Chapter 6: Generating Resources and Energy Storage Technologies

SUMMARY OF KEY FINDINGS

Generating resource development will be driven by the need for reliable, economic, and low-carbon energy supplies, supplemented as needed with firm capacity to maintain system reliability and to provide balancing reserves to complement variable-output energy resources.

Economical and reliable low-carbon energy generation resources available in abundance in the near-term (2010 - 2015) include "local"[1] wind and natural gas combined-cycle plants. These technologies are commercially mature, economically competitive and relatively easy and quick to develop. Energy from these resources costs from about $90 - $110 per megawatt-hour[2]. Other low-to-moderate carbon energy generation resources available in the near-term, but in limited quantities include bioresidue energy recovery projects, natural gas and bioresidue cogeneration, conventional geothermal, new hydropower and energy from upgraded existing hydropower projects. These resources are commercially mature and in many cases economically competitive. They are, however, often small and challenging to develop. Solar photovoltaics, while commercially mature, low-carbon, easy to develop, and available in large quantity, is very expensive.

Wind power in the Northwest has relied on the existing surplus of firm capacity and balancing reserves. Continued wind development and other variable-output energy resources (wave power, tidal current power, and solar photovoltaics) will eventually require adding firm capacity and balancing reserves to maintain the reliable operation of the power system. Simple- and combined-cycle gas turbines, reciprocating engine-generators, compressed air energy storage, flow batteries, pumped storage hydropower, and sodium-sulfide batteries can provide firm capacity and balancing reserves. Further analysis is needed to identify the best alternatives for the Northwest for these technologies, as well as transmission operation efficiencies and smart grid opportunities (see Chapter 12 and Appendix K).

In the medium-term (2015 - 2020), remote resources could be accessed via expansions to the transmission system. These include wind from Montana, Alberta or Wyoming and concentrating solar power from Nevada and other Southwest areas. These resources are typically 40 to 100 percent more expensive than comparable local resources because of the transmission investment and low transmission load factor. The "lumpiness," capital cost, and lead time of the transmission adds investment risk to these options.

[1] "Local" wind refers to wind power that does not rely on the development of high-capacity, long-distance dedicated transmission.
[2] Levelized resource costs appearing in this chapter are for 2015 service, unless otherwise indicated. A more complete discussion of resource costs, including cost estimates for years ranging from 2010 to 2030 is provided in Appendix I.

Conventional coal plants are unlikely to be developed in the near-term because of state CO_2 performance standards and climate policy uncertainty. Additional resources available long-term (2020 - 2030) include advanced nuclear and coal gasification combined-cycle plants. Emerging technologies such as wave power, tidal current power, enhanced geothermal, deep water wind turbines, compact nuclear plants, commercial-scale carbon sequestration, and technologies that capture carbon from steam-electric coal-fired plants may become commercial during this decade.

Construction costs increased 60 to 100 percent between 2004 and mid-2008, driven by increased commodity costs, the declining value of the dollar against overseas currencies, and market incentives for wind and other renewable technologies. The weakening global economy and the difficulty in securing credit has reversed this trend and costs are declining for most technologies. Future costs, however, are highly uncertain. Significant risks associated with power generation include natural gas price volatility and uncertainty (combined-cycle plants), greenhouse gas control policies (coal-fired plants), plant size and lead time (geothermal, nuclear, coal gasification plants, and transmission for importing wind or solar), and technology performance (coal gasification, advanced nuclear plants).

Climate policies will increase the cost of fossil-fueled power generation in proportion to fuel carbon content and plant efficiency. Estimated increases under the mean forecast carbon dioxide allowance prices range from about 20 percent ($18 per megawatt-hour) for gas combined-cycle plants to 40 percent ($42 per megawatt-hour) for coal steam-electric plants.[3] While carbon dioxide separation and sequestration could reduce the cost of compliance, current estimates of the cost and performance of plants so equipped suggest that these features would not be economic compared to other resource alternatives.

INTRODUCTION

This chapter describes the various generating and energy storage alternatives available to the Northwest to meet needs during the planning period. Additional details regarding these alternatives and assumptions regarding cost, performance, and availability are provided in Appendix I.

Electricity is a high value form of energy produced from naturally occurring primary energy sources. These include the fossil fuels (coal, petroleum, and natural gas), geothermal energy, nuclear energy, solar radiation, energy from solar radiation (wind, hydropower, biomass production, ocean waves, ocean thermal gradients, ocean currents, and salinity gradients), and tidal energy.

The energy of these primary resources is captured, converted to electricity, and delivered to the end-user by means of energy conversion systems. An energy conversion system may include fuel extraction, fuel transportation and fuel processing, power generation, and transmission and distribution stages. Most power generation technologies are mechanical devices that capture the energy contained in heated, pressurized or moving fluids, and use this energy to drive an electric power generator. Exceptions include fuel cells (solid-state devices that convert the chemical energy of hydrogen into electric power) and photovoltaics (solid-state devices that convert solar radiation to electric power).

[3] Values are for 2015 service.

Many primary forms of energy are found in the Northwest, including various types of biofuel, coal, geothermal, hydropower, marine energy resources, solar, and wind. Others, including natural gas, uranium, and petroleum are readily transported into the region. The few resources not available in the Northwest include ocean thermal differentials and ocean currents (both insufficient in the Northwest for practical application) and adequate direct normal solar radiation for concentrating solar thermal plants.[4]

This chapter reviews all resources potentially available to meet Northwest electrical needs within the next 20 years; however, only proven resources were further evaluated for the recommended resource portfolio (Chapter 10). The Power Act requires priority be given to resources that are cost-effective, defined as a resource that is available at the estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative.[5] Since resources using reliable, commercially available technologies can meet the region's forecast needs over the 20-year planning period, unproven resources, including those whose availability and quantity is poorly understood or that depend on immature technology were not considered for the portfolio risk analysis. Certain unproven resources, including salinity gradient energy generation, deep water wind power, wave energy, tidal currents, and enhanced geothermal have substantial Northwest potential. Actions to monitor and support development of these technologies are included in this plan.

Energy storage technologies decouple electricity production from consumption and can be used to shift energy from lower value to higher value periods and to provide firm capacity, balancing reserves, and other capacity-related services. Storage technologies that have the greatest value for the Northwest are those that can provide extended (multi-day) energy storage, firm capacity, and balancing reserves. These include compressed-air energy storage, flow batteries, pumped storage hydro, and sodium-sulfur batteries.

Characteristics of potential Northwest generating resources and energy storage technologies are summarized in Table 6-1. The far left column of Table 6-1 lists primary energy resources. The second column shows the leading energy conversion technologies. The third column lists the services available from each resource/technology combination including firm capacity for system reliability, electric energy production, balancing (fast-response) capacity for regulation and load-following, shaping, cogeneration, and polygeneration (production of fuel and other products). The fourth column contains estimates of undeveloped potential in the Northwest. In many cases the available potential is a function of cost; additional resource is available at additional cost. The next column shows the earliest service date for new resources, assuming that project development commences January 2010. Many proposed wind, hydropower, and other projects are at various stages of preconstruction development in the Northwest and could be brought into service prior to the earliest service dates shown. The Reference Capacity Cost column shows the levelized fixed cost of those resources typically used for capacity-related services. The Reference Energy Cost column shows levelized electricity cost for resources primarily used for electricity production. On the far right of the table are listed the principal risks and other issues associated with each resource.

[4] Satellite data suggests that local areas in southwestern Idaho and southeastern Oregon may be suitable for concentrating solar power. Further ground data is needed to confirm this.
[5] Regional Act 3.(4)(A)

Table 6-1: Summary of Generating Resources and Energy Storage Technologies

Resource	Leading Technology	Services	Estimated Undeveloped Potential	Earliest Service	Capacity Cost ($/kW-yr)[6]	Energy Cost ($/MWh)[5]	Key Issues
Renewable Resources							
Hydropower	New projects	Firm capacity Energy	Low hundreds of MWa?	2016	--	$60 and up	Siting constraints Development cost & lead time
	Upgrades to existing projects	Firm capacity Energy Balancing	Low hundreds of MWa?	Project-specific	Project-specific	Project-specific	
Wastewater treatment gas	Reciprocating engines	Firm capacity Energy	7 - 14 MWa	2012	--	$104	Cost (smaller treatment plants)
Landfill gas	Reciprocating engine	Firm capacity Energy	70 MWa	2012	--	$73	Competing uses of biogas
Animal manure	Reciprocating engine	Firm capacity Energy	50 - 110 MWa	2012	--	$80 - $140	Cost Competing uses of biogas
Woody residues	Steam-electric	Firm capacity Energy Cogeneration	665 MWa	2014	--	$88 - $125	Cost CHP revenue Reliable fuel supply
Geothermal	Binary hydrothermal	Firm capacity Energy	370 MWa	2017	--	$81	Investment risk (Exploration & well field confirmation)
	Enhanced geothermal	Firm capacity Energy	Thousands of MWa?	Uncertain	--	Not available	Immature technology
Tidal current	Water current turbines	Energy	Low hundreds of MWa?	Uncertain	--	Not available	Immature technology Environmental impacts Competing uses of sites
Wave	Various buoy & overtopping devices	Energy	Low thousands of MWa?	Uncertain	--	Not available	Immature technology Competing uses of seaspace
Offshore Wind	Floating WTG	Energy	Thousands of MWa?	Uncertain	--	Not available	Immature technology Competing uses of seaspace
Solar	Utility-scale Photovoltaic arrays	Energy	Abundant	2013	--	$280	Cost Poor load/resource coincidence Availability and cost of

[6] 2015 service except as indicated; values above $125/MWh rounded. See Appendix I for more detail.

							balancing services
Solar (Nevada)	Parabolic trough	Firm capacity Energy	600 MWa/500kV circuit	2015	--	OR/WA $230 ID $190	Cost Lack of suitable PNW resource Availability and cost of transmission
Wind (Local)	Wind turbine generators	Energy	OR/WA - 1410 MWa ID - 215 MWa MT - 80 MWa	2013	--	OR/WA $103 ID $109 MT $89	Availability and cost of balancing services
Wind (Alberta)		Energy	760 MWa/+/-500kV DC Ckt	2015	--	OR/WA $140	Availability and cost of balancing services Availability and cost of transmission
Wind (Montana)		Energy	570 MWa/new 500kV Ckt Via CTS Upgrade	2015	--	ID $116 OR/WA $150 OR/WA $130	Availability and cost of balancing services Availability and cost of transmission
Wind (Wyoming)		Energy	570 MWa/500kV Ckt	2015	--	ID $121 OR/WA $150	Availability and cost of balancing services Availability and cost of transmission
Waste Heat							
Waste heat	Bottoming Rankine cycle	Energy	Tens to low hundreds of MW?	2014	--	$63	Suitable host facilities Host facility viability
Fossil Fuels							
Coal	Steam-electric	Firm capacity Energy	Abundant	No CSS 2017 CSS Uncertain	--	No CSS OR/WA $108 (2020) CSS MT > OR/WA via CTS repower $140 (2025)	GHG policy Immature CO_2 separation technology Lack of commercial CO_2 sequestration facility
	Gasification combined-cycle	Firm capacity Energy Balancing Polygeneration	Abundant	No CSS 2017 CSS Uncertain	--	No CSS OR/WA - $118 (2020) CSS MT > OR/WA via CTS repower $140 (2025)	Investment risk Reliability GHG policy Lack of commercial CO_2 sequestration facility
Petroleum coke	Gasification combined-cycle	Firm capacity Energy Balancing	Abundant	No CSS 2017	--	No CSS WA/OR - $120	Investment risk Reliability GHG policy

		Polygeneration		CSS Uncertain		(2020) CSS MT > OR/WA via CTS repower $140 (2025)	Lack of commercial CO_2 sequestration facility
Natural gas	Combined-cycle gas turbine	Firm capacity Energy Balancing Cogeneration	Abundant	2014	Baseload increment $166 Duct-firing increment $113	Baseload $87 Duct-firing increment $117[7]	Gas price volatility & uncertainty
	Aeroderivative gas turbine	Firm capacity (fast-start) Balancing Cogeneration	Abundant	2012	$164	$130	Gas price volatility & uncertainty
	Frame gas turbine	Firm capacity Balancing Cogeneration	Abundant	2012	$134	$140	Gas price volatility & uncertainty
	Hybrid intercooled gas turbine	Firm capacity (fast-start) Balancing Cogeneration	Abundant	2012	$164	$125	Gas price volatility & uncertainty
	Reciprocating engine	Firm capacity (fast-start) Energy Balancing Cogeneration	Abundant	2012	$172	$135	Gas price volatility & uncertainty
Nuclear Fission							
Nuclear	Advanced light water reactor	Firm capacity Energy	Abundant	2023	--	$108 (2025)	Public acceptance Cost escalation Construction delays Regulatory risk "Single shaft" reliability risk
	Small modular reactor	Firm capacity Energy Cogeneration	Abundant	Uncertain	--	Not available	Immature technology
Energy Storage							
Electricity	Compressed air energy storage	Firm capacity Balancing Diurnal shaping	Uncertain	Not evaluated	Uncertain & site-specific	--	Confirming suitable geology Monetizing system

[7] 4,000 hours/year.

							benefits
	Flow batteries	Firm capacity Balancing Diurnal shaping	No inherent limits	Uncertain	Uncertain	--	Immature technology Monetizing system benefits
	Pumped storage hydro	Firm capacity Balancing Diurnal shaping	Thousands of MW	2016	$324	--	Project development Monetizing system benefits
	Sodium-sulfur batteries	Firm capacity Balancing Diurnal shaping	No inherent limits		Uncertain	--	Early commercial technology Monetizing system benefits

GENERATING RESOURCE APPLICATIONS & SERVICES

Energy production has been the primary focus of the generating resource assessments of previous power plans because the Northwest's hydropower system is capacity-rich and energy-limited. Increasing demand for balancing reserves[8] to integrate wind power and a prospective firm-capacity shortfall in coming years has broadened to scope of this plan to consider resource capacity as well as energy characteristics. Generation technologies differ in their ability to provide these services and at what cost. Capacity issues are further discussed in Chapter 12.

The principal power system services of significance to long-term planning are energy, balancing reserves, and firm capacity (the ability to contribute to meeting peak load).[9] Some power plants also provide cogeneration (also referred to as combined heat and power or CHP) or polygeneration. A cogeneration power plant simultaneously produces electricity and thermal energy for industrial and commercial processes or for space conditioning. In addition to providing an additional revenue stream, cogeneration increases the thermal efficiency of fuel use and can reduce the net carbon dioxide production and other environmental effects of electricity production. A polygeneration plant produces chemical products (fertilizer and liquid or solid fuel, for example) in addition to electric power.

Energy

Power plants with low variable-production costs are run primarily to produce electric energy (baseload plants). Little can be saved by curtailing their operation, so they are typically dispatched to the extent that they are available for operation. Because non-fuel variable costs are generally a minor element of production costs, baseload units tend to be those with low (or no) fuel costs such as coal, hydropower, geothermal, biogas, wind, solar, and nuclear plants. Natural gas combined-cycle plants, while using a relatively expensive fuel, are very efficient, so they typically operate as intermediate load units, producing energy at times of higher demand and prices, but curtailed during periods of low energy prices. Cogeneration plants, though often using expensive fuel (natural gas or residue biomass), are efficient and normally have a steady thermal load, so they also operate as baseload plants.

The estimated levelized cost of electricity from new generating resources is shown in Figures 6-1A-C. These costs represent the revenue requirements needed to generate and deliver electricity to the wholesale delivery point (substation) of a local utility. The costs include all costs of providing electricity to the end-user except for distribution costs and losses. Distribution costs and losses are credited to conservation in this plan for comparability to generating resource options.

Four elements of delivered wholesale electricity costs are shown in the charts for each resource option: Plant costs – the cost of constructing and operating the power plant; Integration cost –

[8] Balancing reserves provide regulation and load-following to integrate variable-output renewable energy resources. This is also referred to as system flexibility.

[9] In addition to energy, seven capacity related ancillary services are needed to reliably operate a power system and are therefore commercially significant. These include: regulation, load-following, spinning reserves, non-spinning reserves, supplemental or replacement reserves, voltage support, and black start. See Kirby, B. *Ancillary Services Technical and Commercial Insights*, July 2007 for additional discussion.

the cost of balancing reserves for variable resources; Transmission costs – the costs, including cost of losses to deliver the electricity to the utility; and, CO_2 costs – the forecast cost of securing carbon dioxide allowances. Further discussion of the resource cost estimates is provided in Appendix I.

Figure 6-1A shows resources that could be brought into service in the near-term (2010-14). These include resources with short development and construction lead times such as wind and simple-cycle gas turbines, and longer-lead time plants such as geothermal and new hydropower for which development work[10] is underway. The costs shown in the figure are for projects entering service in 2015 (in 2006 dollar values).

Figure 6-1B includes additional resources that could be brought into service in the mid-term period (2015-19). These include remote wind and solar resources that need new long-distance transmission, and technologies such as coal-fired steam-electric and gasification plants, needing a long time to develop and construct. Although illustrated in the chart for comparative purposes, the coal-fired options are currently precluded by Montana, Oregon, and Washington carbon dioxide performance standards and the Idaho moratorium on coal-fired generation. The costs in the figure are for projects entering service in 2020 (in 2006 dollar values). The effects of forecast technological improvements and fuel prices on the relative cost of certain resources are evident in this and in Figure 6-1C. Several resource alternatives with low and stable costs that appear in Figure 6-1A have been omitted from Figure 6-1B for clarity.

Figure 6-1C shows resources that could be brought into service in the long-term period (2020-29). Nuclear plants and commercial-scale carbon dioxide sequestration facilities using depleted oil and gas fields are assumed to be available by this period. Carbon dioxide sequestration facilities using depleted oil and gas fields could be located in Montana, Wyoming or Saskatchewan and accessible to coal-fired plants located in eastern Montana via high-pressure carbon dioxide pipelines. This could offer the possibility of repowering the Colstrip Transmission System (CTS) with wind power or with coal gasification plants with carbon dioxide separation (Colstrip 1 and 2 will have been in service for 50 years by 2025). The costs shown in the figure are for projects entering service in 2025 (in 2006 dollar values). As in Figure 6-1B, low-cost resource alternatives with relatively stable costs have been omitted for clarity, as have more costly versions of competing technologies (e.g., sub-critical coal steam technology has been omitted in favor of ultra-supercritical technology, for example). These are fully described in Appendix I.

Although the levelized energy costs shown in the figures are often used for initial comparison of resources, evaluating resources for acquisition must consider the needs and characteristics of the system using the resource, the capacity and energy services provided by the resource, and the costs and risks incurred acquisition and operation of the resource. These factors are considered in the resource strategy (Chapters 9 and 10).

[10] "Development" is used in this chapter as the process of preparing to construct a power plant, including site selection; feasibility assessment; environmental, geotechnical and resource assessment; permitting; and preliminary engineering. Project development is generally akin to the resource optioning process referred to elsewhere in the plan.

Figure 6-1A: Levelized Lifecycle Electricity Cost for Generating Options Available in the Near-term (2010-14) [11]

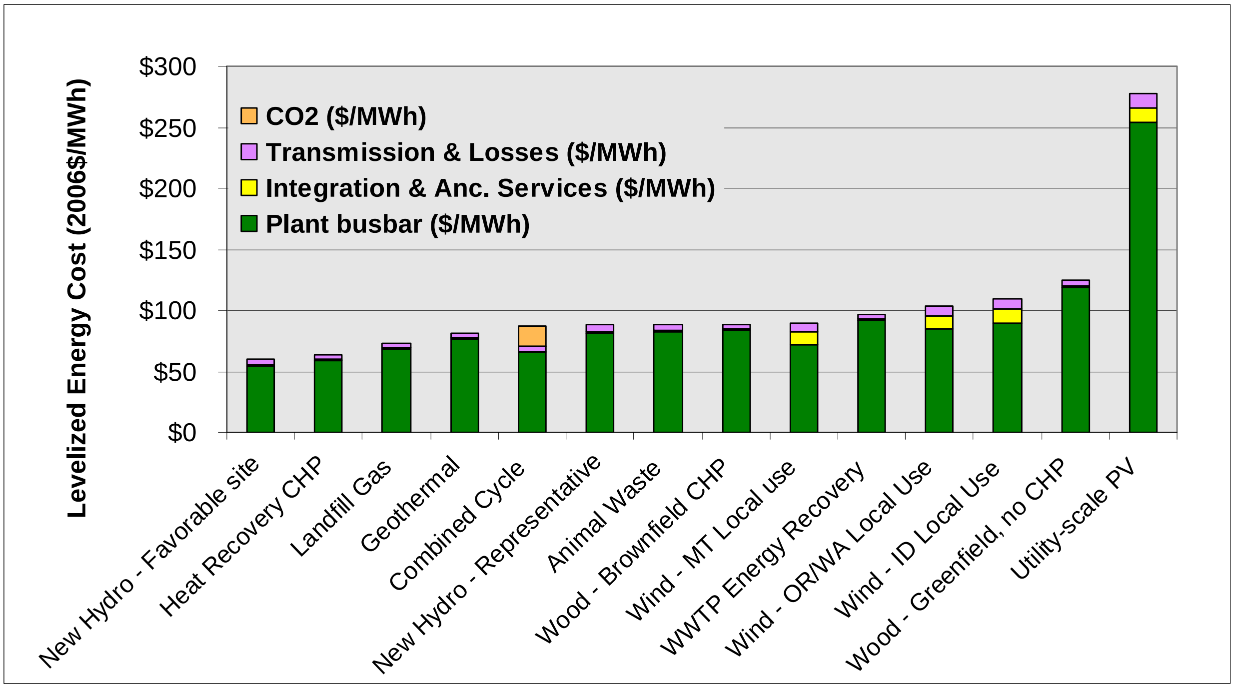
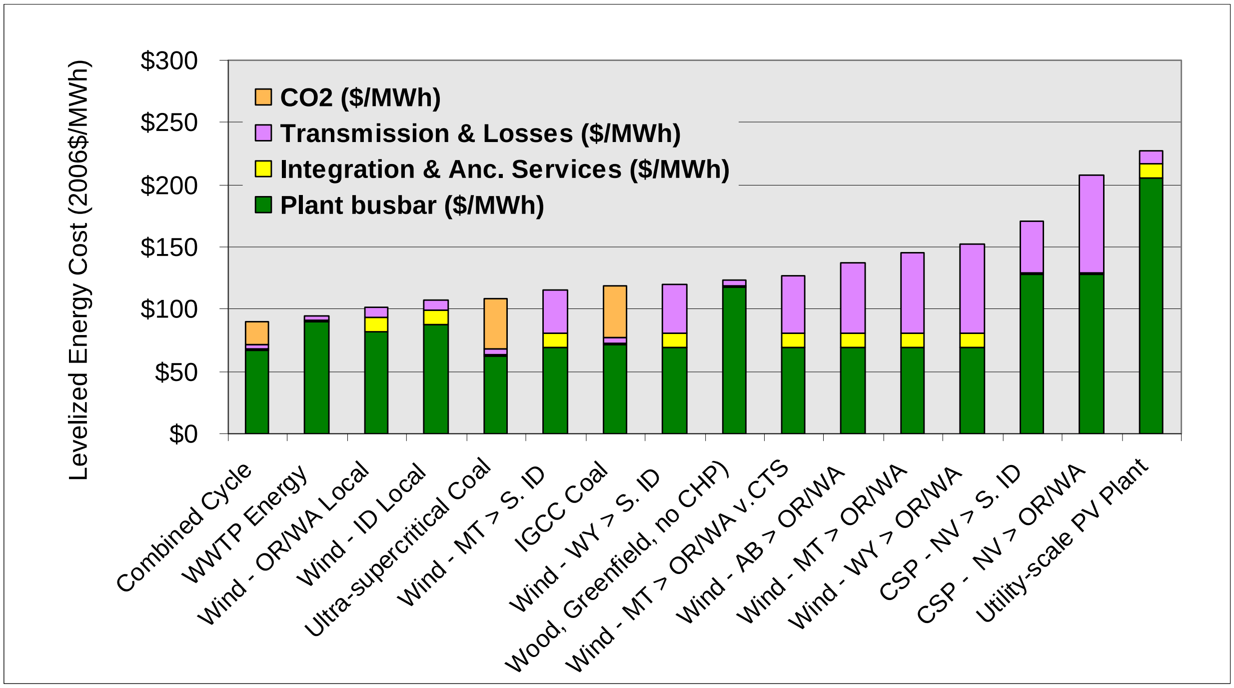
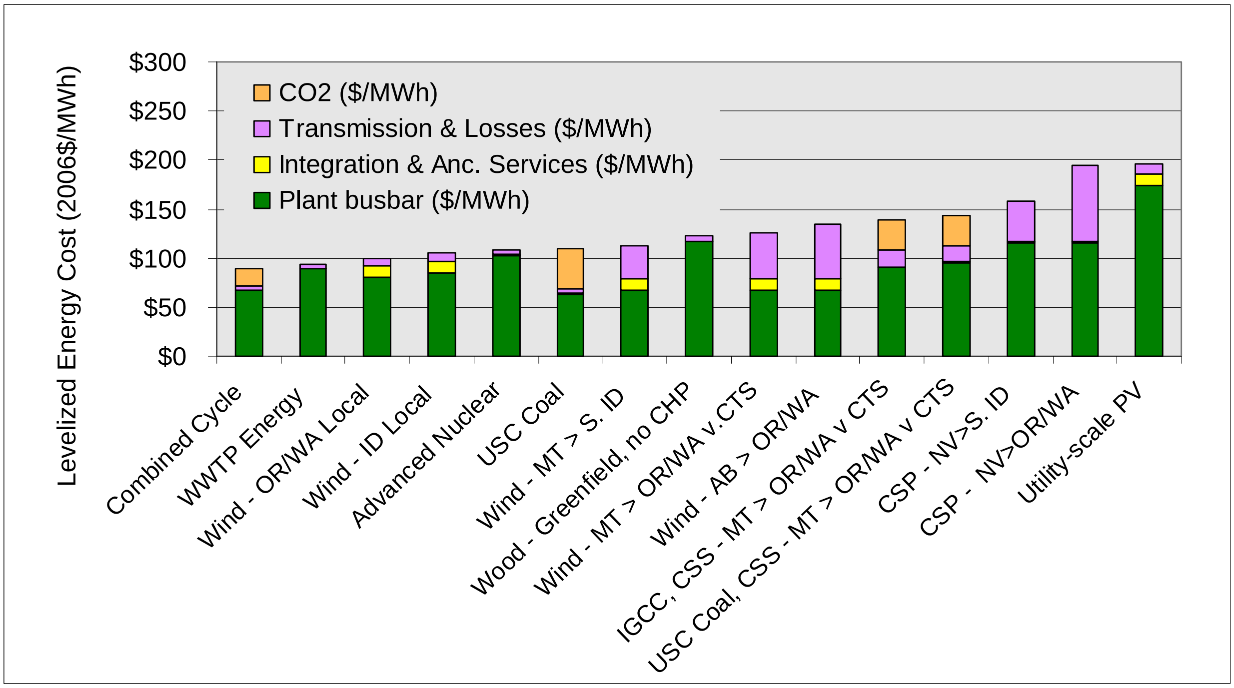


Figure 6-1B: Levelized Lifecycle Electricity Cost for Generating Options Available in the Mid-term (2015-19)[12]



[11] Assumptions: 2015 service, investor-owned utility financing, medium fuel price forecast, wholesale delivery point. CO_2 allowance costs at the mean values of the portfolio analysis. Incentives excluded, except accelerated depreciation. Actual project costs may differ because of site-specific conditions and different financing and timing.
[12] Assumptions as in Figure 6.1A except 2020 service.

Figure 6-1C: Levelized Lifecycle Electricity Cost for Generating Options Available in the Longer-term (2020-25)[13]



Firm Capacity

With the exception of wind and other variable-output resources, most power plants provide firm capacity to meet peak load and provide contingency reserves.[14] In general, non-variable plants can provide capacity up to their net installed capacity less an allowance for forced (unscheduled) outages, though in some cases, contractual, fuel, permitting, and environmental conditions may limit the firm capacity contribution.

Some resources are developed primarily to provide firm capacity. Because they are operated infrequently, variable cost is less important than fixed costs. Also, units intended for peaking service may need rapid startup and load-following ability to avoid displacing generation with a lower variable cost. A comparison of the fixed costs of several resources typically developed for capacity is provided in Figure 6-2. In the case of the combined-cycle option, the cost shown is the incremental cost of duct firing. Duct firing is an inexpensive option for increasing plant output (though at some sacrifice of efficiency) and is usually provided on combined-cycle units. But duct firing capability is limited and other capacity resources are sometimes needed.

As with levelized energy cost estimates, the levelized capacity cost estimates of Figure 6-2 is not the sole criterion for choosing among these options. The technologies shown have different attributes, possibly leading to different choices depending on needs. Aeroderivative and intercooled gas turbines and reciprocating engines, for example, have very rapid start times (less than 10 minutes), allowing them to provide "spinning" reserve, even when shut down. Duct firing and intercooled gas turbines require cooling water, whereas other types of simple-cycle gas

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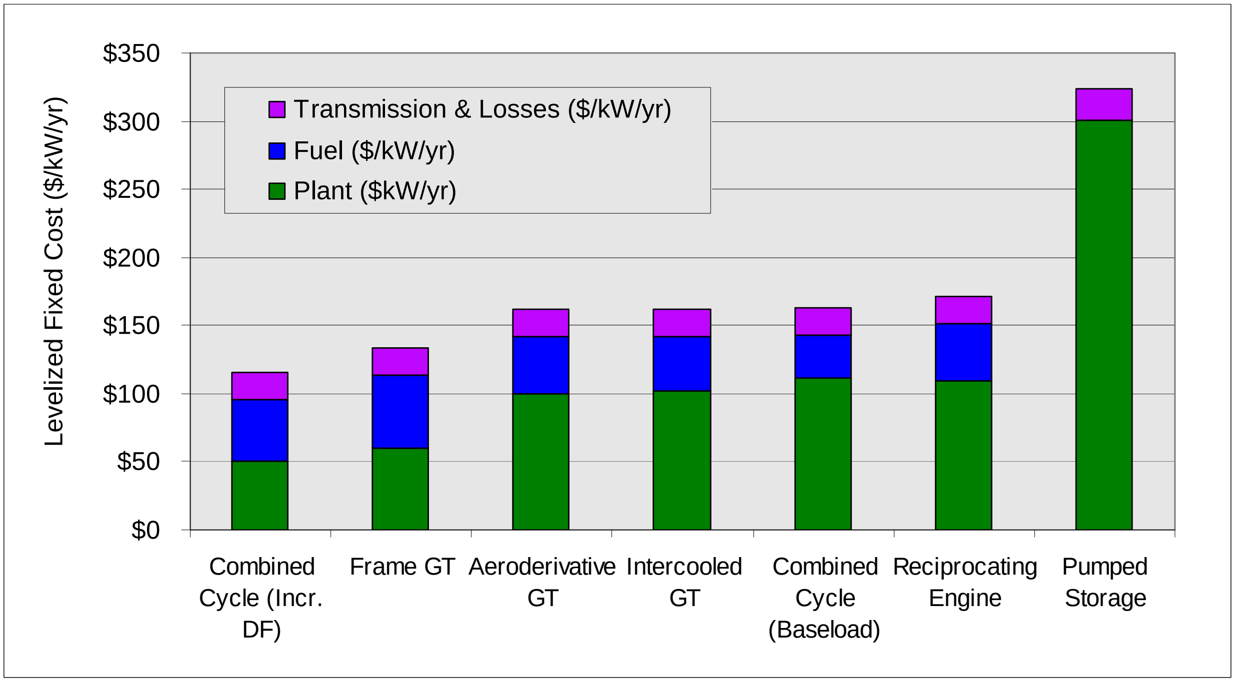
[13] Assumptions as in Figure 6.1A except 2025 service.
[14] Capacity held for use in case of a contingency event such as unplanned loss of generation.

turbine and reciprocating units require very little water, a factor of importance in arid regions. Reciprocating engines and intercooled gas turbines have attractive "turndown" characteristics, meaning that plant operating efficiency remains high even at very low loading. Moreover, anticipated operating conditions can affect fixed costs. Gas turbines, if located in a non-attainment area may need expensive air emission controls.

Figure 6-2: Fixed Cost of Commercially-available Firm Capacity Options[15]



Regulation and Load-following

The large amount of wind power added to the Northwest's power system has increased demand for regulation and load-following services. Regulation is the continuous balancing of generation to load on a second-to-second basis and is typically supplied by fast-response generating units equipped with automatic generation control. Hydropower units are normally used to provide regulation in the Northwest. Though wind power at low penetration does not significantly increase the net second-to-second variability of load and generation, incremental variation is introduced as wind penetration increases. However, the incremental demand for regulation introduced by wind, even at high penetration levels is relatively small compared to the incremental increase in load-following requirements.

Load-following services make up the difference between scheduled (forecasted) generation and actual load. Load-following is currently provided by operating capacity set to provide either upward (incremental) regulation ("Inc") or downward (decremental) regulation ("Dec"). The need to prepare for unpredicted rapid upward and downward ramps in wind output is increasing demand for load-following capability.

[15] 2015 service.

A related service is shaping. Shaping involves the shifting of energy from low value off-peak hours to higher value on-peak hours on a diurnal or multi-day basis. Shaping can also be used to level load on transmission lines serving remote renewable resource areas, thereby reducing incremental transmission costs.

Resources suitable for providing regulation and load-following services have rapid and flexible response capability, good turndown characteristics and, ideally, near-market operating costs (to reduce economic losses during load-following operation). Other desirable attributes include siting flexibility and low part-load emissions. Among new generating resources, the most attractive options for supplying regulation and load-following services are combined-cycle gas turbines, aeroderivative and intercooled simple-cycle gas turbines, and reciprocating engines. Long-duration storage technologies including pumped-storage hydro, compressed-air energy storage, flow batteries, and sodium-sulfur batteries offer similar capability.

Because the balancing capability of the existing system may need to be augmented in future years to support expansion of wind and other variable resources, the cost and value of the various options augmenting balancing capability for the Northwest’s system should be explored. Action GEN-6 calls for this effort, which should consider combined-cycle plants, gas turbine generators, reciprocating engines, pumped-storage hydro, compressed-air energy storage, flow batteries, sodium-sulfur batteries, and demand-side options.

Combined Heat and Power

Combined heat and power (CHP or cogeneration) plants produce both electricity and thermal or mechanical energy for industrial processes, space conditioning or hot water. The fundamental attribute of CHP is higher thermodynamic efficiency compared to the separate production of electricity and thermal or mechanical services. Improved efficiency is achieved through higher initial temperatures and pressures and by use of otherwise wasted thermal energy. Typical benefits of CHP include a net reduction in cost, carbon dioxide, and other environmental impacts; improved economic viability of the host facility; improved system reliability; and reduced transmission and distribution-system costs.

CHP includes diverse combinations of fuel, technologies, and applications, making it difficult to characterize a definitive CHP project. Fuel used for CHP includes waste heat from industrial equipment and processes, natural gas, wood residue, biogas, and spent pulping liquor. Technologies include gas turbine generators, combined-cycle power plants, steam-electric plants, and reciprocating-engine generator sets. Several examples of the expected cost of resources and technologies configured for CHP are described in this Chapter and in Appendix I.

About 3,970 megawatts of CHP is installed in the Northwest. About 1,790 megawatts of this capacity is industrial CHP, closely integrated with the host facility and sized to the thermal load. The remaining 2,180 megawatts are utility-scale combined-cycle plants where steam is extracted to serve an “over-the-fence” thermal load. The operation of industrial CHP is generally determined by thermal demand (i.e., the operation of the thermal host), whereas the operation of utility-scale combined-cycle CHP is largely determined by fuel and electricity prices. Fifteen CHP plants, totaling 143 megawatts of capacity, have been constructed in the Northwest since the release of the Fifth Power Plan in 2004. All of these new plants are industrial CHP and most are fueled by bio-residue.

The greatest near-term CHP potential in the Northwest is at energy-intensive industrial facilities and commercial facilities that have large space conditioning and hot water load. While technical potential exists in the commercial and residential sectors, these tend not to be cost-effective given the current technology. A growing CHP application is energy recovery from agricultural and other bio-residue where the reject heat of the generating unit is used to maintain the waste-digester operating temperatures.

A 2004 assessment[16] identified 14,425 megawatts of technical CHP potential for Idaho, Oregon, and Washington.[17] Under "business-as-usual" assumptions (little improvement in technology, no incentives, and standby charges) the economic potential through 2025 was estimated to be about 1,030 average megawatts of energy. No applications using woody biomass residue were considered, nor were any applications involving capturing waste energy such as gas pipeline compressor stations, cement kilns or metal remelt furnaces. These are promising applications and this estimate of economic potential may be low because of these omissions.

Unfortunately, the full benefits of CHP are rarely seen by the individual parties (utility, host facility, developer) involved in the decision to develop CHP. Many of the barriers to CHP stem from these differing perspectives and include:

- The required return on investment of the host facility is often higher than that of a utility.
- Unless participating as an equity partner, the utility sees no return, and a loss of load.
- Limited capital and competing investment opportunities often constrain the host facility's ability to develop CHP.
- Energy savings benefitting the host facility may not be worth the hassle of installing and operating a CHP plant.
- Difficulty establishing a guaranteed fuel supply for wood residue plants.
- Uncertainties regarding the long-term economic viability of the host facility.
- The location value of CHP is often not reflected in electricity buy-back prices.
- The relative complexity of permitting and environmental compliance for small plants.

Actions to help resolve these issues were identified in the Fifth Power Plan. These remain valid and include:

- Routine surveys to identify CHP and small-scale renewable energy resource development opportunities.

[16] Energy and Environmental Analysis, Inc. *Combined Heat and Power in the Pacific Northwest: Market Assessment*, B-REP-04-5427-004. July 2004.
[17] CHP opportunities in Montana were not assessed in the Energy and Environmental Analysis study.

- Resource evaluation criteria that fully reflects CHP costs and benefits, including the value of energy, capacity, and ancillary services, avoided transmission and distribution costs, and losses and environmental effects.
- Eliminating disincentives to utility acquisition of power from customer-side projects such as the inability of investor-owned utilities to receive a return on investment in generation owned or operated by others.
- Uniform interconnection agreements and technical standards.
- Equitable standby tariffs.
- Provisions to allow the sale of excess customer-generated power through the utility's transmission and distribution system.

Distributed Generation

Distributed generation is located at or near electrical load. Distributed generation can provide: standby power for critical load; regulation of voltage or frequency beyond grid standards; cogeneration; local voltage support; an alternative to expanding transmission or distribution capacity; service to remote load; peak shaving to reduce demand charges; and an alternative source of supply for times of high power prices or system islanding. Distributed energy storage technologies can provide many of the same services and emerging "smart grid" controls can synchronize the operation of numerous individual units to create a virtual large-scale storage facility. The modularity and small-scale of distributed technologies may lead to rapid technological development and cost reduction.

Distributed generation installations are smaller than central-station plants, ranging from tens of kilowatts to about 50 megawatts in capacity. The benefits of distributed generation can best be secured with technologies that are flexible in location and sizing such as small gas-turbine generators, reciprocating-engine generators, boiler-steam turbines, solar photovoltaics, microturbines, and fuel cells. However, distributed generation applications are often uneconomic sources of bulk power compared to central-station generation because of the higher cost of equipment, operation and maintenance, fuel, and their lower thermodynamic efficiency. Still, distributed generation can be an attractive alternative for all the reasons listed earlier.

HYDROELECTRIC POWER

The mountains of the Pacific Northwest and British Columbia experience heavy precipitation, much of which falls as snow, producing large volumes of annual runoff that create the great hydroelectric power resource for the region. The theoretical potential has been estimated to be about 68,000 megawatts of capacity and 40,000 average megawatts of energy. Nearly 33,000 megawatts of this potential capacity has been developed at about 360 projects. Though the remaining theoretical hydroelectric power potential is large, most economically and environmentally feasible sites have been developed. The remaining opportunities are, for the most part, small-scale.

Hydroelectric power is by far the most important generating resource in the Pacific Northwest, providing about two-thirds of the generating capacity and about three-quarters of electric energy on average. The annual average runoff volume, as measured at The Dalles Dam, is 134 million acre-feet but it can range from a low of 78 million acre-feet to a high of 193 million acre-feet. The combined useable storage in U.S. and Canadian reservoirs is only 42 million acre-feet. This means that the system has limited capability to reshape river flows to yield energy better matching the seasonal electricity demand. The Pacific Northwest is a winter-peaking region, yet river flows are highest in spring (during the snow melt) when electricity demand is generally the lowest. Because of this, the region has historically planned its resource acquisitions based on critical hydro conditions, the historical water year[18] with the lowest runoff volume over the winter-peak demand period. Under those conditions, the hydroelectric system produces about 11,800 average megawatts of energy. On average, it produces nearly 16,000 average megawatts of energy, and in the wettest years it can produce over 19,000 average megawatts. For perspective, the annual average regional demand is about 22,000 average megawatts. In order to reflect the important variability of hydroelectric production as water conditions change, the Council's analysis uses a 70-year water record in its analysis.

Existing Hydropower System

The current hydroelectric system has a capacity of about 33,000 megawatts, but it operates at about a 50 percent annual capacity factor because of limited water supply and storage. The Northwest's power supply must be sufficient to accommodate increased demand during a sustained cold snap, heat wave or the temporary loss of a generating resource. The hydroelectric system provides up to 24,000 megawatts of sustainable peaking capacity for the six highest load hours of a day over a consecutive three-day period.

These assumptions for the annual and hourly capability of the hydroelectric system are sensitive to fish and wildlife operations, which have changed in the past and could change in the future. There remain a number of uncertainties surrounding these operations, which could have both positive and negative effects. For example, spillway weirs offer the potential to reduce bypass spill while providing the same or better passage survival. Climate change has the potential to alter river flows, which affect both power production and fish survival. Dam removal or operating reservoirs at lower elevations would further reduce power production.

For the Sixth Power Plan, hydroelectric system capability is based on fish and wildlife operations specified in the 2008 biological opinion. How climate change might affect hydroelectric generation and its impact on the resource strategy is examined via scenario analysis. However, it should be noted that the range of potential changes to hydroelectric generation is relatively small compared to other planning uncertainties.

Integrating Fish & Wildlife and Power Planning

The Power Act requires that the Council's power plan and Bonneville's resource acquisition program assure that the region has sufficient generating resources on hand to serve energy

[18] The water year or hydrologic year is normally defined by the USGS from the beginning of October through the end of September and denoted by the calendar year of the final nine months. The water year of the Columbia River system, however, is modeled from the beginning of September (beginning of operation for reservoir refill) through the end of August.

demand and to accommodate system operations to benefit fish and wildlife.[19] The Act requires the Council to update its fish and wildlife program before revising the power plan, and the amended fish and wildlife program is part of the power plan. The plan then sets forth "a general scheme for implementing conservation measures and developing resources" with "due consideration" for, among other things, "protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival and propagation of anadromous fish."[20]

On average, fish and wildlife operations reduce hydroelectric generation by about 1,200 average megawatts relative to operation with no constraints for fish and wildlife.[21] This energy loss represents about 10 percent of the hydroelectric system's firm generating capability.[22] Bonneville estimates its total financial obligation for the fish and wildlife program to be between $750 to $900 million per year, combining ordinary and capital expenditures, power purchases, and foregone revenues associated with operations to benefit fish and wildlife.

These impacts would definitely affect the adequacy, efficiency, economy, and reliability of the power system if they had been implemented over a short time. However, this has not been the case. Since 1980, the region has periodically amended fish and wildlife related hydroelectric system operations and, in each case, the power system has had time to adapt to these incremental changes. The Council's current assessment[23] indicates that the regional power supply can reliably provide actions specified to benefit fish and wildlife (and absorb the cost of those actions) while maintaining an adequate, efficient, economic, and reliable energy supply. This is so even though the hydroelectric operations for fish and wildlife have a sizeable impact on power generation and cost. The power system has addressed this impact by acquiring conservation and generating resources, by developing resource adequacy standards, and by implementing strategies to minimize power system emergencies and events that might compromise fish operations.

The Council recognizes the need to better identify and analyze long-term uncertainties that affect all elements of fish and power operations. In the action plan, the Council proposes creating a public forum that would bring together power planners and fish and wildlife managers to explore ways to address these uncertainties. Long-term planning issues include climate change, alternative fish and wildlife operations, modifications to treaties affecting the hydroelectric system, and the integration of variable-output resources, in particular how they affect system flexibility and capacity. The forum would provide an opportunity to identify synergies that may exist between power and fish operations and explore ways of taking advantage of those situations.

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[19] For more information please see Appendix M: Fish and Wildlife Interactions.

[20] Northwest Power Act, Sections 4(e)(2), (3)(F), 4(h)(2)

[21] The comparison study, which includes no actions for fish and wildlife, is represented by hydroelectric operations prior to 1980.

[22] Firm hydroelectric generating capability is about 11,900 average megawatts (2007 Bonneville White Book) and is based on the critical hydro year, which is currently defined to be the 1937 historical water year.

[23] See http://www.nwcouncil.org/energy/resource/Adequacy%20Assessment%20Final.doc.

New Hydropower Development

New Hydropower Projects

Though the remaining theoretical hydroelectric power potential is large, most economically and environmentally feasible capacity appears to have been developed. The remaining opportunities for new projects are, for the most part, small-scale. Among these are: adding generating equipment to irrigation, flood control, and other non-power water projects; adding generation to existing hydropower power projects with surplus stream flow; and a few projects at undeveloped sites. A comprehensive assessment of new hydropower potential has not been attempted by the Council since the Fourth Power Plan. In that plan, the Council estimated that about 480 megawatts of additional hydropower capacity was available for development at costs of 9.0 cents per kilowatt-hour or less. This capacity could produce about 200 megawatts of energy on average. Few projects have been developed in the intervening years, and it is likely that the Fourth Power Plan estimate remains representative. Hydropower development costs are sensitive to project configuration, size, and site characteristics. A review of recent projects shows costs ranging from $65 to over $200 per megawatt-hour and a weighted average cost for committed and completed projects of $88 per megawatt-hour. Demand for low-carbon resources and resources qualifying for state renewable portfolio standards has increased interest in hydropower development, and the Council recommends that current efforts to reassess new hydropower potential be continued to improve understanding of the current cost and potential of the resource.

Upgrades to Existing Hydropower Projects

Renovations to restore the original capacity and energy production of existing hydropower projects, and upgrades to yield additional capacity and energy are often much less costly than developing new projects. Most existing projects date from a time when the value of electricity was lower and equipment efficiency less than now, and it is often feasible to implement upgrades such as advanced turbines, generator rewinds, and spillway gate calibration and seal improvement. Even a slight improvement in equipment efficiency at a large project can yield significant energy. The last comprehensive assessment of regional hydropower upgrade potential was completed more than 20 years ago and many renovations and upgrades have been completed in the intervening years. Much like end-use efficiency, improved technology and higher electricity values are likely to have increased the undeveloped potential even as renovations and upgrades have been completed. Informal surveys suggest that several hundred average megawatts or more are potentially available from renovations and upgrades. The Council recommends that a comprehensive assessment of hydropower upgrade potential be undertaken to gain a better understanding of the cost and potential of this resource.

NON-HYDRO RENEWABLE ENERGY RESOURCES

Biofuel

Biofuel includes combustible organic residue from producing and consuming food, fiber, and materials and fuel from dedicated energy crops. Northwest bio-residue includes woody residue (forest, logging, and mill residue and the biogenic components of municipal solid waste), spent pulping liquor, agricultural field residue, animal manure, food processing residue, landfill gas, and wastewater treatment plant digester gas. Hybrid poplar plantations have the greatest potential for dedicated bio-energy production for the electrical sector in the Northwest, but historically have had greater fiber than fuel value.

Landfills

The anaerobic decomposition of organic matter from landfills produces a low-grade (~450 Btu/scf) combustible gas that largely consists of methane and carbon dioxide. Gas production usually begins one or two years following waste emplacement and may last for several decades. The gas is collected and flared for safety reasons and to reduce its greenhouse gas potential.[24] Increasingly, the gas is used directly as a low-grade fuel, upgraded to pipeline-quality gas, or for on-site power generation. A typical power generation facility consists of gas cleanup equipment and one or more reciprocating engine-generator sets. A common business model is third-party development of the gas cleanup and power generation facilities with purchase of the raw gas from the landfill operator.

Seven landfill gas recovery projects totaling 30 megawatts of capacity are in operation in the Northwest. The estimated feasible undeveloped power generation potential in the Northwest is about 70 average megawatts, representing about 80 megawatts of installed capacity. Because several landfill operators are considering injecting the upgraded gas into the natural gas system, a portion of this potential is unlikely to be available for power generation. The reference 3-megawatt project would operate as a must-run baseload project and produce electricity at an estimated cost of $73 per megawatt-hour. Specific projects will vary in cost due to economies of scale, gas quality, and gas production rates. Barriers to developing landfill gas for power generation include competing uses of the gas, low financial incentives[25], and cost, especially for smaller landfills.

Agricultural and Food Wastes

A combustible gas (largely consisting of methane and carbon dioxide) produced by anaerobic digestion of animal manure, food waste, and similar biogenic organic material can be used to generate power. A typical animal manure or food waste energy-recovery plant uses enclosed slurry-fed anaerobic digesters for gas production and reciprocating engine generators for power generation. Heat recovered from the engine-generator is used to maintain digester temperature and dry the residual fiber for animal bedding or soil amendment. These projects provide must-run, baseload, carbon-neutral electricity from an otherwise wasted resource. The most economically feasible facilities for installing energy recovery are large-scale confined animal feeding operations including dairies, swine and poultry facilities using slurry manure handling. European dry fermentation technology, currently being introduced to North America, could broaden energy recovery to feedlots and other operations using dry manure handling.

At least eight large-scale (0.5 megawatts and larger) animal manure energy recovery projects and one food-processing residue project totaling about 13 megawatts are known to be in operation or under construction in the Northwest. The undeveloped potential, primarily at large-scale dairy operations, is estimated to be 50 to 110 average megawatts. Additional potential might be secured through cooperative facilities serving smaller dairy or food processing operations. Power generation costs vary widely and are sensitive to project size and the type of digester. The

[24] Methane has about 21 times the greenhouse warming potential than the carbon dioxide product of its combustion.
[25] Biogas power generation facilities receive a federal production tax credit of about $10 per megawatt-hour for the first ten years of operation - one-half the credit received by wind projects.

reference cost of electricity is $88/megawatt-hour. Costs might range from $80 per megawatt-hour for a large 2.5 megawatt project (~16,000 head of cattle) to about $139 per megawatt-hour for a 450 kilowatt project (~ 2,900 head). Cost and collecting a sufficient supply of manure or other agricultural waste to support economically feasible projects are the biggest obstacles to growth. Aggregating sufficient biomass for an economically-sized plant, and cost in general, particularly for smaller facilities, are the primary barriers to the growth of food waste as a resource.

Waste Water Energy Recovery

In many wastewater treatment facilities, sludge is processed in anaerobic digesters that produce a moderate quality (600 - 650 Btu/kWh) combustible biogas consisting largely of methane and carbon dioxide. Anaerobic digesters require additional heat for optimal operation, and the common method of disposing of the biogas is to use it as a fuel to maintain digester temperature. Surplus is flared. A more productive alternative is to clean the biogas to use as fuel for a cogeneration plant where the heat from the generating unit is used to maintain digester temperature. Reciprocating engines are typically used for this application.

Nineteen wastewater treatment energy recovery projects totaling 22 megawatts are in operation or under construction in the Northwest. Though an estimate of the remaining regional potential was not located, a 2005 assessment prepared for the Oregon Energy Trust estimated 2 megawatts to 4 megawatts of undeveloped near-term potential for Oregon. Extrapolating this estimate to the region based on population suggests a remaining undeveloped near-term potential of 7 megawatts to 14 megawatts.

The reference plant is an 850-kilowatt reciprocating engine generator fueled by gas from the anaerobic digesters of a wastewater treatment plant. Reject engine heat is captured and used to maintain optimal digester temperatures. The reference cost of electricity is $104 per megawatt-hour with the plant operating in baseload mode (seasonal fluctuations may occur due to wastewater treatment plant loading). Capacity, site conditions, financing, and incentives can lead to wide variation in cost. Electricity production costs might range from about $85 per megawatt-hour for larger (1 - 2 megawatts) installations to $120 for smaller installations. The electricity is typically used to offset treatment plant load so electricity production costs compete with retail rates. Cost for smaller treatment plants is the primary barrier to fully developing the remaining potential.

Woody Residue

The largest source of woody residue in the Northwest has been the forest products industry. Currently, there are 23 projects (with 283 megawatts of capacity) using woody residue as a primary fuel operating in the Northwest, a slight increase since the Fifth Power Plan. Surveys indicate that nearly all woody residue produced in the forest products sector are used for fuel or other purposes. Some undeveloped potential is available by separating the biogenic material from municipal solid waste, but the major new potential is forest thinning residue from ecosystem recovery and wildfire hazard reduction efforts, and from more intensively managed commercial timberlands. This additional woody residue could provide about 90 TBtu of fuel energy annually on a reliable, sustained basis. Its price will vary depending on the source, alternative uses, and prevailing economic conditions; but it is expected to average about $3.00 per million Btu in the near-term. Expected introduction of specialized collection and transportation equipment for bulk low-density fuel should result in an annual average real price reduction, estimated to be 1 percent over the period of the plan.

Conventional steam-electric plants with or without CHP will be the chief technology for electricity generation using wood residue in the near term. A sustained annual region-wide fuel supply of 90 TBtu is sufficient to generate about 665 average megawatts using conventional technology. Modular biogasification plants are under development and may be introduced within the next several years. Modular units would open the possibility of "bringing the plant to the fuel" thereby expanding the potential fuel supply, reducing fuel transportation costs and improving the economics of plant operation.

Two reference plants were characterized: one representing favorable development conditions resulting in relatively low power cost, and a second representing longer-term marginal conditions and consequent higher power costs. Favorable development factors that could reduce project costs include the availability of refurbished equipment, sources of low-cost mill or urban wood residue, CHP revenue, a brownfield site with established infrastructure, low-cost financing, and financial incentives. These factors could result in power production costs of $88 per megawatt-hour, or less, within the competitive range for new generating resources.

The longer-term marginal plant is a 25 megawatt stand-alone unit using conventional steam-electric technology, located at a greenfield site and operating primarily on forest thinning residue. This plant would produce electricity at $125 per megawatt-hour. Capital and fuel costs are both major components of the energy cost.

The principal barriers to developing woody biomass plants include high capital and fuel costs, the availability of CHP load, and ensuring an adequate, stable, and economical fuel supply.

Pulping Chemical Recovery

Chemical recovery boilers recover the chemicals from spent pulping liquor. Lignins and other combustible materials in the spent liquor create the fuel. Recovery boilers--usually augmented by power boilers fired by wood residue, natural gas or other fuel--supply steam to the pulping process. Greater efficiency is possible by producing the steam at high pressure and extracting it at the desired pressures from a steam-turbine generator. When the Fourth Power Plan was prepared, eight of the 19 mills then operating in the Northwest were not equipped for cogeneration. Estimates prepared for that plan indicated that an additional 280 average megawatts of electric power could be produced by installing cogeneration equipment at recovery boilers without it. Mills have closed since then and upgrades have been undertaken at several of the remaining plants, including the recent addition of a 55-megawatt generating plant at the Simpson Tacoma Kraft mill. The remaining Northwest potential has not been recently assessed. Limited capital availability, short pay-back periods, and the uncertain economic conditions in the industry typically constrain development.

Geothermal Power Generation

The crustal heat of the earth, produced primarily by the decay of naturally-occurring radioactive isotopes, may be used for power generation. Conventional hydrothermal geothermal electricity generation requires the coincidental presence of fractured or highly porous rock at temperatures of about 300^{o} Fahrenheit or higher and water at depths of about 10,000 feet or less. The most promising Northwest geologic structure for hydrothermal generation is the basin and range province of southeastern Oregon and southern Idaho. Here, natural circulation within vertical faults brings hot fluid toward the surface. Basin and range geothermal resources have been developed for generation in Nevada, Utah, and California, and recently in Idaho. The 13-megawatt Raft River project in Idaho is the first commercial geothermal power plant in the Northwest. Earlier models of the geology of the Cascades Mountains suggested the presence of large geothermal potential. More recent research suggests that while local hydrothermal systems may exist in the Cascades, geothermal potential for generation outside of these local systems is limited or absent. Moreover, development of much of the Cascades potential would be precluded by land-use constraints. Newberry Volcano (Oregon) and Glass Mountain (California) are the only Cascades structures offering geothermal potential not largely precluded by existing land use. These structures may be capable of supporting several hundred megawatts of geothermal generation.

Conventional Geothermal Power Generation

Depending on resource temperature, flashed-steam or binary-cycle geothermal technologies could be used with the liquid-dominated hydrothermal resources of the Pacific Northwest. A preference for binary-cycle or heat-pump technology is emerging because of modularity, applicability to lower temperature geothermal resources, and the environmental advantages of a closed geothermal-fluid cycle. In binary plants, the geothermal fluid is brought to the surface using wells and passed through a heat exchanger where the energy is transferred to a low boiling point fluid. The vaporized low boiling point fluid is used to drive a turbine generator, then condensed and returned to the heat exchanger. The cooled geothermal fluid is re-injected to the geothermal reservoir. This technology operates as a baseload resource. Flashed steam plants typically release a small amount of naturally occurring carbon dioxide from the geothermal fluid, whereas the closed-cycle binary plants release no carbon dioxide. The reference geothermal plant is a binary-cycle plant consisting of three 13-megawatt units. The estimated cost of electricity from this plant is $81 per megawatt-hour--among the lowest-cost generating resources identified in this plan.

A recent U.S. Geological Survey assessment[26] yielded a mean total Northwest hydrothermal electricity generating potential of 1,369 average megawatts. However, geothermal development has historically been constrained by high-risk, low-success exploration and well field confirmation. Using historical Nevada development rates as guidance, the Council has adopted a provisional estimate of 416 megawatts of developable hydrothermal resource for the period of the plan. This would yield about 375 average megawatts of energy. These assumptions should be revisited at the biennial assessment of the Sixth Power Plan.

Enhanced Geothermal Power Generation

The natural presence of the high-temperature permeable rock and fluid conditions required for conventional geothermal plants at feasible drilling depths is uncommon. Much more common are high-temperature, but insufficiently permeable, formations. Enhanced geothermal systems (EGS)[27] create the necessary permeability by fracturing or other means. EGS technology is one

[26] United States Geological Survey. *Assessment of Moderate- and High-Temperature Geothermal Resources of the United States*, 2008.
[27] Also known as engineered geothermal systems.

of several emerging geothermal technologies[28] that could vastly increase the developable geothermal resource. A 2004 MIT assessment of geothermal potential[29] identified three areas of special EGS interest in the Northwest. Two (Oregon Cascades and Snake River Plain) are unique to the Northwest. The USGS study identified 104,000 average megawatts of EGS potential at a 95 percent confidence level in the four Northwest states. Because EGS technology has not been commercially proven, it is not included among the resources evaluated for the portfolio of this plan. Because of its potential, the Council encourages Northwest utilities to support efforts to develop and demonstrate EGS technology.

Marine Energy

Ocean Currents

The kinetic energy of flowing water can be used to generate electricity by water-current turbines operating on a principal similar to wind turbines. Conceptual designs and prototype machines have been developed and an array of current turbines is being installed in New York City's East River (a tidal current rather than an ocean current application). Turbine energy yield is very sensitive to current velocity and little electrical potential is available from the weak and ill-defined currents off the Northwest coast.

Thermal Gradients

An ocean thermal energy conversion (OTEC) power plant extracts energy from the temperature difference that may exist between surface waters and waters at depths of several thousand feet. OTEC technology requires a temperature differential of about 20 degrees Celsius (36 degrees Fahrenheit). Temperature differentials of this magnitude are limited to tropical regions extending to 25 to 30 degrees of latitude. Ocean thermal temperature differentials in the Northwest range from 0 to 12 degrees Celsius (0 - 20 degrees Fahrenheit,) precluding of OTEC technology.

Salinity Gradients

Energy is released when fresh and saline water are mixed. Conceptually, the energy potential created by fresh water streams discharging to salt water bodies can be converted to electricity. Concepts include osmotic hydro turbines, dilytic batteries, vapor pressure turbines, and polymeric salinity gradient engines. Development of salinity gradient generation is underway in Europe with a focus on osmotic technology. The Norwegian utility Statkraft has completed a 4 megawatt prototype osmotic hydro turbine power plant near Oslo with the intention of developing a commercial-scale plant by 2015. A key to commercialization is reducing the cost of the osmotic membrane. Because the theoretical resource potential in the Northwest is substantial, salinity gradient technology should be monitored and an assessment of Northwest potential undertaken when the characteristics and operating requirements of commercial units become better understood.

[28] Others include "Hidden" hydrothermal resources, supercritical volcanic geothermal, oil and gas co-production and geopressured reservoirs.
[29] Massachusetts Institute of Technology. *The Future of Geothermal Energy*, 2004.

Tidal Energy

Tidal energy originates from the loss of the earth's rotational momentum due to drag induced by the gravitational attraction of the moon and other extraterrestrial objects. The conventional approach to capturing tidal energy is through hydroelectric "barrages" constructed across bays or estuaries. These admit water on the rising tide and discharge water through hydro turbines on the ebb. The extreme tidal range, preferably 20 feet or more, required by this technology precludes their application to very few locations where the landform greatly amplifies the tidal range. Environmental considerations aside, developing economical tidal hydroelectric plants in the Northwest using barrage technology is precluded by insufficient tidal range. Mean tidal ranges in the Pacific Northwest are between 4.5 and 10.5 feet with the greatest mean tides found in bays and inlets of southern Puget Sound. A more promising approach to capturing tidal energy in the Northwest is to use kinetic energy of tide-induced currents to generate electricity by water-current turbines. Intermittent tidal currents of three to eight knots occurring locally in Puget Sound and channels within the San Juan Islands my be sufficient to support tidal current generation. Water current turbine technology is in the demonstration stage of development and several Northwest utilities have secured preliminary permits to explore this potential.

Wave Energy

The Northwest coast is one of the better wave energy resource areas in the world. The theoretical wave energy potential of the Washington, Oregon, and Northern California coast is estimated to be about 50,000 average megawatts. The practical potential will be much smaller because of the competing uses of sea space, environmental constraints, and conversion losses. Nonetheless, the developable potential is likely to be substantial, and could provide the Northwest with an attractive source of low-carbon renewable energy. While highly seasonal and subject to storm-driven peaks (winter energy flux may exceed summer rates by a factor of 20), wave energy is continuous and is more predictable than wind, characteristics that may reduce integration costs. Though it would be impractical to capture the full winter energy flux, the seasonal output of a wave energy plant would generally coincide with winter-peaking regional load. A further attribute of wave energy is its location close to westside load centers.

Numerous and diverse wave energy conversion concepts have been proposed and are in various stages of development ranging from conceptualization to pre-commercial demonstration. It is too early to say which technologies will eventually prove best for particular conditions. Wave energy conversion devices will need to perform reliably in a high-energy, corrosive environment, and demonstration projects will be needed to perfect reliable and economic designs. Successful technology demonstration will be followed by commercial pilot projects that could be expanded to full-scale commercial arrays. Because of potential environmental issues and the competition for sea space from commercial and sport fisheries, wildlife refuges and wilderness areas, shipping, undersea cables, and military exclusion zones, site suitability should be assessed and siting protocols established in advance of large-scale commercial development. An important role of demonstration projects will be to gain understanding of site suitability, potential conflicts, impacts, and remediation measures. Assessments of interconnection and integration requirements are also essential. Northwest utilities are encouraged to support these efforts.

Conversion technology, depth, ambient wave energy, ocean floor conditions, and the distance from shore all affect the cost of this resource. A 2004 estimate of the capital and operating costs and electrical productivity of a 90-megawatt commercial-scale plant using Pelamis wave energy converters optimized to Northwest conditions yields costs of $140 to $270 per megawatt-hour[30] for the first array. Experience and economies of production will reduce costs as installed capacity increases. Given the installation of 1,600 megawatts of wave energy plants globally, an amount appearing feasible by the 2020s, technology learning curves from experience in the wind, solar, and other industries yield expected costs of $80 to $150 per megawatt-hour. Wave energy can compete with other generating resources if costs within the lower portion of this range can be achieved.

Solar

The amount of solar radiation available for electricity generation is a function of latitude, atmospheric conditions, and local shading. The best solar resource areas in the Northwest are the inter-mountain basins of south-central and southeastern Oregon and the Snake River plateau of southern Idaho. On an annual average, these areas receive about 75 percent of the irradiation received in Barstow, California, one of the best U.S. sites.

Because of its strong summer seasonality, the Northwest solar resource has potential for serving local summer-peaking load, such as irrigation and air conditioning, but is less suitable for serving general regional load which is forecast to continue to be winter-peaking for many years. There have been no comprehensive studies of site suitability for development, though the potential is large.

Solar energy can be converted to electricity using photovoltaic or solar-thermal technologies.

Photovoltaics

Photovoltaic plants convert sunlight to electricity using solid-state devices. Because no combustion or other chemical reactions are involved, power production is emission-free. No water is consumed other than for periodic cleaning. Power output is variable and battery storage or auxiliary power is required for remote load demanding a constant supply. Grid-connected installations require firm capacity and balancing reserves, though balancing reserve requirements may be mitigated by distributing many small plants over a wide geographic area, thus dampening cloud-driven ramp rates.

Photovoltaic technology is commercially established and is widely employed to serve small remote load too costly for grid service. Strong public and political support has led to attractive financial incentives, so despite the high cost and low productivity, grid-connected installations of several hundred kilowatts or more are becoming common in the Northwest. Multi-megawatt, utility-scale installations are appearing in the Southwest where economics are improved by high coincidence of plant output and load.

A low-cost photovoltaic plant employs thin film photovoltaic cells mounted on fixed racks. The energy conversion efficiency and overall productivity of such a design is low and thin film cells suffer from more rapid degradation than more expensive crystalline silicon cell technology. Crystalline silicon cells operate at higher efficiency and are more durable, but they are also more costly. Plant productivity can be improved by mounting cell arrays on tracking devices to improve daily and seasonal orientation. Maximum productivity is achieved by using

[30] Using the reference cost assumptions used elsewhere in this chapter.

concentrating lenses focusing on high-efficiency multi-junction photovoltaic cells with wide spectral response, mounted on fully automatic dual-axis trackers. Concentrating photovoltaic plants operate on direct (focusable) solar radiation, so are best suited for clear southwestern desert conditions.

The reference plant is a 20-megawatt (AC net), utility-scale station employing flat-plate, non-concentrating crystalline photovoltaic cells and single-axis trackers. The direct-current output of the modules is converted to alternating current for grid interconnection. The relatively small size would permit interconnection at distribution system and sub-transmission voltages, facilitating a high degree of modularity and distribution across a wide geographic area. This would help reduce ramping events driven by cloud movement. The reference plant could yield capacity factors up to 26 percent at the best Northwest locations. If constructed in the near-term, this plant would deliver energy at about $280 per megawatt-hour. Costs are expected to continue to decline at the historical average rate of about 8 percent per year.

Solar Thermal Power Plants

Solar thermal power generation technologies (also referred to as concentrating solar power or CSP) use lenses or mirrors to concentrate solar radiation on a heat exchanger to heat a working fluid. The working fluid is used directly or indirectly to power a turbine or other mechanical engine to drive an electric generator. CSP technologies are broadly categorized by the design of the concentrator and the type of thermal engine. The three basic types are parabolic trough, central receiver, and Sterling dish. Parabolic trough plants, the most mature, have been in commercial operation in California since the 1980s. Plants have been recently completed in Nevada and Spain.[31] These plants employ arrays of mirrored parabolic cross-section troughs that focus solar radiation on a linear heat-exchange pipe filled with circulating heat transfer fluid. The hot fluid is circulated through heat exchangers to generate steam to supply a conventional steam-electric power plant. Parabolic trough plants can be equipped with auxiliary natural gas boilers to stabilize output during cloudy periods and to extend daily operating hours. Plants can also be equipped with thermal storage for the same purpose.

Central-receiver plants employ a field of tracking reflectors (heliostats) that direct solar radiation on an elevated central receiver where energy is transferred to a working fluid, usually a molten salt. The hot molten salt is circulated through heat exchangers to generate steam to supply a conventional steam-electric power plant. Molten salt storage tanks are provided to stabilize output during cloudy periods and to extend daily operating hours. Several demonstration plants have been constructed. The first commercial central receiver plant, a 17-megawatt unit, is scheduled for 2011 service in Spain.

A Stirling dish consists of a tracking parabolic mirror that concentrates solar radiation on the heat exchanger of a small Stirling reciprocating engine at the focal point of the mirror. Individual dishes are small, and utility-scale plants would consist of large arrays of individual dish units. Because of the small size of the individual units, Stirling dish technology may benefit from economies of standardization and production. However, Stirling dish technology is not suitable for thermal storage. The technology is in the demonstration stage.

[31] An in-depth source of information regarding parabolic trough solar-thermal plants is at http://www.nrel.gov/csp/troughnet/.

Concentrating solar plants use direct solar radiation so are best suited for dry, clear sky locations. Though potentially suitable areas might be found in southern Idaho and southeastern Oregon, the most suitable locations are in the Southwest. The reference plant is a 100-megawatt parabolic trough concentrating solar thermal plant, with thermal storage, located in east-central Nevada in the vicinity of Ely. Power would be delivered to southern Idaho via the north segment of the proposed Southwest Intertie Project and then to the Boardman area via portions of the proposed Gateway West and the Boardman-to-Hemingway transmission projects. One 500 kilovolt transmission circuit could deliver about 1,500 megawatts of capacity and about 530 average megawatts of energy. Because of the time needed to construct the necessary transmission, it is unlikely that a solar-thermal plant would be available for serving Northwest load prior to 2015. A plant coming into service in 2015 could deliver energy to southern Idaho for about $190 per megawatt-hour. The additional cost of new transmission from Idaho would raise the cost of delivery to Oregon or Washington to about $230 per megawatt-hour. Technological improvements and economies of production are expected to result in lower power plant cost.

Solar-thermal technology can provide an abundant alternative source of low-carbon energy. Because they can be fitted with thermal storage and supplementary boilers, parabolic trough and central receiver technologies have the further advantage of providing reliable output through the peak load hours of the day. These technologies are particularly attractive in the Southwest where they can be sited near load at a cost approaching that of competing low-carbon resources. The added cost and investment risk of long distance transmission needed for these plants make them less attractive for the Northwest.

Wind

Northwest wind resource areas include coastal sites with strong but irregular storm-driven winter winds and summertime northwesterly winds. Areas lying east of gaps in the Cascade and Rocky mountain ranges such as the Columbia River Gorge, Snoqualmie Pass, and Marias Pass receive concentrated prevailing westerly winds, occasional wintertime northerly winds, and winds generated by east-west pressure differentials. Favorable winds are also found on the north-south ridges of southeastern Oregon and southern Idaho.

Beginning in 1998 with the 25-megawatt Vansycle Ridge project, commercial wind power has grown to exceed 4,000 megawatts of nameplate capacity, and is now the fourth largest component of the Northwest power system in terms of installed capacity. Though some geographic diversification has occurred, capacity remains concentrated in the area of the Columbia Basin east of the Columbia River Gorge. Nearly 80 percent of the total regional wind capacity is located in a 160 mile corridor from The Dalles, Oregon northeast to Pomeroy, Washington.

The rapid rate of development reflects the fundamental attributes of wind power as an abundant, mature, relatively low-cost source of low-carbon energy with local economic benefits. These attributes, combined with an array of market and financial incentives and strong political support within the Northwest and elsewhere in the WECC region are expected to sustain robust development of Northwest wind power.

Wind power in the Northwest has variable output and little firm capacity and therefore requires supplemental firm capacity and balancing reserves. An existing surplus of balancing reserves and firm capacity within the Northwest has enabled the growth of wind power without the need or cost of additional capacity reserves. However, the concentration of installed wind capacity east of the Columbia River Gorge and within a single balancing area (Bonneville) has led to significant ramping events, putting pressure on Bonneville's ability to integrate additional wind development.

The least cost and quickest solutions to integrating additional wind development appear to be reducing the demand for system flexibility and fully accessing the flexibility of the existing system. Measures such as improved load forecasting, up-ramp curtailment, and sub-hourly scheduling can reduce the amount of flexibility required to integrate a given amount of wind capacity. Longer-term, increasing the geographic diversity of wind development by importing wind from remote areas could also reduce the demand for flexibility. Existing system flexibility, scattered across numerous Northwest balancing areas, can be more fully accessed by developing mechanisms to trade balancing services and by expanding dynamic scheduling capability both within the region and with other load areas. Issues of cost allocation will need to be resolved, especially now that substantial amounts (close to 50 percent of 2008 development) of Northwest wind power is marketed to California customers. Following these steps, new balancing reserves and firm capacity from generation, storage or demand-side sources may be required.

The abundance of compatible wheat and grazing land with good wind resources and available transmission has minimized environmental conflicts. As these prime sites are developed and pressure to geographically diversify wind development increases, environmental conflicts may become more common. Identifying sensitive areas and establishing transparent and comprehensive permitting criteria and procedures will help avoid potential conflicts.

The Council assessed the cost and potential for continued wind development to meet local needs in the Columbia Basin, Southern Idaho, and Montana. The Council also examined the cost of importing wind energy to Northwest load centers from Alberta, Montana, and Wyoming wind resource areas. It is unlikely that wind power from Alberta, Montana, or Wyoming would be available to serve Oregon or Washington load prior to 2015 because of the time needed to construct the necessary transmission. These options are summarized in Table 6-2.

Table 6-2: Cost and Availability of New Wind Power (2015)[32]

Resource	Limiting Factor	Capacity (MW)	Energy (MWa)	Cost ($/MW/hr)
Local Montana	20% peak load penetration	215	80	$89
Columbia Basin > PNW Westside	Transmission at embedded cost	4060	1300	$104
Other local OR/WA	20% peak load penetration	340	110	$104
Local Southern Idaho	20% peak load penetration	725	215	$109
Montana > ID	New 500kV AC transmission	1500/circuit	570	$116
Wyoming > ID	New 500kV AC transmission	1500/circuit	570	$121
Montana > OR/WA via CTS Upgrade	Upgrade potential of Colstrip Transmission System	659	244	$128
Alberta > OR/WA	New +/-500kV DC transmission	2000/circuit	760	$138
Montana > OR/WA	New 500kV AC transmission via S. ID	1500/circuit	570	$147
Wyoming > OR/WA	New 500kV AC transmission	1500/circuit	570	$154

To conserve model setup and run time, the four "local" wind resource blocks were consolidated into a single block for the resource portfolio model. For similar reasons, the Montana to Oregon/Washington case was selected as representative of imported wind.[33]

WASTE HEAT ENERGY RECOVERY

Certain industrial processes and engines reject energy at sufficient temperature and volume to justify capturing the energy for electricity production, a process known as recovered energy generation (REG), a form of cogeneration. "Waste heat" is a third priority resource in the Regional Act.[34] Candidate sources of high and medium-temperature waste heat include: cement kilns, glass furnaces, aluminum smelters, metals refining furnaces, open hearth steel furnaces, steel heating furnaces, hydrogen plants, waste incinerators, steam boiler exhaust, gas turbines and reciprocating engine exhaust, heat treating and annealing furnaces, drying and baking ovens, and catalytic crackers. While many of these facilities are usually equipped with recuperators, regenerators, waste-heat recovery boilers, and other devices to capture a portion of the reject heat, bottoming-cycle cogeneration could also be installed on some of them. Recovered energy generation is attractive because of its efficiency, baseload operation, and little, if any, incremental air emissions or carbon dioxide production. Heat recovery boilers with steam-turbine generators are the conventional approach to using waste heat for electric power generation. However, small-scale, modular organic Rankine cycle power plants (Ormat and others) suitable for lower-temperature energy sources have expanded the potential applications for recovered energy generation.

The reference plant is a 5-megawatt organic Rankine-cycle generating unit using exhaust gas from the mechanical drive gas turbines of a natural gas compressor station. This unit would operate in baseload mode with some fluctuation due to seasonal variation in gas flow (coincident

[32] Estimates of capacity and energy are of delivered potential, incremental to installed capacity operating or under construction as of end of 2008.

[33] A review of the cost estimates following this initial portfolio run suggested that Alberta wind has potential as the least-cost imported wind option for Oregon and Washington load. Because of the larger incremental size of imported Alberta wind (2,000 MW vs. 1,500 MW), further analysis is needed to confirm the least-risk/least cost imported wind option.

[34] Northwest Power Act, Section 4(e)(1).

with regional electrical load). At $63 per megawatt-hour, electricity from the reference plant would be among the lowest-cost of the new generating resources identified for this plan.

An inventory of potential Northwest opportunities for the development of recovered energy generation was not located; however, such opportunities are known to exist. For example, more than 50 natural gas pipeline compressor stations are located in the Northwest. Recovered energy cogeneration facilities for trunkline compressor station applications are typically about 5 megawatts in capacity, suggesting significant potential. Cement kilns, steel processing facilities, and glass furnaces offer additional possibilities. The potential is sufficiently attractive to warrant an effort on the part of Bonneville and regional utilities to identify and develop them.

FOSSIL FUELS

Coal

Coal resources available to the Northwest include the Powder River basin fields of eastern Montana and Wyoming, the East Kootenay fields of southeastern British Columbia, the Green River basin of southwestern Wyoming, the Uinta basin of northeastern Utah and northwestern Colorado, and extensive deposits in Alberta. Coal could also be obtained by barge from the Quinsam mines of Vancouver Island or the Chuitna mines of Alaska. Mines at Centralia, Washington, have recently closed and the Centralia power plant is now supplied by rail.

Sufficient coal is available to the region to easily support all regional electric power needs through the planning period. Improvements in mining and rail haul productivity have resulted in generally declining constant dollar production costs. Climate policy and overseas demand are the important factors affecting future coal prices. Though carbon dioxide penalties would tend to depress future demand and prices, commercialization of technologies for separating and sequestering carbon dioxide would rejuvenate demand for coal. This plan uses Powder River Basin coal as the reference coal. The minemouth price of Powder River Basin coal is forecast $0.64/MMBtu in 2010, increasing to $0.71 in 2029 (medium case). Transportation adders based on rail costs are used to adjust prices to other locations. Further discussion of fuel prices is provided in Chapter 2 and Appendix A.

Coal is the major source of electricity in the United States as a whole, but constitutes only 13 percent (7,300 megawatts) of generating capacity and about 25 percent of the electric energy supply in the Northwest. Pulverized coal-fired steam-electric plants, though a mature technology, continue to improve by using higher temperatures and more efficient steam cycles. The preferred technology for new North American plants is shifting from subcritical steam cycles with thermal efficiency of about 37 percent to supercritical cycles with thermal efficiency of 37 percent to 40 percent. Ultra-supercritical units with thermal efficiencies of 41 percent to 43 percent are being constructed in Europe and Asia and have been proposed in the United States.

Continuing to use coal for power generation will hinge on efforts to reduce carbon dioxide production. While abundant in the United States, coal has the highest carbon content of all the major types of fossil fuel.[35] Moreover, conventional coal-fired plants operate at a lower

[35] The carbon content of petroleum coke is somewhat greater than that of coal.

efficiency than gas-fired plants. Despite the relatively small penetration of coal capacity in the Northwest, coal combustion is responsible for 85 percent to 90 percent of the carbon dioxide from the Northwest electricity sector. Reducing per megawatt-hour carbon dioxide production from coal-fired plants can be achieved by increased thermal efficiency, fuel switching, and carbon dioxide capture and sequestration. For new construction, increasing the efficiency of combustion is the least cost and logical first step to reducing carbon dioxide production. Ultra-supercritical plants, for example, produce about 80 percent of the carbon dioxide of conventional coal-fired units. Switching from sub-bituminous to certain bituminous coals can reduce carbon dioxide production from existing as well as new plants by several percent, but the economics and net impact on carbon dioxide production are case-specific because of coal production and transportation considerations. Co-firing biomass can reduce carbon dioxide production, but the biomass quantities and co-firing percentages are limited. Carbon capture and sequestration will be required to control carbon dioxide releases to the levels needed to achieve proposed greenhouse gas reduction targets if continued reliance on coal is desired. While carbon capture technology for coal gasification plants is commercially available, capture technology for steam-electric plants remains under development. Though legal issues remain, sequestration in depleted oil or gas fields is commercially proven. Suitable oil and gas reservoirs are limited in the Northwest and though other geologic alternatives are potentially available, including deep saline aquifers and possibly flood basalt sequestration, these remain to be proven and commercialized.

Coal-fired Steam-electric Plants

New steam-electric coal-fired power plants increasingly employ supercritical or ultra-supercritical technology utilizing increasingly higher steam pressure and temperature. Fuel prices and variable costs are low, and these plants operate as baseload units. The key challenge to continued use of coal-fired steam-electric technology is developing an economical technology to separate carbon dioxide from the products of combustion and establishing commercial-scale carbon sequestration facilities. One approach to carbon dioxide separation for steam-electric plants is oxy-firing, in which the furnace is supplied with pure oxygen, rather than air for combustion. This would produce a flue gas consisting largely of carbon dioxide and water vapor from which the carbon dioxide could be readily separated. An alternative approach is chemical separation of carbon dioxide from the flue gas of a conventional air-fired furnace. The latter appears to be the leading technology, but is unlikely to be commercially available before 2020.

Because of the lead time required to develop and construct a coal-fired, steam-electric power plant, it is unlikely that a new plant could be placed in service until the mid-term of the planning period. The reference plant for this period is a 450-megawatt supercritical unit. The plant would be equipped with a full suite of criteria air emission[36] control equipment and activated charcoal injection for reducing mercury emissions. Because the technology is not currently commercial, the reference plant is not provided with carbon dioxide separation equipment. The plant could provide firm capacity and energy services and limited balancing reserves. This plant would not comply with Washington, Montana or Oregon carbon dioxide performance standards, and currently could not be constructed in Idaho because of that state's moratorium on coal-fired power plant development. The estimated levelized lifecycle electricity cost for a this plant at an

[36] Emission controlled under the Clean Air act of 1990. These include sulfur dioxide, nitrogen oxides, particulates, hydrocarbons, and carbon monoxide.

eastern Oregon or Washington location is $113 per megawatt-hour, including forecast levelized carbon dioxide allowance costs of $44 per megawatt-hour (2020 service).

By the mid-2020s carbon separation technology for steam-electric plants may be commercially available. Likewise, commercial-scale carbon sequestration facilities may be available, particularly those using depleted oil and gas fields. Also by this time, new steam-electric plants are likely to employ higher-efficiency ultra-supercritical steam conditions. The reference plant for this period is a 450-megawatt ultra-supercritical unit, equipped for removal of 90 percent of flue gas carbon dioxide. This plant could comply with Washington, Montana or Oregon carbon dioxide performance standards and supplement or replace existing coal-fired units. The example is assumed to be a repower of the existing Colstrip transmission system. The estimated levelized lifecycle electricity cost is $143 per megawatt-hour, including transmission costs of $16 per megawatt-hour and carbon dioxide sequestration and residual allowance costs of $31 per megawatt-hour (2025 service). Electricity from this plant would be much more expensive than the forecast cost of power from a gas combined-cycle plant without carbon separation; however, the coal plant would not bear fuel price volatility risk associated with natural gas-fired generation.

Coal-fired Gasification Combined-cycle Plants

Pressurized fluidized-bed combustion and coal gasification technologies allow the application of efficient gas turbine combined-cycle technology to coal-fired generation. This reduces fuel consumption, improves operating flexibility, and lowers carbon dioxide production. Of the two technologies, coal gasification is further along in commercial development and offers the benefits of low-cost mercury removal, superior control of criteria air emissions, optional separation of carbon for sequestration, and optional co-production of hydrogen, liquid fuel, or other petrochemicals. Several coal gasification project proposals were announced in North America during the early 2000s. However, escalating costs and refined engineering indicating that non-carbon emissions and plant efficiency would not be significantly better than supercritical steam electric plants has dampened enthusiasm. Uncertainties regarding the timing and magnitude of greenhouse gas regulation and the availability of carbon sequestration facilities have further clouded the future of these plants and only a handful of proposals remain active.

Because of the lead time required to develop and construct a coal gasification combined-cycle power plant, it is unlikely that a new plant could be placed in service until the mid-term of the planning period. The reference plant is a 623 megawatt integrated coal-fired gasification combined-cycle plant using an oxygen-blown Conoco-Philips gasifier, sulfur recovery, particulate filters, and carbon bed mercury control. The Conoco-Philips technology is thought to be suitable for sub-bituminous Powder River Basin coal, and could also be fired with bituminous coal or petroleum coke. The clean synthesis gas supplies a gas turbine combined-cycle power generation plant that would provide firm capacity, energy, and balancing reserves. This plant would not comply with Washington, Montana or Oregon carbon dioxide performance standards, and currently could not be constructed in Idaho because of that state's moratorium on coal-fired power plant development. The estimated levelized lifecycle electricity cost for an eastern Oregon or Washington location is $118 per megawatt-hour, including forecast levelized carbon dioxide allowance costs of $41 per megawatt-hour (2020 service).

The reference IGCC plant for the long-tem is equipped to remove 88 percent of flue gas carbon dioxide. This plant could comply with Washington, Montana or Oregon carbon dioxide performance standards and supplement or replace existing coal-fired units. The representative plant is a repower of the existing Colstrip transmission system. The estimated levelized lifecycle electricity cost is $121 per megawatt-hour, including transmission costs of $17 per megawatt-hour and carbon dioxide sequestration and residual allowance costs of $31 per megawatt-hour (2025 service).

Natural Gas

Natural gas is a mixture of naturally occurring combustible gases, including methane, ethane, propane, butane, isobutene, and pentanes found in porous geologic structures, often in association with petroleum or coal deposits. Raw natural gas is recovered by means of wells, and is processed to remove the condensable fractions (propane, butane, isobutene and pentanes), carbon dioxide, water, and impurities. The resulting product, consisting of methane (~90 percent) and ethane is odorized and compressed for transport by pipeline to markets. The "natural" natural gas supply can be slightly augmented with methane recovered from landfills and from anaerobic digestion of organic wastes. Methane can also be synthesized from coal.

Natural gas is a valuable energy resource because of its clean-burning properties, ease of transportation, low carbon dioxide production and diversity of applications. Gas is used directly for numerous residential, commercial, and industrial end uses and to produce electricity using steam, gas turbine, and reciprocating engine technologies. Natural gas is also the principal feedstock in the manufacture of ammonia and ammonia-based fertilizers.

Low natural gas prices and the development of efficient, low-cost, environmentally attractive gas-fired combined-cycle power plants led to a surge of construction early in the 1990s and again following the 2000/2001 energy crisis. Natural gas power plants represent about 16 percent (9,100 megawatts) of Northwest generating capacity. Of this, 6,960 megawatts are combined-cycle units, 1,830 megawatts are peaking units, and 350 megawatts are industrial cogeneration units.

Natural Gas Supply and Price

Though natural gas has been produced in Montana, and to a limited extent in local areas west of the Cascades, the Pacific Northwest does not have significant indigenous gas resources. Rather, gas is imported by pipeline from the Western Canada Sedimentary Basin of Alberta and British Columbia, the Rocky Mountain Basin of Wyoming and Colorado, and the San Juan Basin of New Mexico. Rising natural gas prices following the energy crisis of 2000-01 prompted interest in constructing liquefied natural gas (LNG) terminals to secure access to lower-cost overseas supplies. Interest in LNG facilities has waned because of declining gas prices due to falling demand, expansion of unconventional sources such as coal-bed methane and tight formations, and new conventional discoveries in British Columbia.

Worldwide, the proven reserves-to-production ratio of natural gas has declined in recent years, from a recent high of about 68 years in 2001 to 60 years in 2008.[37] With limited LNG-transfer capacity, North America is largely a self-contained market with a much lower reserves-to-production ratio, about 10 years. However, a significant amount of natural gas remains undiscovered and reserves have trended upward for many years, more than offsetting increasing

[37] BP *Statistical Review of World Energy*, June 2009.

consumption.[38] New sources of supply, including "Frontier Gas" from the Alaskan North Slope and the McKenzie Delta, unconventional sources such as coal bed methane and tight sands, U.S. and Canadian offshore fields, and LNG are expected to make up shortfalls and set North American marginal prices in the long-term. Natural gas delivered on a firm basis to a power plant east of the Cascades is forecast to increase from $4.48/MMBtu in 2010 to $7.72/MMBtu in 2029 in the medium case (about 2.2 percent/year in constant 2006 dollars). Westside prices are expected to run about 50 to 60 cents per MMBtu higher. Unpredictable periods of price volatility are likely to occur during this period. The natural gas price forecast is further discussed in Chapter 2 and Appendix A.

Natural Gas Generating Technologies

Natural gas and liquid petroleum products are the most flexible of energy resources in terms of technologies and applications. Generating technologies that can be fueled by natural gas include steam-electric plants, gas turbine generators, gas turbine combined-cycle plants, reciprocating engine generators, and fuel cells. Applications run the gamut: base-load energy production, regulation and load-following, peaking, cogeneration, and distributed generation. Gas turbine generators, combined-cycle plants, and reciprocating engines are expected to continue to play a major role in electricity production. Fuel cells and microturbines may see some specialized applications, but appear unlikely to be major players in the near- to mid-term because of cost and reliability issues.

Simple-cycle Gas Turbine Power Plants

Simple-cycle gas turbine power plants (also called gas turbine generators or combustion turbines) consist of one or two combustion gas turbines driving an electric generator. These are compact, modular generating plants with rapid-response startup and load-following capability, and are extensively used for meeting short-duration peak load. A wide range of unit sizes is available, from sub-megawatt to 270 megawatts. Low to moderate capital costs and superb operating flexibility make simple-cycle gas turbines attractive for peaking and grid support applications. Though the inherent operating flexibility of these units is suitable for providing regulation and load following, conventional frame or aeroderivative simple-cycle units are not often used for this purpose because of their relatively low efficiency and the cost of natural gas. Likewise, simple-cycle gas turbines are rarely been used for baseload energy production unless equipped with exhaust heat recovery cogeneration. Higher-efficiency intercooled gas turbines have recently been introduced with the objective of providing regulation and load-following services. All gas turbine generators feature highly modular construction, short construction time, compact size, and low water consumption.[39] Equipment is available to control air emissions to low levels.

Because of the ability of the hydropower system to supply peaking and flexible capacity, simple-cycle gas turbines have historically been a minor element of the Northwest power system. However, simple-cycle gas turbines have been added to the Northwest system in recent years to provide energy during poor water conditions, to support cogeneration loads, to support increasing summer peak loads and to provide regulation and load-following services.

[38] Energy Information Administration. *International Energy Outlook 2008 (DOE/EIA-0484(2008)).* June 2008. Fig. 43.
[39] Larger amounts of water are required for intercooled or cogeneration units and units using air inlet evaporative cooling or water injection for power augmentation or nitrogen oxide control.

Gas turbine generators are generally divided into three classes: heavy-duty industrial machines specifically designed for stationary applications (so-called “frame” machines), “aeroderivative” machines using aircraft gas-turbine engines adapted to stationary applications, and “hybrid” intercooled machines with high part-load efficiency (the GE LMS100) intended for intermediate and load-following applications. Gas turbines for power generation benefit from research driven by military and commercial aircraft applications, and though a mature technology, improvement in gas turbine performance is expected to continue in the coming decades.

The reference frame plant consists of a single 85-megawatt (nominal) capacity unit located at an existing gas-fired power plant site. Natural gas is supplied on a firm gas transportation contract with capacity-release capability. No backup fuel is provided. Air emission controls include water injection and selective catalytic reduction for nitrogen oxide control and an oxidation catalyst for carbon and volatile organic compound reduction. This type of plant would normally serve peak load and provide replacement reserves. The levelized total fixed capacity cost (capital, fuel, O&M, and transmission) for 2015 service is $134 per kilowatt-year.

The reference aeroderivative plant consists of two 45-megawatt (nominal) aeroderivative gas turbine generators located at an existing gas-fired power plant site. Natural gas is supplied on a firm gas transportation contract with capacity-release capability. No backup fuel is provided. Air emission controls include water injection and selective catalytic reduction for nitrogen oxide control and an oxidation catalyst for carbon and volatile organic compound reduction. This type of plant would normally serve peak load. Its rapid startup (less than 10 minute) capability would also allow it to provide rapid-response reserves while shutdown. The levelized total fixed capacity cost (capital, fuel, O&M, and transmission) for 2015 service is $164 per kilowatt-year. Levelized energy cost is estimated to be $130 per megawatt-hour if the plant were operated as a 4000 equivalent full power hour per year intermediate load facility, as might be the case if providing balancing capacity.

The reference intercooled plant consists of a 100-megawatt (nominal) hybrid intercooled gas turbine generator located at an existing gas-fired power plant site. Natural gas is supplied on a firm gas transportation contract with capacity-release capability. No backup fuel is provided. Air emission controls include water injection and selective catalytic reduction for nitrogen oxide control and an oxidation catalyst for carbon and volatile organic compound reduction. The higher efficiency and flatter heat rate curve of this type of plant would allow it to serve intermediate as well as peak load, and economically provide balancing reserves as well as rapid-response and replacement reserves. The levelized total fixed capacity cost (capital, fuel, O&M and transmission) for 2015 service is $164 per kilowatt-year. Levelized energy cost is estimated to be $126 per megawatt-hour if the plant were operated as a 4000 equivalent full power hour per year intermediate load facility, as might be the case if providing balancing capacity.

Reciprocating Engine-generators

Reciprocating-engine generators (also known as internal combustion engines, ICs or gen-sets) consist of a compression or spark-ignition reciprocating engine driving a generator, typically mounted on a frame and supplied as a modular unit. Unit sizes for power system applications range from about 1 to 15 megawatts. Conventionally, reciprocating generators are used for small, isolated power systems, emergency capacity at sites susceptible to transmission outages, and to provide emergency power and black start capacity at larger power plants. Other power system applications include units modified to operate on biogas from landfills or anaerobic digestion of waste biomass, mobile units for emergency service, and "recip farms" installed as a hedge to high power prices during the 2000-2001 energy crisis. On the load side, reciprocating units are permanently installed to provide backup power for hospitals, elevators, and emergency lighting in high-occupancy buildings and other critical load. Except for biogas units, these applications typically use light fuel oil stored on site.

The introduction of more efficient and cleaner reciprocating generators in recent years, coupled with the increasing need for load-following services for wind generation, has increased interest in the use of arrays of gas-fired reciprocating generators to provide peaking and load-following services. A typical installation consists of five to 20 units of 3 to 16 megawatts capacity each. The resulting plant is highly reliable with high efficiency across a wide load range; ideal for load-following. Because the output of reciprocating engines is less sensitive to elevation than gas turbine output, reciprocating units may be advantageous for higher-elevation locations for peaking and load-following applications. Reciprocating units can also be fitted with exhaust, turbocharger, and lube oil heat recovery for low-temperature cogeneration load.

The reference plant consists of 12 8-megawatt units operating on natural gas supplied on a firm gas transportation contract with capacity release capability. Air emission controls include selective catalytic reduction for nitrogen oxide control and an oxidation catalyst for carbon and volatile organic compound reduction. This plant can provide regulation and load-following, contingency reserves, and other ancillary services. The relatively high efficiency (41 percent) allows the plant to economically serve peak and even intermediate loads. The capacity cost of this plant is estimated to be $172/kW-year. Levelized energy cost is estimated to be $135 per megawatt-hour if the plant were operated as a 4,000 equivalent full power hour-per-year intermediate load facility, as might be the case if providing balancing capacity.

Combined-cycle Gas Turbine Power Plants

Gas turbine combined-cycle power plants consist of one or more gas turbine generators provided with exhaust heat recovery steam generators. Steam raised in the heat recovery units powers a steam-turbine generator, increasing the overall thermal efficiency of the plant compared to simple-cycle gas turbines. The reference combined-cycle unit, for example, has a baseload efficiency of 49 percent compared to a full-load efficiency of 36 percent for the reference hybrid intercooled gas turbine. Combined-cycle plants can serve cogeneration steam load (at some loss of electricity production) by extracting steam at the needed pressure from the heat-recovery steam generator or steam turbine. Additional generating capacity (power augmentation) can be obtained at low cost by oversizing the steam turbine generator and providing the heat recovery steam generator with natural gas burners (duct firing). Because the resulting capacity increment operates at somewhat lower electrical efficiency than the base plant, it is usually reserved for peaking operation. Because of their reliability and efficiency, low capital costs, short lead-time, operating flexibility, and low air emissions, gas-fired combined-cycle plants have been the bulk power generation resource of choice since the early 1990s.

The reference plant is a single advanced "H-class" gas turbine generator and one steam turbine generator. The base-load capacity is 390 megawatts with an additional 25 megawatts of duct-firing power augmentation. Fuel is natural gas supplied on a firm transportation contract with capacity-release capability. No backup fuel is provided. Air emission controls include dry low-nitrogen oxide combustors and selective catalytic reduction for nitrogen oxide control and an oxidation catalyst for carbon and volatile organic compound control. Condenser cooling is wet mechanical draft. In the Northwest, this plant would operate in baseload mode during the summer and winter seasons and as a marginal plant during high hydro runoff and low load seasons. The plant could also operate at partial (80 – 90 percent) load to provide regulation and load-following, though at some sacrifice in efficiency. Year-round baseload operation (80 percent of full load capacity) would yield reference energy costs of $92 per megawatt-hour including forecast carbon dioxide allowance costs of $18 per megawatt-hour. More typical operation in the Northwest at capacity factors ranging from 65 percent to 35 percent would result in reference electricity production costs from $97 to $122 per megawatt-hour. Cogeneration revenues could slightly reduce electricity production costs.[40]

Petroleum

Petroleum fuel, including propane, distillate, and residual fuel oils are universally available at prices largely determined by the global market. In general, other than for special uses such as for backup fuel, peaking or emergency service power plants, and power generation in remote areas where its transportability and storability are essential, petroleum-derived fuel cannot compete with natural gas for electric power generation. Forecast prices for petroleum fuel are discussed in Chapter 2 and Appendix A.

Petroleum Coke

Petroleum coke is a carbonaceous solid byproduct of cracking residual fuel oil in a delayed coker to extract higher value products. The supply of petroleum coke is increasing as refineries increasingly crack residual fuel oil to yield higher value products and draw upon lower quality crudes. The Energy Information Administration reports that the refinery yield of petroleum coke has increased from 4.3 percent in 1995 to 5.3 percent in 2008 (as percent of total refinery product slate). Higher purity petroleum coke is used for aluminum smelting anodes, whereas fuel-grade petroleum coke is primarily used for firing cement kilns and power plants. About two-thirds of the merchantable petroleum coke originating in U.S. refineries is exported, primarily to Latin America, Japan, Europe, and Canada. The remainder is gasified in refinery trigeneration plants or marketed to electric power generators, calciners, cement kilns, and other industries. Because of its low ash content and very high heating value (14,000 Btu/lb compared to 8,000 - 8,800 Btu/lb for Power River Basin coal), petroleum coke transportation costs are lower than for coal on a Btu basis. However, petroleum coke is usually priced at a discount to coal because of its typically higher sulfur and metals content. Because refineries can economically dispose of petroleum coke at a loss because of the added value of the lighter products obtained from cracking residual, there is a great deal of pricing flexibility and the discount to coal is highly variable. Further discounting may occur in the future because of the higher carbon content of petroleum coke compared to coal (225 vs. 212 pounds per million Btu). Based on limited available pricing information, the discount to subbituminous coal is about 80 percent.

Gasification combined-cycle plants would be the preferred technology for power generation using petroleum coke because of the superior ability to control sulfur and heavy metals, and in the longer term, to capture and sequester carbon dioxide. Because of possible supply limitations and fluctuating prices relative to coal, it is likely that a plant would be fueled using a blend of

[40] Combined-cycle cogeneration plants normally support a relatively small steam load.

petroleum coke and coal. This plant, however, would not comply with Washington, Montana or Oregon carbon dioxide performance standards.

NUCLEAR

Nuclear power plants produce electricity from energy released by the controlled fission of certain isotopes of heavy elements such as uranium, thorium, and plutonium. Commercial light water reactors used in the United States are normally fueled with a mixture of two isotopes of natural uranium, about 3 percent fissionable U-235 and 97 percent non-fissionable, but fertile U-238. The U-238 is transmuted to fissionable Pu-239 within the reactor by absorption of a neutron. Though reactors using thorium and "bred" plutonium have been developed in anticipation of eventual shortages of natural uranium, it appears that the industry can rely on abundant supplies of natural uranium for the foreseeable future. The price of fabricated nuclear fuel is forecast to be relatively stable, averaging $0.73/MMBtu through the planning period.

Commercial nuclear plants in the United States are based on light water reactor (LWR) technology developed in the 1950s. One unit, the 1,200-megawatt Columbia Generating Station operates in the Northwest. Motivated by improved plant designs, the need for new low-carbon baseload resources and financial incentives of the Energy Policy Act of 2005, nuclear development activity has resumed in the United States following a three-decade hiatus. As of late 2009, developers have submitted applications to the Nuclear Regulatory Commission for combined construction and operating licenses for 27 new units at 17 sites, largely in the southeast. Most proposals are planned for service in the late teens, and construction of the initial units is expected to be contingent on federal incentives. The proposed plants employ evolutionary LWR designs with increased use of passively operated safety systems and factory-assembled standardized modular components. These features should improve safety, reduce cost, and increase reliability.

Work is also underway on developing small modular reactors (SMRs). SMRs are conceived as modular, scalable, largely factory-assembled plants of 25 to 350 megawatts generating capacity. Compared to 1,100 to 1,800 megawatt conventional reactors, the smaller size and modular construction of SMRs are intended to reduce capital cost and investment risk by employing a greater degree of factory assembly, shortening construction lead time and better matching plant size to customer needs through scaling of multiple units. Smaller plant size may also permit greater siting flexibility and cogeneration potential and can benefit system reliability through reduction in "single-shaft" outage risk. Proposed SMR designs offer improved safety through features such as integral construction (all reactor coolant systems contained within a single pressure vessel), below-ground emplacement, and lifetime, factory-installed fuel supplies. The SMR concept is not new or unique - over 50 SMR designs have been proposed - however, the enormous investment and long lead time needed to construct conventional reactor plants plus increasing interest in deploying carbon-free nuclear technology in developing countries has resulted in unprecedented interest in SMR technology. Completion of the first demonstration SMRs is at least a decade away. Designs must be completed, NRC design certification secured, and demonstration projects permitted, financed, constructed and tested.

Nuclear plants could be an attractive source of dependable capacity and baseload low-carbon energy that is largely immune to high natural gas prices and climate policy. However, a new nuclear unit would entail the risks of construction delay, regulatory uncertainty, escalating costs, and the reliability risk associated with a large single-shaft machine. The reference plant is a single 1,100 megawatt advanced-light water reactor unit. The reference cost of power from this unit is estimated to be $108 per megawatt-hour (2025 service). Construction of a new unit in the Northwest would likely require the successful completion and operation of at least one of the proposed new units elsewhere in the United States, established spent-nuclear fuel disposal policy, and aggressive development of equally cost-effective conservation and renewable resources. These conditions would likely preclude operation of a new conventional nuclear plant in the Northwest prior to the early to mid-2020s.

ENERGY STORAGE TECHNOLOGIES

A challenge to increasing the penetration of variable-output renewable resources like wind, solar, wave, and tidal current generation is shaping the variable and not fully predictable output of these resources to meet the power quality standards and load of the power system. One approach is to use dispatchable firm generation like hydropower, which is currently used to integrate wind power in the Northwest. An alternative is energy storage technologies. Energy storage technologies decouple the production and consumption of electricity, and can provide regulation, sub-hourly load-following, hour-to-hour storage and shaping, firm capacity, and other ancillary services. Storage projects located within a renewable resource zone could flatten the output of variable-output generation, thereby increasing transmission load factors and improving the economics of long-distance transmission.

A variety of storage technologies are commercially available or under development, including pumped storage hydropower, compressed air energy storage, numerous types of electrically rechargeable batteries, metal-air batteries, several types of flow batteries, flywheels, electromagnets, and capacitors. For the foreseeable future, only a subset of these have the “bulk” or “massive” energy storage potential needed to integrate utility-scale renewable energy resources.[41] This requires megawatt-scale power ratings, run times of hours and extended charge/discharge capability. The most promising systems include compressed air energy storage, flow batteries, pumped-storage hydropower, and sodium-sulfur batteries.

A common constraint to deploying energy storage systems is that the project developer is unable to capture the full value of the system’s services. The generation, transmission and distribution sectors may each realize benefits, but it is often difficult for the developer of a storage project to fully capture the benefits of his project. No formal market exists in the Northwest for the services provided by energy storage systems, and with one exception,[42] no successful example of non-utility development of a utility-scale storage project is found in the West.

A second constraint is the need for frequent cycling. Amortization of the capital cost of these technologies, which tends to be relatively high, requires that they be employed frequently and for as many services as they are capable of delivering. One reason little pumped storage capacity has been developed in the Northwest, despite favorable sites, is that most of the region does not experience strong daily summer-afternoon peaks in energy use, which would create a daily off-peak/on-peak arbitrage opportunity common to other areas of the country.

[41] Individual units need not be at a megawatt/hour scale. Megawatt/hour scale could be achieved by deploying a large number of responsive grid-connected small-scale units, as for example provided by the aggregate storage capability of a fleet of plug-in hybrid vehicles.
[42] The 40-megawatt Olevenhain - Hodges project near San Diego.

Compressed Air Energy Storage

A compressed-air energy storage (CAES) plant is an early commercial technology that can provide load-following and energy shaping over periods up to several days. "Conventional" compressed air energy storage plants consist of motor-driven air compressors that use low-cost, off-peak electricity to compress air into an underground cavern. During high-demand periods, the stored energy is recovered by releasing the compressed air through a natural gas-fired combustion turbine to generate electricity. The compressed air reduces or eliminates the normal gas turbine compression load, greatly reducing its fuel consumption. A CAES combustion turbine might have a heat rate of 4,000 Btu/kWh compared to the 9,300 - 12,000 Btu/kWh heat rate of a stand-alone simple-cycle gas turbine. The efficiency of the process is further improved by heating the compressed air with the combustion turbine exhaust prior to introducing it to the turbine combustors. The economics of a conventional CAES plant requires sufficient spread between on- and off-peak prices to cover compression and storage losses (about 25 percent) plus the cost of the natural gas used to fire the gas turbine. Economic amortization of the capital cost requires frequent cycling such as that needed to serve a daily summer peak load in a warm climate.

Two compressed-air energy storage plants are currently in operation. The first 290-megawatt plant was placed into operation in Germany in 1978. A 110-megawatt plant using an improved design, including turbine exhaust recuperators, was constructed in 1991 in Alabama. These plants were intended to shift energy from off-peak hours to on-peak hours in power systems with low-cost, coal-fired baseload energy. However, the inherently high degree of flexibility of CAES plants would make them capable of load-following and for shaping the output of wind generation. The Arkansas project has storage capacity for 26 hours of full-load operation, and can ramp from standby to full load in about five minutes. CAES plants located at remote wind resource areas could shape wind project output to improve the transmission load factor. The fast start and rapid ramp rate capability could provide decremental load following capability. High part-load efficiency could provide economic load-following capability compared to conventional simple-cycle gas turbines.

A variety of second generation CAES concepts have been advanced to integrate variable-output renewable resources. Unlike earlier designs, these plants would use standard industrial components, multiple motor-driven compressors, and separate multiple air expansion turbine-generators to improve efficiency, provide additional operating flexibility, and reduce cost. Concepts include a no-fuel adiabatic CAES in which the thermal energy of compression would be stored as a substitute for fuel in the expansion-generation process.

Potential locations are available in the Northwest. Solution-mined salt caverns, excavated hard rock chambers, depleted oil or natural gas fields, or other porous geologic media could be used for the compressed air storage reservoir. Recent proposals for small-scale (~ 15 megawatts) CAES would employ above-ground pressure vessels or buried high-pressure piping, further increasing siting flexibility, though at greater cost.

CAES technology has potential in the Northwest to improve the load factor of transmission used to deliver power from remotely located wind and solar generation, and for within-hour and hour-to-hour load-following and shaping services. An advantage compared to pumped storage hydropower is greater siting flexibility. A disadvantage (except for adiabatic concepts) is the need for natural gas to fire the output generator and the resulting air emissions. The available cost information is not adequate to support a meaningful comparison of CAES with alternatives. Though cost estimates have been published for the various second generation CAES concepts, these are preliminary and suitable only for comparison among CAES alternatives. Moreover, CAES costs are sensitive to geology and storage volume. Second generation demonstration project results and a Northwest feasibility study would be required to accurately fix the relative cost of CAES and other sources of system flexibility.

Flow Batteries

First used in 1884 to power the airship *La France*, flow batteries are a rechargeable battery with external electrolyte storage. The electrolyte is pumped through a stack of electrolytic cells to charge or discharge the battery. External electrolyte storage permits independent scale-up of energy storage capability (governed by storage tank capacity) and power output (governed by cell area and electrolyte transfer rate). Flow batteries are characterized by rapid response, ability to hold charge, and longevity in terms of charge/discharge cycles. Three technologies are under development: vanadium redox, zinc bromine, and polysulfide bromine. Flow batteries offer modularity, sizing flexibility, siting flexibility, and zero emission operation. A potential disadvantage is their relatively low energy density, requiring large electrolyte storage facilities to achieve needed energy storage capability.

Flow battery technology is in the demonstration stage. Several installations up to 500 kilowatt capacity and five megawatt-hour storage capacity are reported in Japan and a 2-megawatt capacity demonstration project is under construction in Ireland. Cycle efficiency is 70 to 75 percent with the potential for improvement. Capital costs are relatively high--one U.S. demonstration plant of 250 kilowatts capacity and 2 megawatt-hours of storage is reported to have cost $4,000 per kilowatt. However, current cost and performance is likely not representative of production units.

Pumped-storage Hydropower

Pumped-storage hydropower is an established commercially mature technology. A typical project consists of an upper reservoir and a lower reservoir connected by a water transfer system with reversible pump-generators. Energy is stored by pumping water from the lower to the upper reservoir using the pump-generators in motor-pumping mode. Energy is recovered by discharging the stored water through the pump-generators operating as turbine-generator mode. Cycle efficiency ranges from 75 percent to 82 percent. Seventeen pumped-storage projects constituting more than 4,700 megawatts of capacity are installed in WECC. One project is located in the Northwest--the 6-unit, 314 megawatt Grand Coulee pumped-generator at Banks Lake. This plant is primarily used for pumping water up to Banks Lake, the headworks of the Columbia Basin Irrigation System.

Most existing pumped-storage projects were designed to shift energy from nighttime low variable-cost thermal units to afternoon peak-load periods on a daily cycle. However, pumped storage can also provide capacity, frequency regulation, voltage and reactive support, load-following, and longer-term shaping of energy from variable-output resources without the fuel consumption, carbon dioxide production, and other environmental impacts associated with thermal generation. Importantly for the Northwest, pumped storage could provide within-hour incremental and decremental response to wind ramping events.

Pumped-storage projects require suitable topography and geologic conditions for constructing upper and lower reservoirs at significantly different elevations within close proximity. Subsurface lower reservoirs are technically feasible, though much more expensive. A water supply is required for initial reservoir charge and makeup. Currently, 13 pumped storage projects ranging in size from 180 to 2,000 megawatts and totaling nearly 14,000 megawatts have been proposed in Idaho, Oregon, and Washington, suggesting no shortage of suitable sites. Construction costs are project-specific. Factors influencing cost include the availability of an existing water body that can be used for one of the reservoirs (usually the lower), storage capacity, and transmission interconnection distance. Though $1,000 per kilowatt of installed capacity is often quoted as a representative cost of pumped storage hydro, a review of available cost estimates suggests that $1,750 to $2,500 per kilowatt[43] is more representative of current construction cost. The principal constraints to pumped storage development are the complexity and lead time of the development process, capital cost, and the recovery of revenues for the services provided.

Sodium-sulfur Batteries

A sodium sulfur battery is a high energy-density high-temperature rechargeable battery consisting of molten sodium and molten sulfur electrodes separated by a ceramic electrolyte. The technology is in the early commercial stage with about 190 installations in Japan, totaling about 270 megawatts capacity. About 9 megawatts of sodium-sulfur battery capacity is installed in the United States. The largest unit in operation is Rokkasho in Northern Japan, a 34-megawatt unit with a 245 megawatt-hours storage capability used to integrate wind power. Advantages of sodium-sulfur batteries include high energy density, high cycle efficiency (89 percent), modularity, siting flexibility in either centralized or distributed configurations. Sodium-sulfur batteries are currently moderately expensive with capital costs in the $2,500 - 3,000 per megawatt range but increasing production rates are expected to lead to cost reductions.

SUMMARY OF REFERENCE PLANT CHARACTERISTICS

Key planning characteristics of the reference power plants are compiled in Table 6-3. Derivation of these values is described in Appendix I. The definitions of the values appearing in the table are as follows:

Plant size: The unit size (installed capacity) used in the Council's planning models.
Heat rate: The fuel conversion efficiency of fuel-burning technologies in Btu/kWh. Degraded lifecycle average. Higher heating value (HHV) for consistency with fuel pricing.
Availability/Capacity factor: Availability ((1 - forced outage rate)*(1 - scheduled outage rate)) for firm capacity technologies. Expected capacity factor (adjusted for availability) for energy-limited technologies.
Total plant cost: The overnight (instantaneous) project development and construction cost in constant 2006 year dollar values as of mid-2008. Includes direct and indirect construction costs, engineering, owner's development and administration costs and contingencies. Excludes

[43] Overnight costs.

financing fees and allowance for funds used during construction. Construction costs must be adjusted as described in Appendix I to arrive at the expected cost for a given service year. Capital and fixed operating costs are assumed to be fixed at start of construction.

Fixed O&M: Fixed operating and maintenance cost in constant 2006 year dollars as of mid-2008. Includes operating labor, maintenance costs and overhead. Interim capital replacement costs included if significant. Excludes property tax and insurance. Fixed O&M costs must be adjusted as described in Appendix I to arrive at the expected cost for a given service year.

Variable O&M: Variable operating and maintenance costs in constant 2006 year dollars as of mid-2008. Includes consumables such as water, chemicals and lubricants. Excludes the cost of CO_2 sequestration for examples with CO_2 separation and sequestration.

Integration cost: The cost of providing regulation and sub-hourly load-following services for system integration. These increase over the planning period. Forecast values are provided in Appendix I. Excludes the cost of storage for shaping to load.

Transmission cost: The cost of dedicated long-distance transmission, if any, plus within-region wheeling cost.

Transmission losses: Total transmission losses (Long-distance transmission plus point-to-point within-region delivery).

Plant development and construction: The first value is the time in months to develop a project from conception to first major expenditure (generally major equipment order); The second value is the time in months to complete construction of one unit from the first major expenditure. Excludes time required for developing and constructing long-distance transmission for remote resource examples.

Earliest service year: Assumed earliest service for new plants..

Developable potential: The estimated total developable potential of energy-limited resources over the 2010 - 2029 period.

Table 6-3: Key Planning Assumptions for Reference Power Plants

Reference Plant	Plant Size (MW)	Heat Rate (HHV Btu/kWh)	Capacity Factor/ Availability	Total Plant Cost ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)	Integration Cost	Trans Cost [44]($/kW/yr)	Trans Losses[45]	Plant Dev / Construction (mos)	Earliest Service	Developable Potential (MWa)
Animal manure energy recovery	0.85	10,250	75%	$5000	$45	$15	--	$17	1.9%	12/12	2012	50 - 110
Landfill gas energy recovery	2 x 1.6/unit	10,060	85%	$2350	$26	$19	--	$17	1.9%	18/15	2012	70
Waste water energy recovery	0.85	10,250	85%	$5000	$40	$30	--	$17	1.9%	18/15	2012	7 - 14
Woody residue - Greenfield, no CHP	25	15,500[46]	80%	$4000	$180	$3.70	--	$17	1.9%	24/24	2014	665
Woody residue - Brownfield, CHP	25	19,300[47]	80%	$3000	$194	$0.73	--	$17	1.9%	24/24	2014	Not separately estimated
Geothermal - binary	3x13/unit	28,500	90%	$4800	$175	$4.50	--	$17	1.9%	36/36	2017	375
Hydropower - new	10	--	50%	$3000	$90	Incl in fixed	--	$17	1.9%	48/24	2016	100's
Solar - CSP (NV > ID)	100	--	36%	$4700	$60	$1.00	--	$102	4.0%	24/24	2015	530/500kV ckt
Solar - CSP (NV > OR/WA)	100	--	36%	$4700	$60	$1.00	--	$189	6.5%	24/24	2015	530/500kV ckt
Solar - Tracking PV	20	--	S. ID - 26% MT - 25% OR - 25% E. WA - 24%	$9000	$36	Incl in fixed	$7.98	$17	1.9%	12/24	2013	Ltd by integration capability
Solar - Tracking PV (NV)	20	--	30%	$9000	$36	Incl in fixed	$7.98	$96	4.0%	12/24	2015	435/500kV ckt
Wind (ID Local)	100	--	30%	$2100	$40	$2.00	$7.98	$17	1.9%	18/15	2013	215
Wind (MT Local)	100	--	38%	$2100	$40	$2.00	$7.98	$17	1.9%	18/15	2013	80
Wind (OR/WA Local)	100	--	32%	$2100	$40	$2.00	$7.98	$17	1.9%	18/15	2013	1410
Wind (AB > OR/WA)	100	--	38%	$2100	$40	$2.00	$7.98	$179	4.3%	18/15	2015	570/500kV ckt
Wind (MT > ID)	100	--	38%	$2100	$40	$2.00	$7.98	$104	4.2%	18/15	2015	570/500kV ckt
Wind (MT > OR/WA)	100	--	38%	$2100	$40	$2.00	$7.98	$198	6.4%	18/15	2015	570/500kV ckt
Wind (MT > OR/WA via CTS)	100	--	38%	$2100	$40	$2.00	$7.98	$120	10%	18/15	2015	244/500kV ckt
Wind (WY > ID)	100	--	38%	$2100	$40	$2.00	$7.98	$120	4.5%	18/15	2015	570/500kV ckt
Wind (WY > OR/WA)	100	--	38%	$2100	$40	$2.00	$7.98	$219	7.0%	18/15	2015	570/500kV ckt
Waste heat recovery	5	38,000	80%	$3500	Incl in var.	$8.00	--	$17	1.9%	24/24	2014	10's - 100's
Coal - Supercritical steam	450	9000	85%	$3500	$60	$2.75	--	$17	1.9%	36/48	2017	--
Coal - Ultra-Supercritical steam	450	8010	85%	$3570	$60	$2.75	--	$17	1.9%	36/48	2017	--
Coal - USC steam w/90% CSS	450	10,170	85%	$5495	$128	$5.85	--	$17	1.9%	36/48	2023	--
Coal - IGCC	623	8680	80%	$3600	$45	$6.30	--	$17	1.9%	36/48	2017	--
Coal - IGCC w/88% CSS	518	10760	80%	$4800	$60	$8.50	--	$17	1.9%	36/48	2023	--
NG - Frame gas turbine	85	11960	91%	$610	$11	$1.00	--	$17	1.9%	18/15	2012	--
NG - Aero gas turbine	2 x 47/unit	9370	91%	$1050	$13	$4.00	--	$17	1.9%	18/15	2012	--
NG - Intercooled gas turbine	99	8870	91%	$1130	$8	$5.00	--	$17	1.9%	18/15	2012	--
NG - Reciprocating engine plant	12 x 8.3/unit	8850	93%	$1150	$13	$10.00	--	$17	1.9%	18/15	2012	--
NG - Combined-cycle	Baseload - 390 Peak incr - 25	Baseload - 6930 Pk incr - 9500	89%	$1120	$14	$1.70	--	$17	1.9%	24/30	2014	--
Nuclear	1117	10,400	90%	$5500	$90	$1.00	--	$17	1.9%	48/72	2023	--

44 Combined operating cost of local (in-region) transmission plus construction and operating cost of transmission (if any) to access remote resources, expressed as a fixed O&M cost. Excludes the $1.00/MWh variable O&M cost of local transmission which should be added to all estimates.

45 Combined local (in-region) transmission losses plus losses associated with transmission (if any) to access remote resources.

46 Full plant heat rate.

47 Full plant heat rate.