Electric Resource Alternatives

Contents

Section one of this appendix is designed to provide additional information about PSE's existing fleet of electric resources. Section two offers context related to a variety of electric resource alternatives, including a brief technology summary, information about the viability and availability of each resource for PSE, and estimated ranges for anticipated capital and operating costs.

1. Existing Resources

PSE's existing resources include supply-side resources, demand-side resources, and Green Power and small-scale renewables. Supply-side resources include power generated by PSE-owned and contracted facilities, primarily hydroelectric power and power from coal-fired plants, natural gas-fueled turbines, and wind-powered resources. Demand-side resource contributions to the resource pool are generated on the customer side of the meter, primarily through energy efficiency programs. Green Power and small-scale renewables are two renewable energy programs offered by PSE, one for customers who want to support additional development of renewable energy through voluntary bill payments, and one for customers who produce their own power from small-scale renewables.

Supply-side resources

The following tables describe PSE's existing electric resources using the Net Maximum Capacity of each plant in megawatts. 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 deratings, less the losses associated with auxiliary loads. This is consistent with the way plant capacities are described in the 10K report[1] that PSE files with the U.S. Securities and Exchange Commission and the Form 1 report we file with the Federal Energy Regulatory Commission.

You may notice that PSE sometimes references different plant capacity values in different publications. This is 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. When describing the relative size of resources, it is often 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.

Hydroelectricity

While restrictions to protect endangered species limit the operational flexibility of hydroelectric resources, these generating assets remain valuable because of their ability to track customer load, and because of their low cost relative to other power resources. High precipitation 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 sources 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.

[1] PSE's most recent 10K report was filed with the U.S. Securities and Exchange Commission in March 2013 for the year ending December 31, 2012.

APPENDIX D – ELECTRIC RESOURCE ALTERNATIVES

Figure D-1

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	79	None
Snoqualmie Falls	PSE	100	54[2]	None
Electron	PSE	100	22[3]	None
Total PSE-Owned			**246**	
Wells	Douglas Co. PUD	29.9	251	3/31/18
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	0.8[4]	9	04/04/52
Priest Rapids	Grant Co. PUD	0.8[4]	9	04/04/52
Mid-Columbia Total			**750**	
Total Hydro			**996[5]**	

NOTES
1 Net maximum capacity reflects PSE's share only.
2 Snoqualmie Falls is running at partial capacity while powerhouse 1 is off-line for redevelopment. The plant is expected to be fully operational and provide a net maximum capacity of approximately 54 MW upon completion of powerhouse 1, which is expected in the second quarter of 2013.
3 As of December 31, 2012, Electron project output is limited to approximately 7 MW due to the condition of the flume that conveys water to the plant. This limitation is expected to continue in 2013.
4 Based on Grant Co. PUD current load forecast for 2012; our share will be reduced to this level in 2013.
5 Individual resource and Mid-Columbia totals are rounded to the nearest megawatt.

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 three hydroelectric power facilities. The project contains modern fish-enhancement systems including a "floating surface collector" to safely capture juvenile salmon in Baker Lake for downstream transport around both dams, and a second, newer collector 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 the Federal Energy Regulatory Commission (FERC) for construction and operation. These licenses normally are for periods of 30 to 50 years and then they must be renewed. In October 2008, after a lengthy renewal process, FERC issued a 50-year license allowing PSE to generate 707,600 MWh (average annual output) from the Baker River project.

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 300,000 MWh per year.

ELECTRON HYDROELECTRIC PROJECT. Located about 25 miles southeast of Tacoma in the western foothills of Mount Rainier, this facility was completed in 1904. The project draws water from the Puyallup River and funnels it to the power plant via a 10-mile span of wooden flume that runs through the winding river valley.

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 operating expenses for 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. 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. The agreement extends through October 2031. PSE has two agreements with Grant County PUD for a share of the output of the Wanapum and Priest Rapids developments. PSE receives a combined share of power from both projects; this share declines over time as the PUD's loads increase. The agreements with Grant County PUD will continue through the term of any new FERC license, which is through April 4, 2052.

WHITE RIVER PROJECT. In January 2004, PSE stopped generating electricity at White River because relicensing and environmental expenses would have driven power costs well above available alternatives. The utility subsequently sold the assets of its White River Hydroelectric Project, including the Lake Tapps reservoir, to the Cascade Water Alliance. The lake will be used to support a new regional source of drinking water.

Coal

The **COLSTRIP GENERATING PLANT** supplies PSE customers with reliable, low-cost electric power. It also contributes diversity to the electric resource portfolio. Currently the facility supplies 18 to 20 percent of the baseload energy that serves PSE demand. The plant consists of four coal-fired steam electric plant units located in eastern Montana about 120 miles southeast of Billings. 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.

Gas-fired Combined-cycle combustion turbines

PSE has six combined-cycle combustion turbine (CCCT) resources with a combined net maximum capacity of 1,256 MW. 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 simple-cycle turbines.

PSE's CCCT fleet includes **MINT FARM** in Cowlitz County, **FREDERICKSON 1** in Pierce County, **GOLDENDALE** in Klickitat County, and **ENCOGEN, FERNDALE,** and **SUMAS** in Whatcom County. We own 49.85 percent of Frederickson 1, a combined-cycle plant co-owned and operated by a subsidiary of Atlantic Power.

Wind energy

PSE is the largest utility owner and operator of wind-power facilities in the Northwest. **HOPKINS RIDGE**, located in Columbia County, Wash., has a net maximum capacity of 157 MW and began commercial operation in November 2005. **WILD HORSE**, located in Kittitas County near Ellensburg, has a net maximum capacity of 273 MW and came online in December 2006. (The facility originally had a 229 MW capacity, but was expanded by 44 MW in 2010.) Combined, the two projects generate enough electricity, on average, to power approximately 120,000 homes. Both projects have contributed to their respective local economies by providing permanent family-wage jobs, local supply and services procurement, and payment of production royalties to local landowners. In addition, they have increased county tax bases, enabling local government to provide additional services (for example, Columbia County launched a new health clinic). The

Wild Horse site also features the Pacific Northwest's largest solar power array, with 2,723 photovoltaic solar panels, including the first made-in-Washington solar panels.[2] The Wild Horse array can produce up to 500 kW 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, Texas.

In February 2012, PSE brought online its third and largest wind farm, the **LOWER SNAKE RIVER WIND FACILITY.** The 343 MW operation is located in Garfield County, Wash. The project generates enough electricity, on average, to power approximately 100,000 homes.

Figure D-2 presents details about the company's coal, CCCT, and wind resources.

[2] *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.*

Figure D-2

Coal, CCCT, and Wind 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	100%	253
CCCT	Frederickson 1[2]	49.85%	136
CCCT	Goldendale	100%	278
CCCT	Mint Farm	100%	297
CCCT	Sumas	100%	127
Total CCCT			**1,256**
Wind	Hopkins Ridge	100%	157
Wind	Lower Snake River, Phase 1	100%	343
Wind	Wild Horse	100%	273
Total Wind			**773**

NOTES
1 Net maximum capacity reflects PSE's share only.
2 Frederickson 1 CCCT unit is co-owned with Atlantic Power Corporation - USA.

Gas-fired simple-cycle combustion turbines.

PSE’s four simple-cycle combustion turbine plants contribute a net maximum capacity of 612 MW. Although they typically operate only a few days each year, they provide important peaking capability and help us meet operating reserve requirements. The company displaces these resources when lower-cost energy is available for purchase. The **FREDONIA** facility is located near Mount Vernon, about 75 miles north of Seattle in Skagit County. In February 2009, PSE purchased **WHITEHORN** units 2 & 3 in northwestern Whatcom County. The **FREDERICKSON GENERATING STATION**, located south of Seattle in east Pierce County, is comprised of two combustion turbine units with a combined net maximum capacity of 149 MW. Details are shown in Figure D-3 below.

Figure D-3
Simple-cycle Combustion Turbines

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

[1] Net maximum capacity reflects PSE's share only.

Other long-term contracts

Long-term contracts consist of agreements with independent producers and other utilities to supply electricity to PSE. Fuel sources include hydropower, gas, waste products, and system deliveries without a designated supply resource. These contracts are summarized in Figure D-4. Short-term contracts 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 claims against the Bonneville Power Administration (BPA) regarding its action to halt construction on nuclear project WNP-3, 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 four surrogate nuclear plants similar in design to WNP-3. In exchange, PSE provides power to BPA from its combustion turbines, if requested, except during the month of May.

POWEREX PURCASE FOR POINT ROBERTS. Powerex delivers electric power 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.

BPA 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 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 power from BPA from November through February; this compensates 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 300 MW of seasonal capacity, together with 413,000 MWh of energy, on a one-for-one basis under this system-delivery purchased power contract. PSE is a winter-peaking utility and PG&E is a summer-peaking utility, so we provide power to PG&E from June through September, and PG&E provides power to us 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 to return one-half of the firm power benefits to Canada until the expiration of the PUD contracts or 2024, whichever occurs first. This is energy that PSE provides rather than receives, so it is a negative number (-38.6 aMW for 2013).

BARCLAYS BANK. Under this agreement, which runs through February 2015, Barclays delivers around-the-clock power to PSE during the winter months of November through February. This is a system-delivery of 75 MW per hour, not a unit-specific, purchased power contract.

TRANSALTA CENTRALIA. Under the terms of this agreement, PSE will buy 180 MW of firm, base-load coal transition power from TransAlta starting in December 2014. In the following 12 months 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 will benefit PSE customers by providing a source of low-cost power, while advancing 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 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 will receive 100 MW of energy from the Klamath natural gas-fired peaking facility in Klamath Falls, Ore.

KLONDIKE III. 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 total. This agreement remains in effect until November 2026.

SCHEDULE 91 CONTRACTS. PSE's portfolio includes a number of Schedule 91 electric power contracts (included in Figure D-4) with small power producers – 5 MW or less – in PSE's electric service area offering 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-4

Long-term Contracts for Electric Power Generation

NAME	POWER TYPE	CONTRACT EXPIRATION	CAPACITY (MW)[1]
BPA- WNP-3 Exchange	System	6/30/2017	82
Powerex/Pt.Roberts	System	Ongoing	8
BPA Baker Replacement	Hydro	9/5/2029	7
PG&E Seasonal Exchange-PSE	Thermal	Ongoing	300
Canadian EA	Hydro	09/15/2024	- 40.5
Barclays Bank	System	02/28/2015	75
Centralia Transition Coal	Transition Coal	12/31/2025	180[2]
Klamath Toll	Natural Gas	2/29/2016	100
Klondike III	Wind	11/31/2026	50
Twin Falls	Hydro-QF	3/8/2025	20
Koma Kulshan	Hydro-QF	3/31/2037	10.9
Weeks Falls	Hydro-QF	12/31/2022	4.6
Hutchison Creek	Hydro-QF	9/30/2016	1.0
Cascade Clean Energy- Sygitowicz	Hydro-QF	2/21/2014	<1
Qualco Dairy	Biogas	12/11/2013	<1
Farm Power Lynden	Schedule 91 - Biogas	12/31/2019	<1
Farm Power Rexville	Schedule 91 - Biogas	12/31/2019	<1
Rainier Biogas	Schedule 91 – Biogas	12/31/2020	1.0
Vanderhaak Dairy	Schedule 91 – Biogas	12/31/2019	<1
Van Dyk	Schedule 91 – Biogas	12/31/2020	<1
Bio Energy	Schedule 91 - Biogas	12/31/2021	4.88
Edaleen Dairy	Schedule 91 – Biogas	12/31/2021	<1
Bio fuels, WA	Schedule 91 – Biogas	12/31/2021	4.5
Skookumchuck	Schedule 91 – Hydro	12/31/2020	1
Smith Creek	Schedule 91 – Hydro	12/31/2020	<1
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	12/31/2021	<1
Finn Hill Solar (Lake Wash SD)	Schedule 91 – Solar	12/31/2021	<1
Knudson Wind	Schedule 91 – Wind	12/31/2019	<1
3 Bar-G Wind	Schedule 91 – Wind	12/31/2019	1.395
Swauk Wind	Schedule 91 – Wind	12/31/2021	4.25
Total			**828**

Notes
1 Capacity reflects PSE share only.
2 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.

Transmission contracts

Transmission capacity to the Mid-Columbia (Mid-C) market hub gives PSE access to the principle market hub in the Northwest and one of the major trading hubs in the WECC. It is the central market for northwest hydroelectric generation. As shown in Chapter 5, Figure 5-1, Mid-C transmission access to market is a significant portion of PSE’s peak supply portfolio. The majority of this transmission is contracted from BPA on a long-term basis. PSE owns 450 MW of capacity to Mid-C.

PSE’s transmission contracts with BPA and owned capacity are shown in Figure D-5 below.

Figure D-5

Transmission Resources as of 12/31/12

NAME	EFFECTIVE DATE	TERMINATION DATE	TRANSMISSION DEMAND
BPA Mid-C Transmission			
Midway	11/1/2012	11/1/2017	100
Midway	10/1/2008	10/1/2013	115
Midway	3/1/2009	3/1/2014	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	11/1/2009	11/1/2014	40
Rocky Reach	11/1/2009	11/1/2014	40
Rocky Reach	11/1/2009	11/1/2014	40
Rocky Reach	11/1/2009	11/1/2014	5
Rocky Reach	11/1/2009	11/1/2014	55
Rocky Reach	11/1/2011	11/1/2031	160
Vantage	11/1/2012	11/1/2017	100
Vantage	12/1/2010	12/1/2014	235[1]
Vantage	11/1/2009	11/1/2014	27
Vantage	11/1/2009	11/1/2014	27
Vantage	11/1/2009	11/1/2014	27
Vantage	11/1/2009	11/1/2014	3
Vantage	11/1/2009	11/1/2014	36
Vantage	11/1/2009	11/1/2014	5
Wells	1/24/1966	8/31/2018	266
NWE Purchase IR Conversion	10/1/2011	10/1/2016	94
Spokane Municipal Waste	3/1/2011	3/1/2016	23
Total BPA Mid-C Transmission			2038

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			2488

Notes:

1 The capacity of this contract decreases from 235 to 209 MW upon expiration of the existing contract as of 12/1/2014

As shown, PSE has 2,038 MW of BPA transmission capacity and owns 450 MW of capacity for a total of 2,488 MW. Also shown in Figure D-5 are the capacities and contract periods for the various BPA contracts. By December 2014, BPA contracts totaling 664 MW will be evaluated for renewal.

Demand-side resources

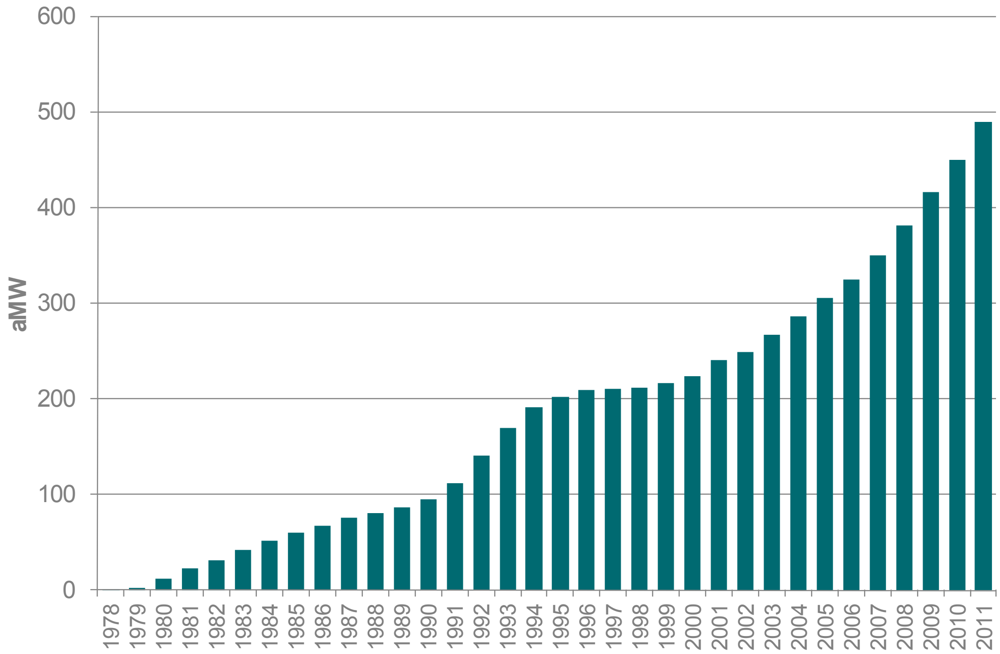
Existing demand-side resources

Demand-side resources (DSR) are generally generated or saved on the customer side of the meter, with the exception of distributed generation, which is on the company's distribution system.[3] While DSR includes demand-response, fuel conversion, distributed generation, and distribution efficiency, energy efficiency measures are by far the most substantial contributor to resource need. During the 2010-2011 tariff period, the 72.7 aMW contributed by these programs amounted to enough energy to power approximately 55,000 homes. Since 1978, the annual first-year savings (as reported at the customer meter) has increased more than 300%, from 9 aMW in 1978 to 39.1 aMW in 2011. The cumulative investment and savings from 1978 through 2011 are over $800 million and 490 aMW respectively. This represents more than the annual output from PSE's share of Colstrip 1 & 2, and is equivalent to the electricity used by about 372,000 homes for a year. As with supply-side resources, PSE evaluates energy efficiency programs for cost-effectiveness and suitability within a lowest reasonable cost strategy.

[3] *The WA State Energy Independence Act RCW19.285.030 (5) defines conservation as follows: "Conservation" means any reduction in electric power consumption resulting from increases in the efficiency of energy use, production, or distribution.*

Figure D-6

Cumulative Electric Energy Savings from DSR, 1978 to 2011



Our energy efficiency programs serve all types of customers – residential, low-income, commercial, and industrial. Energy savings targets and the programs to achieve those targets are established every two years. The 2010-2011 biennial program period concluded at the end of 2011; current programs operate January 1, 2012 through December 31, 2013. The majority of electric energy efficiency programs are funded using electric "rider" funds collected from all customers.[4]

For the 2012-2013 period, a two-year target of approximately 76 aMW in energy savings was adopted. This goal was based on extensive analysis of savings potentials and developed in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group (CRAG) and Integrated Resource Plan Advisory Group (IRPAG).

[4] *See Electric Rate Schedule 120 for more information.*

Current electric energy efficiency programs

The two largest programs offered by PSE to customers are the Commercial and Industrial Retrofit Program and the residential Energy Efficient Lighting Programs.

The **COMMERCIAL AND INDUSTRIAL RETROFIT PROGRAM** offers expert assistance and grants to help existing commercial and industrial customers use electricity and natural gas more efficiently via cost-effective and energy efficient equipment, designs, and operations. This program gave out grants totaling more than $13.6 million to over 830 business customers in 2012 to achieve a savings of over 70,000 MWh.

The **ENERGY EFFICIENT LIGHTING PROGRAMS** offer instant rebates for residential customers and builders who purchase Energy Star fixtures and compact fluorescent light bulbs. This program provided incentives totaling more than $6 million, which resulted in the installation of over 3.5 million CFL lamps and fixtures in 2011 to achieve savings of over 86,000 MWh.

Figure D-7
Annual Energy Efficiency Program Summary, 2010-2013
(Dollars in millions, savings in megawatt hours and average megawatts)

Program	2010 - 2011 Actual	’10-’11 2-Year Budget./Goal	’10-’11 Actual vs. Budget % Total	2012 Actual	’12-’13 2-Year Budget./Goal	’12 Actual vs. ‘12-‘13 % Total
Electric Program Costs	$ 153	$ 167	92.0%	$ 92	$ 193	48%
Savings - MWh	636,000	622,000	102%	339,500	666,000	51%
Savings - aMW	72.60	71.00		38.76	76.03	

Figure D-7 shows program performance compared to two-year budget and savings goals for the biennial 2010-2011 electric energy efficiency programs, and records 2012 progress against 2012-2013 budget and savings goals.

During 2010-2011, electric energy efficiency programs saved a total of 77 aMW of electricity at a cost of $153 million. The company surpassed two-year savings goals while operating at a cost that was under budget. In 2012, these programs saved 39 aMW of electricity at a cost of $92 million. The average cost for acquiring energy efficiency in 2010-2011 was approximately $240 per MWh, compared to a budgeted cost of approximately $290 per MWh in the 2012-13 program cycle.

Green power and small-scale renewables

PSE's customer renewable energy programs continue to grow. The Green Power Program serves customers who want additional renewable energy, and the Customer Renewables Program serves those who generate renewable energy on a small scale. Our customers find value as well as social benefits in the programs, and PSE embraces and encourages their use.

Green Power Program

PSE's Green Power Program, launched in 2001, allows customers to voluntarily purchase retail electric energy from qualified renewable energy resources. Since 2005, the National Renewable Energy Laboratory has recognized PSE as one of the top 10 utilities for Renewable Energy Sales and Total Number of Green Power Participants. Between 2010 and 2012, the number of subscribers increased from 29,398 to 34,962, and the number of megawatt-hours purchased increased from 314,893 to 365,796.

To supply green power, the program purchases renewable energy credits (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.; Acciona Energy, a broker of national wind RECs; and 3Degrees, a REC broker based in San Francisco. These suppliers provide PSE's Green Power Program with a portfolio of resources including wind, biomass, low-impact hydropower, biogas and biomass. In addition, the Green Power Program currently purchases RECs directly from eleven small, local producers in order to support the development of new small renewable resources. The list includes the Vander Haak Dairy (now FPE Renewables), Farm Power Rexville, Farm Power Lynden, Qualco Energy, Edaleen Cow Power, Van Dyk-S Holsteins, Rainier Biogas, Ellensburg Community Solar, 3Bar G community wind, and First Up! Knudson community wind, and the Nooksack Hydro Facility.

The Green Power Program has also provided over $150,000 in grant funding to six cities for solar demonstration projects located on municipal facilities. For example, in 2011, the Green Power Program awarded a $20,000 grant to the City of Olympia for a project to be installed on the Olympia Timberland Library; and a $10,000 grant to the City of Lacey for a site to be determined. The grants were in recognition of a successful Green Power Community Challenge in which the two cities increased the net participation in the program by over 500 participants. In addition, the Green Power Program awarded a

$25,000 grant to the City of Mercer Island after a successful Green Power Challenge, where the Island residents increased participation in the program by 55 percent during 2012. The funds will be used toward a solar project to be installed on the island's community center. Other projects have been installed in Bellingham, Whidbey Island, and Vashon Island.

This past spring, PSE's Green Power Program issued a request for proposals (RFP) for RECs to help supply the balance of our portfolio needs in the next 2 to 3 years. After several years of climbing REC prices, we noted that Washington and Northwest REC prices had fallen significantly since our last RFP, issued three years earlier. This is largely due to an increasing supply of renewable energy and initial compliance targets having been met by the region's utilities. 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.

Rates

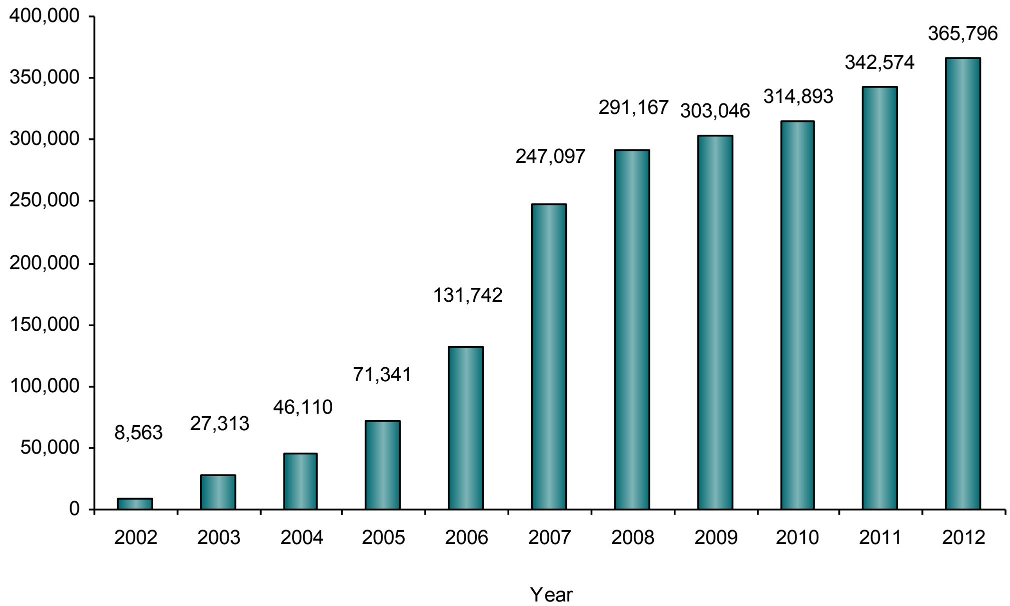
The standard rate for green power is $0.0125 per kWh. Customers can purchase 160 kWh blocks for $2 per block with a two-block minimum, or they can choose to participate in the "100% Green Power Option." Introduced in 2007, this option adjusts the amount of the customer's monthly green power purchase 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 25 customers since it was introduced in 2005.

Since 2000, PSE has been working to increase participation in the Green Power Program to five percent of all electric customers. To help achieve that goal, PSE contracted with 3Degrees, a third-party REC broker. 3Degrees has developed and refined education and outreach techniques while working with other utility partners across the country. Since their contract was initiated with PSE in January 2009, customer growth has increased by over 62 percent. Participation has increased by 10 percent and 8 percent in 2011 and 2012, respectively. As of December 31, 2012, over 3 percent of electric customers are participating in the program.

Figure D-8

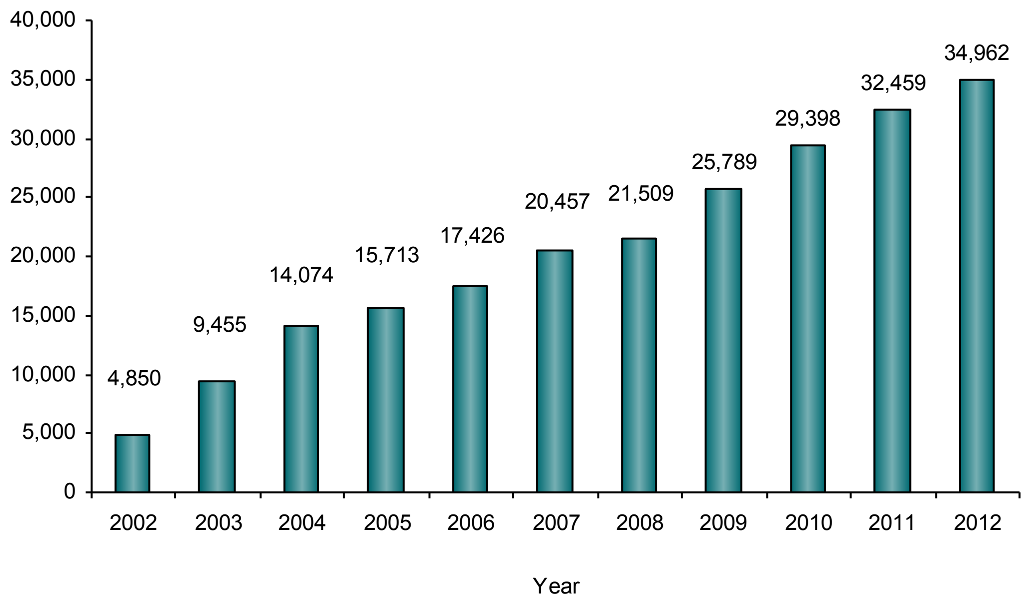
Green Power Kilowatt-hours Sold, 2002-2012



In 2012, the average residential customer purchase was 626 kWh per month, and the average commercial customer purchase was 2,188 kWh. The average 2012 large-volume purchase, by account, under Schedule 136 was 27,065 kWh per month.

Figure D-9 illustrates the number of subscribers by year. Of our 34,962 Green Power subscribers at the end of 2012, 34,014 were residential customers, 627 accounts were commercial accounts, and 321 accounts were assigned under the large-volume commercial agreement. Cities with the most residential and commercial participants include Olympia with 4,329, Bellingham with 4,186, Bellevue with 2,208, Kirkland with 1,609, and Redmond with 1,314. Vashon Island has the highest percentage of participants, with more than 13 percent of customers enrolled.

Figure D-9
Green Power Subscribers, 2002-2012



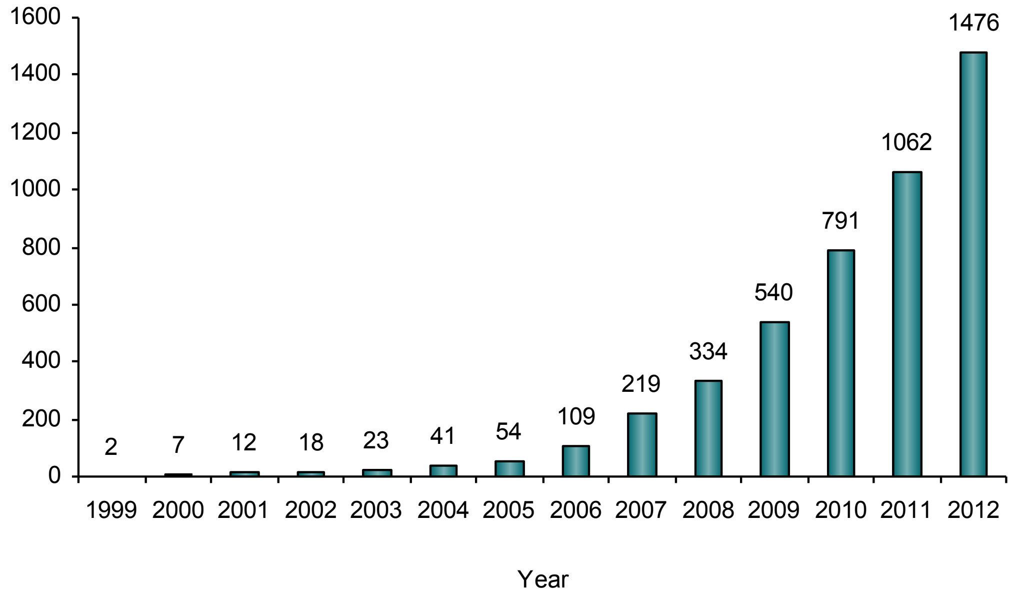
Customer renewables programs

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 ten years, as Figure D-10 shows. For 2012, PSE added 414 new net metered customers for a total of 1,476.

Figure D-10
Net Metered Customers Total Per Year, 1999-2012



The vast majority of customer systems (96 percent) are solar photovoltaic (PV) installations with an average generating capacity of 5.3 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 4.3 kW. Overall, the program was capable of producing more than 7.8 MW of nameplate capacity at the end of 2012.

Figure D-11

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	13	6.99	90.88
Micro hydro	5	4.14	20.70
Solar array	1,420	5.32	7,550.95
Wind turbine	38	2.93	111.22
Total Number of Systems	**1,476**	**Total Capacity of All Systems**	**7,773.74**

Figure D-12

Net Metered Systems by County

County	Number of Net Meters
Whatcom	226
King	420
Jefferson	138
Skagit	121
Island	108
Kitsap	182
Thurston	191
Kittitas	39
Pierce	51

RENEWABLE ENERGY COST RECOVERY. In 2005, PSE launched Production Metering in response to WAC 458-20-273. 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. Payments are made to interconnected electric customers who own and operate eligible renewable energy systems including solar PV, wind, or anaerobic digesters (the four micro hydroelectric customers are not eligible under the current law). Annual amounts range from 12 cents to

$1.08 per kWh produced by their system. PSE receives a state tax credit equal to the aggregate incentive payments made to customers. By the end of 2012, PSE had paid $1,106,000 to 1,200 customers eligible for production payments. The PSE tariff governing Production Metering is Schedule 151.

2. Electric Resource Alternatives

This section is designed to provide a brief overview of technology alternatives for electric power generation. It encompasses mature technologies, but emphasis is placed on new methods of power generation with near- and mid-term commercial viability.

All data has been gathered from public sources except where noted, and in these instances it is non-sensitive PSE data. It should be noted that many data sources are the manufacturers themselves, who may provide optimistic availability, cost, and production figures.

Summary table of electric generating technologies

Figure D-13

Cost and Performance of New Central Station Electricity Generating Technologies[5]

Technology	Online Year	Size (MW)	Lead Time (Years)	Overnight Cost in 2010 (2010 $/kW)	Variable O&M ($2010 Mills/kWh)	Fixed O&M ($2010/kW)	Heat Rate in 2011 (Btu/kWh)
Scrubbed Coal New	2015	1300	4	2,844	4.25	29.67	8,800
Integrated Coal-Gasification Comb Cycle (IGCC)	2015	1200	4	3,220	6.87	48.90	8,700
IGCC with carbon sequestration	2017	520	4	5,348	8.04	69.30	10,700
Conv Gas/Oil Comb	2014	540	3	977	3.43	14.39	7,050

[5] *Source: U. S. Energy Information Administration/Assumptions to the Annual Energy Outlook August 2012*

Technology	Online Year	Size (MW)	Lead Time (Years)	Overnight Cost in 2010 (2010 $/kW)	Variable O&M ($2010 Mills/kWh)	Fixed O&M ($2010/kW)	Heat Rate in 2011 (Btu/kWh)
Cycle							
Advanced Gas/Oil Comb Cycle (CC)	2014	400	3	1,003	3.11	14.62	6,430
Advanced CC with carbon sequestration	2017	340	3	2,060	6.45	30.25	7,525
Conv Combustion Turbine	2013	85	2	974	14.70	6.98	10,745
Adv Combustion Turbine	2013	210	2	666	9.87	6.70	9,750
Fuel Cells	2014	10	3	6,836	0.00	350.00	9,500
Advanced Nuclear	2017	2236	6	5,335	2.04	88.75	10,460
Distributed Generation - Base	2014	2	3	1,434	7.46	16.78	9,050
Distributed Generation - Peak	2013	1	2	1,722	7.46	16.78	10,056
Biomass	2015	50	4	3,859	5.00	100.55	13,500
Geothermal	2011	50	4	2,513	9.64	108.62	9,760
MSW - Landfill Gas	2011	50	3	8,233	8.33	378.76	13,648
Conventional Hydropower	2015	500	4	2,347	2.55	14.27	9,760
Wind	2011	100	3	2,437	0.00	28.07	9,760
Wind Offshore	2015	400	4	5,974	0.00	53.33	9,760
Solar Thermal	2014	100	3	4,691	0.00	64.00	9,760
Photovoltaic	2013	150	2	4,755	0.00	16.70	9,760

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"), and is found mostly in the timber, pulp and paper industries. This dynamic has limited the size of power available for export to date. The typical plant size we have observed is 25 MW to 50 MW. One major advantage of biomass plants is that they provide firm capacity and can operate as a base-load 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: two years for development and permitting, and two years for major equipment lead-time and construction. The U.S. Energy Information Administration estimates capital costs of approximately $3,859/kW in its *Annual Energy Outlook 2012*.

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. A report recently released by the National Energy Technology Laboratory of the U.S. Department of Energy indicates it may take 20 years for carbon capture and storage (CCS) technology for power generating plants to become commercially available.

Commercial availability. RCW 80.80 sets a generation performance standard for electric generating plants and prohibits Washington utilities from building plants or entering into long-term electricity purchase contracts from units that emit more that 1,100 pounds of GHGs per MWh. 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. This regulation makes it unlawful for PSE to build a new coal-fired power plant or enter a long-term purchase agreement to buy electricity produced by coal unless the plant includes carbon capture and sequestration (CCS) technology to reduce GHG emissions to a level below the RCW 80.80 standard. The status of CCS development makes it impossible to accurately estimate the cost of electricity from a coal-fired generating plant that meets these requirements.

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

Energy storage

The term "energy storage" may refer to a wide range of technologies from batteries to flywheels, and superconducting magnets to large-scale pumped storage. There are a variety of potential technology options for the electric sector, each with unique operational, performance, cost, and technological maturity characteristics. For the purposes of this section, we intend to refer more to emerging forms of energy storage such as batteries, flywheels, and compressed air. Pumped hydro is addressed in its own section of this chapter.

Commercial availability. Energy storage devices vary widely in their technological maturity and commercial availability, with new technologies and variants continuing to emerge. Two studies are particularly helpful in surveying the technology landscape: In February 2010, Sandia National Labs published *Energy Storage for the Electric Grid: Benefits and Market Potential Assessment Guide* (Sandia Report No. SAND2010-0815). In December 2010, EPRI published Electricity Energy Storage Technology Options (EPRI Report No. 1020676). This section relies heavily on insights from these reports.

The anticipated need for energy storage within the electric system has channeled over $700 million in funding from the Dept. of Energy for at least three dozen demonstration projects. Such real-world tests will soon provide needed data and information on the robustness of such systems, including performance and durability, life-cycle costs, and risks. Some storage companies are finding success, while others have struggled, such as Beacon Power, manufacturer of flywheel storage system, and A123 Systems, a manufacturer of grid-scale and automotive lithium-ion batteries. Both recently announced bankruptcy. That said, other companies see opportunity and PSE received two energy storage proposals in the 2011 RFP, one of which was a tolling arrangement for up to 200 MW of peaking capacity, from a major multinational power company. We see this as a sign that energy storage hold promise and merits continued evaluation.

Cost and performance assumptions. Each type of energy storage technology has its own cost and operating cost parameters. In general, based on present-day technology, some energy storage systems will not be economical because more technology development is needed to lower their capital costs. PSE is hopeful that costs will continue to decline with scale, and that the technologies continue to improve. Technology costs and application benefits are sensitive to the configuration of the storage system both in terms of discharge capacity (MW) and energy storage capacity (MWh). The following data from EPRI serves as useful guide through the diverse landscape of energy storage technologies, performance characteristics, and estimated costs.

Figure D-14
Energy Storage Characteristics by Application (Megawatt-scale)[6]

Technology Option	Maturity	Capacity (MWh)	Power (MW)	Duration (hrs)	% Efficiency (total cycles)	Total Cost ($/kW)	Cost ($/kW-h)
Bulk Energy Storage to Support System and Renewables Integration							
Pumped Hydro	Mature	1680-5300	280-530	6-10	80-82 (>13,000)	2500-4300	420-430
		5400-14,000	900-1400	6-10		1500-2700	250-270
CT-CAES (underground)	Demo	1440-3600	180	8	See note 1 (>13,000)	960	120
				20		1150	60
CAES (underground)	Commercial	1080	135	8	See note 1 (>13,000)	1000	125
		2700		20		1250	60
Sodium-Sulfur	Commercial	300	50	6	75 (4500)	3100-3300	520-550
Advanced Lead-Acid	Commercial	200	50	4	85-90 (2200)	1799-1900	425-475
	Commercial	250	20-50	5	85-90 (4500)	4600-4900	920-980
	Demo	400	100	4	85-90 (4500)	2700	675
Vanadium Redox	Demo	250	50	5	65-75 (>10,000)	3100-3700	620-740

[6] *Electric Power Research Institute (EPRI), "Electricity Energy Storage Technology Options: A White Paper Primer on Applications, Costs, and Benefits," (Technical Update, December 2010), p. xxiii-xxiv.*

Technology Option	Maturity	Capacity (MWh)	Power (MW)	Duration (hrs)	% Efficiency (total cycles)	Total Cost ($/kW)	Cost Cost ($/kW-h)
Zn/Br Redox	Demo	250	50	5	60 (>10,000)	1450-1750	290-350
Fe/Cr Redox	R&D	250	50	5	75 (>10,000)	1800-1900	360-380
Zn/air Redox	R&D	250	50	5	75 (>10,000)	1440-1700	290-340
Energy Storage for ISO Fast Frequency Regulation and Renewables Integration							
Flywheel	Demo	5	20	0.25	85-87 (>100,000)	1950-2200	7800-8800
Li-ion	Demo	0.25-25	1-100	0.25-1	87-92 (>100,000)	1085-1550	4340-6200
Advanced Lead-Acid	Demo	0.25-50	1-100	0.25-1	75-90 (>100,000)	950-1590	2770-3800
Energy Storage for Utility T&D Grid Support Applications							
CAES (aboveground)	Demo	250	50	5	See note 1 (>10,000)	1950-2150	390-430
Advanced Lead-Acid	Demo	3.2-48	1-12	3.2-4	75-90 (4500)	2000-4600	625-1150
Sodium-Sulfur	Commercial	7.2	1	7.2	75 (4500)	3200-4000	445-555
Zn/Br Flow	Demo	5-50	1-10	5	60-65 (>10,000)	1670-2015	340-1350
Vanadium Redox	Demo	4-40	1-10	4	65-70 (>10,000)	3000-3310	750-830
Fe/Cr Flow	R&D	4	1	4	75 (10,000)	1200-1600	300-400
Zn/air	R&D	5.4	1	5.4	75 (4500)	1750-1900	325-350
Li-ion	Demo	4-24	1-10	2-4	90-94 (4500)	1800-4100	900-1700
Energy Storage for Commercial and Industrial Applications							
Advanced Lead-Acid	Demo-Commercial	0.1-10	0.2-1	4-10	75-90 (4500)	2800-4600	700-460
Sodium-Sulfur	Commercial	7.2	2	7.2	75 (4500)	3200-4000	445-555
Zn/Br Flow	Demo	0.625	0.125	5	60-63 (>10,000)	2420	485-440
		2.5	0.5	5		2200	
Vanadium Flow	Demo	0.6-4	0.2-1.2	3.5-3.3	65-70 (>10,000)	4380-3020	1250-910
Li-ion	Demo	0.1-0.8	0.05-0.2	2-4	80-93 (4500)	3000-4400	950-1900

Table Notes:

1. Refer to the full EPRI report for important key assumptions and explanations behind these estimates. All systems are modular and can be configured in both smaller and larger sizes not represented. Figures are estimated ranges for the total capital installed cost estimates of “current” systems based on 2010 inputs from vendors and system integrators. Included are the costs of power electronics if applicable, all costs for installation, step-up transformer, and grid interconnection to utility standards. Smart-grid communication and controls are also assumed to be included. For batteries, values are reported at rated conditions based on reported depth of discharge. Costs include process and project contingency depending on technical maturity. The cost in $ per kW-h is calculated by dividing the total cost by the hours of storage duration.
2. For CAES and Pumped Hydro, larger and smaller systems are possible. For below ground CAES the heat rate may range from ~3,845-3,860 Btu per kWh and the energy ratio is 0.68-0.78; for aboveground CAES the heat rate is ~4,000 Btu per kWh and the energy ratio is ~1.0.

3. For C&I and Residential applications lower CapEx costs may be possible if the battery system is integrated and installed with a photovoltaic system.
4. First-of-a-kind system costs will be higher than shown. Future system costs may be lower than shown after early demonstrations are proven and products become standardized.

Preliminary cost-benefit analysis. One of the advantages of energy storage is that it can theoretically provide more than one benefit to the electric system, such as peak shaving, grid balancing, and T&D upgrade deferral. The particular challenge for a vertically integrated utility such as PSE is assigning value to those particular services. With no market and price signal for ancillary services such as frequency regulation, an avoided-cost methodology must be used. PSE has been observing developments in energy storage for some time, and when two proposals were received in the 2011 RFP, we performed a preliminary cost-benefit analysis based on storage system pricing contained in those proposals. The methodology for our analysis follows.

Capacity was valued at the incremental avoided cost of the frame peaker simple-cycle combustion turbine (SCCT) with oil back-up. Further, the storage system with 4 hours of discharge capacity was run though a loss of load probability (LOLP) analysis, which indicated that due to the limited discharge duration, the storage system would provide 82% as much capacity value as a typical SCCT. Typical SCCTs can operate indefinitely during system-wide contingency events, whereas energy storage systems with limited discharge cannot.

Distribution upgrade deferral was valued at the incremental avoided cost for upgrading a standard 25 MVA substation at $280/kW. While few distributed storage systems can completely eliminate the need for system upgrades, they can reasonably defer them for several years.

Transmission was valued at the avoided cost of average transmission contracts, at $30 per kW-yr. The value assigned was taken from the Electric Conservation Cost Effectiveness Standard Model.

Grid balancing was valued using a proprietary production cost model that is used to simulate various levels of wind interconnected to our system and the flexibility need and cost to integrate wind and balance load. The primary benefit of energy storage is reducing the number and duration of operating peakers when uneconomical. This analysis is preliminary.

Arbitrage was valued using actual market data for 9/1/2011 – 8/31/2012, assuming our traders executed perfect peak/off-peak scheduling and trades. Given the generally low spreads in the region, and the losses from charging and discharging, as well as transmission and distribution losses, the value of arbitrage is low.

Oversupply reduction was estimated by combining the peak/off-peak spread from capturing surplus energy plus the value of PTC's and RECs from curtailed wind for 15 days per year of oversupply situations. Because these events generally involve very large amounts of energy relative to the storage system and generally occur infrequently, the value of the benefit is not large.

Figure D-15
Preliminary Storage Analysis Summary

Value Stream	$/kW-yr
Avoided Capacity	$ 85
Substation Upgrade Deferral	$ 26
Avoided Transmission	$ 30
Grid Balancing	$ 39
Arbitrage	$ 7
Oversupply Reduction	$ 2
Total Value	**$ 189**
Total Storage System Cost	**$ 300**

While there still appears to be a large gap between the annual levelized cost of the storage system and the combined potential avoided costs to PSE, our valuation methodology needs improvement, which may increase the value of some value streams. In addition, we anticipate continued technology improvement and declining costs.

Energy storage pilot project

In collaboration with Primus Power, Pacific Northwest National Labs, and with funding from the Bonneville Power Administration and the Dept. of Energy, PSE will be undertaking a potential pilot project to investigate and demonstrate distributed energy storage on the PSE system. The goal of this project will be to assess and then demonstrate the net benefits of using energy storage located close to the customer in the distribution grid to manage demand. The project will take place in three phases, where the objective of the first phase will be to analyze the values storage located in the distribution grid can bring to Puget Sound Energy (PSE) and BPA. In the second phase, Primus Power EnergyPods will be installed at a high value location and piloted. Operations will then be demonstrated, optimized, and evaluated in third phase of the study.

Fuel cells

Fuel cells combine fuel (typically carbon-based) 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 percent to 60 percent. In some cases, conversion rates can be boosted higher using heat recovery and reuse. Fuel cells operate or are being developed at sizes that range from hundreds of watts to tens of megawatts. Smaller fuel cells power items like portable electric equipment, larger ones can be used to power equipment, buildings, or provide back-up 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. (Source: Department of Energy, Energy Efficiency and Renewable Energy, Fuel Cell Technologies Program.)

Provided that feedstocks are kept clean of impurities, fuel cell performance is very reliable. They are often used as back-up 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 a gross generation scale. The largest fuel cell project underway in the United States is a 154.5 MW project being built in Connecticut at a cost of over $5,000/kW. Another project in Delaware will distribute up to 30 MW of fuel cells in blocks at several substations. 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 has no incentives specific to fuel cells. Fuel cell costs are estimated to be at least $5,000/kW, and some projects appear to be as high as $10,000/ kW before subsidies.

Geothermal

Geothermal generation technologies use the natural heat under the surface 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, but few sites offer very hot (greater than 235 degrees Celsius) hydrothermal fluids that are predominantly steam.[7]

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).[8]

BINARY-CYCLE POWER PLANTS can use lower temperature hydrothermal fluids (107 degrees Celsius to 182 degrees Celsius) 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.[9]

The United States, Japan, England, France, Germany, and Belgium are testing **ENHANCED GEOTHERMAL** or "hot dry rock" technologies.[10] These systems involve the drilling of 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. There are small operating facilities in Germany and France, and several

[7] *Renewable Energy Policy Project, http://repp.org/geothermal/geothermal_brief_power_technologyandgeneration.html*
[8] *EERE, http://www1.eere.energy.gov/geothermal/gerthermal_basics.html*
[9] *Ibid*
[10] *Geothermal Education Office, 2000, http://geothermal.marin.org/pwrheat.html*

commercial facilities are under development in Australia. The U.S. Department of Energy has funded a test project in the United States.

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. This issue affected the largest geothermal complex in the United States, the Geysers projects in California, due to resource depletion. Additional water recycling has been improved the situation in recent years.

Commercial availability. Currently, approximately 3,187 MW of geothermal generating capacity is online in the United States, with 97 percent of that capacity in California or Nevada.[11] The only operating geothermal plants in the Northwest are the 0.28 MW plant in Klamath Falls, Ore., and the 15.8 MW Raft River plant in Idaho.

The Northwest has been subject to considerable exploration activity over the past several years, with an estimated 900 MW in some stage of development.[12] Most of this is in very early development, and may or may not have obtained site access and drilled exploratory wells. Most projects have not yet proven their output, though several are in testing at this time. Currently, three projects in the Northwest, a total of approximately 70 MW in capacity, are reported to be under construction, Neal Hot Springs and Crump Geyser in Oregon, and an expansion of the Raft River project in Idaho.

Other Northwest projects are planned in Oregon and Idaho, but these are further behind in development. It would take at least four years before they were ready for commercial operation, if the resources prove viable.

Geothermal energy plants are capital intensive, with estimated capital costs of approximately $5,580/kW for traditional dual flash geothermal steam plants according to the U.S. Department of Energy in 2010. 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. Generally, operating costs are relatively low due to a zero fuel cost, but this can vary due to site conditions as well.

[11] *Geothermal Energy Association*
[12] *U.S. Geothermal Power and Production Update, April 2012.*

Natural gas

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 50 percent (HHV) 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.

This technology is commercially available. Greenfield development requires approximately five years: two years for development and permitting; two years for major equipment lead-time; and one year for construction.

Natural gas supply is assumed to be firm year round and based on projected Northwest 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, but the capacity contribution to peak load should be reduced by 7 percent to account for reserves.

Simple-cycle combustion turbines

There are three principal types of simple-cycle combustion turbines for "peaking" applications: frame, aeroderivative (aero), and reciprocating (recip) engines. Frame CTs are also known as "industrial" or "heavy-duty" CTs; these are generally larger in capacity and feature frames, bearings, and blading of heavier construction. In 2012, PSE reviewed the typical cost and performance characteristics of these technology types and determined that frame and aero CTs are the best fit economically for the Pacific Northwest market and PSE's needs.

FRAME COMBUSTION TURBINE. 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 15 percent to 35 percent (HHV) at full load. These units are typically less flexible than their aero and recip counterparts, meaning they cannot reduce output beyond about 50 percent to 60 percent, they have slower ramp rates (on the order of 15 MW/min), and though some can start in ten minutes, the output achieved in ten minutes is typically not base-load.

Frame CTs are commercially available. Greenfield development requires approximately four years: two years for development and permitting, one-and-a-half years for major equipment lead-time, and a half-year for construction.

AERODERIVATIVE (AERO) COMBUSTION TURBINES. Aeroderivative (aero) 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 30 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 50 to 90 MW per min. Another key difference between aero and frame units is size. Aero CTs are typically smaller in size, from 40 to 100 MW each. This small scale allows for modularity and reducing shaft risk, but also tends to reduce economies of scale.

This technology is commercially available. Greenfield development requires approximately four years: two years for development and permitting, one-and-a-half years for major equipment lead-time, and a half-year for construction.

RECIPROCATING (RECIP) ENGINES. Compared to the frame and aeroderivative technologies, reciprocating engines are a relatively newer technology; consequently they are less commonly used in power generation. 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% to 40% while some newer units claim efficiencies as high as nearly 50%. However, reciprocating engines are constrained by their size. The largest commercially available reciprocating engine produces just 18 MW, much less than the typical frame or aero turbine. Larger sized generation projects would require a relatively greater number of reciprocating units compared to an equivalent-sized project implementing either an aero or frame turbine, reducing economies of scale.

Greenfield development requires approximately four years: two years for development and permitting, one-and-a-half years for major equipment lead-time, and a half-year for construction. PSE does not take the risk of contracting for major equipment before permits are in hand. Private developers, on the other hand, are often willing to take that risk and can accelerate the development timeframe by about one year.

Nuclear

Like other types of thermal generating resources (coal-, oil-, and gas-fired), nuclear power plants produce electricity by boiling water into steam at elevated temperature and pressure. The thermal energy of the steam is converted to mechanical energy in a steam turbine driving an electrical generator to produce electricity. Instead of burning fossil fuels, the nuclear power plant uses solid ceramic pellets of uranium, developing heat in a process called “fission” or the splitting of uranium atoms in a nuclear reactor.

Nuclear fuel consists of two types of uranium, U-238 and U-235. The atomic nucleus of uranium is composed of 92 protons and 143 neutrons. When split, the uranium nuclei break up, releasing high energy neutrons and heat. As these neutrons impact other uranium atoms, those atomic nuclei also split, releasing neutrons of their own, along with additional heat. These neutrons in turn strike other atoms, splitting them and triggering other such collisions in a chain reaction. When that happens, a self-sustaining fission reaction has begun.

To control the nuclear fission reaction, control rods are inserted into the reactor vessel that absorb neutrons without contributing to the fission reaction. These control rods may be inserted or withdrawn to varying degrees, slowing or accelerating the reaction.

The nuclear fleet

Today, there are 104 commercial nuclear power plants operating in the United States, the largest of which is Palo Verde in Arizona, whose three nuclear reactors together produce 3,942 MW.[13] The performance of the 104 U.S. nuclear plants has been excellent, with a combined energy output of 821 million MWh in 2011.[14] The total number of kWh produced by the reactors has steadily increased over the last five years. The fleet-

[13] *Source: Nuclear Energy Institute – Resources & Stats*
[14] *Source: World Nuclear Association – Nuclear Power in the U.S. – January 2013*

averaged capacity factor for 9 of the last 10 years has been maintained at about 90 percent.[15] Approximately two-thirds of U.S. nuclear plants are pressurized water designs while the remaining one-third use boiling water designs.

In 2012, over 80 percent of the 104 licensed reactor units have either received a new license or are under review for license renewal; 31 units operate under their original license. At this time, 14 nuclear power plants are in varying stages of decommissioning, including Trojan,[16] which is located in Oregon.

The Nuclear Regulatory Commission (NRC) is reviewing new reactor applications and issued its first combined Construction and Operating Licenses in early 2012 (called a combined license or COL) to Southern Nuclear Operating Company for Vogtle 3 & 4 and to South Carolina Electric and Gas for V.C. Summer 2 & 3. The NRC expects to review approximately 10 additional COL applications for 16 new reactors over the next several years. Lessons learned from the Fukushima accident in Japan are being included in new design certification, COL, and ESP reviews.

Globally, there were 437[17] operating commercial nuclear power reactors in 31 countries (including the U.S. fleet) with a total installed capacity of 372,210 megawatts electric (MWe). Worldwide, there are 68[18] nuclear plants under construction, including in China (29), Russian Federation (11), India (7), Korea (3), Japan (3),Bulgaria (2), Taiwan (2), Slovakian Republic (2), Ukraine (2), Japan (2), Argentina (1), Brazil (1), Finland (1), France (1), Iran (1), Pakistan (1), and the UAE (1).

In the United States, five nuclear power reactors are under construction, including TVA's Watts Bar 2 in Tennessee with a capacity of 1,165 MW, which is scheduled to begin operation in 2016 and 2017; and V.C. Summer 2 & 3 in South Carolina with a capacity of 1,154 MW, which is scheduled to begin operation in 2017 and 2018.

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15 *Source:* http://www.nei.org/corporatesite/media/filefolder/US_Nuclear_Generating_Statistics.xls

16 *Trojan is currently in DECON status: Equipment, structures, and portions of the facility containing radioactive contaminants have been removed or decontaminated to a level that permits release of the property and termination of the NRC license.*

17 *Source: European Nuclear Society - Nuclear power plants, world-wide – January 2013*

18 *Source: European Nuclear Society - Nuclear power plants, world-wide – January 2011*

Fukushima accident[19]

On March 11, 2011, a magnitude 9.0 earthquake, centered 130 km offshore from the city of Sendai on the eastern cost of Honshu Island, produced devastating infrastructure damage in Japan. What is known as the Great East Japan Earthquake was a double quake lasting about 3 minutes, and it produced a tsunami that inundated about 560 square kilometers in Japan, resulting in over 19,000 deaths and extensive damage to coastal ports and towns.

Four Fukushima reactors were damaged beyond recovery in the tsunami and subsequent meltdown and/or explosion, and they will be completely demolished in 30-40 years – much the same time frame as for any decommissioned nuclear plant.

In April 2012, the US Electric Power Research Institute published Fukushima Daiichi Accident – Technical Causal Factor Analysis, which identified the accident's root cause (beyond tsunami flooding and its effects) as a "…failure to consider the possibility of the rupture of combinations of geological fault segments in the vicinity of the plant." This lesson has not been lost on the global nuclear industry, and license review procedures in most countries have been revised to reflect this higher level of geological scrutiny.

Select U.S. nuclear construction projects update[20]

WATTS BAR UNIT 2. The 1,165 MW reactor is expected to come online in 2015 at a cost of about $4.3 billion, a projected cost increase of 72 percent since the 2011 IRP. Its twin, Watts Bar Unit 1, started operation in 1996. Watts Bar 2 is expected to provide power at 5.6 ¢ per kWh, an increase of 27percent since the 2011 IRP. Even with schedule delays and cost increases, TVA projects that energy from Watts Bar 2 will be approximately equal to the levelized cost of a natural gas-fired plant, assuming fuel pricing of $2.50 per mmBTU, albeit with far greater commercial and technology risk.

VOGTLE 3 & 4. In February 2012, the NRC issued the combined Construction and Operating Licenses (COL) for Vogtle Units 3 & 4. These were the first COLs ever issued in the United States for a new nuclear energy facility. The Vogtle 3 & 4 construction project is approximately one-third complete. Site works are largely complete in preparation for the two 1,200 MWe Westinghouse AP1000 reactors. The unit 3 reactor

[19] *Source: Abridged from http://www.world-nuclear.org/info/fukushima_accident_inf129.html*
[20] *Source: World Nuclear Association - Nuclear Power in the USA – December 2010*

vessel has shipped from South Korea, the unit 3 condenser is nearly complete, and the unit 4 condenser is under construction.

Overall project cost is running about 4 percent below the cost estimate prepared in 2009. The two units are expected to start commercial service in 2016 and 2017.

V.C. SUMMER 2 & 3. In March 2012, the NRC issued the combined Construction and Operating Licenses (COL) for V.C Summer Units 2 & 3. Construction ramped up considerably after receipt of the COLs with site work already quite advanced. Foundation work is ongoing at both units; however, delays related to placement of the lower reactor vessel containment bowl rebar mat have caused the layoff of an undisclosed number of construction workers while the issue is analyzed and the project schedule is reevaluated. A similar problem has surfaced at Vogtle as well. The total project cost of $9.8 billion includes forecast inflation and owners' costs for site preparation, contingencies and project financing. Actual expenditures are reported to be running about 2 percent under budget, and the project is still scheduled to enter commercial service in 2017 and 2018.

Policy considerations*.* The Energy Policy Act of 2005 provided financial incentives for the construction of advanced nuclear plants. The incentives include a 2.1¢ per kWh tax credit for the first 6,000 MWe of capacity in the first 8 years of operation, and federal loan guarantees for the project cost. After putting this program in place in 2008, the Department of Energy (DOE) received 19 applications for 14 plants involving 21 reactors. The total amount of guarantees requested is $122 billion, but only $18.5 billion has been authorized for the program, and a further $2 billion for construction of nuclear front-end facilities – uranium enrichment plants. The Department of Energy also contributed to front-end funding with an additional $2 billion allocation. No additional loan guarantees have been authorized, nor were any included in the budget request for fiscal year 2013.

Following the requirements of the Nuclear Waste Policy Act, the DOE submitted a license application for the Yucca Mountain repository in 2008. Congress mandated and is providing the funding for the NRC to complete a license review. The Obama administration has stated that Yucca Mountain is no longer an option for nuclear waste disposal.

In January 2013, the DOE announced a new waste strategy that would create a new organization to manage the siting, development, and operation of the future waste stores, to be established with "an appropriate balance between independence ... and the need for oversight by Congress and the Executive Branch." This strategy may take the form of a federal government corporation or an independent government agency. It envisions a "pilot interim store" opening by 2021, with a priority on taking used nuclear fuel from current shutdown power plant sites. By 2025, a larger "full-scale interim store" would open, and by 2048 an underground disposal facility would be in place to permanently store and dispose of the material. The mandate for the new organization excludes reprocessing of used fuel. At this time, Congress has not acted to fund the development any such organization.

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 United States during the 1980s and early 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, the public controversy over nuclear power contributed to some of the construction delays and cost overruns. The situation is little changed today, with regulatory uncertainty from the Fukushima accident, commercial uncertainty from the falling cost of natural gas, construction uncertainty for any large and complex project, and policy uncertainty for ongoing construction loan guarantees.

As indicated in Figure D-13, the capital cost of developing a new nuclear power plant is higher than most conventional and renewable technologies, as is the fixed and variable operations cost. Nuclear carries significant technology, credit, permitting, policy, and waste disposal risks; and design revision implications following the Fukushima accident are still not yet fully appreciated. Its high cost and high uncertainty make nuclear technology an undue risk for PSE at this time. PSE will continue to follow emerging trends in this technology, and may include it in future resource plans if evolving national policies and the technological maturity of newer designs sufficiently reduce project risks and cost uncertainty for our customers.

In 2012, a senior analyst for Moody's stated that building a nuclear power plant is perceived as risky by credit rating agencies – and in some cases could lead to a ratings downgrade of the utility concerned. "The risks are writ larger when you think of a nuclear project [than for other forms of generation], because construction and planning is that much more tortuous, construction risk is higher and from an operational point of they have a high fixed cost base."[21]

In July 2012, Jeff Immelt, CEO of General Electric, acknowledged, "When I talk to the guys who run the oil companies they say look, they're finding more gas all the time. It's just hard to justify nuclear, really hard. Gas is so cheap and at some point, really, economics rule. So I think some combination of gas, and either wind or solar…that's where we see most countries around the world going."[22]

Pumped hydro

Pumped hydro is large, mature, and utility-scale technology currently used at many locations in the United States and around the world. A pumped-hydro plant generally resembles a conventional dam, except that instead of impounding water, the water is raised to the reservoir level by consuming electricity. Pumped-hydro employs off-peak electricity to pump water from a reservoir up to another reservoir at a higher elevation. When electricity is needed, water is released from the high reservoir through a turbine into the low reservoir to generate electricity. With each round-trip, some of the energy being converted is lost, typically about 15-25%. Energy storage capability is limited only by the size of the available upper reservoir.

PSE has met with several pumped-hydro developers in the past few years and will continue to explore the benefits and costs of pumped hydro and the value it could bring as a viable peaking, flexibility, and reliability resource.

Commercial availability. Pumped-hydro facilities are commercially available, but the siting, permitting, and associated environmental impact processes can be complex and take many years. Access to supplemental external water refill can also be a concern. There is growing interest in re-examining opportunities for pumped hydro in the United States, particularly in view of the large amounts of wind, solar, and nuclear generation that may be deployed over the next few decades, driving additional system flexibility needs. New variable-speed drive technology is being applied to new sites allowing for more flexible operation and faster switching between pumping and discharging modes.

[21] *Source: ICIS "New nuclear electricity costs hit utility ratings - Moody's" March 2012*
[22] *Source: Financial Times, June 30, 2012; Pilita Clark, Environment Correspondent*

Cost and performance assumptions. Projects may be sized in a wide range from 200 to 4,000 MW with between 6 and 20 hours of storage. Pumped hydro plants typically operate at about 76 percent to 85 percent efficiency depending on design. Pumped hydro plants have very long lives on the order of 50 years, and fast response times that enable them to participate equally well in voltage and frequency regulation, spinning reserve, and non-spinning reserves markets, as well as energy arbitrage and system capacity support. The following table from EPRI illustrates the most common configurations and associated performance and cost characteristics.

Figure D-16
Pumped Hydro Plant Capacity, Energy, Efficiency, and Cost

<table>
<tr><th>Plant Size</th><th>Capacity (MW)</th><th>Energy (MWh)</th><th>Duration (hrs)</th><th>Efficiency (%)</th><th>Total Cost ($/kW)</th></tr>
<tr><td>Small</td><td>280-530</td><td>1,680-5,300</td><td>6-10</td><td rowspan="2">80-82</td><td>2,500-4,300</td></tr>
<tr><td>Large</td><td>900-1,400</td><td>5,400-14,000</td><td>6-10</td><td>1,500-2,700</td></tr>
</table>

Source: Electric Energy Storage Technology Options: A White Paper Primer on Applications, Costs and Benefits. EPRI, Palo Alto, CA, 2010. 1020676.

Solar energy

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.

PHOTOVOLTAICS are semiconductors that generate direct electric currents. The current then typically runs through an inverter to create alternating current; then it can be tied into the grid. Photovoltaics have been in use for decades, but only recently, as costs have dropped, has their use started to grow significantly. Most photovoltaics are based on silicon imprinted with electric contacts, much like computer chips, but other technologies, notably several chemistries of thin-film photovoltaics, have gained substantial market share. Thin-film photovoltaics offer lower production costs, but also have lower efficiencies (up to 12 percent efficiency) than silicon-based photovoltaics (up to 24 percent efficiency), so thin-film technology requires greater surface area than silicon-based technology to generate the same amount of electricity. All photovoltaic technologies have significant ongoing research efforts, which have been increasing conversion efficiencies and decreasing costs. Photovoltaics are installed in arrays that range from a few watts for sensor or communication applications, up to hundreds of MW for utility-scale power generation.

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 enough 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 late 2012, there were approximately 5,900 MW of installed photovoltaics in the United States. Over 500 MW of solar thermal plants operate in the United States, and projects totaling more than 1,300 MW are currently under development.

Commercial availability. Currently, renewable portfolio standards (RPS) drive most utility-scale solar development in the United States. Customer preference, not cost-effectiveness, drives residential development, and is supported with generous state and federal incentives. At the end of 2012, PSE had 7.2 MW of solar photovoltaics installed (about 60 percent of Washington's total), Idaho 0.2 MW, and Oregon 14 MW. Collectively, these amount to an output of approximately a 3 aMW over a year. Oregon's solar development is growing because the state's RPS requires the installation of about 20 MW of solar photovoltaics, and because of the state's Business Energy Tax Credit. In comparison, California had over 750 MW installed photovoltaics as of the end of 2009 and approximately 300 MW of solar thermal plants.

With less sunlight than other areas of the country, and incentive structures that limit development to smaller systems, photovoltaic development has been slow in the Northwest. Likewise, concentrating PV and concentrating solar thermal systems have not been developed, again because of the Northwest's relatively low percentage of direct sunlight, which these systems require for generation.

Cost and performance assumptions. PSE has had a positive experience with the performance of our 500 kW Wild Horse Solar Demonstration Project, which has outperformed its pre-construction production estimates. PV systems in western Washington are expected to have capacity factors of approximately 10 percent to 11 percent, while those in eastern Washington could achieve capacity factors as high as 18 percent.

Since PSE built the Wild Horse Solar Demonstration Project in 2007, costs have declined considerably, reaching national averages of approximately $6.50 per Watt-dc for residential systems, $5.75 per Watt-dc for commercial systems, and $4.00 per Watt-dc for utility scale systems (Solar Electric Industry Association, 2010). Many residential customers have seen costs below $4.00 per Watt –dc with larger systems. PSE's calculations of the lowest levelized cost for utility-scale solar systems located in eastern Washington have ranged from $0.18 to $0.25 per kWh, which significantly exceeds costs for other renewable energy sources, such as wind.

Solar thermal plants have proven reliable over time, with the SEGS plants in California operating since the 1980s. While the limited number of recent developments makes it difficult to estimate current costs, best-known current costs are shown in Figure D-16.

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 2,500 MW in generating capacity.

WASTE THERMAL PROCESSING FACILITIES. This includes gasification, pyrolisis, and reverse polymerization. These facilities add heat energy to waste and control the oxygen available to break down the waste into components without combusting it. Typically, a syngas is generated, which can be combusted for heat or to produce electricity. A number of pilot facilities once operated in the United States, but only a few remain today.

LANDFILL GAS AND MUNICIPAL WASTEWATER TREATMENT FACILITIES. Most landfills in the United States collect methane from the decomposition of wastes in the landfill. Many larger municipal wastewater plants also operate anaerobic systems to produce gas from their organic solids. Both of these processes produce a low quality gas with approximately half the methane content of natural gas. This low quality gas can be collected and scrubbed to remove impurities or improve the heat quality of the gas. The gas can then be used to fuel a boiler for heat recovery, or a turbine, or reciprocating engine, to generate electricity. As of June 2012, approximately 59,453 U.S. landfills generate electricity today with a combined capacity of 18,351 MW.

Commercial availability. Under Washington's RPS, landfill gas qualifies as a renewable energy resource, but municipal solid waste does not. Under proposed revisions to the RPS that were being considered in the state legislature at the time PSE was developing its 2013 IRP, the definitions of wastes and biomass would be clarified to allow some new wastes, such as food wastes, to qualify as renewable energy sources.

Currently, several waste-to-energy facilities are operating in or near PSE's electric service area. Two landfills use landfill gas for electric generation in Washington state; combined, they produce an output of approximately 12.4 MW. 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. Two waste combustion facilities operate in the Northwest: the 13.1 MW Covanta facility in Brooks, Ore., and the 26 MW Spokane waste-to-energy facility. The Spokane facility currently holds a purchased power agreement (PPA) with PSE. 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.

Cost and performance assumptions. Eight hundred sixty-seven waste combustion facilities and 59,453 landfill gas-to-energy facilities were operating in the United States by the end of 2010, but relatively few have been built in recent years. This makes reliable cost data difficult to obtain. The U.S. Department of Energy estimates capital costs for landfill gas projects at approximately $2,400 per kW. Waste combustion projects are similar to biomass projects, which have estimated construction costs of approximately $3,400 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.

Water-based generation – 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 and the rotors then 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. Currently, the largest operating tidal generation facility in the world is the Rance Tidal Power barrage system in France, which has a generating capacity of approximately 240 MW. In-stream turbines up to 1.2 MW in size have been tested in Canada, Scotland, and South Korea.

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. 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.

Commercial availability. Currently, only one tidal power site is under development in the Northwest, Snohomish PUD's Admiralty Inlet site. Plans call for the installation of 2 to 3 test turbines, producing a total of 1 MW by mid-2014 with an estimated cost of $20 million. Snohomish PUD also holds preliminary permits for developments of other sites in Puget Sound, though Admiralty Inlet is by far the largest. Tacoma Power considered development in the Tacoma Narrows, but ultimately abandoned the project. 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.

In general, the limiting factors in development of wave and tidal power projects have been long and complex permitting process timelines, relatively little experience with siting, and the early-stage nature of the generation technologies. 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. From initial permit application until equipment installation, the process can take up to five years.

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 some have not even reached that point. The best-known cost estimates for development at scale are shown below. These are subject to considerable uncertainty, as they assume a certain scale-up in the respective industries, with the attending decrease in costs.

Figure D-17

Tidal and Wave Energy Plant Cost Estimates

Resource Type	Capital Cost ($/kW)	Levelized Cost ($/MWh)	Commercial Installation Size (kW)	Expected Life (years)	Typical Capacity Factor
Tidal1	$2,300 / kW	$112	16,000	20	35 %
Wave2	$3,375 – 6,747/ kW	$150-240	90,000	20	40 %

Table Notes:
(1) Source: Electric Power Research Institute, EPRI
(2) Sources: UK Carbon Trust, EPRI

Wind energy

Off-shore wind resources

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 4,000,000 MW 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.[23]

Globally, approximately 8,975 MW of off-shore wind resources are currently planned or in operation, in Europe, China, Japan, and the United Kingdom.[24] The largest offshore wind farm is Walney 1 & 2 located in the Irish Sea in the UK. The number of people working in the UK'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.

Commercial availability. Currently, no offshore wind projects are under development on the West Coast of the United States.[25] Most U.S. projects have been proposed for the East Coast and Great Lakes regions. The nearest proposed project to PSE's service territory is the Naikun Offshore Wind Project in British Columbia. The developer has selected Siemens SWT-4.0-130 4 MW turbines, and Siemens will assist NaiKun Wind Energy Group with project development. The NaiKun Wind project has achieved an advanced stage of development with environmental approvals from the Provincial and Federal Governments, and agreements are in place with key suppliers and First Nations. Given its development status, construction can begin within two years of the award of a purchased power agreement.

According to the Department of the Interior, the U.S. will offer leases to federal acreage off the coasts of Virginia, Massachusetts, and Rhode Island for offshore wind farm

[23] *Source: U.S. Department of Energy Wind Program*
[24] *Source: Lindoe Offshore Renewables Center, http://www.lorc.dk/offshore-wind-farms-map/list*
[25] *Source: U.S. Offcoast Wind Collective - http://www.usowc.org/*

development during the first half of 2013. These competitive lease sales will be the first held under an Obama administration's initiative to fast-track permitting for offshore wind farms. The leases would grant wind-development rights to about 277,550 acres, though the winning bidders would still have to clear additional environmental reviews and secure financing.[26]

Cost and performance pssumptions. 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.[27] 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.[28] 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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26 *Source: Wall Street Journal, Washington Wire, November 2012*

27 *Source: NREL - Large Scale Offshore Wind Power in the United States, Opportunities and Barriers, 2010*

28 *Source: Berkeley Lab, 2011*

Land-based wind resources

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. Commercially available machines are in the 2.0 to 3.0 MW range with hub heights of 80 to 100 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 consist of the following activities at a minimum: one to two years for development, permitting and major equipment lead-time; and one year for construction.