Bulk Electricity Generating Technologies

This appendix describes the technical characteristics and cost and performance assumptions used by the Northwest Conservation and Power Council for resources and technologies expected to be available to meet bulk power generation needs during the period of the power plan. These resources and technologies are explicitly modeled in the Council's risk and reliability models and are characterized in the considerable detail required by these models. Other generating resources and technologies are described in Appendix J - Cogeneration and Distributed Generation. The intent of this appendix is to characterize typical facilities, recognizing that actual projects will differ from these assumptions in the particulars. These assumptions are used in for the Council's price forecasting, system reliability and risk assessment models, for the Council's periodic assessments of system reliability and for the assessment of other issues where generic information concerning power plants is needed.

PROJECT FINANCING

Project financing assumptions are shown in Table I-1 for three types of possible project owners. Because the Council's plan is regional in scope, assumptions must be made regarding the expected mix of ownership for each resource. For the purpose of electricity price forecasting, the Council uses the weighted average of the expected mix of project owners for each resource type. For example, trends suggest that most wind projects will continue to be developed by independent power producers. Thus the "expected mix" for future wind capacity is 15 percent consumer-owned utility, 15 percent investor-owned utility and 70 percent independent power producer. For comparative evaluation of resources, including the portfolio analysis and the benchmark prices appearing in the plan, the Council uses a "standard" ownership mix. This consists of 20 percent consumer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer ownership. The expected mix of project owners is provided in the tables of resource modeling characteristics appearing in this appendix.

Table I-1: Project financing assumptions

Developer:	Consumer-owned Utility	Investor-owned Utility	Independent Developer
General			
General inflation	2.5%		
Debt financing fee	2.0%		
Project financing terms			
Debt repayment period	30 years	30 years	15 years
Capital amortization period		20 years	20 years
Debt/Equity ratio	100%	50%/50%	Development: 0%/100% Construction: 60%/40% Long-term: 60%/40%

Developer:	Consumer-owned Utility	Investor-owned Utility	Independent Developer
Interest on debt (real/nominal)	2.3%/4.9%	4.7%/7.3%	Development: n/a Construction: 3.9%/6.5% Long-term financing: 5.2%/7.8%
Return on equity (real/nominal)		8.3/11%	12.2/15%
After-tax cost-of-capital (real/nominal)	2.3 %/4.9%	5.0%/7.7%	6.1%/8.9%
Discount Rate (real/nominal)	2.3 %/4.9%	5.0%/7.7%	6.1%/8.9%
Taxes & insurance			
Federal income tax rate	n/a	35%	35%
Federal investment tax credit	n/a	0%	0%
Tax recovery period	n/a	20 years	20 years
State income tax rate	n/a	5.9%	5.9%
Property tax	0%	1.4%	1.4%
Insurance	0.25%	0.25%	0.25%

FUEL PRICES

The price forecasts for coal, fuel oil and natural gas are described in Appendix B.

COAL-FIRED STEAM-ELECTRIC PLANTS

Coal-fired steam-electric power plants are a mature technology, in use for over a century. Coal is the largest source of electric power in the United States as a whole, and the second largest supply component of the western grid. Over 36,000 megawatts of coal steam-electric power plants are in service in the WECC region[1], comprising about 23 percent of generating capacity. Beginning in the late 1980s, the economic and environmental advantages of combined-cycle gas turbines resulted in that technology eclipsing coal-fired steam-electric technology for new resource development in North America. Less than 500 megawatts of new coal-fired steam electric plant has entered service on the western grid since 1990.

The prospect for coal-generated electricity is changing. The economic and environmental characteristics of coal-fired steam-electric power plants have improved in recent years and show evidence for continuing evolutionary improvement. This, plus stable or declining coal prices and high natural gas prices are reinvigorating the competition between coal and natural gas. Over 960 megawatts of new coal steam capacity are currently under construction in the WECC region.

[1] WECC is the reliability council for the western interconnected grid, extending from British Columbia and Alberta on the north to Baja California, Arizona, New Mexico and the El Paso area in the south.

Technology

The pulverized coal-fired power plant is the established technology for producing electricity from coal. The basic components of a steam-electric pulverized coal-fired power plant include a coal storage, handling and preparation section, a furnace and steam generator and a steam turbine-generator. Coal is ground to dust-like consistency, blown into the furnace and burned in suspension. The energy from the burning coal generates steam that is used to drive the steam turbine-generator. Ancillary equipment and systems include flue gas treatment equipment and stack, an ash handling system, a condenser cooling system, and a switchyard and transmission interconnection. Environmental control has become increasingly important and newer units are typically equipped with low-NOx burners, sulfur dioxide removal equipment, filters for particulate removal and closed-cycle cooling systems. Selective catalytic reduction of NOx and CO emission is becoming increasingly common and post-combustion mercury control is expected to be required in the future. Often, several units of similar design will be co-located to take advantage of economies of design, infrastructure, construction and operation. In the west, coal-fired plants have generally been sited near the mine-mouth, though some plants are supplied with coal by rail at intermediate locations between mine-mouth and load centers.

Most North American coal steam-electric plants operate at sub-critical steam conditions. Supercritical steam cycles operate at higher temperature and pressure conditions at which the liquid and gas phases of water are indistinguishable. This results in higher thermal efficiency with corresponding reductions in fuel cost, carbon dioxide production, air emissions and water consumption. Supercritical units are widely used in Europe and Japan. Some were installed in North America in the 1960s and 70s but the technology was not widely adopted because of low coal costs and the poor reliability of some early units. Recent European and Japanese experience has been satisfactory[2] and many believe that supercritical technology will penetrate the North American market over the next couple of decades. We assume that future pulverized coal steam electric power plants will move toward the greater use of supercritical steam cycles. For purposes of forecasting the cost and performance of advanced technology, we assume full penetration of supercritical technology within 20 years at a cost penalty of 2 percent and a heat rate improvement of 5 percent[3] (World Bank, 1998).

Economics

The cost of power from a coal gasification power plant is comprised of capital service costs, fixed and variable non-fuel operating and maintenance costs, fixed and variable fuel costs and transmission costs. Coal-fired power plants are a capital-intensive generating technology. A relatively large capital investment is made for the purpose of using relatively low-cost fuel. Though they can be engineered to provide load following, capital-intensive technologies are normally used for baseload operation.

The capital cost of new coal-fired steam-electric plants has declined about 25 percent in constant dollars since the early 1990s. This is attributable to plant performance improvements, automation and reliability improvements, equipment cost reduction,

[2] World Bank. Supercritical Coal-fired Power Plants. *Energy Issues* No 19. April 1999
[3] World Bank. Technologies for Reducing Emissions in Coal-fired Power Plants. Energy Issues No 14. August 1998.

shortened construction schedule, and increased market competition[4]. Meanwhile, coal prices have also declined in response to stagnant demand and productivity improvements in mining and transportation[5]. By way of comparison, in the Council's 1991 power plan, the overnight capital cost of a new coal-fired steam-electric plant was estimated to be $1,775 per kilowatt and the cost of Montana coal $0.68 per million Btu (escalated to year 2000 dollars). The comparable capital and fuel costs of this plan are $1,230 per kilowatt and $0.52 per million Btu, respectively.

Development Issues

Though the economics have improved, important issues associated with development of coal-fired power plants remain. Transmission, mercury emissions and carbon dioxide production appear to be the most significant.

Transmission issues will affect the siting and development of future coal-fired power plants in the Northwest. Coal supplies, though abundant, tend to lie at considerable distance from Northwest load centers. Environmental concerns will likely preclude siting of new coal plants close to load centers. However, new plants could be sited at intermediate locations having good rail and transmission access. Delivered coal cost will be greater that the mine mouth cost of coal because of the need to haul the coal by rail. Also, fuel cost component of the rail haul costs is sensitive to fuel oil price volatility and uncertainty. Alternatively, new plants could be sited at or near the mine mouth. Coal will be less expensive and free of fuel oil price uncertainties. Though the eastern transmission interties are largely committed, several hundred megawatts of additional transmission capacity may be available at low cost through better use of existing capacity and low-cost upgrades to existing circuits. This potential is currently under evaluation. Export of additional power from eastern Montana coalfields would require the construction of new long-distance transmission circuits. Preliminary estimates of the cost of an additional 500kV circuit out of eastern Montana indicate that the resulting cost of power delivered to the Mid-Columbia area would not be competitive with the cost of power from coal plants sited in the Mid-Columbia area using rail haul coal. Additional obstacles to construction of new eastern intertie circuits include long lead time (six to eight years from conception to energization), limited corridor options for crossing the Rocky Mountains and the current lack of an entity capable of large-scale transmission planning, financing and construction.

Coal combustion releases elemental mercury, some of which passes into the atmosphere and accumulates in the food chain where it poses a health hazard. On average, about 36 percent of the mercury contained in the coal is retained in ash or removed by existing controls.[6] Additional control of power plant mercury emissions is not currently required, however the EPA is under court order to issue rules governing control of mercury by March 2005. A promising approach to controlling mercury emissions from coal steam-electric plants is to augment mercury capture in existing particulate filters using activated carbon injection. Short-term tests of activated carbon injection on power plants using sub-bituminous coal increased capture rates to 65 percent of potential emissions. The estimated

[4] U.S. Department of Energy. *Market-based Advanced Coal Power Systems*. March 1999.
[5] The recent runup in coal prices is attributed to short-term supply-demand imbalances.
[6] U.S. Environmental protection Agency. Control of Mercury Emissions from Coal-fired Electric Utility Boilers. January 2004.

costs of the representative pulverized coal-fired power plant described below include an allowance for activated charcoal injection for mercury control.

Among the fossil fuels, coal has the highest proportion of carbon to hydrogen. This places coal-fired generation at greater risk than other resources regarding possible future limits on the production of carbon dioxide. The most promising approach to dealing with the carbon dioxide production of coal combustion is through improved generating plant efficiency and carbon dioxide separation and sequestration. Introduction of supercritical steam cycles will improve the thermal efficiency of pulverized coal-fired power plants and reduce the per-kilowatt production of carbon dioxide. However, generating technologies based on coal gasification appears to be a more effective approach for achieving both higher efficiencies and economical carbon dioxide separation capability.

Northwest potential

New pulverized coal-fired power plants could be constructed in the Northwest for the principal purpose of providing base load power. Because of the abundance of coal in western North America, supplies are adequate to meet any plausible Northwest needs over the period of this plan. While environmental concerns would likely make siting west of the Cascades near the Puget Sound and Portland load centers difficult, existing and potential plant sites elsewhere are sufficient to meet anticipated needs for the period of the plan. New plants could be constructed at or near mine-mouth in eastern Montana, in the inter-montane region of eastern Washington, Oregon and southern Idaho and in areas adjacent to the region including northern Nevada, Alberta and British Columbia.

Plants developed in the inter-montane portion of the region might require incremental rail upgrades for coal supply and local grid reinforcement and to deliver power to westside load centers. Plants located in eastern Montana could supply local loads and export up to several hundred megawatts of power to the Mid-Columbia area using existing non-firm transmission capacity and relatively low-cost upgrades to the existing transmission system. Further development of plants in eastern Montana to serve western loads would require construction of additional transmission circuits to the Mid-Columbia area. As a general rule-of-thumb, one 500 kV AC circuit could transmit the output of 1,000 megawatts of generating capacity.

Reference plant

The reference plant is a 400-megawatt sub-critical pulverized coal-fired unit, co-located with similar units. The plant would be equipped with low-NOx burners and selective catalytic reduction for control of nitrogen oxides. The plant would also be equipped with flue gas de-sulfurization, fabric filter particulate control and activated charcoal injection for additional reduction of mercury emissions. The capital costs include a shared local switchyard and transmission interconnection, but do not include dedicated long-distance transmission facilities.

The base case plant uses evaporative (wet) condenser cooling. Dry cooling uses less water, and might be more suitable for arid areas of the West. But dry cooling reduces the thermal efficiency of a steam-electric plant by about 10 percent, and proportionally increases per-kilowatt air emissions and carbon dioxide production. The effect is about three times greater for steam-electric plants than for gas turbine combined-cycle power plants, where recent proposals have trended toward dry condenser cooling. For this reason, we assume that the majority of new coal-fired power plants would be located in areas where water availability is not critical and would use evaporative cooling.

The assumptions of this plan regarding new coal-fired steam-electric plants are described in Table I-3. Specific proposals for new coal-fired power plants might differ substantially from this case. Important variables include the steam cycle (sub-critical vs. supercritical), method of condenser cooling, transmission interconnection, the level of equipment redundancy and reliability, number of units constructed at the same site and how scheduled, level of air emission control, the type of coal used and method of delivery.

The Northwest Transmission Assessment Committee of the Northwest Power Pool is developing cost estimates for additional transmission from eastern Montana to the Mid-Columbia area. As of this writing, only very preliminary estimates of the cost of a new 500 kV AC circuit were available. These, together with other modeling assumptions regarding additional eastern Montana - Mid-Columbia transmission are shown in Table I-4.

The benchmark[7] levelized electricity production costs for the reference coal-fired power plant, power delivered as shown, are as follows:

Eastern Montana, local service	$32/MWh
Eastern Montana, via existing transmission to Mid-Columbia area	$38/MWh
Eastern Montana, via new transmission to Mid-Columbia area	$62/MWh
Mid-Columbia, rail haul coal from eastern Montana	$38/MWh

[7] Average financing cost for 20 percent customer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer developer mix; 2010 service; medium case fuel price forecast; 80 percent capacity factor, year 2000 dollars. No CO2 penalty.

Table I-3: Resource characterization: Coal-fired steam-electric plant (Year 2000 dollars)

Description and technical performance		
Facility	400 MW (nominal) pulverized coal-fired subcritical steam-electric plant, 2400 psig/1000^{o}F/1000^{o}F reheat. "Reduced redundancy" low-cost design. Evaporative cooling. Low-NOx burners; flue gas desulfurization; fabric particulate filter and activated charcoal filters. Co-sited with one or more additional units.	Reference plant from U.S. Department of Energy, *Market-based Advanced Coal Power Systems*, March 1999 (USDOE, 1999), modified to suit western coal and site conditions and anticipated mercury control requirements.
Status	Commercially mature	
Application	Baseload power generation	
Fuel	Western low-sulfur subbituminous coal. Rail-haul or mine-mouth delivery.	
Service life	30 years	
Power (net)	400 MW.	
Operating limits	Minimum load: 50 %. Cold startup: 12 hours Ramp rate: 0.5%/min	Values consistent with reduced-redundancy, low-cost design. Improved performance is available at additional cost.
Availability	Scheduled outage: 35 days/yr Equivalent forced outage rate: 7% Mean time to repair: 40 hours Equivalent annual availability: 84%	Scheduled outage is average of 1995 - 99 NERC *Generating Availability Data System* (GADS) scheduled outage factor for 200 - 399 MW coal-fired units, rounded to nearest day. Forced outage rate is average of GADS equivalent forced outage factor for 200 - 399 MW coal-fired units. Forced outage rate is intended as a lifecycle average. Generally higher for startup year, lower by second year, then slowly increasing over remainder plant life.
Heat rate (HHV, net, ISO conditions)	9550 Btu/kWh (annual average, 2002 base technology).	Midpoint from Kitto, J. B. *Developments in Pulverized Coal-fired Boiler Technology*. Babcock & Wilcox, April 1996, increased 0.8% for SCR.
Vintage heat rate improvement	0.26 %/yr (2002-25)	Assumes full penetration of supercritical steam cycle by 2021 with 5% reduction in heat rate. World Bank. *Technologies for Reducing Emissions in Coal-fired Power Plants* (World Bank 1998). Energy Issues No 14. August 1998.
Seasonal power output (ambient air temperature sensitivity)	Not significant	
Elevation adjustment for power output	Not significant	

Costs		
Capital cost (Overnight, development and construction)	$1243/kW	Assumes two units at a site completed within two years of one another. Single unit costs assumed to be 10% greater. Assumes development costs are capitalized. Overnight cost excludes financing fees and interest during construction.
Development & construction cash flow (%/yr)	Cash flow for "straight-through" 78-month development & construction schedule: 0.5%/0.5%/2%/10%/37%/37%/13%.	See Table I-4 for phased development assumptions used in portfolio risk studies.
Fixed operating costs	$40/kW/yr	From DOE (1999), excluding property taxes and insurance plus $15/yr capital replacement.
Variable operating costs	$1.75/MWh	Includes consumables & SCR catalyst replacement, makeup water, wastewater and ash disposal costs. From DOE (1999) plus $0.25 allowance for SCR catalyst replacement and $0.75/MWh for additional reagent and disposal costs for Hg control.
Incentives/Byproduct credits/CO2 penalties	Separately included in the Council's models.	
Interconnection and regional transmission costs	$15.00/kW/yr	Bonneville point-to-point transmission rate (PTP-02) plus Scheduling, System Control and Dispatch, and Reactive Supply and Voltage Control ancillary services, rounded. Bonneville 2004 transmission tariff.
Transmission loss to market hub	1.9%	Bonneville contractual line losses.
Technology vintage cost change (constant dollar escalation)	0.1 %/yr (2002-25)	Assumes full penetration of supercritical steam cycle by 2021 with 2 % increase in capital and fixed operating costs. World Bank (1998).

Air emissions		
Particulates (PM-10)	0.072T/GWh	Roundup Power Project, MT, as permitted
SO2	0.575 T/GWh	Ibid
NOx	0.336 T/GWh	Ibid
CO	0.719 T/GWh	Ibid
VOC	0.014 T/GWh	Ibid
CO_2	1012 T/GWh	Based on average carbon content of U.S. subbituminous coals (212 lb/MMBtu) and lifecycle average heat rate.

Development		
Assumed mix of developers	For electricity price forecasting: Consumer-owned utility: 25% Investor-owned utility: 25% Independent power producer: 50% For resource comparisons & portfolio analysis: Consumer-owned utility: 20% Investor-owned utility: 40% Independent power producer: 40%	Price forecasting (expected) mix is a GRAC recommendation. Resource comparison mix is a standard mix for comparison of resources. See Appendix B for project financing assumptions.
Development & construction schedule	Development - 36 Months Construction - 42 months	"Straight-through" development. See Table I-4 for phased development assumptions used in portfolio risk studies.
Earliest commercial service	Permitted sites (MT only) - 2008 New sites - 2011	
Site availability and development limits through 2025.	MT in-state - no limit MT to Mid-Columbia - 400 MW w/o transmission expansion No development in western OR or WA	Primary coal resource sufficient to meet

Table I-4: Preliminary modeling characteristics - new 500kV transmission circuit from Colstrip area to Mid-Columbia (year 2000 dollars)

Capacity	1000 MW	Delivered
Losses	6.6%	
Capital cost (Overnight, development and construction)	$1590/kW	Based on delivered capacity
Operating costs	$8.00/kW/yr	Based on delivered capacity
Development & construction schedule	Development - 48 months Construction - 36 months	

Project Phasing Assumptions for the Portfolio Analysis

As described in Chapter 6, the portfolio risk model uses resource development flexibility as one means of coping with future uncertainties. Three phases of resource development are modeled: project development, optional construction and committed construction. The project development phase consists of siting, permitting and other pre-construction activities. Optional construction extends from the notice to proceed to irrevocable commitment of the major portion of construction cost (typically, completion of major equipment foundations in preparation for receipt of major plant equipment). The balance of construction through commercial operation is considered to be committed. In the portfolio model, plant construction can be continued, suspended or terminated at the conclusion of project development or optional construction phases. Projects can also be terminated while suspended. The cost and schedule assumptions associated with these decisions are shown in Table I-5. The cumulative schedule of the three project phases shown in Table I-5 is longer than the "straight-through" development and construction schedule shown in Table I-3.

Table I-5: Coal-fired steam-electric plant project phased development assumptions for risk analysis (year 2000 dollars)[8]

	Development	Optional Construction	Committed Construction
Defining milestones	Feasibility study through completion of permitting	Notice to proceed to major equipment foundations complete	Start of boiler steel erection to commercial operation
Time to complete (single unit, nearest quarter)	36 months	18 months	27 months
Cash expended (% of overnight capital)	3%	27%	70%
Cost to suspend at end of phase ($/kW)	Negligible	$234	--
Cost to hold at end of phase ($/kW/yr)	$1	$10	--
Maximum hold time from end of phase	60 months	60 months	--
Cost of termination following suspension ($/kW)	Negligible	$26	--
Cost of immediate termination ($/kW)	Negligible	$158	--

COAL-FIRED GASIFICATION COMBINED-CYCLE PLANTS

The production of synthetic gas fuel from coal and other solid or liquid fuels offers the opportunity for improving the environmental and economic aspects of generating electricity from coal, an abundant and low-cost energy resource. Coal gasification permits the use of efficient gas turbine combined cycle power generation, allows excellent control of air pollutants and facilitates the separation of carbon dioxide for sequestration (See Appendix K for discussion of carbon dioxide sequestration). Gasification plants can be equipped for co-production of liquid fuels, petrochemicals chemicals or hydrogen, creating the opportunity for more flexible and economical plant utilization. Gasification technology can also be used to produce synthetic fuels from petroleum coke, bitumen and biomass, providing a means of using the energy of these otherwise difficult fuels. Coal gasification power plants are in the demonstration stage of development. Issues needing resolution before widespread deployment include capital cost reduction, provision of overall plant performance warranties and demonstration of consistent plant reliability.

Coal gasification is an old technology, having been introduced in the early nineteenth century to produce "town gas" for heating and illumination. Development of the North American natural gas transportation network in the mid-20th century brought cleaner and less-expensive natural gas to urban markets and the old town gas plants, numbering over 1,000 at one time, were retired. Currently, gasification is widely employed in the

[8] The portfolio risk model was calibrated in year 2004 dollars for draft plan analysis. Assumptions are presented here in year 2000 dollars for consistency with other assumptions and forecasts appearing in the plan. Year 2004 dollars are obtained by multiplying year 2000 dollars by an inflation factor of 1.10.

petrochemical industry for processing of coal and petroleum residues into higher value products. Other than several demonstration projects[9], coal gasification has not penetrated the North American power generation industry. This is attributable to the availability of low-cost natural gas until recently, efficient, reliable and low-cost gas-fired combined-cycle gas turbine power plants and the high initial cost and reliability issues with gasification power plants. Rising natural gas prices, the prospect of more stringent control of particulates and mercury, and increasing acknowledgement that the production of carbon dioxide must be reduced is increasing interest in coal-fired gasification power plants.

Technology

The leading plant configuration for electric power generation using gasified coal is the integrated gasifier combined-cycle (IGCC) power plant. Integration refers to the extraction of pressurized air from the gas turbine compressor for use as feedstock to the air separation plant, and use of the energy released in the gasification process for power generation to improve net plant efficiency. These plants use the combined-cycle gas turbine power generating technology widely used for natural gas electricity generation. A variety of gasification technologies have been developed for use with different feedstocks and for producing different products. Pressurized oxygen-blown designs are favored for power generation. Pressurization and the use of oxygen for the gasification reaction reduce the volume of the resulting raw synthetic gas. This reduces the cost of gas cleanup, eliminates the need for syngas compression and reduces the cost of CO_2 separation if that is desired.

The principal components of an integrated gasifier combined-cycle generating plant are as follows:

- *Coal preparation*: The coal preparation section includes the on-site fuel inventory and equipment to prepare the coal for introduction to the gasifier. The coal is crushed or ground to size and (depending upon the gasification process) either suspended in slurry or dried for feeding to the gasifier.

- *Air separation*: The air separation plant produces oxygen for the gasification reaction. Use of oxygen, rather than air as the gasification oxidant increases the energy content and reduces the volume of the synthesis gas. This reduces the cost of gas cleanup and also reduces formation of nitrogen oxides in the gas turbine. Air separation plants currently use energy-intensive cryogenic processes in which incoming air is chilled to a liquid and distilled to separate the nitrogen, oxygen and other constituents. For example, about 20 percent of the power output of the Tampa Electric IGCC demonstration plant is consumed by air separation. Large-scale membrane separation technology under development is expected to require less energy, yield improvement in net plant efficiency.

[9] Currently operating coal gasification power plants in the U.S. are the Tampa Electric Integrated Gasification Combined-cycle Project (Polk Power Station) using theChevron-Texaco gasification process, and the Wabash River Coal Gasification Repowering Project, using the ConocoPhilips E-Gas process. Additional information regarding these projects can be obtained from the U.S. Department of Energy coal and natural gas power systems website (www.fe.doe.gov/programs/powersystems/index.html.)

- *Gasification*: Processed coal and oxygen are fed to the gasifier, a large pressure vessel. The coal is partially combusted, yielding heat and raw synthetic gas consisting largely of hydrogen, carbon monoxide and carbon dioxide. Coarse particulate material is removed and recycled to the gasifier. Non-combustible coal constituents form slag and are drained, solidified, then crushed for disposal or for marketable aggregate. The leading gasification processes suitable for power generation are the Chevron-Texaco, E-Gas and Shell processes. The Texaco process is used in the Tampa Electric Polk gasification power plant and the E-Gas process is used in the Wabash River coal gasification plant. The Shell process is used at the DEMKOLEC plant at Buggenum, The Netherlands. These plants have operated successfully for several years.

- *Gas processing:* The raw synthetic gas is scrubbed, cooled, and filtered to remove particulate material to prevent damage to downstream equipment and to control air emissions. Sulfur compounds are removed using regenerative sorbants then converted to marketable elemental sulfur. If CO_2 is to be separated or hydrogen-based co-products to be produced, the synthetic gas is passed through a series of water gas shift reactors. Here, the CO fraction reacts with water to form CO_2 and hydrogen. Though about 40 to 50 percent of the mercury in the feedstock coal remains in the slag, additional mercury capture can be achieved at this point by passing the synthetic gas through activated carbon beds.

- *CO_2 separation:* The relatively low volume of pressurized synthetic gas fuel provides a more economic means of separating carbon dioxide compared to removing the carbon dioxide from the larger volume of post-combustion flue gasses in a conventional steam-electric plant. Separation of up to 90 percent of the carbon dioxide content of the synthesis gas appears to be feasible using available technologies. Carbon dioxide can be separated from the synthesis gas using the same selective regenerative sorbent process used to remove sulfur compounds. The carbon dioxide could than be compressed to its high-density supercritical phase for transport to sequestration sites. An existing non-generating gasification plant, Dakota Gasification, uses a sorbent process to capture a portion of its carbon dioxide production. The carbon dioxide is piped 205 miles to Weyburn, Saskatchewan where it is injected for enhanced oil recovery. Though commercial, sorbent CO_2 removal is energy-intensive. Research is underway, mostly at the theoretical or laboratory stage, development of selective separation membrane technology capable of withstanding the operating conditions of a gasification power plant.

- *Power generation*: The finished synthetic gas is fired in a gas turbine of the same basic design as those used for natural gas combined-cycle power plants. Nitrogen from the air separation plant can be injected to augment the mass flow. The turbine exhaust gas is passed through a heat recovery steam generator to produce steam. This steam, plus steam produced by the synthetic gas coolers is used to drive a steam turbine generator. Reliable operation of F-class gas turbines on coal-based medium-Btu synthesis gas has been demonstrated and a plant constructed today would likely use this technology. More efficient H-class machines, currently being demonstrated on natural gas fuel would likely be used in future gasification power plants.

A pure, or nearly so hydrogen feedstock results from subjecting the synthesis gas to a water gas shift reaction followed CO_2 separation. F-class gas turbines have operated successfully on fuel hydrogen concentrations as high as 38 percent. Similar turbines have operated at hydrogen concentrations of 60 percent. Limited short-term testing has confirmed that F-class machines can operate on 100 percent hydrogen fuel. However, long-term reliable operation of gas turbines on pure hydrogen will require resolution of significant technical issues including hydrogen embrittlement, flashback, hot section material degradation and NOx control.

Fuel cells use pure hydrogen as fuel, so are natural candidates for use in a coal gasification facility with CO_2 separation. One concept consists of a combined-cycle plant using high temperature fuel cells with heat recovery and a steam turbine bottoming cycle. Cost and lifetime are key obstacles to employing fuel cells in this application. Current fuel cell costs of $2,000 - 4,000 per kilowatt must be significantly reduced for economical application to a gasification plant.

Economics

The cost of power from a coal gasification power plant is comprised of capital service costs, fixed and variable non-fuel operating and maintenance costs, fixed and variable fuel costs and transmission costs. The capital cost of a coal gasification combined-cycle power plant (without CO_2 separation) is estimated to be about 15 to 20 percent higher than the cost of conventional pulverized coal-fired units. However, because coal gasification power plants are a new technology, it is likely that cost will decline as the technology is deployed, whereas it is expected that the costs of conventional technology may increase, particularly as additional emission control requirements are enacted.

Even more so than conventional coal plants, a relatively large capital investment in a gasification plant is made for the purpose of using a low-cost fuel. Because high reliability is essential to amortizing the capital investment, multiple air separation, gasification and synthetic gas processing trains would likely be provided to ensure high plant availability. Though a basic coal gasification power plant would normally be used for baseload power production, synthetic liquid fuel or chemical manufacturing capability could be provided for additional operating flexibility. Depending upon the economics of power production, the synthetic gas output could be shifted between the combined-cycle power plant and synthetic liquid fuel or chemical production.

Development Issues

Two gasification combined-cycle power plants are currently operating in North America and additional plants could be ordered and built today. However, high and uncertain capital costs, the extended (though ultimately successful) shakedown periods required for the existing demonstration projects and lack of overall plant performance warranties precluding commercial financing have kept coal gasification power plants from full commercialization.

Had natural gas combined-cycle plants not been the bulk power generating technology of choice for the past 15 years, these concerns undoubtedly would have been resolved. However, high natural gas prices, diminishing North American natural gas supplies and increasing acceptance of the need to curtail carbon dioxide production have prompted renewed interest in coal gasification power plants. Recent developments accelerating commercialization of gasification power plants include the May 2004 announcement by Conoco-Philips and Fluor Corporation of an alliance to develop, design, construct and operate projects utilizing Conoco-Philips E-Gas coal gasification technology; the June 2004 announcement by General Electric that it would acquire the Chevron-Texaco gasification technology business, the August 2004 announcement by American Electric Power that it plans to construct 1,000 megawatts of coal gasification power generation capacity by 2010, the October 2004 announcement of a partnership between General Electric and Bechtel to offer a standard coal gasification combined-cycle power plant, the October 2004 announcement by Cinergy that it had signed an agreement with GE/Bechtal to construct a 600 megawatt coal gasification power plant in Indiana, and the October 2004 announcement that Excelsior Energy had been selected for a US DOE grant to assist in the financing of 532 MW coal gasification power plant to be located in Minnesota.

Probable siting difficulties would likely preclude siting of new coal-fired plants near Westside Northwest load centers. New plants could be located in eastern Washington or Oregon, or Southern Idaho, with fuel supplied by rail. Rail haul costs would prompt the operators of plants located in this part of the region to use medium-Btu bituminous coal from Wyoming or Utah. Reinforcement of cross-Cascades transmission capacity might eventually be required for plants located in this area. Alternatively, plants could be located near mine-mouth in Wyoming, Eastern Montana, or Utah. New high voltage transmission circuits would be required for new mine-mouth coal plant development exceeding several hundred megawatts. As discussed in the section on conventional coal-fired power plants, only preliminary estimates of the cost of new transmission are available, however, more refined estimates are in development.

Sequestration of carbon dioxide may mandate the location of gasification power plants in the eastern portion of the region. Though ocean sequestration may eventually be proven feasible, opening opportunities for plants employing carbon dioxide separation in the western portion of the region, only certain geologic formations present in eastern Montana currently appear to be suitable for carbon dioxide sequestration (Appendix K). Thus, gasification power plants would have to be located in eastern Montana and would require new transmission interconnection to take advantage of carbon dioxide separation capability.

Northwest Applications

Because of the abundance of coal in western North America, supplies are adequate to meet any plausible Northwest needs over the period of this plan. Coal-fired power plants constructed in the Northwest within the next several years would likely employ conventional pulverized coal technology. However, the increasing interest in coal-fired power generation and the prospect of more stringent particulate control and control requirements for mercury and CO_2 is accelerating the commercialization of coal gasification technology. It appears that a basic gasification power plant without CO_2 separation could be operating in the Northwest as early as 2011.

Locational constraints differ somewhat from those of conventional coal-fired plants. The Superior environmental performance of gasification power plants may make siting west of the Cascades near the Puget Sound and Portland load centers less challenging. However, if carbon dioxide is to be separated and sequestered, plant sites may be limited to the vicinity of deep saline aquifers and bedded salt formations of eastern Montana.

Plants developed in the inter-montane portion of the region might require incremental rail upgrades for coal supply and local grid reinforcement and to deliver power to westside load centers. Plants located in eastern Montana could supply local loads and export up to several hundred megawatts of power to the Mid-Columbia area using existing non-firm transmission capacity and relatively low-cost upgrades to the existing transmission system, if not preempted by earlier generating plant development. Further development of plants in eastern Montana to serve western loads would require construction of additional transmission circuits to the Mid-Columbia area. As a general rule-of-thumb, one 500 kV AC circuit could transmit the output of 1,000 megawatts of generating capacity.

Reference Plants

The cost and performance characteristics of two IGCC plant designs are described in Table I-6. The 425 megawatt plant would not be equipped with carbon dioxide separation equipment. This type of plant could be located anywhere in the Northwest that coal and transmission are available. The extremely low air emissions could facilitate siting near load centers. The issues that have constrained commercial development of these plants are rapidly being resolved. This could lead to full commercial projects as early as 2011. This schedule is generally consistent with the proposed AEP coal gasification power plants.

The second plant is of the same general design, but includes equipment for the separation of 90 percent of the carbon dioxide produced by plant operation. It appears likely that this type of plant would have to be located in the eastern portion of the region to access geologic formations suitable for carbon dioxide sequestration. Net power output is reduced to 401 megawatt because of the additional energy required for the carbon dioxide separation and compression to pipeline transportation pressure. Though the technologies for carbon dioxide capture, transport and injection are commercially available, extended gas turbine operation on high hydrogen fuel will require further development and testing. Moreover, carbon dioxide sequestration in potentially suitable eastern Montana formations has not been demonstrated. The cost estimates of Table I-6 do not include the costs of carbon dioxide transportation or sequestration. Carbon dioxide transportation and sequestration cost estimates are provided in Appendix K to permit estimation of the total cost of power production from this plant.

Not included in the plants described in Table I-6 are liquid or hydrogen fuel co-production facilities. Inclusion of product co-production capability would increase the operational flexibility of the plant, including the ability to firm the output of wind power plants.

The benchmark[10] levelized electricity production costs for the reference coal-gasification power plant without carbon dioxide separation, power delivered as shown, are as follows:

Eastern Montana, local service	$33/MWh
Eastern Montana, via existing transmission to Mid-Columbia area	$38/MWh
Eastern Montana, via new transmission to Mid-Columbia area	$58/MWh
Mid-Columbia, rail haul coal from eastern Montana	$38/MWh

Table I-6: Resource characterization: Coal-fired gasification combined-cycle plants (Year 2000 dollars)
Source EPRI 2000 unless noted

Description and technical performance			
Facility	Case A: 425 MW coal-fired integrated gasification combined-cycle power plant. Cryogenic air separation, pressurized oxygen-blown entrained-flow gasifier, solvent-based absorption sulfur stripping unit, carbon bed adsorption mercury removal and H-class gas turbine combined-cycle generating plant. (EPRI 2000 Case 3B)	Case B: 401 MW coal-fired integrated gasification combined-cycle power plant with 90% CO2 capture. Cryogenic air separation, pressurized oxygen-blown entrained-flow gasifier, water gas shift reactors, solvent-based selective absorption sulfur and CO2 separation, carbon bed adsorption mercury removal, CO2 compression to 2200psig and F-class gas turbine combined-cycle generating plant. (EPRI 2000 Case 3A w/2200psig CO2 product)	
Current Status	w/F-Class GT - Demonstration w/H-class GT - Conceptual	Conceptual	
Application	Baseload power generation	Baseload power generation	
Fuel	Western low-sulfur subbituminous coal	Same as Case A	
Service life	30 years	Same as Case A	
Power	474 MW (gross) 425 MW (net)	490 MW (gross) 401 MW (net)	
Operating limits	Minimum load: 75 % Cold restart: 24 hrs Ramp rate: 3 %/min	Same as Case A	Minimum is Negishi experience (JGC 2003). Lower rates may be possible with 2x1 combined-cycle configuration . Cold restart is Tampa Electric experience. Ramp rate is maximum w/o flare Negishi experience.

[10] Average financing cost for 20 percent customer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer developer mix; 2010 service; Montana coal, medium case price forecast; 80 percent capacity factor, year 2000 dollars. No CO2 penalty.

Description and technical performance			
Availability	Scheduled outage: 28 days/yr Equivalent forced outage rate: 10% Equivalent annual availability: 83%.	Same as Case A	Design objectives for proposed WePower plant (GTW 2004). Multiple gasifier designs could increase availability to 90% or greater.
Heat rate (HHV, net, ISO conditions)	7915 Btu/kWh w/H-class gas turbine. F-class turbine would yield heat rates of 8500 - 9000 Btu/kWh.	9290 Btu/kWh w/H-class gas turbine. F-class turbine would yield heat rates of 10,000 - 10,600 Btu/kWh.	
Heat rate improvement (surrogate for cumulative effect of non-cost technical improvements)	-0.5 %/yr average from 2002 base through 2025	Same as Case A	Value used for combined-cycle gas turbines.
Seasonal power output (ambient air temperature sensitivity)	Assumed to be similar to those used for gas-fired combined-cycle power plants (Figure I-1).	Same as Case A	
Elevation adjustment for power output	Assumed to be similar to those used for gas-fired combined-cycle power plants (Table I-10).	Same as Case A	

Costs			
Capital cost (Overnight, development and construction)	$1400/kW Range $1300 - $1600/kW	$1805/kW Range $1650 - $1950/kW	Costs from EPRI, 2000 adjusted for additional mercury removal, project development and owner's costs. Escalated to year 2000 dollars.
Construction period cash flow (%/yr)	15%/35%/35%/15%	Same as Case A	
Fixed operating costs	$45.00/kW/yr	$53.00/kW/yr	
Variable operating costs	$1.50/MWh	$1.60/MWh	Consumables from EPRI, 2000 plus mercury removal O&M from Parsons, 2002. EPRI 2000 provides turbine maintenance costs as fixed O&M though most gas turbine costs are variable.
CO2 transportation and sequestration	n/a	See Appendix K	
Byproduct credits	None assumed	None assumed	Potential sulfur and CO2 byproduct credit (CO2 for enhanced gas or oil recovery).

Costs			
Interconnection and regional transmission costs	$15.00/kW/yr	Same as Case A	Bonneville point-to-point transmission rate (PTP-02) plus Scheduling, System Control and Dispatch, and Reactive Supply and Voltage Control ancillary services, rounded. Bonneville 2004 transmission tariff.
Transmission loss to market hub	1.9%	Same as Case A	Bonneville contractual line losses.
Technology vintage cost change (constant dollar escalation)	-0.5 %/yr average from 2002 base through 2025 (capital and fixed O&M costs)	Same as Case A	Approximate 95% technical progress ratio (5% learning rate). See combined-cycle description for derivation.

Air Emissions & Water consumption			
Particulates (PM-10)	Negligible	Negligible	
SO2	Negligible	Negligible	Low sulfur coal and 99.8% removal of residual sulfur
NOx	< 0.11T/GWh	< 0.11T/GWh	
CO	0.015 T/GWh	0.017 T/GWh	O'Keefe, 2003, scaled to heat rate
VOC	0.005 T/GWh	0.005 T/GWh	O'Keefe, 2003, scaled to heat rate
CO_2	791 T/GWh	81 T/GWh (90% removal)	
Hg	6.3×10^{-6} T/GWh	7.4×10^{-6} T/GWh	90% removal
Water Consumption	412 T/GWh	820 T/GWh	

Development			
Developer	For electricity price forecasting: Consumer-owned utility: 25% Investor-owned utility: 25% Independent power producer: 50% For resource comparisons & portfolio analysis: Consumer-owned utility: 20% Investor-owned utility: 40% Independent power producer: 40%	For electricity price forecasting: Consumer-owned utility: 25% Investor-owned utility: 25% Independent power producer: 50% For resource comparisons & portfolio analysis: Consumer-owned utility: 20% Investor-owned utility: 40% Independent power producer: 40%	Price forecasting (expected) mix is the GRAC recommendation for conventional coal-fired power plants. Resource comparison mix is used for the portfolio analysis and other benchmark comparisons of resources.

Development			
Development and construction schedule	Development - 36mo Construction - 48 mo	Same as Case A.	Development schedule is consistent with O'Keefe. Construction currently would require 54 months (O'Keefe, 2003). Expected to shorten to 38 months with experience. "Straight-through" development. See Table I-6 for phased development assumptions used in portfolio studies.
Earliest commercial service	2011	2011 for enhanced oil or gas recovery CO2 sequestration. 2015 - 2020 for novel CO2 repositories.	
PNW Site Availability	Site availability sufficient to meet regional load growth requirements through 2025.	Site availability sufficient to meet regional load growth requirements through 2025. Suitable geologic CO2 sequestration sites may be limited to eastern Montana. Montana development would require additional transmission development to serve western load centers.	

Project Phasing Assumptions for the Portfolio Analysis

As described in Chapter 6, the portfolio risk model uses resource development flexibility as one means of coping with future uncertainties. Three phases of resource development are modeled: project development, optional construction and committed construction. The project development phase consists of siting, permitting and other pre-construction activities. Optional construction extends from the notice to proceed to irrevocable commitment of the major portion of construction cost (typically, completion of major equipment foundations in preparation for receipt of major plant equipment). The balance of construction through commercial operation is considered to be committed. In the portfolio model, plant construction can be continued, suspended or terminated at the conclusion of project development or optional construction phases. Projects can also be terminated while suspended. The cost and schedule assumptions associated with these decisions are shown in Table I-7. The cumulative schedule of the three project phases shown in Table I-7 is longer than the "straight-through" development and construction schedule shown in Table I-6.

Table I-7: Coal-fired gasification combined-cycle project phased development assumptions for the portfolio analysis (year 2000 dollars)[11]

	Development	Optional Construction	Committed Construction
Defining milestones	Feasibility study through completion of permitting	Notice to proceed to major equipment foundations complete	Accept major equipment to commercial operation
Time to complete (single unit, nearest quarter)	36 months	24 months	24 months
Cash expended (% of overnight capital)	2%	28%	70%
Cost to suspend at end of phase ($/kW)	Negligible	$218	--
Cost to hold at end of phase ($/kW/yr)	$1	$13	--
Maximum hold time from end of phase	60 months	60 months	--
Cost of termination following suspension ($/kW)	Negligible	$41	--
Cost of immediate termination ($/kW)	Negligible	$180	--

NATURAL GAS-FIRED SIMPLE-CYCLE GAS TURBINE POWER PLANTS

A simple-cycle gas turbine power plant (also called a combustion turbine or gas turbine generator) is an electric power generator driven by a gas turbine. Attributes of simple-cycle gas turbines include modularity, low capital cost, short development and construction period, compact size, siting flexibility and operational flexibility. The principal disadvantage is low thermal efficiency. Because of their low thermal efficiency compared to combined-cycle plants, simple-cycle gas turbines are typically used for low duty factor applications such as peak load and emergency backup service. Energy can be recovered from the turbine exhaust for steam generation, hot water production or direct use for industrial or commercial process heating. This greatly improves thermal efficiency and such plants are normally operated as base load units.

Because of the ability of the Northwest hydropower system to supply short-term peaking capacity, simple-cycle gas turbines have been a minor element of the regional power system. As of January 2004, about 1,560 megawatts of simple-cycle gas turbine capacity were installed in the Northwest, comprising about 3 percent of system capacity. One thousand three hundred thirty megawatts of this capacity is pure simple-cycle and 230 megawatts is cogeneration. The power price excursions, threats of shortages and poor hydro conditions of 2000 and 2001 sparked interest in simple-cycle turbines as a hedge against high power

[11] The portfolio risk model was calibrated in year 2004 dollars for draft plan analysis. Assumptions are presented here in year 2000 dollars for consistency with other assumptions and forecasts appearing in the plan. Year 2004 dollars are obtained by multiplying year 2000 dollars by an inflation factor of 1.10.

prices, shortages and poor water. About 360 megawatts of simple-cycle gas turbine capacity has been installed in the region since 2000, primarily by large industrial consumers exposed to wholesale power prices, utilities exposed to hydropower uncertainty or growing peak loads.

Technology

A simple-cycle gas turbine generator consists of a one or two-stage air compressor, fuel combustors, one or two power turbines and an electric generator, all mounted on one or two rotating shafts. The entire assembly is typically skid-mounted as a modular unit. Some designs use two gas turbines to power a single generator. Pressurized air from the air compressor is heated by burning liquid or gas fuel in the fuel combustors. The hot pressurized air is expanded through the power turbine. The power turbine drives the compressor and the electric power generator. Lube oil, starting, fuel forwarding, and control systems complete the basic package. A wide range of unit sizes is available, from less than 5 to greater than 170 megawatts.

Gas turbine designs include heavy industrial machines specifically designed for stationary applications and "aeroderivative" machines - aircraft engines adapted to stationary applications. The higher pressure (compression) ratios of aeroderivative machines result in a more efficient and compact unit than frame machines of equivalent output. Because of their lighter construction, aeroderivative machines provide superior operational flexibility including rapid black start capability, short run-up, rapid cool-down and overpower operating capability. Aeroderivative machines are highly modular and major maintenance is often accomplished by swapping out major components or the entire engine for a replacement, shortening maintenance outages. These attributes come at a price - industrial machines cost less on a per-kilowatt capacity basis and can be longer-lived. Both aeroderivative and industrial gas turbine technological development is strongly driven by military and aerospace gas turbine applications.

A simple-cycle gas turbine power plant consists of one to several gas turbine generator units. The generator sets are typically equipped with inlet air filters and exhaust silencers and are installed in acoustic enclosures. Water or steam injection, intercooling[12] or inlet air cooling can be used to increase power output. Nitrogen oxides (NOx) from fuel combustion are the principal emission of concern. Basic NOx control is accomplished by use of "low-NOx" combustors. Exhaust gas catalysts can further reduce nitrogen oxide and carbon monoxide production. Other plant components may include a switchyard, fuel gas compressors, a water treatment facility (if units are equipped with water or steam injection) and control and maintenance facilities. Fuel oil storage and supply system may be provided for alternate fuel purposes. Simple-cycle gas turbine generators are often co-located with gas-fired combined-cycle plants to take advantage of shared site infrastructure and operating and maintenance personnel.

Gas turbines can operate on either gas or liquid fuels. Pipeline natural gas is the fuel of choice in the Northwest because of historically low and relatively stable prices, widespread

[12] Chilling the compressed air between air compression stages.

availability and low air emissions. Distillate fuel oil, once widely used as backup fuel, has become less common because of environmental concerns regarding air emissions and on-site fuel storage and increased maintenance and testing. It is common to ensure fuel availability by securing firm gas transportation. Propane or liquified petroleum gas (LPG) are occasionally used as backup fuel.

Economics

The cost of power from a gas turbine plant is comprised of capital service costs, fixed and variable non-fuel operating and maintenance costs, fixed and variable fuel costs and transmission costs. Capital costs of a gas turbine generator plants vary greatly because of the wide range of ancillary equipment that may be required for the particular application. Features such as fuel gas compressors, selective catalytic controls for nitrogen oxides and carbon monoxide and water or steam injection add to the cost of the basic package. Transmission interconnection, gas pipeline laterals and other site infrastructure requirements can add greatly to the cost of a plant. A further factor affecting plant costs is equipment demand. During the price runups of 2000 and 2001, equipment prices ran 25 to 30 percent higher than current levels. The reported construction cost of aeroderivative units built in WECC since 2000 range from about $420 to $1,390 per kilowatt with an average of $740. The range for plants using industrial machines is $300 to $1,000 per kilowatt with an average of $580. The reference overnight capital cost of simple-cycle gas turbine power plants used for this plan is $600 per kilowatt. This is based on an aeroderivative unit. Reasons for this cost being somewhat lower than average are that it is an overnight cost, excluding interest during construction; it is in year 2000 dollars, whereas most of the WECC examples were constructed later; most of the WECC examples were built in response to the energy crisis of 2000 and 2001 during a sellers market; and finally, most of the examples are California projects with more constrained siting and design requirements that are required in the Northwest.

Fuel prices and the relatively low efficiency of simple-cycle gas turbines low are not a key issue for plants used for peaking and emergency use. Fuel cost is of greater concern for base-loaded cogeneration plants, however, the incremental fuel consumption attributable to electric power generation ("fuel charged to power") for cogeneration units is low compared to a pure simple-cycle machine. For example, the full-load heat rates of the reference gas turbine plants of this plan are as follows: aeroderivative, no cogeneration - 9,955 Btu per kilowatt-hour; industrial, combined-cycle - 7,340 Btu per kilowatt-hour; aeroderivative, cogeneration - 5,280 Btu per kilowatt-hour. Simple-cycle gas turbines have been constructed in the Northwest for the purpose of backing up the non-firm output of hydropower plants. The cost of fuel for this application can be significant since the turbine may need to operate at a high capacity factor over many months of a poor water year.

Development Issues

Simple-cycle gas turbines are generally easy to site and develop compared to most other power generating facilities.   Sites having a natural gas supply and grid interconnection facilities are common, the projects are unobtrusive, water requirements minimal and air emissions can be controlled to low levels. Simple-cycle gas turbine generators are often sited in conjunction with natural-gas-fired combined-cycle and steam plants to take advantage of the existing infrastructure.

Air emissions can be of concern, particularly in locations near load centers where ambient nitrogen oxide and carbon monoxide levels approach or exceed criteria levels. Post-combustion controls and operational limits are used to meet air emission requirements in these areas. The commercial introduction of high temperature selective catalytic controls for NOx and CO has enabled the control of NOx and CO emissions from simple-cycle gas turbines to levels comparable to combined-cycle power plants. Sulfur dioxide form fuel oil operation is controlled by use of low-sulfur fuel oil and by operational limits. Noise and vibration has been a concern at sites near residential and commercial areas and extra inlet air and exhaust silencing and noise buffering may be required at sensitive sites. Water is required for units employing water or steam injection but is not usually an issue for simple-cycle machines because of relatively low consumption. Gas-fired simple-cycle plants produce moderate levels of carbon dioxide per unit energy output.

Northwest Potential

Applications for simple-cycle gas turbines in the Northwest include backup for non-firm hydropower in poor water years (“hydropower firming”), peak load service, emergency system support, cogeneration (discussed in Appendix J), and as an alternative source of power during period of high power prices. Though simple-cycle turbines could be used to shape the output of windpower plants, the hydropower system is expected to be a more economic alternative for the levels of windpower development anticipated in this plan. Suitable sites are abundant and the most likely applications use little fuel. If natural gas use continues to grow, additional regional gas transportation or storage capacity may be needed to supply peak period gas needed to maintain the operating capability of simple-cycle gas turbines held for reserve or peaking purposes. Local gas transportation constraints may currently exist. Electric transmission is unlikely to be constraining because of the ability to site gas turbine generators close to loads.

Reference plant

The reference plant is based on an aeroderivative gas turbine generator such as the General Electric LM6000. The capacity of this class of machine ranges from 40 to 50 megawatts. The cost and performance characteristics of this plant are provided in Table I-8. Recently constructed simple-cycle projects in the Northwest have used both smaller machines as well as larger industrial gas turbines. Key characteristics of a plant using a typical industrial machine are also provided in Table I-8. The smaller gas turbines used for distributed generation are described in Appendix J.

Fuel is assumed to be pipeline natural gas. A firm gas transportation contract with capacity release provisions is assumed in lieu of backup fuel. Air emission controls include water injection and selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC reduction. Costs are representative of a two-unit installation co-located at an existing gas-fired power plant.

Benchmark[13] levelized electricity production costs for reference simple-cycle turbines are as follows:

Aeroderivative, 10 percent capacity factor (peaking or hydro firming service)	$152/MWh.
Industrial, 10 percent capacity factor (peaking or hydro firming service)	$127/MWh
Aeroderivative, 80 percent capacity factor (baseload service)	$57/MWh.
Industrial, 80 percent capacity factor (baseload service)	$53/MWh

The capacity cost (fixed costs, generally a better comparative measure of the cost of peaking or emergency duty projects) of the reference aeroderivative unit under the benchmark financing assumptions is $89 per kilowatt per year. The benchmark capacity cost of a typical plant using industrial gas turbine technology is $50 per kilowatt per year.

Table I-8: Resource characterization: Natural gas fuelled simple-cycle gas turbine power plant (Year 2000 dollars)

Description and technical performance		
Facility	Natural gas-fired twin-unit aeroderivative simple-cycle gas turbine plant. Reference plant consists of (2) 47 MW gas turbine generators and typical ancillary equipment. Low-NOx combustors, water injection and SCR for NOx control and CO oxidizing catalyst for CO and VOC control.	Selected cost and performance assumptions for a basic plant (low-NOx burners emission control) using typical (80 - 170 MW) industrial-grade gas turbines are noted. Additional emission controls and other ancillary equipment will increase costs. Industrial turbine performance will differ for some characteristics not noted.
Status	Commercially mature	
Applications	Peaking duty, hydropower or windpower firming, emergency service	
Fuel	Pipeline natural gas. Firm transportation contract with capacity release provisions.	
Service life	30 years	
Power (net)	New & clean: 47 MW/unit Lifecycle average: 46 MW/unit	New & Clean: GE LM6000PC Sprint ISO rating less 2% inlet & exhaust losses. Lifecycle average is based on capacity degradation of 4% at hot gas path maintenance time, 75% restoration at hot gas path maintenance and 100% restoration at major overhauls.
Operating limits	Minimum load: 25% of single turbine baseload rating. Cold startup: 8 minutes Ramp rate: 12.5 %/min	Heat rate begins to increase rapidly at about 70% load. Startup time & ramp rate are for Pratt & Whitney FT8.

[13] Average financing cost for 20 percent customer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer developer mix; 2010 service; firm natural gas, Westside delivery, medium case price forecast; no wheeling charges or losses, year 2000 dollars. No CO2 penalty.

Description and technical performance		
Availability	Scheduled outage: 10 days/yr Equivalent forced outage rate: 3.6% Mean time to repair: 80 hours Equivalent annual availability: 94%	The scheduled outage rate is based on a planned maintenance schedule comprised of 7-day annual inspections, 10-day hot gas path inspection & overhauls every sixth year and a 28-day major overhaul every twelfth year (inspection sequence is per General Electric recommendations. Actual intervals are a function of startups and hours of operation.). The assumed rate also includes two additional 28-day scheduled outages during the 30-year plant life. Based on the LM6000 fleet engine reliability of 98.8% (Fig 2 General Electric Power Systems. *GE Aeroderivative Gas Turbines - Design and Operating Features*, GER 3695e) and the assumption that engine-related outages represent about a third of all forced outages for a simple-cycle plant. Mean time to repair is NERC Generating Availability Data System (GADS) average for full outages.
Heat rate (HHV, net, ISO conditions)	New & clean: 9900 Btu/kWh Lifetime average: 9960 Btu/kWh Industrial machine: 10,500 Btu/kWh (lifetime average).	New & Clean is GRAC recommendation based on operator experience and typical vendor warranties. Lifecycle average based on capacity degradation of 1% during the hot gas path maintenance interval; 50% restoration at hot gas path maintenance and 100% restoration at major overhauls.
Heat rate improvement (surrogate for cumulative effect of non-cost technical improvements)	-0.5 %/yr average from 2002 base through 2025	Approximate 95% technical progress ratio (5% learning rate). See combined-cycle description for derivation.
Seasonal power output (ambient air temperature sensitivity)	Assumed to be similar to those used for gas-fired combined-cycle power plants (Figure I-1).	
Elevation adjustment for power output	Assumed to be similar to those used for gas-fired combined-cycle power plants (Table I-10).	

Costs		
Capital cost	$600/kW (overnight cost) Industrial machine: $375/kW.	Includes development and construction. Overnight cost excludes financing fees and interest during construction. Based on new and clean rating. Derived from reported plant costs (2002-03), adjusted to approximate equilibrium market conditions. Single unit cost about 10% greater.
Construction period cash flow (%/yr)	100% (one year construction)	See Table I-8 for phased development assumptions used in portfolio risk studies.
Fixed operating costs	$8.00/kW/yr. Industrial machine: $6.00/kW/yr.	Includes labor, fixed service costs, management fees and general and administrative costs and allowance for equipment replacement costs (some normally capitalized). Excludes property taxes and insurance (separately calculated in the Council's models as 1.4%/yr and 0.25%/yr of assessed value). Fixed O&M costs for a single unit plant estimated to be 167% of example plant costs. Based on new and clean rating.
Variable operating costs	$8/MWh Industrial machine: $4.00/MWh	Routine O&M, consumables, utilities and miscellaneous variable costs plus major maintenance expressed as a variable cost. Excludes greenhouse gas offset fee (separately calculated in the Council's models).
Incentives/Byproduct credits/CO2 penalties	Separately included in the Council's models.	
Interconnection and regional transmission costs	Simple-cycle units are assumed to be located within a utility's service territory.	
Regional transmission losses	Simple-cycle units are assumed to be located within a utility's service territory.	
Technology vintage cost change (constant dollar escalation)	-0.5 %/yr average from 2002 base through 2025 (capital and fixed O&M costs)	Approximate 95% technical progress ratio (5% learning rate). See combined-cycle description for derivation.

Typical air emissions (Plant site, excluding gas production & delivery)		
Particulates (PM-10)	0.09 T/GWh	Typical emissions at normal operation over range of loads (50 to 100%). From West Cascades Energy Facility Prevention of Significant Deterioration Application November 2003. http://www.lrapa.org/permitting/applications_submitted/
SO2	0.09 T/GWh	Ibid
NOx	0.009 - 0.01 T/GWh	Ibid
CO	0.09 - 0.11 T/GWh	Ibid
Hydrocarbons/VOC	0.08 T/GWh	Ibid
CO_2	582T/GWh	Based on EPA standard natural gas carbon content assumption (117 lb/MMBtu) and lifecycle average heat rate.

Development		
Assumed mix of developers	Expected mix: Consumer-owned utility: 40% Investor-owned utility: 40% Independent power producer: 20% Benchmark mix: Consumer-owned utility: 20% Investor-owned utility: 40% Independent power producer: 40%	Price forecasting (expected) mix is the GRAC recommendation for conventional coal-fired power plants. Resource comparison mix is used for the portfolio analysis and other benchmark comparisons of resources.
Development & construction schedule	Development - 18 months Construction - 12 months	"Straight-through" development. See Table I-8 for phased development assumptions used in portfolio risk studies.
Earliest commercial service	New sites - 2006	
Site availability and development limits through 2025	Adequate to meet forecast Northwest needs.	

Project Phasing Assumptions for the Portfolio Analysis

As described in Chapter 6, the portfolio risk model uses resource development flexibility as one means of coping with future uncertainties. Three phases of resource development are modeled: project development, optional construction and committed construction. The project development phase consists of siting, permitting and other pre-construction activities. Optional construction extends from the notice to proceed to irrevocable commitment of the major portion of construction cost (typically, completion of major equipment foundations in preparation for receipt of major plant equipment). The balance of construction through commercial operation is considered to be committed. In the portfolio model, plant construction can be continued, suspended or terminated at the conclusion of project development or optional construction phases. Projects can also be terminated while suspended. The cost and schedule assumptions associated with these decisions are shown in Table I-9. The cumulative schedule of the three project phases shown in Table I-9 is longer than the "straight-through" development and construction schedule shown in Table I-8.

Table I-9: Natural gas-fired simple-cycle project phased development assumptions for risk analysis (year 2000 dollars)[14]

	Project Development	Optional Construction	Committed Construction
Defining milestones	Feasibility study through completion of permitting	Notice to proceed to major equipment foundations complete	Accept major equipment to commercial operation
Time to complete (single unit, nearest quarter)	18 months	12 months	3 months
Cash expended (% of overnight capital)	2%	94%	5%
Cost to suspend at end of phase ($/kW)	Negligible	$25	--
Cost to hold at end of phase ($/kW/yr)	$1	$17	--
Maximum hold time from end of phase	60 months	60 months	--
Cost of termination following suspension ($/kW)	Negligible	-$158	--
Cost of immediate termination ($/kW)	Negligible	-$125	--

NATURAL GAS FUELED COMBINED-CYCLE GAS TURBINE POWER PLANTS

For over a decade, high thermal efficiency, low initial cost, high reliability, low air emissions, and until recently, low natural gas prices have led to the choice of combined-cycle gas turbines for new bulk power generation. Other attractive features include operational flexibility, inexpensive optional power augmentation for peak period operation and relatively low carbon dioxide production. Combined-cycle power plants have become an important element of the Northwest power system, comprising 68 percent of generating capacity additions from 2000 through 2004. Natural gas-fired combined-cycle capacity has increased to 14 percent of regional generating capacity.

Technology

A combined-cycle gas turbine power plant consists of one or more gas turbine generators equipped with heat recovery steam generators to capture heat from the turbine exhaust. Steam produced in the heat recovery steam generators powers a steam turbine generator to produce additional electric power. Use of the otherwise wasted heat of the turbine exhaust gas yields high thermal efficiency compared to other combustion technologies. Combined-

[14] The portfolio risk model was calibrated in year 2004 dollars for draft plan analysis. Assumptions are presented here in year 2000 dollars for consistency with other assumptions and forecasts appearing in the plan. Year 2004 dollars are obtained by multiplying year 2000 dollars by an inflation factor of 1.10.

cycle plants currently entering service can convert about 50 percent of the chemical energy of natural gas into electricity (HHV basis[15]). Cogeneration provides additional efficiency. In these, steam is bled from the steam generator, steam turbine or turbine exhaust to serve thermal loads[16].

A single-train combined-cycle plant consists of one gas turbine, a heat recovery steam generator (HSRG) and a steam turbine generator ("1 x 1" or "single train" configuration), often all mounted on a single shaft. F-class gas turbines - the most common technology in use for large plants - in this configuration can produce about 270 megawatts. Uncommon in the Northwest, but common in high load growth are plants using two or even three gas turbine generators and heat recovery steam generators feeding a single, proportionally larger steam turbine generator. Larger plant sizes result in construction and operational economies and slightly improved efficiency. A 2 x 1 configuration using F-class technology will produce about 540 megawatts of capacity. Other plant components include a switchyard for electrical interconnection, cooling towers for cooling the steam turbine condenser, a water treatment facility and control and maintenance facilities.

Additional peaking capacity can be obtained by use of inlet air chilling and duct firing (direct combustion of natural gas in the heat recovery steam generator to produce additional steam). 20 to 50 megawatts can be gained from a single-train F-class plant with duct firing. Though the incremental thermal efficiency of duct firing is lower than that of the base combined-cycle plant, the incremental capital cost is low and the additional electrical output can be valuable during peak load periods.

Gas turbines can operate on either gas or liquid fuels. Pipeline natural gas is the fuel of choice because of historically low and relatively stable prices, extensive delivery network and low air emissions. Distillate fuel oil can be used as a backup fuel, however, its use for this purpose has become less common in recent years because of additional emissions of sulfur oxides, deleterious effects on catalysts for the control of nitrogen oxides and carbon monoxide and increased testing and maintenance. It is common to ensure fuel availability by subscribing to firm gas transportation.

Combined-cycle plant development benefits from improved gas turbine technology, in turn driven by military and aerospace applications. The tradeoff to improving gas turbine efficiency is to increase power turbine inlet temperatures while maintaining reliability and maintaining or reducing NOx formation. Most recently completed combined-cycle plants use "F-class" gas turbine technology. F-class machines are distinguished by firing temperatures of 1,300^{o}C (2370^{o} F) and basic [17]HHV heat rates of 6,640 - 6,680 Btu per kilowatt-hour in combined-cycle configuration. More advanced "G-class" machines, now in early commercial service, operate at firing temperatures of about 1,400^{o} C (2550^{o} F) and basic HHV heat rates of 6,490 - 6,510 Btu per kilowatt-hour in combined-cycle configuration. H-class machines, entering commercial demonstration, feature steam cooling

[15] The energy content of natural gas can be expressed on a higher heating value or lower heating value basis. Higher heating value includes the heat of vaporization of water formed as a product of combustion, whereas lower heating value does not. While it is customary for manufacturers to rate equipment on a lower heating value basis, fuel is generally purchased on the basis of higher heating value. Higher heating value is used as a convention in Council documents unless otherwise stated.
[16] Though increasing overall thermal efficiency, steam bleed for CHP applications will reduce the electrical output of the plant.
[17] Higher heat value, new and clean, excluding air intake, exhaust and auxiliary equipment losses.

of hot section parts, firing temperatures in the 1,430^{o} C range (2,610^{o} F), and an expected HHV heat rate of 6,320 Btu per kilowatt-hour.

Economics

The cost of power from a combined-cycle plant is comprised of capital service costs, fixed and variable non-fuel operating and maintenance costs, fixed and variable fuel costs and transmission costs. Typically the largest component of these costs will be variable fuel cost. Combined-cycle gas turbines deliver high efficiency at low capital cost. The overnight capital cost of the reference combined-cycle plant, $525 per kilowatt, is the lowest of any of the generating technologies in this plan except for industrial simple-cycle gas turbines. As long as natural gas prices remained low, the result was a power plant capable of economical baseload operation at low capital investment - an unbeatable combination leading to the predominance of combined-cycle plant for capacity additions on the western grid over the past decade. Higher gas prices combined with depressed power prices have eroded this competitive advantage and many combined-cycle plants are currently operating at low capacity factors. The future economic position of combined-cycle plants is uncertain. If natural gas prices decline from current highs, these plans may again become economically competitive baseload generating plants. Their economic position could be further improved by more aggressive efforts to reduce carbon dioxide production. The low carbon-to-hydrogen ratio of natural gas and the high thermal efficiency of combined-cycle units could position the technology to displace conventional coal-fired plants if universal carbon dioxide caps or penalties were established.

Development Issues

Though natural gas production activities can incur significant environmental impacts, the environmental effects of combined cycle power plants are relatively minor. The principal environmental concerns associated with the operation of combined-cycle gas turbine plants are emissions of nitrogen oxides and carbon monoxide. Fuel oil operation may produce in addition, sulfur dioxide. Nitrogen oxide abatement is accomplished by use of "dry low-NOx" combustors and selective catalytic reduction within the heat recovery steam generator. Limited quantities of ammonia are released by operation of the nitrogen oxide selective catalytic reduction system. Carbon monoxide emissions are typically controlled by use of an oxidation catalyst within the heat recovery steam generator. If operating on natural gas, no special controls are used for particulates or sulfur oxides as these are produced only in trace amounts. Low sulfur fuel oil and limitation on hours of operation are used to control sulfur oxides when using fuel oil.

Though proportionally about two thirds less than for steam-electric technologies, the cooling water consumption of combined-cycle plants is significant if evaporative cooling is used. Water consumption for power plant condenser cooling appears to be an issue of increasing importance in the arid west. Water consumption can be reduced by use of dry (closed-cycle) cooling, though at added cost and reduced efficiency. Over time it appears likely that an increasing number of new projects will use dry cooling.

Carbon dioxide, a greenhouse gas, is an unavoidable product of combustion of fossil fuels. However, because of the relatively low carbon content of natural gas and the high efficiency of combined-cycle technology, the carbon dioxide production of a gas-fired combined-cycle plant on a unit output basis is much lower than that of other fossil fuel technologies. The reference plant, described below, would produce about 0.8 pounds CO_2 per kilowatt-hour output, whereas a new coal-fired power plant would produce about 2 pounds CO_2 per kilowatt-hour.

Northwest Potential

New combined-cycle power plants would be constructed in the Northwest for the purpose of providing base and intermediate load service. While the economics of combined-cycle plants are currently less favorable than in the recent past, a decline in natural gas prices or more aggressive carbon dioxide control efforts could lead to additional development of combined-cycle plants. Suitable sites are abundant, including many close to Westside load centers. Proximity to natural gas mainlines and access to loads via existing high voltage transmission are the key site requirements. Secondary factors include water availability, ambient air quality and elevation. Permits are currently in place for several thousand megawatts of new combined-cycle capacity and are being sought for several thousand more.

More constraining may be future natural gas supplies. While there is currently no physical shortage of domestic natural gas, consensus is emerging that ability to tap the abundant off-shore sources of natural gas via LNG import capability will be necessary to control long-term natural gas prices.

Reference plant

The reference plant is based on an F-class gas turbine generator in 2 x 1 combined-cycle configuration. The baseload capacity is 540 megawatts and the plant includes an additional 70 megawatts of power augmentation using duct burners. The plant is fuelled with pipeline natural gas using an incrementally-priced firm gas transportation contract with capacity release provision. No backup fuel is provided. Air emission controls include dry low-NOx combustors and selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC control. Condenser cooling is wet mechanical draft. Specific characteristics of the reference plant are shown in Table I-10. Key cost and performance characteristics for a single-train (1x1) plant are also noted.

Benchmark[18] levelized electricity production costs for reference combined-cycle turbines are as follows:

540/610 MW combined-cycle, baseload increment, 80 percent capacity factor	\$41/MWh
540/610 MW combined-cycle, peaking increment, 10 percent capacity factor	\$117/MWh
270/305 MW combined-cycle, baseload increment, 80 percent capacity factor	\$43/MWh
270/305 MW combined-cycle, peaking increment, 10 percent capacity factor	\$126/MWh

[18] Average financing cost for 20 percent customer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer developer mix; 2010 service; firm natural gas, Westside delivery, medium case price forecast; no wheeling charges or losses, year 2000 dollars. No CO2 penalty.

The capacity cost (fixed costs, generally a better comparative measure of the cost of peaking or emergency duty projects) for the peaking increment of the reference 540/610 megawatt unit under the benchmark financing assumptions is $71 per kilowatt per year. The capacity cost for the peaking increment of the reference 270/305 megawatt unit under the benchmark financing assumptions is $79 per kilowatt per year.

Table I-10: Resource characterization: Natural gas combined-cycle plant (Year 2000 dollars)

Description and technical performance		
Facility	Natural gas-fired combined-cycle gas turbine power plant. 2 GT x 1 ST configuration. F Class gas turbine technology. 540 MW new & clean baseload output @ ISO conditions, plus 70 MW of capacity augmentation (duct-firing). No cogeneration load. Dry SCR for NOx control, CO catalyst for CO control. Wet mechanical draft cooling.	Key cost and performance assumptions for single train (1x1) plants are noted.
Status	Commercially mature	
Application	Baseload and peaking generation, cogeneration	
Fuel	Pipeline natural gas. Firm transportation contract with capacity release provisions.	
Service life	30 years	
Power (net)	New & clean: 540 MW (baseload), 610 MW (peak) Lifetime average: 528 MW (baseload), 597 MW (peak)	Lifetime average is based on 1 % degradation per year and 98.75% recovery at hot gas path inspection or major overhaul (General Electric).
Operating limits	Minimum load: 40% of baseload rating. Cold startup: 3 hours Ramp rate: 7 %/min	Minimum load for single-train plant is 80% of baseload rating. Minimum load is assumed to be one gas turbine in service at point of minimum constant firing temperature operation.
Availability	Scheduled outage: 18 days/yr Equivalent forced outage rate: 5% Mean time to repair: 24 hours Equivalent annual availability: 90% (Reduce 2.2% if using new & clean capacity)	The scheduled outage rate is based on a planned maintenance schedule comprised of 7-day annual inspections, 10-day hot gas path inspection & overhauls every third year and a 28-day major overhaul every sixth year (General Electric recommendations for baseload service). The assumed rate also includes two additional 28-day scheduled outages and one six-month plant rebuild during the 30-year plant life. The forced outage rate is from NERC Generating Availability Data System (GADS) weighted average equivalent forced outage rate for combined-cycle plants. Mean time to repair is GADS average for full outages.

Description and technical performance		
Heat rate (HHV, net, ISO conditions)	New & clean (Btu/kWh): 6880 (baseload); 9290 (incremental duct firing); 7180 (full power) Lifetime average (Btu/kWh): 7030 (baseload); 9500 (incremental duct firing); 7340 (full power). 2002 base technology.	Baseload is new & clean rating for GE 207FA. Lifetime average is new & clean value derated by 2.2%. Degradation estimates are from General Electric. Duct firing heat rate is Generating Resource Advisory Committee (GRAC) recommendation.
Technology vintage heat rate improvement (Surrogate for cumulative non-cost technical improvements)	-0.5 %/yr average from 2002 base through 2025	Approximate 95% technical progress ratio (5% learning rate). Mid-range between EIA Assumptions to the Annual Energy Outlook 2004 (Table 39) (pessimistic) & Chalmers University of Technology, Feb 2001 (Sweden) (optimistic). Forecast WECC penetration is used as surrogate for global production.
Seasonal power output (ambient air temperature sensitivity)	Figure I-1	Figure I-1 is based on power output ambient temperature curve for a General Electric STAG combined-cycle plant, from Figure 34 of GE Combined-cycle Product Line and performance (GER 3574H) and 30-year monthly average temperatures for the sites shown.
Elevation adjustment for power output	Table I-11	Based on the altitude correction curve of Figure 9 of General Electric Power Systems GE Gas Turbine Performance characteristics (GER 3567H).

Costs & development schedule		
Capital cost (Overnight, development and construction)	Baseload configuration: $565/kW Power augmentation configuration: $525/kW Incremental cost of power augmentation (duct burners) $225/kW.	Assumes development costs are capitalized. Overnight cost excludes financing fees and interest during construction. 1x1 plant estimated to cost 110% of example plant. Based on new and clean rating. Derived from reported plant costs (2002), adjusted to approximate equilibrium market conditions.
Development & construction cash flow (%/yr)	Cash flow for "straight-through" 48-month development & construction schedule: 2%/2%/24%/72%	See Table I-11 for phased development assumptions used in portfolio risk studies.
Fixed operating costs	Baseload configuration: $8.85/kW/yr. Power augmentation configuration: $8.10/kW/yr.	Includes operating labor, routine maintenance, general & overhead, fees, contingency, and allowances for (normally) capitalized equipment replacement costs and startup costs. Excludes property taxes and insurance (separately calculated in the Council's models as 1.4%/yr and 0.25%/yr of assessed value). Fixed O&M costs for a 1x1 plant estimated to be 167% of example plant costs. Values are based on new and clean rating.

Costs & development schedule		
Variable operating costs	$2.80/MWh	Includes consumables, SCR catalyst replacement, makeup water and wastewater disposal costs, long-term major equipment service agreement, contingency and an allowance for sales tax. Excludes any CO2 offset fees or penalties.
Incentives/Byproduct credits/CO2 penalties	Separately included in the Council's models.	
Interconnection and regional transmission costs	$15.00/kW/yr	Bonneville point-to-point transmission rate (PTP-02) plus Scheduling, System Control and Dispatch, and Reactive Supply and Voltage Control ancillary services, rounded. Bonneville 2004 transmission tariff.
Regional transmission losses	1.9%	Bonneville contractual line losses.
Technology vintage cost change (constant dollar escalation)	-0.5 %/yr average from 2002 base through 2025 (capital and fixed O&M costs)	See technology vintage heat rate improvement, above.

Typical air emissions (Plant site, excluding gas production & delivery)		
Particulates (PM-10)	0.02 T/GWh	River Road project permit limit
SO2	0.002 T/GWh	River Road project actual
NOx	0.039 T/GWh	Ibid
CO	0.005 T/GWh	Ibid
Hydrocarbon/VOC	0.0003 T/GWh	Ibid
Ammonia	0.0000006 T/GWh	Ibid. Slip from catalyst.
CO_2	411 T/GWh (baseload operation) 429 T/GWh (full power operation)	Based on EPA standard natural gas carbon content assumption (117 lb/MMBtu) and lifecycle average heat rates.

Development		
Assumed mix of developers	For electricity price forecasting: Consumer-owned utility: 20% Investor-owned utility: 20% Independent power producer: 60% For resource comparisons & portfolio analysis: Consumer-owned utility: 20% Investor-owned utility: 40% Independent power producer: 40%	Price forecasting (expected) mix is a GRAC recommendation. Resource comparison mix is a standard mix for comparison of resources.
Development & construction schedule	Development - 24 Months Construction - 24 months	"Straight-through" development. See Table I-11 for phased development assumptions used in portfolio risk studies.
Earliest commercial service	Suspended projects - 2006 Permitted sites - 2007	
Site availability and development limits through 2025	Adequate to meet forecast Northwest needs.	

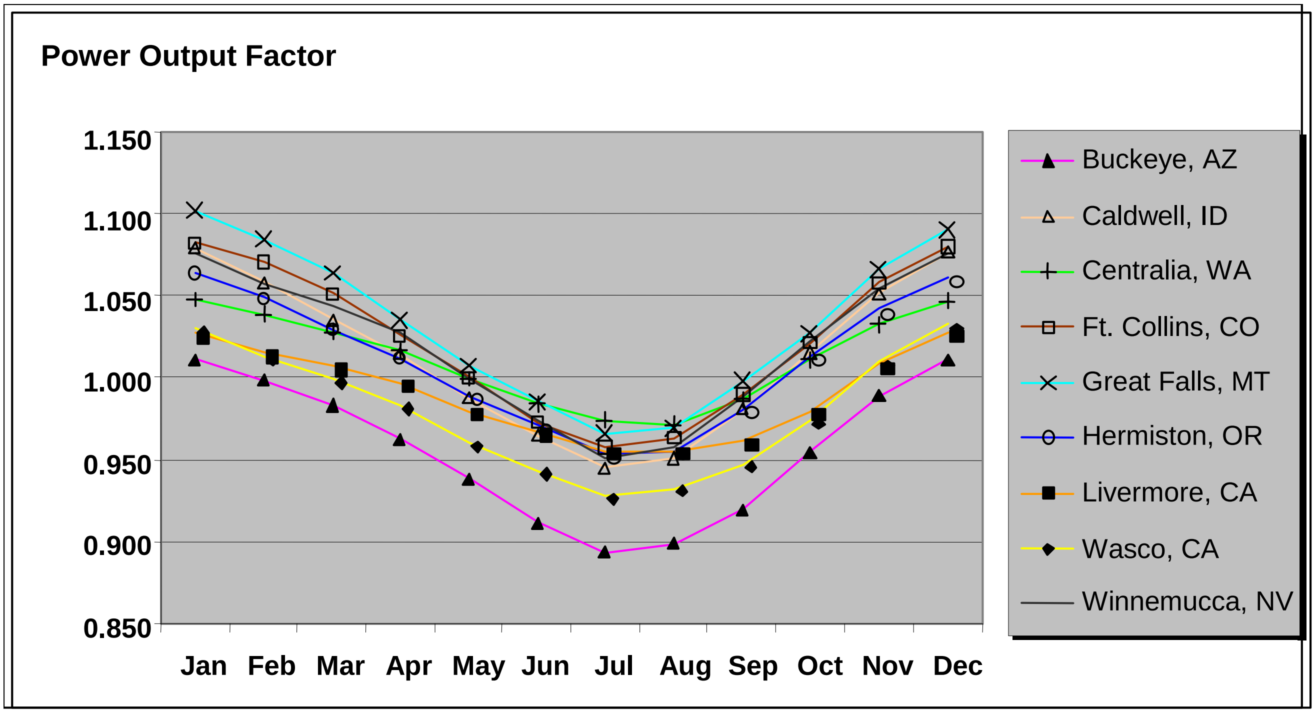

Figure I-1: Gas turbine combined-cycle average monthly power output temperature correction factors for selected locations (relative to ISO conditions)

Table I-11: Gas turbine power output elevation correction factors for selected locations

Location	Elevation (ft)	Power Output Factor
Buckeye, AZ (near Palo Verde)	890	0.972
Caldwell, ID	2370	0.923
Centralia, WA	185	0.995
Ft. Collins, CO	5004	0.836
Great Falls, MT	3663	0.880
Hermiston, OR	640	0.980
Livermore, CA	480	0.985
Wasco, CA (nr. Kern County plants)	345	0.990
Winnemucca, NV	4298	0.859

Project Phasing Assumptions for the Portfolio Analysis

As described in Chapter 6, the portfolio risk model uses resource development flexibility as one means of coping with future uncertainties. Three phases of resource development are modeled: project development, optional construction and committed construction. The project development phase consists of siting, permitting and other pre-construction activities. Optional construction extends from the notice to proceed to irrevocable commitment of the major portion of construction cost (typically, completion of major equipment foundations in preparation for receipt of major plant equipment). The balance of construction through commercial operation is considered to be committed. In the portfolio model, plant construction can be continued, suspended or terminated at the conclusion of project development or optional construction phases. Projects can also be terminated while suspended. The cost and schedule assumptions associated with these decisions are shown in Table I-12. The cumulative schedule of the three project phases shown in Table I-12 is longer than the "straight-through" development and construction schedule shown in Table I-10.

Table I-12: Natural gas combined-cycle project phased development assumptions for risk analysis (year 2000 dollars)[19]

	Development	**Optional Construction**	**Committed Construction**
Defining milestones	Feasibility study through completion of permitting	Notice to proceed to major equipment foundations complete	Accept major equipment to commercial operation
Time to complete (single unit, nearest quarter)	24 months	15 months	12 months
Cash expended (% of overnight capital)	4%	24%	72%
Cost to suspend at end of phase ($/kW)	Negligible	$169	--
Cost to hold at end of phase ($/kW/yr)	$1	$4	--
Maximum hold time from end of phase	60 months	60 months	--
Cost of termination following suspension ($/kW)	Negligible	$25	--
Cost of immediate termination ($/kW)	Negligible	$100	--

WINDPOWER

The first commercial-scale wind plant in the Northwest was the 25 megawatt Vansycle project in Umatilla County, Oregon, placed in service in 1998. Development of windpower proceeded rapidly following the energy crisis of 2000 and six commercial-scale projects totaling 541 megawatts of capacity are now in-service in the region. Regional utilities also own or contract for the output of Wyoming projects developed during this same period. Together, these projects currently comprise 651 megawatts of installed capacity, about 1.3 percent of the total capacity available to the region. This capacity produces about 220 average megawatts of energy. Declining power prices and expiration of federal production tax credits at the end of 2003 brought an end to this period of rapid wind power development. However, Northwest utilities continue to be interested in securing additional windpower and

[19] The portfolio risk model was calibrated in year 2004 dollars for draft plan analysis. Assumptions are presented here in year 2000 dollars for consistency with other assumptions and forecasts appearing in the plan. Year 2004 dollars are obtained by multiplying year 2000 dollars by an inflation factor of 1.10.

development is expected to resume following the recent extension of the production tax credit through 2005.

Technology

Wind energy is converted to electricity by wind turbine generators - tower-mounted electric generators driven by rotating airfoils. Because of the low energy density of wind, utility-scale wind turbine generators are physically large, and a wind power plant comprised of tens to hundreds of units. In addition to the wind turbine generators, a wind power plant (often called a “wind farm”) includes meteorological towers, service roads, a control system (often remote), a voltage transformation and transmission system connecting the individual turbines to a central substation, a substation to step up voltage for long-distance transmission and an electrical interconnection to the main transmission grid.

The typical utility-scale wind turbine generator is a horizontal axis machine of 600 to 1,500 kilowatts capacity with a three-bladed rotor 150 to 250 feet in diameter. The machines are mounted on tubular towers ranging to over 250 feet in height. Trends in machine design include improved airfoils; larger machines; taller towers and improved controls. Improved airfoils increase energy capture. Larger machines provide economies of manufacturing, installation and operation. Because wind speed generally increases with elevation above the surface, taller towers and larger machines intercept more energy. Machines for terrestrial applications are fully commercial and as reliable as other forms of power generation. Turbine size has increased rapidly in recent years and multi-megawatt (2 - 4.5 megawatts) machines are being introduced. These are expected to see initial service in European offshore applications.

Economics

The cost of power from a wind plant is comprised of capital service costs, fixed and variable operating and maintenance costs, system integration costs and transmission costs. Capital costs represent the largest component of overall costs and machine costs the largest component of capital costs. Though capital costs of wind power plants have remained relatively constant near $1,000 per kilowatt for several years, production costs have declined because of improvements in turbine performance and reliability, site selection and turbine layout. Busbar (unshaped) energy production costs at better sites are now in the range of $40-50 per megawatt-hour, excluding incentives.

Shaping costs are reported to be in the range of $3 to 7 per megawatt-hour, much lower than earlier estimates. While this range may be representative of the cost of shaping the output of the next several hundred megawatts of wind power developed in the region, shaping costs for additional levels of windpower development are uncertain. In the Northwest, shaping of additional increments of windpower capacity may draw water from higher value uses, increasing shaping cost. Offsetting this is the possible effect of geographic diversity in reducing the variability of windpower output. We assume a $4.55 per megawatt-hour shaping cost for the first 2,500 megawatts of wind capacity. The cost of shaping the second 2,500 megawatts of wind capacity, and any Montana capacity is assumed to be $9.75 per megawatt-hour.

The competitive position of wind power remains heavily dependent upon the federal production tax credit and to a lesser extent the value of green tags. Project construction ceased with expiration of the production tax credit at the end of 2003. The recent one-year reinstatement of the production tax credit will likely bring the cost of windpower below wholesale power value and result in a cycle of new development. But unless natural gas prices remain high, and mandatory carbon dioxide penalties enacted, it will be several years before wind power can compete with other resource options without incentives. The most important incentive is the federal production tax credit, currently about $18 per megawatt-hour, available for the first ten years of project operation. Complementing the production tax credit have been energy premiums resulting from the market for “green” power that has developed in recent years. This market is driven by retail green power offerings, utility efforts to diversify and “green up” resource portfolios, green power acquisition mandates imposed by public utility commissions as a condition of utility acquisitions, renewable portfolio standards and system benefits funds established in conjunction with industry restructuring. Because of the great uncertainty regarding future production tax credit and green tag values, these are modeled as uncertainties in the portfolio risk analysis (Chapter 6).

Development Issues

Many of the issues that formerly impeded the development of wind power have been largely resolved in recent years, clearing the way for the significant development that has occurred in the Northwest. Avian mortality, aesthetic and cultural impacts have been alleviated in the Northwest by the use of sites in dryland agriculture. The impact of wind machines on birds, which has been significant at some California wind plants has been also reduced by better understanding of the interrelationship of birds, habitat and wind turbines. Siting on arid habitat of low ecological productivity, elimination of perching sites on wind machines, slower turbine rotation speeds, and siting of individual turbines with a better understanding of avian behavior have greatly reduced avian mortality at recently developed projects. Bat mortality, however, is of concern at some sites.

It appears likely that several hundred to a thousand or more megawatts of wind power can be shaped at relatively low cost. The cost of firming and shaping the full amount of wind energy included in this plan are uncertain, pending further operating experience and analysis. Northwest wind development to date has not required expansion of transmission capacity, which can be expensive for wind developers because of the low capacity factor of wind plants. The wind potential included in this plan is expected to be accessible without significant expansion of transmission capacity.

Development of the high quality and extensive wind resources of eastern Montana is confronted by the same transmission issues faced by development of mine mouth coal-fired power plants in eastern Montana, except that the comparatively low capacity factor of a wind project renders transmission even more expensive. Though the eastern transmission interties are largely committed, several hundred megawatts of additional transmission capacity may be available at low cost through better use of existing capacity and low-cost upgrades to existing circuits. This potential is currently under evaluation. Export of additional power from eastern Montana would require the construction of new long-distance transmission circuits. Preliminary estimates of the cost of an additional 500kV circuit out of eastern

Montana indicate that the resulting cost of power delivered to the Mid-Columbia area would not be competitive with the cost of power from wind plants sited in resource areas of lesser quality west of the Continental Divide. Additional obstacles to construction of new eastern intertie circuits include long lead time (six to eight years from conception to energization), limited corridor options for crossing the Rocky Mountains and the current lack of an entity capable of large-scale transmission planning, financing and construction.

Northwest Potential

Winds blow everywhere and a few very windy days annually may earn a site a windy reputation, but only areas with sustained strong winds averaging roughly 15 mph, or more are suitable for electric power generation. A good wind resource area will have smooth topography and low vegetation to minimize turbulence, sufficient developable area to achieve economies of scale, daily and seasonal wind characteristics coincident to electrical loads, nearby transmission, complementary land use and absence of sensitive species and habitat. Because of the low capacity factors typical of wind generation, transmission of unshaped wind energy is expensive. Interconnection distance and distance to shaping resources are very important.

Because of complex topography and land use limitations, only localized areas of the Northwest are potentially suitable for windpower development. However, excellent sites are found within the region. Wind resource areas in the Northwest include coastal sites with strong but irregular storm driven winds and summertime northwesterly winds. Areas lying east of gaps in the Cascade and Rocky mountain ranges receive concentrated prevailing westerly winds plus wintertime northerly winds and winds generated by east-west pressure differentials. The Stateline area east of the Columbia River Gorge, Kittitas County in Washington and the Blackfoot area of north central Montana are of this type. A third type of regional wind resource area is found on the north-south ridges of the Basin and Range geologic region of southeastern Oregon and southern Idaho.

Intensive prospecting and monitoring are required to confirm the potential of a wind resource area. Though much wind resource information is proprietary, the results of early resource assessment efforts of the Bonneville Power Administration, the U.S. Department of Energy and the State of Montana, recently compiled resource maps based on computer modeling plus a the locations of announced wind projects give a sense of the general location and characteristics of prime Northwest wind resource areas. Educated guesses by members of the Council's Generating Resource Advisory Committee suggest that several thousand megawatts of developable potential occur within feasible interconnection distance of existing transmission. This estimate is supported by the 3,600 megawatts aggregate capacity of announced but undeveloped wind projects. For the base case portfolio analyses and power price forecasting we assume 5,000 megawatts of developable potential west of the Continental Divide.

Reference plants

The reference plant is a 100-megawatt wind plant located in a prime wind resource area within 10 to 20 miles of an existing substation. The plant would consist of 50 to 100 utility-scale wind machines. Sites west of the Rocky Mountains are classified into two blocks of 2,500 megawatts each. The first block represents the best, undeveloped sites, with an average capacity factor of 30 percent. These sites are assumed to be the first developed and thereby secure relatively low shaping costs of $4.55 per megawatt-hour. The second block is of lesser quality, yielding a capacity factor of 28 percent[20]. Because these lesser quality sites are likely to be developed later than the first block, they are assumed to incur higher shaping costs of $9.75 per megawatt-hour. Sites east of the Rocky Mountains are assumed to yield a capacity factor of 36 percent and incur a shaping cost of $9.75 per megawatt-hour. These sites are electrically isolated from the regional load centers and would require construction of long-distance transmission to access outside markets. Planning assumptions for the three resource blocks are provided in Table I-13.

The Northwest Transmission Assessment Committee of the Northwest Power Pool is developing cost estimates for additional transmission from eastern Montana to the Mid-Columbia area. As of this writing, only very preliminary estimates of the cost of a new 500 kV AC circuit were available. These, together with other modeling assumptions regarding additional eastern Montana - Mid-Columbia transmission are shown in Table I-4.

The benchmark[21] levelized electricity production costs for reference wind power plants, power shaped and delivered as shown, are as follows:

Eastern Montana, local service	$41/MWh
Eastern Montana, via existing transmission to Mid-Columbia area	$40/MWh
Eastern Montana, via new transmission to Mid-Columbia area, shaped @Mid-C	$82/MWh
Mid-Columbia, Block I	$43/MWh
Mid-Columbia, Block II	$50/MWh

[20] Because of portfolio model limitations, this block was assumed to operate at a 30 percent capacity factor.
[21] Average financing cost for 20 percent customer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer developer mix; 2010 service; Montana coal, year 2000 dollars. No production tax credit or green tag credit.

Table I-13: Resource characterization: Wind power plants (Year 2000 dollars)

Facility description and technical performance		
Facility	100 MW central-station wind power project.	Utility-scale projects may range from 25 to 300 MW.
Status	Commercial	.
Application	Intermittent baseload power generation	
Fuel	n/a	
Service life	30 years	Typical design life for Danish wind turbine generators is estimated to be 20 years (Danish Wind Industry Association). 30 years, with allowance for capital replacement is used for consistency with other resources.
Power	100 MW	Net of in-farm and local interconnection losses.
Operating limits	n/a	
Availability	Scheduled outage: Included in capacity factor estimate. Equivalent forced outage rate: Included in capacity factor estimate. Mean time to repair: Zero hours	
Capacity factor	West of Continental Divide Block 1: 30% West of Continental Divide Block 2: 28% East of Continental Divide Block 3: 36%	Net of in-farm and local interconnection losses and outages and elevation (atmospheric density) effects.
Technology development	2000-04 annual average: -3.1 % 2005-09 annual average: -2.3 % 2010-14 annual average: -2.1 % 2015-19 annual average: -1.9 %	Applied to capital and fixed O&M cost. Represents effective reduction in production cost from cost & performance improvements. Based on 90% technical progress ratio (10% learning rate), derived from historical trends.
Seasonal power output	Table I-14	
Diurnal power output	None assumed	Insufficient evidence of diurnal pattern for Northwest resource areas.
Elevation adjustment for power output	Implicit in capacity factor.	

Costs		
Development & construction	$1010/kW (overnight). Range $1120/kW (25 MW project) to $930/kW (300 MW project).	Includes project development, turbines, site improvements, erection, substation, startup costs & working capital. "Overnight" cost excludes interest during construction.
Development and construction annual cash flow	1% - 13% - 86%	"Straight-through" development. See Table I-4 for phased development assumptions used in portfolio risk studies.
Capital replacement	$2.50/kW/yr	Levelized cost of major capital replacements over life of facility (e.g. blade or gearbox replacement) (EPRI, 1997)

Costs		
Fixed operating cost	$17.50/kW/yr. plus property tax & insurance. Property tax: 1.4%/yr of capital investment Insurance: 0.25%/yr of capital investment	Includes operating labor, routine maintenance, general & overhead costs
Variable operating cost	$1.00/MWh	Land lease
Interconnection and in-region firm-point-to-point transmission and required ancillary services.	$15.00/kW/yr	Bonneville point-to-point transmission rate (PTP-02) plus Scheduling, System Control and Dispatch, and Reactive Supply and Voltage Control ancillary services, rounded
Transmission energy loss adjustment.	1.9%	Represents transmission losses within modeled load-resource area. Losses between load-resource areas are separately modeled. (BPA contractual line losses.) Omit for busbar calculations.
Vintage cost escalation (technology development)	2000-04 annual average: -3.1 % 2005-09 annual average: -2.3 % 2010-14 annual average: -2.1 % 2015-19 annual average: -1.9 %	Net reduction in capital and fixed O&M cost of cost & performance improvements. Based on 10% learning rate (90% progress ratio) for each doubling in global capacity.
Shaping cost	West of Continental Divide Block 1: $4.55/MWh West of Continental Divide Block 2: $9.75MWh East of Continental Divide Block 3: $9.75/MWh	Applied to simulate flat product comparable to dispatchable resources.
Production tax credit	Modeled as described in Chapter 6	
Value of “green” attributes	Modeled as described in Chapter 6	

Development		
Assumed mix of developers	For electricity price forecasting: Consumer-owned utility: 15% Investor-owned utility: 15% Independent power producer: 70% For resource comparisons & portfolio analysis: Consumer-owned utility: 20% Investor-owned utility: 40% Independent power producer: 40%	Price forecasting (expected) mix is a GRAC recommendation. Resource comparison mix is a standard mix for comparison of resources.
Development & construction schedule	Development - 18 months Construction - 12 months	“Straight-through” development. See Table I-4 for phased development assumptions used in portfolio risk studies.
Earliest commercial service	Permitted sites - 2005 New sites - 2008	
Resource availability and development limits 2005 - 2024	West of Cascades: 500 MW ID, OR, WA east of Cascades: 4500 MW MT in-state - no limit MT to Mid-Columbia - 400 MW w/existing transmission	

Table I-14: Normalized monthly wind energy distribution

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Basin & Range	1.19	1.39	1.07	1.05	0.94	0.71	0.56	0.61	0.72	0.74	1.59	1.43
Cascades & Inland	1.03	0.90	1.07	1.07	1.21	1.07	1.11	1.07	0.94	0.73	0.85	0.96
Northwest Coast	1.19	1.57	1.07	0.86	0.84	0.84	1.01	0.54	0.66	0.80	1.40	1.21
Rockies & Plains	1.61	1.57	1.02	0.84	0.77	0.73	0.35	0.42	0.52	1.00	1.30	1.88

Project Phasing Assumptions for the Portfolio Analysis

As described in Chapter 6, the portfolio risk model uses resource development flexibility as one means of coping with future uncertainties. Three phases of resource development are modeled: project development, optional construction and committed construction. The project development phase consists of siting, permitting and other pre-construction activities. Optional construction extends from the notice to proceed to irrevocable commitment of the major portion of construction cost (typically, completion of major equipment foundations in preparation for receipt of major plant equipment). The balance of construction through commercial operation is considered to be committed. In the portfolio model, plant construction can be continued, suspended or terminated at the conclusion of project development or optional construction phases. Projects can also be terminated while suspended. The cost and schedule assumptions associated with these decisions are shown in Table I-15. The cumulative schedule of the three project phases shown in Table I-15 is longer than the "straight-through" development and construction schedule shown in Table I-13.

Table I-15: Wind project phased development assumptions for risk analysis (year 2000 dollars)[22]

	Development	Optional Construction	Committed Construction
Defining milestones	Feasibility study through completion of permitting	Turbine order through ready to ship	Turbine acceptance to commercial operation
Time to complete (nearest quarter)	18 months	9 months	6 months
Cash expended (% of overnight capital)	2%	12%	86%
Cost to suspend at end of phase ($/kW)	Negligible	$263	--
Cost to hold at end of phase ($/kW/yr)	$1	$4	--

[22] The portfolio risk model was calibrated in year 2004 dollars for draft plan analysis. Assumptions are presented here in year 2000 dollars for consistency with other assumptions and forecasts appearing in the plan. Year 2004 dollars are obtained by multiplying year 2000 dollars by an inflation factor of 1.10.

	Development	Optional Construction	Committed Construction
Maximum hold time from end of phase	60 months	60 months	--
Cost of termination following suspension ($/kW)	Negligible	63	--
Cost of immediate termination ($/kW)	Negligible	$308	--

ALBERTA OIL SANDS COGENERATION

The oil sands[23] of northern Alberta contain an estimated 1.6 trillion barrels initial volume in place, the largest petroleum deposits outside the Middle East. Three major resource areas are present - Athabasca, Peace River and Cold Lake. Oil sands are comprised of unconsolidated grains of sand surrounded by a film of water and embedded in matrix of bitumen[24], water and gas (air and some methane). The mean bitumen content of Alberta oil sands ranges from 10 to 12 percent by weight. Extracted bitumen can be upgraded to a synthetic crude oil that can be processed by conventional refineries. Rising oil prices have made bitumen extraction and processing economic and production is expected to expand rapidly in coming years. Oil sands production currently comprise about one third of total Canadian oil production.

Bitumen is recovered from near-surface deposits using open pit mining followed by separation of the bitumen from the extracted oil sands. The extraction process uses hot water to separate the bitumen from the sand. About 75 percent of the bitumen is recovered and the residue is returned to the pit. Yield is about one barrel of oil for every two tons of extracted oil sands.

Bitumen from deep deposits is recovered using in-situ methods. The predominant method is steam assisted gravity drainage (SAGD). Steam is injected via injection wells to raise the temperature of the formation to the point where the bitumen will flow. The liquid bitumen is recovered using conventional production wells. It is estimated that about 80 percent of recoverable reserves will use in-situ methods.

The steam for in-situ injection can be produced using coke or natural gas-fired boilers. A more efficient approach is to cogenerate steam using gas turbine generators. Natural gas or synthetic gas derived from residuals of bitumen upgrading is used to fuel the gas turbines. Approximately 2,000 megawatts of oil sands cogeneration is in service. Additional development of electric generating capacity is constrained by limited transmission access to electricity markets. A 2,000-megawatt DC intertie from the oil sands region to the Celilo converter station near The Dalles, with intermediate converter stations near Calgary and possibly Spokane has been proposed as a means of opening markets for electricity from oil sands cogeneration. The transmission could be energized as early as 2011.

[23] Formerly known as “tar sands”.
[24] Bitumen is a heavy, solid or semi-solid black or brown hydrocarbon comprised of asphaltenes, resins and oils, soluble in organic solvents. Alberta oil sands bitumen is the consistency of cold molasses at room temperature.

Economics

The cost of power from a gas turbine power plant is comprised of capital service costs, fixed and variable non-fuel operating and maintenance costs, fixed and variable fuel costs and transmission costs. In a cogeneration facility the fuel cost components are generally allocated between the cogeneration thermal load and electricity generation using a "fuel charged to power" heat rate. For a gas turbine cogeneration plant this heat rate is considerably lower than the stand-alone heat rate of the gas turbine unit. For example, the expected fuel charged to power heat rate of the proposed F-class gas turbine cogeneration units for oil sands application is 5,800 Btu per kilowatt-hour (HHV). This compares to a stand-alone HHV heat rate for an F-class machine of 10,390 Btu per kilowatt-hour. Because of the low effective heat rate and need for a constant steam supply, a gas turbine cogeneration unit will run at a high capacity factor, typically higher than a stand-alone baseload power plant. Though an 80 percent capacity factor is assumed for the benchmark costs given below, oil sands cogeneration units could operate at capacity factors of 90 to 95 percent.

The transmission costs given in Table I-16 are preliminary estimates provided by the proponents of the DC intertie. For very long distance interties, DC transmission costs are typically lower than for AC circuits. Nonetheless, the preliminary estimates appear to be low compared to the preliminary estimates for new transmission from eastern Montana. The Northwest Transmission Assessment Committee of the Northwest Power Pool will be refining these transmission estimates over the next several months.

Development Issues

Preliminary estimates suggest that power from oil sands cogeneration could be delivered to the Northwest at a levelized cost of $43 per megawatt-hour. While slightly higher than the comparable cost of electricity from a new gas fired combined cycle plant in the Mid-Columbia area, the higher thermal efficiency of oil sands cogeneration may offer better protection from natural gas price volatility. Moreover, a gasification process for deriving fuel gas from oil sands processing residuals is available. This alternative fuel could further isolate oil sands cogeneration from natural gas price risk. Also, because of the lower heat rate, the incremental carbon dioxide production of cogeneration is less than for stand-alone gas-fired generation, reducing the risk associated with possible future carbon dioxide control measures.

Development of the proposed intertie, however, would present a major challenge. Transmission siting and permitting efforts in the U.S., especially for new corridors, has proven difficult. Subscription financing is proposed. While effective for financing incremental natural gas pipeline expansions, subscription for financing large-scale transmission expansions is untested. Finally, the 2,000-megawatt capacity increment is likely too large for the Northwest to accept at one time. Some means of shortening commitment lead-time, phasing project output, or selling a portion to California Utilities would improve the feasibility for development.

Northwest Potential

The proposed DC intertie would deliver 2,000 megawatts of power to the Celilo area or to points south on the existing AC or DC interties. Whether larger increments of power are potentially available would depend upon future levels of oil sands production. Smaller, more easily integrated increments of power could be provided, but at additional cost because of transmission economies of scale. For example, a 500 kV AC transmission circuit could deliver approximately 1,000 megawatts of power. Refinement of transmission cost estimates, currently underway, will provide better estimates of the cost of various levels of development.

Reference plant

The estimated cost and technical performance a proposed 2,000 MW DC intertie from the Alberta oil sands region to Celilo and the associated gas turbine cogeneration units have been provided to the Council by Northern Lights. Northern Lights is a subsidiary of TransCanada formed to investigate and promote the concept. The project would consist of a single-circuit +/- 500kV DC transmission line from the Ft McMurray area of Alberta to the Celilo converter station in Oregon. The line would deliver 2,000 megawatts of capacity at Celilo with an input of about 2,160 megawatts. Intermediate converter taps could be provided near Calgary and near Spokane.

Electricity would be provided by 12 F-class gas turbine generators equipped with heat recovery steam generators. Each turbine would produce about 180 megawatts of electrical capacity plus steam for in-situ recovery of oil sands bitumen. The cost and performance assumptions of Table I-16 assume use of firm pipeline natural gas as fuel. A demonstration gasification project using bitumen processing byproducts is under development. If successful, the cogeneration units could be fired using synthetic gas.

Where necessary to support the Council's modeling, the Council's generic power plant assumptions have been used to augment the information supplied by TransCanada. Because of uncertainties regarding the cost and routing of the transmission intertie, the estimates of Table I-16 are considered to be very preliminary at his point

The benchmark[25] levelized electricity production costs for the reference plant, power delivered to Celilo, are $43 per megawatt-hour.

[25] Average financing cost for 20 percent customer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer developer mix; 2010 service; Alberta natural gas, medium case price forecast; 90 percent capacity factor, year 2000 dollars. Based on fuel charged to power. No CO2 penalty.

Table I-16: Resource characterization: Alberta oil sands cogeneration and transmission intertie (Year 2000 dollars)

Description and technical performance		
Facility	180 MW natural gas-fired 7F-class simple-cycle gas turbine plant with heat recovery steam generator. 2000 MW DC circuit - Ft McMurray area to Celilo.	
Status	Commercially mature	
Applications	Baseload power generation with cogenerated steam for bitumen recovery	
Fuel	Pipeline natural gas. Firm transportation contract with capacity release provisions.	Council's forecast Alberta firm natural gas.
Service life	30 years	
Power (net)	180 MW/unit	
Operating limits	Minimum load: n/avail Cold startup: n/avail Ramp rate: n/avail	
Availability	Equivalent annual availability: 95%	
Heat rate (HHV)	5800 Btu/kWh (fuel charged to power)	
Heat rate improvement (surrogate for cumulative effect of non-cost technical improvements)	-0.5 %/yr average from 2002 base through 2025	Approximate 95% technical progress ratio (5% learning rate). See combined-cycle description for derivation.
Seasonal power output (ambient air temperature sensitivity)	Assumed to be similar to those used for gas-fired combined-cycle power plants (Figure I-1).	
Elevation adjustment for power output	Included in gas turbine rating	

Costs		
Capital cost	Gas turbine cogeneration units: $506/kW Transmission: $621/kW	Overnight costs at 0.76 $US:$Cdn exchange rate.
Construction period cash flow (%/yr)	Gas turbine cogeneration units: 100% (one year construction) Transmission: 18%/27%/56% (3 year construction)	See Table I-8 for phased development assumptions used in portfolio risk studies.
Fixed operating costs	Gas turbine cogeneration units: Inc. in variable O&M. Transmission: $9.32	
Variable operating costs	Gas turbine cogeneration units: $2.78/MWh Transmission: $0.00	TransCanada value net of property tax & insurance
Incentives/Byproduct credits/CO2 penalties	Separately included in the Council's models.	
Interconnection and regional transmission costs	See above.	
Transmission losses	7.7% (to Celilo)	

Costs		
Technology vintage cost change (constant dollar escalation)	Gas turbine cogeneration units: -0.5 %/yr average from 2002 base through 2025 (capital and fixed O&M costs) Transmission: None	Approximate 95% technical progress ratio (5% learning rate). See combined-cycle description for derivation.

Typical air emissions (Plant site, excluding gas production & delivery)		
Particulates (PM-10)	Not available	
SO2	Not available	
NOx	Not available	
CO	Not available	
Hydrocarbons/VOC	Not available	
CO_2	365T/GWh	Based on EPA standard natural gas carbon content assumption (117 lb/MMBtu) and fuel charged to power heat rate. Corrected for transmission losses.

Development		
Assumed mix of developers	Benchmark mix: Consumer-owned utility: 20% Investor-owned utility: 40% Independent power producer: 40%	Resource comparison mix is used for the portfolio analysis and other benchmark comparisons of resources.
Development & construction schedule	Gas turbine cogeneration units: Development - 18 months Construction - 12 months Transmission Development - 48 months Construction - 36 months	"Straight-through" development. See Table I-8 for phased development assumptions used in portfolio risk studies.
Earliest commercial service	2011	
Resource availability through 2025	2000 MW	

Project Phasing Assumptions for the Portfolio Analysis

As described in Chapter 6, the portfolio risk model uses resource development flexibility as one means of coping with future uncertainties. Three phases of resource development are defined in the portfolio risk model: project development, optional construction and committed construction. Development of Alberta oil sands cogeneration for the Northwest market would have to be structured around the long lead time and large capacity increment of the proposed 2,000 megawatt DC transmission intertie. Because phased development of the proposed DC intertie is unlikely to be practical, the generation would have to be developed within a relatively brief period in order to fully use the transmission investment. The Council assumed that development of the generating capacity would occur in two 1,000 megawatt blocks. The first would be timed for completion coincidentally with the transmission intertie. The second block would be brought into service a year later. In the portfolio model, plant construction can be continued, suspended or terminated at the conclusion of project development or optional construction phases. Projects can also be terminated while suspended. The cost and schedule assumptions associated with these decisions are shown in Table I-17.

Table I-17: Alberta oil sands cogeneration and transmission intertie phased development assumptions for risk analysis (year 2000 dollars)[26]

	Project Development	Optional Construction	Committed Construction
Defining milestones	Initiate transmission system planning	Order major transmission equipment and materials.	Delivery of major transmission equipment and materials to commercial operation of second 1000 MW block of generation.
Time to complete (single unit, nearest quarter)	48 months	12 months	36 months
Cash expended (% of overnight capital)	5%	9%	86%
Cost to suspend at end of phase ($/kW)	Negligible	$340	--
Cost to hold at end of phase ($/kW/yr)	$1	$13	--
Maximum hold time from end of phase	60 months	60 months	--
Cost of termination following suspension ($/kW)	Negligible	-$74	--
Cost of immediate termination ($/kW)	Negligible	-$259	--

[26] The portfolio risk model was calibrated in year 2004 dollars for draft plan analysis. Assumptions are presented here in year 2000 dollars for consistency with other assumptions and forecasts appearing in the plan. Year 2004 dollars are obtained by multiplying year 2000 dollars by an inflation factor of 1.10.

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