, cutting all but a core staff to manage the business and a single machine still operating at the European Marine Energy Centre in Orkney.[41]

Currently, there are no operating tidal energy projects on the West Coast. In late 2014, Snohomish PUD abandoned plans to develop a 1 MW installation at the Admiralty Inlet.[42] Several years ago, Tacoma Power considered and later abandoned plans to pursue a project in the Tacoma Narrows. A small system has been tested off Vancouver Island, B.C, but no further development is planned at this time.

Several sites have been tested for wave power in the Northwest. The Reedsport, Ore. site is the furthest along in development. Current plans call for 10 buoy-type floating tidal power generators, with a combined capacity of 1.5 MW. However, reports of schedule delays in recent years suggest that launch of an initial test buoy is unlikely before at least 2016.[43]

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38 / Bloomberg New Energy Finance website. Retrieved from http://about.bnef.com/press-releases/tidal-stream-wave-power-lot-still-prove/, August 2014.
39 / Pelamis website. Retrieved from http://www.pelamiswave.com/news/news/173/Pelamis-Wave-Power-Limited-Pelamis-to-be-put-into-administration, November 2014.
40 / Bloomberg website. Retrieved from http://www.bloomberg.com/news/2014-11-25/siemens-exits-tidal-power-industry-blaming-slow-development.html, November 2014.
41 / Aquamarine Power website. Retrieved from http://www.aquamarinepower.com/news/aquamarine-power-announces-plans-to-downsize-business.aspx, December 2014.
42 / The Seattle Times website. Retrieved from http://seattletimes.com/html/localnews/2024665977_tidalprojectstalled1xml.html, October 2014.
43 / The Oregonian website. Retrieved from http://www.oregonlive.com/environment/index.ssf/2013/08/oregon_wave_energy_stalls_off.html, August 2013-.

In general, the limiting factors in developing wave and tidal power projects have been 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 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.

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.

Cost and performance assumptions. 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.

Wind, Off-shore Generation. Off-shore wind generation uses horizontal-axis wind turbines specifically designed for use in harsh marine environments. Offshore wind resources are abundant, stronger and blow more consistently than land-based wind resources. Data on the resource potential suggest more than 4,000 GW could be accessed in state and federal waters along the coasts of the United States and the Great Lakes, approximately four times the combined generating capacity of all U.S. electric power plants.[44]

Globally, almost 9,000 MW of off-shore wind resources were planned or in operation in Europe, China, Japan and the United Kingdom as of early 2015.[45] The largest offshore wind farm is Walney 1 and 2 located in the Irish Sea in the U.K. The number of people working in the U.K.'s offshore sector grew from 700 in 2007 to around 3,200 in 2011.

Existing offshore wind installations have mainly been located in water depths of less than 30 meters and constructed with driven-pile foundations, though some gravity foundations exist and a number of new designs are under development for tripod platforms and floating platforms. One floating platform wind turbine is currently in operation off Norway.

44 / *U.S. Department of Energy Wind Program.*
45 / *Lindoe Offshore Renewables Center, http://www.lorc.dk/offshore-wind-farms-map/list.*

Commercial availability. As of January 2015, there are no operating offshore wind projects in the United States. The U.S. Department of the Interior has begun offering leases to federal acreage off the coasts of Virginia, Massachusetts and Rhode Island for offshore wind farm development. In total, 14 U.S. projects, representing approximately 4.9 GW of potential capacity, can now be considered in advanced stages of development. In the Pacific Northwest region, there is one deep-water project under development in Oregon. The 30 MW Principle Power "Windfloat Pacific" project is currently in the environmental assessment process.[46] The next-nearest project is the Naikun Offshore Wind Project in British Columbia. The 400 MW project has achieved an advanced stage of development and gained environmental approvals from the provincial and federal governments. It is currently seeking a power purchase agreement.

Cost and performance assumptions. Due to sustained winds, off-shore wind is expected to operate at higher capacity factors than land-based wind projects. However, the costs of marine construction and operations considerably exceed those of land-based construction and operation. Since no projects have been successfully developed or constructed in the United States at this time, the capital cost of off-shore wind development is difficult to predict. Estimates indicate these could be at least $4,000 per KW, which is far from competitive with land-based turbines.[47] As a point of reference, the 130-turbine Cape Wind PPA is priced at 18.7¢ per kWh, while the weighted average cost of land-based wind energy is less than 6¢ per kWh.[48] Given this 3x cost differential, off-shore wind energy is simply not cost competitive with land-based developments unless significant technological improvement takes place.

Policy considerations. To encourage development of off-shore wind resources, the Obama administration announced funding in 2012 for seven projects. The Department of Energy says the funding of up to $168 million over six years will expedite development of the nation's first off-shore wind farms. None are operational yet, but 9 have reached the advanced development phase and 24 more are in earlier development stages.

Under the Department of Energy's new funding, which builds upon $42 million in R&D awards given last year, each project will receive up to $4 million to complete engineering, site evaluation and planning. The department will then select up to three of the projects and offer each up to $47 million to facilitate commercial operation by 2017. The seven projects are in six states; the closest to PSE is Principle Power's proposed wind farm off Coos Bay, Ore.

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46 / *Offshore Wind Market Analysis: 2014 Market Assessment.*
47 / *NREL - Large Scale Offshore Wind Power in the United States, Opportunities and Barriers, 2010.*
48 / *Berkeley Lab, 2011.*

Demand-side Resources Modeled

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 the same 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.[49]

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 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/standards.

49 / 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.

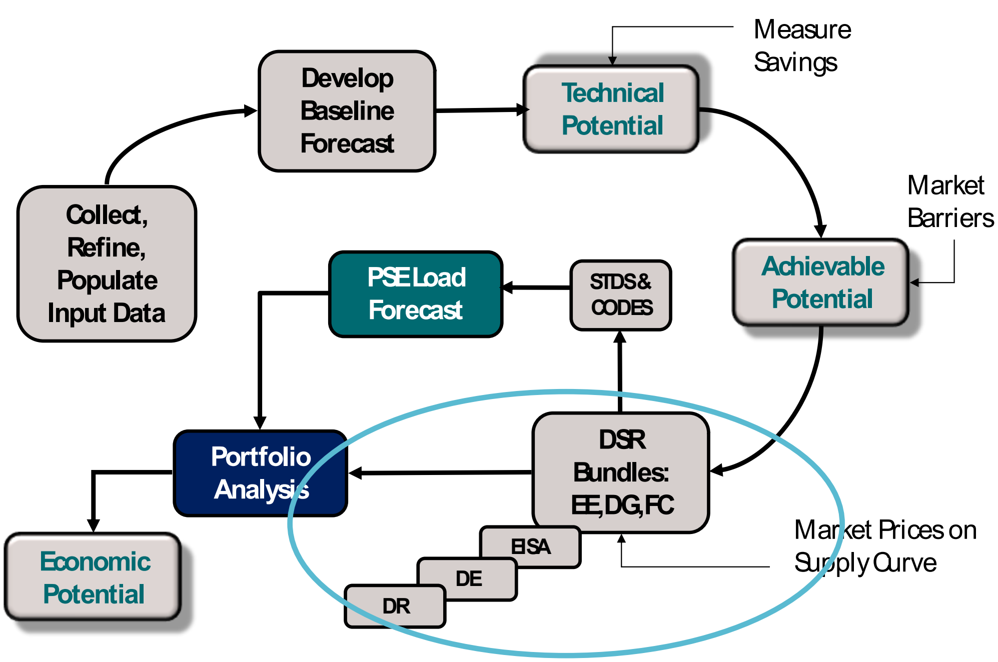
Treatment of Demand-side Resource Alternatives. First, each demand-side measure was screened for technical potential. Screening for technical potential assumed that all energy and demand saving opportunities could be captured regardless of cost or market barriers, so the full spectrum of technologies, 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-26 illustrates the methodology PSE used to assess demand-side resource potential in the IRP. Appendix J, Demand-side Resources, contains a detailed discussion of the demand-side resource evaluation and development of the DSR bundles performed for PSE by Cadmus.

Figure D-26: General Methodology for Assessing Demand-side Resource Potential



The following tables summarize the results of the Cadmus analysis of demand-side resources presented in Appendix J. Bundles A through H include energy efficiency, fuel conversion and distributed generation. Each bundle adds measures to the bundle that preceded it.

Figure D-27: Annual Energy Savings (aMW)

	Bundle											
	A	A1	B	B1	C	D	E	F	G	H	DE	C&S
2016	6.8	10.9	12.2	12.7	13.3	13.4	13.9	14.0	14.9	18.9	0.3	12.8
2017	22.7	35.7	39.4	41.1	43.1	43.7	45.2	45.5	48.5	61.2	0.9	33.4
2018	40.1	64.3	70.4	73.4	77.6	78.8	81.7	82.3	87.3	109.5	1.5	45.1
2019	55.8	92.2	102.4	106.8	113.5	115.3	119.8	120.9	128.0	159.8	2.2	55.3
2020	69.3	118.5	133.0	139.1	148.9	151.4	157.7	159.3	168.7	210.4	2.8	70.7
2021	81.2	143.0	160.5	168.3	181.6	184.9	193.1	195.4	206.9	258.6	3.4	86.8
2022	93.2	166.8	188.4	198.0	215.0	219.2	229.4	232.4	246.1	308.2	4.1	95.1
2023	105.2	190.3	215.9	227.2	248.0	253.0	265.1	268.8	284.7	358.1	4.7	102.9
2024	117.7	214.4	243.2	256.2	280.7	286.4	300.4	304.7	322.7	408.7	5.4	111.2
2025	129.4	236.5	268.3	282.9	311.0	317.5	333.3	338.0	358.2	455.7	6.1	117.6
2026	137.4	252.1	285.7	301.5	332.8	339.8	356.9	362.0	383.4	489.7	6.9	123.2
2027	140.9	260.0	294.1	310.8	344.6	351.9	370.4	375.6	397.1	509.2	7.9	128.2
2028	144.8	268.5	303.1	320.8	357.1	364.6	385.2	390.6	412.2	530.5	9.0	133.6
2029	148.3	276.1	311.2	329.6	368.4	376.2	398.4	403.9	425.6	551.2	10.0	138.8
2030	152.1	284.1	319.7	339.0	380.2	388.3	412.0	417.7	439.6	574.4	11.0	143.4
2031	155.7	291.9	327.9	348.0	393.3	401.7	427.1	432.9	454.9	599.0	12.0	147.5
2032	159.9	300.9	337.5	358.5	409.5	418.3	445.5	451.4	473.7	627.8	13.2	151.9
2033	162.9	307.5	344.3	365.9	421.8	430.9	459.4	465.3	487.7	649.2	14.2	155.1
2034	166.4	315.0	352.3	374.5	435.3	444.7	474.5	480.5	503.0	671.8	15.3	158.4
2035	170.2	323.1	360.8	383.7	448.9	458.7	489.6	495.7	518.3	693.9	16.5	162.1

Figure D-28: Total December Peak Reduction (MW)

	Bundle											
	A	A1	B	B1	C	D	E	F	G	H	DE	C&S
2016	19.4	13.8	3.5	2.0	1.9	0.6	1.5	0.4	4.8	12.5	1.0	33.3
2017	42.2	29.4	6.6	4.3	5.0	1.7	3.7	1.0	10.1	27.3	1.9	47.8
2018	64.4	49.1	9.9	6.9	8.6	3.0	6.3	1.9	15.3	43.1	2.9	61.1
2019	83.1	67.0	17.4	9.7	12.7	4.4	9.4	3.0	20.6	59.7	3.9	72.1
2020	99.8	87.9	21.3	13.0	17.5	6.2	12.9	4.5	26.3	78.3	4.9	98.7
2021	116.1	106.7	25.7	16.6	23.0	8.2	17.0	6.3	32.1	98.2	5.9	109.2
2022	133.3	125.3	32.4	20.4	28.6	10.4	21.3	8.2	37.7	118.8	6.9	120.0
2023	149.4	142.3	36.3	23.4	33.4	11.9	24.6	9.4	43.1	138.8	7.9	129.1
2024	165.4	158.8	40.3	26.0	37.9	13.3	27.6	10.4	47.9	157.5	8.9	138.3
2025	181.4	175.1	44.2	29.1	42.9	14.9	30.9	11.6	53.4	177.1	10.1	144.4
2026	186.8	183.5	45.0	30.7	45.2	15.3	32.0	11.7	53.9	185.6	11.6	150.9
2027	192.2	192.6	45.7	32.4	47.6	15.7	34.8	11.9	54.6	194.8	13.2	156.7
2028	197.6	200.6	46.4	33.6	49.5	15.9	37.1	11.9	54.5	202.3	14.8	164.7
2029	202.1	208.7	47.0	34.7	51.4	16.1	38.9	11.8	54.2	213.2	16.5	169.8
2030	207.0	216.0	47.5	35.9	53.1	16.3	40.5	11.7	54.1	223.8	18.1	175.6
2031	211.8	224.0	48.1	37.4	59.6	16.8	42.8	11.8	54.5	236.3	19.8	178.8
2032	218.3	233.5	48.8	39.4	65.6	17.4	45.1	12.1	55.5	249.8	21.4	184.0
2033	224.3	241.5	49.5	40.7	71.1	17.8	46.8	12.1	55.5	259.9	23.1	189.7
2034	229.3	248.9	50.0	41.9	75.9	18.1	48.1	12.1	55.5	268.2	24.9	193.3

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.

Figure D-29: Annual Costs (dollars in thousands)

(Codes and Standards has no cost and is considered a must-take bundle.)

BUNDLE	A	A1	B	B1	C	D	E	F	G	H	DE
2016	$7,770	$25,901	$13,170	$6,787	$9,357	$3,423	$10,369	$2,134	$28,563	$1,223,578	$467
2017	$8,889	$30,144	$11,431	$7,804	$14,871	$5,123	$14,113	$3,550	$30,640	$1,316,151	$467
2018	$8,571	$39,352	$12,578	$8,157	$17,590	$5,714	$16,345	$4,688	$30,939	$1,362,048	$467
2019	$7,952	$36,413	$28,276	$8,370	$20,077	$6,288	$18,409	$5,815	$31,353	$1,404,268	$467
2020	$7,439	$42,626	$14,399	$8,870	$22,316	$7,012	$20,283	$6,898	$31,843	$1,431,323	$467
2021	$7,413	$37,851	$15,913	$9,259	$24,266	$7,643	$22,082	$7,971	$32,319	$1,470,076	$467
2022	$7,494	$38,733	$24,246	$9,880	$26,090	$8,411	$23,826	$9,071	$32,857	$1,527,540	$467
2023	$7,543	$36,956	$15,264	$8,405	$24,122	$6,620	$19,956	$5,805	$31,618	$1,642,856	$467
2024	$7,579	$37,521	$15,528	$8,435	$24,506	$6,708	$20,108	$5,809	$31,650	$1,643,710	$467
2025	$7,510	$34,825	$14,955	$8,306	$24,778	$6,792	$20,203	$5,799	$31,647	$1,608,998	$545
2026	$2,104	$13,956	$2,581	$3,866	$15,208	$1,842	$8,003	$328	$2,092	$907,481	$701
2027	$2,094	$13,791	$2,408	$3,811	$14,920	$1,856	$22,402	$328	$2,075	$902,440	$701
2028	$2,280	$13,969	$2,360	$3,885	$14,810	$1,953	$20,427	$346	$2,088	$919,372	$701
2029	$2,194	$13,623	$2,291	$3,613	$14,193	$1,888	$17,475	$340	$2,058	$1,030,451	$701
2030	$2,243	$13,576	$2,243	$3,601	$13,720	$1,908	$15,044	$346	$2,105	$1,009,367	$701
2031	$2,235	$13,387	$2,199	$3,443	$48,305	$3,446	$19,737	$348	$2,151	$1,057,984	$701
2032	$2,295	$13,376	$2,171	$3,453	$41,098	$3,182	$16,796	$358	$2,214	$995,098	$701
2033	$2,240	$13,083	$2,130	$3,285	$43,056	$2,951	$14,589	$359	$2,250	$949,034	$701
2034	$2,254	$13,066	$2,118	$3,270	$38,260	$2,852	$12,717	$363	$2,340	$918,834	$701
2035	$2,241	$12,914	$2,105	$3,221	$33,124	$2,679	$11,035	$367	$2,389	$905,542	$701

Demand-response Programs are organized into 5 categories. These include:

1. Residential Direct Load Control (DLC) Space Heating
2. Residential DLC Water Heating
3. Residential Critical Peak Pricing (CPP)
4. Commercial and Industrial CPP
5. Commercial and Industrial Curtailment

Figure D-30 describes the total December peak reduction achieved by each program, and Figure D-31 describes the costs for each program.

Figure D-30: Demand-response Programs, Total December Peak Reduction (MW)

	Program				
	1	2	3	4	5
2016	6	6	0	0	12
2017	6	6	0	0	24
2018	33	32	2	0	37
2019	33	33	2	0	50
2020	68	67	10	1	51
2021	69	68	10	1	51
2022	70	69	20	2	52
2023	71	70	21	2	53
2024	72	71	21	2	54
2025	74	72	21	2	55
2026	75	73	22	2	56
2027	76	74	22	2	56
2028	77	75	22	2	57
2029	78	76	22	2	58
2030	79	77	23	2	59
2031	80	78	23	2	60
2032	81	79	23	2	61
2033	82	80	24	2	62
2034	83	81	24	2	63
2035	84	82	24	2	64

Figure D-31: Demand-response Annual Costs (dollars in thousands)

	Program				
	1	2	3	4	5
2016	$3,503	$7,622	$400	$400	$1,224
2017	$777	$2,330	$301	$157	$2,569
2018	$15,918	$34,207	$2,363	$64	$4,061
2019	$2,630	$7,086	$1,348	$680	$5,642
2020	$23,214	$50,445	$10,297	$278	$5,878
2021	$4,565	$11,367	$2,012	$929	$6,091
2022	$4,766	$11,862	$14,163	$387	$6,342
2023	$4,939	$12,301	$513	$36	$6,604
2024	$5,117	$12,754	$517	$37	$6,899
2025	$5,300	$13,218	$520	$38	$7,172
2026	$5,488	$13,695	$524	$39	$7,448
2027	$5,681	$14,184	$528	$41	$7,726
2028	$5,878	$14,686	$531	$43	$8,085
2029	$6,081	$15,202	$534	$44	$8,409
2030	$6,291	$15,734	$539	$46	$8,769
2031	$6,508	$16,285	$545	$49	$9,127
2032	$6,734	$16,857	$552	$51	$9,520
2033	$6,970	$17,453	$563	$53	$9,910
2034	$7,229	$18,103	$584	$55	$10,318
2035	$7,494	$18,762	$603	$56	$10,743