Appendix I: Generating Resources - Background Information

INTRODUCTION

This appendix describes the development of the planning assumptions for new generating resources for use in the Sixth Power Plan. The first part describes conventions, the approach to the development of capital cost estimates, and calculation of levelized costs. The second section describes the development of certain data and assumptions such as resource incentives, carbon sequestration costs, and transmission and integration costs that are applied to more than one resource type. The final section describes the development of assumptions for the reference power plants used to characterize the various generating resources considered for the power plan, and the estimates of developable resource potential.

GENERAL APPROACH AND ASSUMPTIONS

Conventions

The following conventions are used in this Appendix and in Chapter 6:

Price Year: The price year from which future changes in real costs are calculated is 2008.

Year Dollars: Costs are expressed in constant 2006 dollars.

Technology Base Year: The technology base year from which future changes in technology are calculated is 2008.

Project Scope: The scope of resource cost estimates includes the cost of project development, construction, operation and decommissioning, integration costs for variable resources, the cost and losses of transmission to the wholesale receiving point of a load-serving entity and the mean value forecasted cost of carbon dioxide (CO_2) allowances.

Heat Rate: Heat rates are full load, net plant lifetime averages, expressed as higher heating value.

Total Plant Cost: Capital costs are expressed in overnight (instantaneous) Total Plant Costs. "Total Plant Costs" are the sum of direct and indirect engineering, procurement, and construction (EPC) costs, plus Owner's Costs in constant 2006 year dollars. Owners costs include non-EPC costs incurred by the project developer, such as permits and licenses, land and right-of-way acquisition, social justice costs, project development costs, legal fees, owners engineering, project and construction management staff, startup costs, site infrastructure (transmission, road, water, rail, waste water disposal, etc.), taxes, spares, furnishings and working capital. Not included in Total Plant Cost are financing costs, escalation incurred during construction (EDC), and interest incurred during construction (IDC). These are separately calculated in the Council's analyses to yield total investment cost.

Total Investment Cost: Total investment cost includes the cost of securing financing, IDC, and EDC for a specified service year and plant owner.

Capital Cost Estimates

The capital cost estimates for the reference power plants are based on published sources. These include preconstruction estimates and as-built costs reported in the media, PUC filings and other documents for specific projects, and generic cost estimates for specific technologies and projects appearing in publically-available reports. Using this information, the Council develops an estimate of per-kilowatt Total Project Costs for each reference plant

The raw cost data used to develop reference plant cost estimates represent different vintages, project scope, and year dollars, and may or may not include the costs of financing, escalation, and interest during construction. In some cases, highly detailed, disaggregated cost estimates are available, in other cases only a single number. Reported costs must be normalized to a common vintage, scope, year dollars, and to overnight value. This is especially important for this plan because of the rapid escalation of construction costs from 2004 to mid-2008 and the subsequent softening of costs because of the economic situation. The information needed to make these adjustments is usually documented in technology assessments and feasibility studies. However, the needed information is often incomplete or entirely missing in media reports, necessitating assumptions. The general approach used to normalize costs is as follows; additional detail regarding specific technologies is provided in the respective technology sections.

- Project capacity is adjusted to common metrics. For thermal projects this is net output under ISO conditions. Wind project costs are based on installed turbine capacity and utility-scale solar project costs are adjusted to net AC output.

- Reported estimates were adjusted to represent a plant configuration approximating the reference plant. Plants having configurations highly unrepresentative of the reference plant were eliminated from the samples. For example, reported costs for simple-cycle combustion turbine plants consisting of more than four units were omitted. In other cases, costs were increased or decreased to adjust for major design characteristics. For example, the reported cost of thermal plants with dry cooling was adjusted downward to represent the cost of plants employing evaporative cooling.

- Estimates were adjusted to include all owner's costs (project development, land, infrastructure and financing). Unless otherwise noted in the source, cost estimates reported prior to completion are assumed to be overnight construction cost, exclusive of owner's costs. These were increased to account for owner's costs. Reported costs for completed plants are assumed to include all owner's costs.

- Costs reported for specific locations were adjusted to an average construction cost index for the Pacific Northwest states using the state civil adjustment factors of USACE (2008).

- Costs were adjusted to represent overnight costs. Cost estimates reported prior to completion are assumed to be total plant costs so were not adjusted other than conversion to constant (real) 2006 dollars. Reported costs for completed projects are assumed to be total investment costs in as-expended (nominal). For these cases, the equivalent overnight total plant costs in year 2006 dollars are calculated using the Council's MicroFin project financing and levelization model.

Because of the substantial escalation in plant construction costs between 2004 and 2008, it is necessary to plot costs by vintage to gain a sense of representative 2008 price year. Costs of completed plants or plants under construction are assumed to represent costs as of the initial year of construction (i.e., fixed price EPC contracts). The vintage of costs reported for plants not yet under construction is assumed to be the year of publication. Some resources, particularly those where large samples are available and with plants of uniform design yielded well-defined distributions. Figure I-18 (wind plants) is one such example. In cases with well-defined distributions, the representative 2008 base year cost was taken as the approximate average of 2008 costs and the range of normalized reported costs (less obvious outliers).

Other resources yielded poorly-defined distributions because of small sample sizes, plants with widely varying characteristics, or for other reasons. An example is I-4, landfill gas energy recovery projects. In these cases, the selection of the reference plant base year cost was influenced by the source and apparent quality of individual samples and the shape of the IHS Cambridge Energy Research Associates Power Capital Cost Index[1] (converted to real terms).

Capital costs forecasts are based on the interaction of two factors - near-term declines resulting from contraction of the credit market and reduction in demand for goods since mid-2008, and, over the longer-term, the effect of technological improvements and economies of production, particularly for less-mature technologies. In general, capital costs (in real terms) are assumed to drop from mid-2008 highs to market equilibrium values by 2011. Market equilibrium values are assumed to be the average of 2004 and 2008 capital costs (in 2006 constant year dollar values). Further declines resulting from technological advances and economies of production are based on rates observed in the years prior to 2004. These assumptions are described below for the various reference plants.

Project Financing

Power plants can be constructed by investor-owned utilities, consumer-owned utilities and independent power project developers. Each of these entities uses different project financing mechanisms. The differing financing mechanisms and financial incentives available for some

[1] http://www.cera.com/aspx/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=10429

resources result in different total investment costs and annual capital service requirements for otherwise identical projects. In general, financing by consumer-owned utilities results in lower capital service requirement than financing by either investor-owned utilities or independent developers. The objective of the Council's plan is to choose among types of resources rather than to recommend the development of specific resources. For this reason, a single type of resource developer is chosen to provide consistent comparisons of resource costs. Investor-owned utility financing is used as the basis in this power plan.

Plant investment costs are calculated using the Council's MicroFin model. MicroFin is a spreadsheet model used to calculate annual and levelized lifecycle minimum revenue requirements for various resources. Accelerated depreciation is normalized for investor-owned utility financing. Investment and production tax credits are credited as available against project costs. MicroFin is used by the Council to calculate levelized electricity costs for broad comparisons among resource alternatives, to calculate levelized fixed costs required to model new resource option in the AURORA$^{xmp®}$ model and to calculate the levelized cost of the three phases of development and construction (Option, Early Construction, and Committed Construction) required for the Regional Portfolio Model. Though investor-owned utility financing is used as the standard for this plan, MicroFin can also model typical consumer-owned utility financing and non-third party independent power developer financing. Operation of MicroFin is further described in the Levelized Cost section, below.

The financing parameter values used in MicroFin are shown in Table I-1.

Table I-1: Assumptions regarding financing and other common parameters (Values are nominal unless stated)

	Municipal/ PUD	Investor-Owned Utility	Independent Power Producer
Federal Income Tax Rate	--	35%	35%
Federal Investment Tax Credit	--	See Incentives	See Incentives
FIT Recovery Period	--	See Incentives	See Incentives
State Income Tax Rate	--	5.0%	5.0%
State Investment Tax Credit	--	None	None
SIT Recovery Period	--	Same as federal	Same as federal
Property Tax	1.4%	1.4%	1.4%
Insurance	0.25%	0.25%	0.25%
Debt Term	Economic life	Economic life	15 years max
Equity return	--	Economic life	15 years max

	Municipal/ PUD	Investor-Owned Utility	Independent Power Producer
Debt fraction - Development	100%	50%	0%
Debt fraction - Construction	100%	50%	60%
Debt fraction - Term	100%	50%	60%
Debt interest - Development	5.1%	7.1%	--
Debt interest - Construction	5.1%	7.1%	5.8%
Debt interest - Term	5.1%	7.1%	7.1%
Return on Equity - Development	--	10.2%	13.7%
Return on Equity - Construction	--	10.2%	13.7%
Return on Equity - Term	--	10.2%	13.7%
Debt Financing Fee	2.0%	2.0%	2.0%
Discount Rate	1.75%	5.5%	5.8%
General Inflation Rate	1.7% (2008 - 30 average)		

Incentives

Existing federal energy production tax credit and investment tax credit are assumed to apply to qualifying resources for their currently authorized term. Existing provisions for accelerated depreciation are assumed to continue indefinitely. Numerous complexities and options are present in the tax code with respect to these incentives and simplifications are made here, for example, the "tax credit appetite" of the developing entity is not assumed to be limited. No conversions to investment tax credit are taken. Assumptions regarding federal incentives are provided in Table I-2.

Table I-2: Assumptions regarding federal incentives (2006 year dollar values)

Resource	PTC[2] (Alternative to ITC)	ITC[3] (Alternative to PTC)	Accelerated Depreciation Recovery Period[3]
Biomass (Open loop)	$9.85/MWh thru 2013	None	7-year
CHP[4] (OL Biomass)	$9.85/MWh thru 2013[5]	10% thru 2016[6]	5-year

[2] The federal production tax credit is generally available for the first ten years of operation.
[3] Investment tax credit and accelerated depreciation may be limited to only a portion of total plant investment. In this plan the credits are assumed to apply to the entire investment.
[4] Including waste heat energy recovery.

Resource	PTC[2] (Alternative to ITC)	ITC[3] (Alternative to PTC)	Accelerated Depreciation Recovery Period[3]
CHP[4] (NG)	None	10% thru 2016[6]	5-year
Geothermal	$19.70/MWh thru 2013	10% (no expiration date)	5-year
Hydropower[7]	$9.85/MWh thru 2013	None	20-year
Solar	$9.85/MWh thru 2013	30% thru 2016, 10% thereafter	5-year
Wind	$19.70/MWh thru 2012	None	5-year

State incentives represent within-region income transfers and are not considered in calculating project costs[8].

Levelized Costs

The levelized production costs appearing in this appendix are forecast costs in constant 2006 year dollars, levelized over the anticipated economic life of the plant. The costs include:

- plant costs (plant development and construction, operation, maintenance, fuel, and byproduct credits)
- integration costs (regulation and load following)
- transmission costs and cost of transmission losses
- carbon dioxide allowance (emission) costs

The following general assumptions are used for calculating levelized costs of capacity and energy:

- Reference plant configuration and location
- Investor-owned utility financing
- Medium fuel price forecast
- Delivery to a load-serving entity, including the cost of transmission losses.
- Plant capacity and heat rate are degraded to the maintenance-adjusted forecast average for the economic life of the plant where this information is available.

---

[5] Denied if investment tax credit is taken (26 USC ¶ 48(c)(3).
[6] Tests regarding size, net thermal efficiency and percentage energy to electrical and non-electrical loads apply to CHP facilities (26 USC ¶ 48(c)(3).
[7] Qualifications apply.
[8] This treatment is not entirely consistent with the treatment of state taxes. These also represent within-region income transfer. Omitting state taxes, however, would eliminate a fairly significant cost that is in-theory applicable to all resources.

- Federal production and investment tax credits as currently authorized

- Accelerated depreciation for federal income tax purposes

Renewable energy credits and state incentives are excluded. . Actual project costs may differ, to a greater or lesser degree, from the costs appearing here because of factors including site-specific conditions, incentives, financing, and timing.

Levelized electricity costs for a given resource and technology may vary by initial year of service because of the forecast changes in fuel prices, carbon dioxide allowance costs, and system integration costs. Forecast changes in capital costs due to technological improvements and production economies will also affect costs through time. A particularly significant effect is the current decline in construction costs for many resources because of the tight credit market and weak economy

The cost of transmission for remote resource options requiring new long-distance transmission assumes no network credit for the transmission improvements. Network credit could reduce transmission costs for these alternatives.

Levelized lifecycle energy and capital costs are computed using the Council's MicroFin revenue requirements model. MicroFin, an Excel spreadsheet model, is used to compute levelized capital costs for new resource options for the AURORA$^{xmp®}$ Electric Market Model and for the Council's Regional Portfolio Model. An overview of the operation of MicroFin is as follows:

> Total project investment is calculated for the selected year of construction using the estimated total plant cost, plant capacity, cost escalation factors, construction cash flow estimates and the construction financing of the selected type of project developer. Consumer-owned utility, investor-owned utility and independent project developer financing options are available in MicroFin. Most resource costs reported in this plan assume investor-owned utility financing.
>
> Annual capital-related costs (debt interest, debt principal, return on equity, recovery of equity, and state and federal taxes) are calculated for the total project investment using the long-term financing characteristics and tax obligations of the selected type of developer. Financial incentives such as accelerated depreciation, investment tax credit, and production tax credits are applied at this point.
>
> Annual property tax and insurance payments are calculated based on depreciated plant value.
>
> Annual energy production is calculated based on plant capacity and capacity factor.
>
> Annual fixed fuel costs are calculated based on escalated fixed fuel costs and plant capacity. Annual variable fuel costs are based on escalated variable fuel costs, heat rate, and energy production.
>
> Annual fixed O&M costs are calculated based on escalated fixed O&M costs and plant capacity. Annual variable O&M costs are based on escalated variable O&M costs and energy production.

Annual emission costs are calculated based on fuel consumption, fuel carbon content, and forecast CO_2 allowance costs.

Annual transmission costs are calculated based on plant capacity and escalated unit transmission costs. Integration costs are calculated based on forecast integration costs and energy production.

The value of transmission losses is calculated based on total annual costs and the transmission loss factor.

The net present value for the initial year of service is calculated for each component of annual cost over the life of the project. The levelized annual cost stream yielding the same net present value is then calculated for each component. The discount rate used for the net present value and levelization is the weighted after-tax cost of capital for the selected type of project developer.

The resulting levelized cost components are converted to unit (per-megawatt-hour) values, discounted to the base year (2006 dollar values) and summed to yield total revenue requirements.

A copy of MicroFin, with the resource, fuel financing, and other assumptions used to calculate investment costs and project revenue requirements for this plan is available from the Council upon request.

GENERAL FORECASTS

Transmission

The common point of reference for the costs of generating resources and energy efficiency measures is the wholesale delivery point to local load-serving entities (e.g., the substation interconnecting a local utility to the regional transmission network). The costs and losses of transmission from the point of generating project interconnection to the wholesale point of delivery are included in estimated generating resource cost. The avoided cost and avoided losses of distribution are credited to energy efficiency resources in the Council's analyses.

The cost of resources serving local loads (e.g., Oregon and Washington resources serving Oregon and Washington loads) include local (in-region) transmission costs and losses. The cost of resources serving remote loads (e.g., Montana resources serving Oregon and Washington loads) include the estimated cost and losses of needed long-distance transmission plus local transmission costs and losses.

Local transmission costs and losses

Local transmission costs are based on the 2010 Bonneville Power Administration Transmission and Ancillary Service Rate Schedules (BPA 2009). The representative local transmission cost is an approximation of the long-term firm point-to-point service (PTP) rate plus required Ancillary Services and Control Area Services (ACS) rates (scheduling system control and dispatch, reactive supply and voltage control, regulation and frequency response, spinning reserve, and supplemental reserve). The estimated fixed component is $17/kW/yr and the variable component is $1.00/MWh (2006 dollars). The estimated cost of regulation and load-following required to integrate variable generation is separately included, as described in the following section. Local transmission losses are assumed to be 1.9% (BPA 2008, Schedule 9).

Transmission to access remote resources

The cost of long-distance transmission to access remote resources is based upon the estimated cost of actual proposed new long-distance transmission alignments serving the resource areas of interest (Table I-3). The costs and losses associated with each route were estimated using an adaptation of the Options Analysis Tool developed by the Northwest Transmission Assessment Committee (NTAC) Canada-Northwest-California (C-N-C) study group (NTAC, 2006). Distances and general configuration (AC or DC, voltage, substations with and without transformation, etc.) were estimated from published information regarding the actual proposed transmission projects. The NTAC C-N-C Option Analysis Tool uses representative per mile and per component costs. These were updated and the values are shown in Table I-4. For all cases (except the Colstrip Transmission system upgrade case,[9]) the cost and losses of in-region point-to-point service were added to long-distance transmission costs and losses.

[9] Colstrip upgrade capacity, costs and losses were derived from the NTAC Montana Transmission Study (NTAC, 2005) and included upgrades needed to expand transmission capacity to the I-5 corridor.

Table I-3: Transmission to access remote resources (2006 year dollar values)

Resource & Load Area	Alignment	Point of Injection	Point of Delivery	Configuration	Length (mi)	Substations w/Xformers	Substations w/o Xformers	DC Terminals	Capital Cost (MM$)	Transmission O&M ($/kW/yr)	Losses (%)
MT Wind to S. ID	MSTI	Townsend, MT	Midpoint, ID	500kV AC	415	2	1	--	$1107	$25.80	2.2%
MT Wind to OR/WA	MSTI/Gateway W. Seg. 8/B2H	Townsend, MT	Boardman, OR	500kV AC	844	1	5	--	$2168	$50.60	4.4%
AB Wind to OR/WA	Northern Lights	Milo, AB	Buckley, OR	+/- 500kV DC	615	--	--	2	$1938	$45.21	2.4%
WY Wind - S.ID	Gateway W. Segs. 2, 3, 4 & 7	Aeolus, WY	Cedar Hill, ID	500kV AC	471	2	3	--	$1299	$30.30	2.5%
WY Wind - OR/WA	Gateway W Segs. 2, 3, 4, 7 & 9/ B2H	Aeolus, WY	Boardman, OR	500kV AC	927	1	7	--	$2422	$56.50	5.0%
NV Solar - S.ID	WRV - Thirtymile/ SWIP North	White R. Valley, NV	Midpoint, ID	500kV AC	370	2	1	--	$1002	$23.40	2.1%
NV Solar - OR/WA	WRV - Thirtymile/ SWIP North/Gateway W. Seg. 8/B2H	White R. Valley, NV	Boardman, OR	500kV AC	799	1	5	--	$2062	$48.12	4.5%
MT Wind to OR/WA	Colstrip Transmission System Upgrade	Judith Basin Area, MT	I-5 Corridor	500kV AC	--	--	--	--	$621	$33.00	8.0%

Table I-4: Long-distance transmission - Common assumptions (2006$)

Item	Value	Source
O&M (% of overnight capital cost)	3.5% (exclusive of property tax & insurance)	MSTI
500kV Substation w/Transformation	$51.5 MM (each)	BPA personal communication(2008)
500kV Substation w/o Transformation	$30.0 MM	BPA personal communication(2008)
500kV AC single circuit	$2.0 MM/mi (typical eastside)	BPA personal communication(2008)
+/- 500kV DC circuit	$1.97/mi	NTAC C-N-C (2005)
500kV DC Terminal	$242 MM	NTAC C-N-C (2005)
500kV AC capacity	1500 MW	NTAC C-N-C (2005)
+/- 500kV DC capacity	2000 MW	NTAC C-N-C (2005)
+/- 500kV DC losses	0.115 MW/mi @ 2000 MW	NTAC C-N-C (2005)
+/- 500kV DC converter losses	0.7%	NTAC C-N-C (2005)
500kV AC losses	0.094 MW/mi @ 1000 MW	NTAC C-N-C (2005)
Earliest service	2015	

Integration Cost for Variable Resources

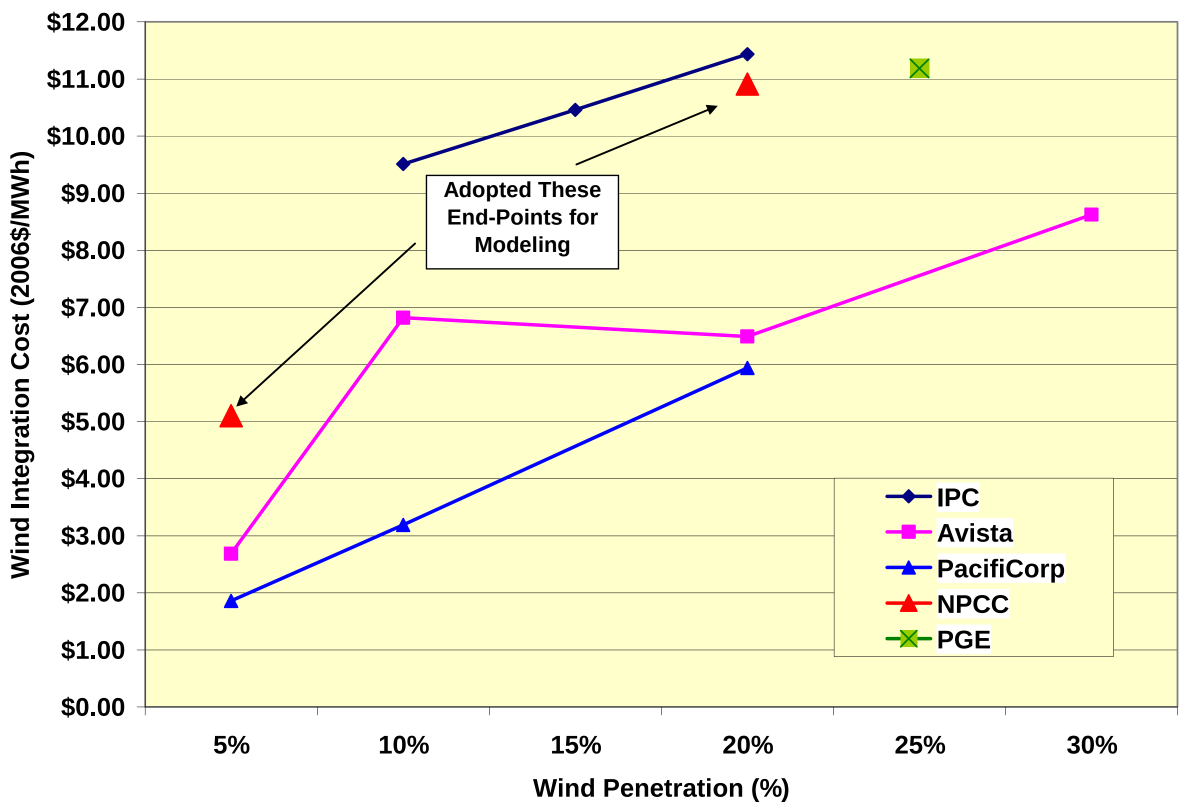
Balancing services (regulation and sub-hourly load-following) for integration of variable output renewable resources such as wind and solar are provided by reserving generating capacity for upward-regulation (“up-reg”) and for down-regulation (“down-reg”). Upward-regulation capability is the ability to increase generation to offset unforecasted loss of variable resource output. Down-regulation is the ability to reduce generation to offset unforecasted increases in variable resource output. Unless the variable resource is not operating, or is operating at full output, up-regulation and down-regulation must be provided simultaneously.

The provision of balancing services incurs cost because of foregone revenues or savings. Reserving capacity for up-regulation incurs foregone revenue that would have been received if the reserved capacity could have been profitably dispatched into the market. Reserving capacity for down-regulation incurs cost if the variable cost of the reserved capacity is greater than the market value of power. For these reasons, the cost of providing balancing services is sensitive to the wholesale value of power and the resource used to provide the services. Moreover, the cost of providing balancing services is a function of the penetration of installed variable resource capacity compared to peak load.

Only capacity that is technically and environmentally capable of rapidly responding to changes in load (flexible capacity) is suitable for providing balancing services. Hydro capacity, though technically extremely flexible and frequently used to provide balancing services, can result in consumption of water, a limited energy source, during periods of low market value. An optimal balancing resource is technically and environmentally capable of flexible operation and has variable operating costs close to the market value of power.

The cost of providing balancing services is best estimated with a system impact study where the costs of operating the system with and without a given amount of variable resources are compared. This type of analysis was not performed for estimating regional variable resource integration costs because of time and modeling considerations. Rather, an approximate relationship of within-hour balancing costs to wind penetration was subjectively developed from wind integration studies undertaken by various regional utilities (Figure I-1).

Figure I-1: Wind integration cost estimates as a function of wind penetration from various wind integration studies



The lower end-point of the proposed regional cost curve represents a cost of about $5.00 per MWh at 2% penetration (currently about 500 MW). The upper end-point represents a cost of $10.90 at 17% system penetration (currently about 6,000 MW). For purposes of the initial resource assessment, wholesale price forecasts and resource portfolio model development, penetration (and therefore integration cost) was assumed to be a linear function of time. The forecast was rebased for the 2010 - 2029 planning period based on an estimated installed regional wind capacity through 2009 of 11%. This yields a 2010 integration cost of $8.85/MWh. The upper end of the integration cost curve ($10.90/MWh) was assumed to be reached in 2024, and run flat in real terms thereafter (Table I-5).

Table I-5: Forecast regulation and load-following cost and CO_2 allowance prices

	Regulation and Load-following ($/MWh)	CO2 Allowance Costs ($/tonCO2)
2010	$8.85	$0.00
2011	$8.99	$0.00
2012	$9.14	$8.05
2013	$9.29	$10.39
2014	$9.43	$13.00
2015	$9.58	$15.14
2016	$9.73	$16.93
2017	$9.87	$19.15
2018	$10.02	$21.70
2019	$10.17	$24.23
2020	$10.31	$26.76
2021	$10.46	$29.15
2022	$10.61	$31.79
2023	$10.75	$34.59
2024	$10.90	$36.85
2025	$10.90	$39.32
2026	$10.90	$41.23
2027	$10.90	$43.29
2028	$10.90	$45.67
2029	$10.90	$46.72

Carbon Dioxide Allowance Prices

The mean value of CO_2 allowance (or equivalent tax) prices from the Regional Portfolio Model (RPM) studies using the distribution described in Chapter 2 is used for estimating the levelized electricity costs of fossil fuel resources for initial comparisons of resource alternatives. These values are shown in Table I-5.

Carbon Dioxide Sequestration

Numerous possibilities exist for isolating carbon dioxide produced by fossil fuel combustion from the atmosphere for long periods of time. The CO_2 from coal-fired power generating facilities is an attractive target for sequestration because power plants are large stationary point sources of CO_2, and many plants are located within a feasible transportation distance from potential sequestration sites.

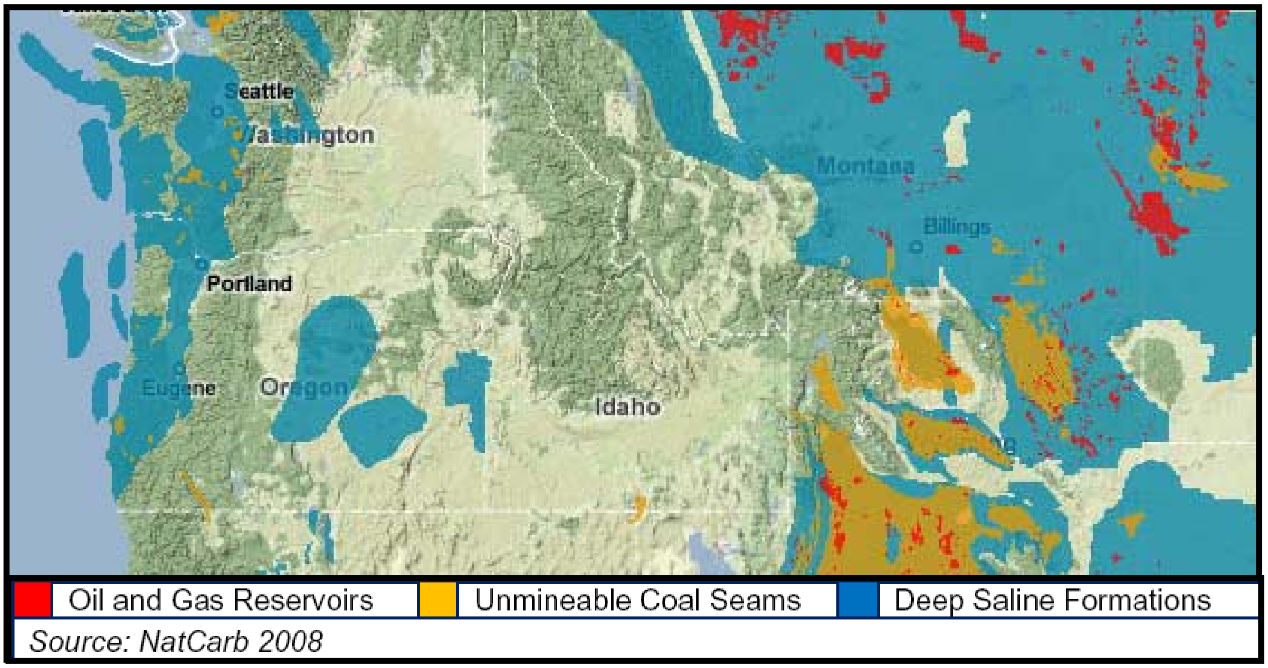
Proposals for long-term storage of CO_2 from power plant operation include deep oceanic injection and several geologic mechanisms. The general concept is to separate CO2 at the power plant into a relatively pure form, compress the CO_2 to a liquid state, and transport the liquid to the sequestration facility by pipeline for injection. The pipeline operating pressure would be sufficient for injection without further compression at the sequestration facility.

Oceanic CO_2 injection, though feasible, is controversial because of potential impacts on the ocean environment and marine life. Pilot projects in Hawaii and Norway have been cancelled as a result. Certain marine treaties now prohibit storage of CO_2 in the water column or seabed (IEA, 2008a). Geologic sequestration options with Northwest potential are described below. The following discussion is compiled from EcoSecurities (2008), IEA (2004), IEA (2008a) and the Big Sky Carbon Sequestration Partnership (http://www.bigskyco2.org).

CO_2-enhanced oil recovery: Carbon dioxide enhanced oil recovery (CO_2-EOR) is an established process whereby CO_2 is injected into oil fields to enhance recovery of remaining oil. The CO_2 repressurizes the reservoir and promotes release of remaining oil through viscosity reduction and other means. CO_2-EOR has been in commercial use for about three decades and about 3% of current world oil production is recovered using this technology. CO_2 sequestration is incidental to current CO_2-EOR operations, the objective of which is profitably recovering oil. EOR operations undertaken for the purpose of CO_2 sequestration would not necessarily operate at a profit, though the value of the recovered oil would help offset overall costs. An added complexity of a sequestration operation is the need to ensure long-term reservoir integrity. While natural gas and oil reservoirs are inherently of great integrity, developed fields are punctured with wells that if improperly plugged, could release sequestered CO_2. It is believed that enhanced oil recovery using CO_2 could eventually be applied to most oil fields, though the CO_2 sequestration capacity of depleted oil fields is relatively small compared to CO_2 production from power generation facilities. Scattered oilfields are found in eastern Montana (Figure I-2) and additional opportunities in Alberta, Wyoming, and the Dakotas may be within feasible CO_2 transportation distance.

CO_2-enhanced natural gas recovery: Carbon dioxide enhanced natural gas recovery (CO_2-EGR) is a method of augmenting natural gas recovery and of reducing drawdown-related subsidence by repressurizing depleted natural gas fields. CO_2 is denser and more viscous than methane at reservoir conditions so the remaining methane tends to float above the injected CO_2. Methane withdrawal could continue until the methane becomes excessively diluted with CO_2 that has broken through the overlying methane layer. A commercial-scale EGR demonstration project is underway in the North Sea, however the technology is not fully developed. As with CO2-EOR, a major issue is ensuring long-term reservoir integrity. Though the CO_2 sequestration potential of EGR might be larger than that of EOR, the economics are less favorable because of the lower revenue from the recovered methane per ton of injected CO_2.

Figure I-2: Potential CO2 storage sites in the Northwest (www.natcarb.org)



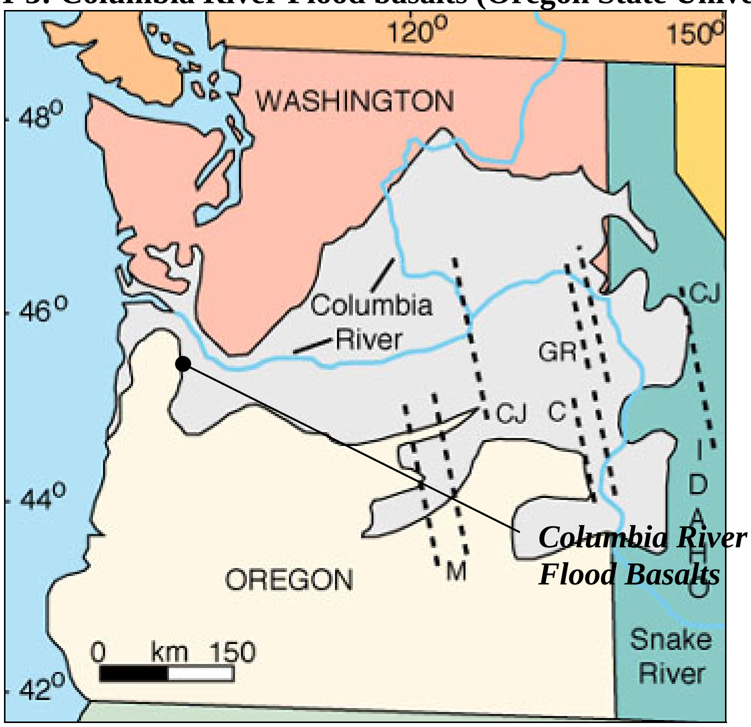
Depleted oil or gas fields: Carbon dioxide could be sequestered in depleted oil or gas fields using CO_2-EGR injection technology. The global theoretical potential for sequestering CO_2 in depleted oil and gas fields is of the same order of magnitude as for CO_2-EGR. Similar issues regarding resource integrity would be present and net cost would be higher because of the absence of byproduct oil or gas. Existing production wells could be repurposed for CO_2 injection.

CO_2-enhanced coal bed methane recovery (ECBM): Coal beds typically contain large amounts of methane-rich gas adsorbed to the coal. Because carbon dioxide is preferentially adsorbed to coal, injection of CO_2 into deep unmineable coal seams could sequester the CO_2 and produce methane as a marketable product. CO_2 is physically adsorbed to the coal, increasing confidence in long-term storage integrity. Coal measures potentially offering ECBM potential are scattered within the four states and a substantial area of potential is present in Wyoming (Figure I-2). The effectiveness and economic feasibility of enhanced coal bed methane recovery using CO_2 injection is promising but has yet to be fully demonstrated.

Deep saline aquifers: Deep saline aquifers consisting of porous rocks saturated with brine are found throughout the world, many located in the same sedimentary basins from which coal and other fossil fuels are extracted. The brines are of high salt content and typically unsuitable for agricultural use or human consumption. If confined by underlying and overlying layers of restricted permeability these formations may be suitable for long-term storage of very large quantities of CO_2. Though initially accumulating under the cap rock, the injected CO2 is expected to eventually dissolve in the brine, promoting secure long-term storage. Deep saline formations are located below the coalfields of eastern Montana and between the Cascades and the coast (Figure I-2). The technical feasibility of CO_2 storage in deep saline aquifers has been demonstrated in the North Sea. Remaining questions relate to the amount of CO_2 that can be injected into a given aquifer volume, the long-term expansion and migration of the CO2 plume, and the geochemical reactions expected to occur over time.

Flood basalt formations: The Columbia River flood basalts and possibly other basalt formations present a potential CO2 sequestration option of particular interest to the Northwest. Flood basalts consisting of several hundred individual flows, each tens to hundreds of feet in thickness, cover the central Columbia Basin and extend to the Pacific along the course of the Columbia River (Figure I-3). Many of the individual flows consist of a fractured and highly porous upper layer and a dense impermeable lower layer. Carbon dioxide could be stored in the porous upper layer, trapped between the dense lower layers of the same flow and the adjacent overlying flow. Preliminary experiments indicate that carbon dioxide would be rapidly converted to solid carbonaceous minerals in the basaltic environment, ensuring permanent storage.

Figure I-3: Columbia River Flood basalts (Oregon State University)



The U.S. DOE Regional Carbon Sequestration Partnerships and the National Carbon Sequestration Database and Geographical Information System are assessing the potential for carbon sequestration for individual U.S. states and Canadian provinces. Results are published and periodically updated in the *Carbon Sequestration Atlas of the United States and Canada* (USDOE, 2008). The top section of Table I-6 shows the current estimates of technical sequestration potential for the four Northwest states for three types of formations potentially suitable for CO_2 sequestration. The values in this section are from the *Carbon Sequestration Atlas.* To provide perspective regarding this potential, the lower section of the table expresses the technical potential in terms of the number of years of CO_2 storage potential at the estimated CO_2 production rate from Northwest coal-fired power plants in 2005. Practical storage potential is likely to be much less than the theoretical potential. This suggests that though sequestration in oil and gas reservoirs and unminable coal seams is, in general, technically more advanced than sequestration in deep saline formations, and moreover, may yield marketable oil or gas to help offset sequestration costs, deep saline formations appear to be the principal candidate for sequestration of significant amounts of CO_2 over the long-term.

Table I-6: Theoretical storage potential of several Northwest CO_2 sequestration options

	Oil and Gas Reservoirs	Unmineable Coal Seams	Deep Saline Formations
Technical Potential (MM tonsCO2)			
ID	0	Not reported	Not reported
MT	1388	322	291,948 -1,087,714
OR	0	Not reported	18,400 - 73,600
WA	0	3080-3395	99,270 -397,077
Total	1388	3402	409,617 -1,558,391
Technical Potential (Years @ 2005 CO2 production rate)			
ID	0	--	--
MT	28	7	6000 - 22,000
OR	0	--	400 - 1500
WA	0	63 - 69	2000 - 8,000
Total	28	70 - 76	8300 - 32,000

The overall cost of carbon dioxide separation and sequestration includes the incremental capital and operating costs of the power plant facilities for separation and compression of CO_2, including the effects of additional electrical and steam loads on plant heat rate, the capital and operating costs of transporting the compressed, liquified CO_2, and the capital and operating costs of the sequestration facility, including long-term monitoring of reservoir integrity. The incremental costs and heat rate penalty for power plants with CO_2 separation are included in the description of the reference coal-fired power plants in the Assumptions for Reference Plants section of this appendix.

The estimated cost of transporting CO2 from power plant to sequestration facility ranges from $1 - $8/tonne CO2 ($0.90 - $7.20/ton) (EcoSecurities, 2008). The estimated cost of sequestering CO2 in depleted oil fields ranges from $0.50 - $4.00/tonne CO2 ($0.45 - $3.30/ton) and in depleted gas fields from $0.50 - $12.00/tonne CO2 ($0.45 - $10.90/ton) (EcoSecurities, 2008). Storage in deep saline aquifers is estimated to cost from $0.40 - $4.50/tonne CO2 ($0.36 - $4.10/ton) (EcoSecurities, 2008).

For purposes of this plan, CO2 transportation costs are assumed to average $4.00/ton CO2 - an approximation of the $1 - 8/tonne CO_2 range cited in EcoSecurities (2008). CO2 transportation is a mature technology and current cost estimates should be a reliable indicator of actual future costs. While appealing because of the potential revenue from recovered oil and gas, any serious attempt to reduce atmospheric releases of CO_2 would appear to quickly overwhelm the available capacity of partially depleted oil or gas fields in the Northwest. Sequestration in deep saline formations currently appears to be the most promising candidate for large-scale sequestration in the Northwest. The concept is in the early stages of development, however, and experience with developing technologies suggests that costs are bound to rise much higher than current estimates as the concept is commercialized. For this reason, the Council assumes CO_2 sequestration costs average $22.50/ton CO_2, the high end of the $15 - 25/tonne CO_2 overall North American cost range cited in IEA (2008a).

A commercial-scale deep saline sequestration facility in the Northwest is assumed to be available for operation no earlier than 2023. Given the research, development and demonstration needed to resolve remaining technical issues, the legal and institutional questions needing resolution and the development and construction time required for a commercial-scale CO2 sequestration facility and transportation pipelines, such a facility may not be feasible within the planning period.

ASSUMPTIONS FOR REFERENCE PLANTS

Landfill Gas Energy Recovery

A landfill gas energy recovery plant uses the methane content of the gas produced as a result of the decomposition of landfill contents to generate electric power. The complete recovery system includes an array of collection wells, collection piping, gas cleanup equipment, and one or more generator sets, usually using reciprocating engines. Typically, the gas collection system is installed as a requirement of landfill operation and the raw gas sold to the operator of the power plant.

Reference Plant: The reference plant consists of two 1.6 MW reciprocating engine generating unit fuelled by landfill gas. The scope includes gas processing equipment, engine-generator sets, powerhouse and maintenance structure, and power generation site infrastructure.

Fuel: A typical business arrangement is for the power plant operator to purchase the raw landfill gas from the landfill operator. The landfill operator is responsible for installing and operating the wellfield and collection system. The published sources of information regarding landfill gas prices suggest a wide range. Lazard (2008) reports landfill gas fuel costs ranging from $1.50 to $3.00/MMBtu. The Idaho Statesman reports that Ada County collects $0.89/MMBtu plus 40% of REC and PTC credits for the Ada County Landfill Waste-to-Energy plant. The effective fuel price (fuel plus 40% of the value of incentives) for the Ada plant 2007 was $1.50/MMBtu. Because the Ada price lies at the low end of the range reported by Lazard, a somewhat higher expected price, $2.00/MMBtu, is used for this plan - higher than Ada county but towards the low end of the Lazard range.

Heat rate: The heat rate of the reference plant is 10,060 Btu/kWh. Heat rate is inversely correlated with engine capacity and is derived from the following capacity - heat rate relationship for small reciprocating engines, from Exhibit 3-10 of WGA (2006):

Heat Rate (HHV) = $10159x^{-0.0555}$

Where x is the plant capacity in megawatts

Availability parameters: Plant availability parameters are as follows:

Scheduled maintenance - 14 days/yr

Equivalent forced outage rate - 8%

Mean time to repair - Not estimated (stochastic outages not modeled)

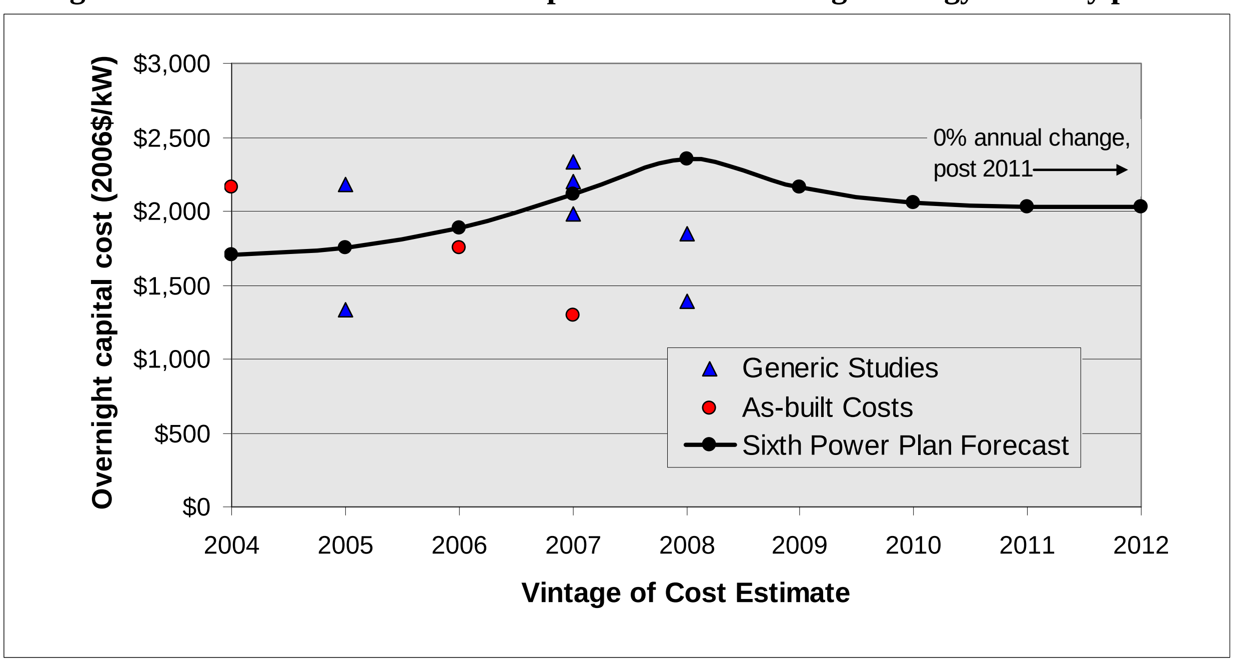
Equivalent annual availability - 88%

Unit Commitment Parameters**:** Landfill gas energy recovery plants operate as must-run units at an annual capacity factor of 85%, based on CEC (2007).

Total Plant Cost: The "overnight" total plant cost of the reference plant is $2,350/kW installed capacity (2008 price year). This estimate is based on reported as-built costs for three landfill gas energy recovery plants and four generic estimates of plant development costs. Three of the latter were range estimates consisting of low and high bound costs. These cost observations, normalized as described in the Capital Cost Analysis subsection of this Appendix, are plotted by vintage in Figure I-4. The increase in capital costs from 2004 to 2008, observed for most power generation technologies, is not clearly evident here, particularly for the as-built costs. A reason may be that the built projects were of substantially different scopes (e.g., with or without the gas collection system). For this reason, the representative project cost estimate was based on a projection of the 2005 and 2007 generic cost estimates, which together with the 2006 actual project cost seem to reasonably track observed power plant cost escalation during this period. Because landfill gas energy recovery projects were not modeled in the Regional Portfolio Model, capital cost uncertainty was not estimated.

Construction costs are forecast to decline by 8% (real) in 2009, and then continue to decline to market equilibrium conditions, represented by the average of 2004 and 2008 costs, by 2011. Construction costs are assumed to remain constant in real terms thereafter.

Figure I-4: Published and forecast capital costs of landfill gas energy recovery plants



Development and Construction Schedule, Cash Flows: Development and construction schedule and cash flow assumptions for a landfill gas energy recovery plant are those assumed for reciprocating engine power plants:

> **Development** (Feasibility study, permitting, geophysical assessment, preliminary engineering) - 18 mo., 3 % of total plant cost
>
> **Early Construction** (Final engineering, major equipment order, site preparation) - 9 mo., 9% of total plant cost
>
> **Committed Construction** (Delivery of major equipment, completion of construction and testing) - 6 mo., 88% of total plant cost

Operating and maintenance costs: Operating and maintenance costs for landfill gas energy recovery plants were based on California Energy Commission (CEC) estimates. The CEC estimates are consistent with other available estimates of the O&M costs of these plants when adjusted to comparable year dollars. Moreover, the CEC O&M costs are broken into fixed and variable components and exclude property tax and insurance, consistent with the Council's representative resource costs. Fixed O&M cost for landfill gas energy recovery ($26/kW/yr) is estimated to be 1.1% of the overnight capital cost described above. The 1.1% is based on the ratio of fixed O&M cost to overnight cost of Appendix B ("Economic Assumptions: Landfill Gas Fuel to Energy") of CEC (2007). The variable O&M cost ($19/MWh) was derived in a similar manner as 0.8% of total plant cost. Fixed O&M cost assumed to vary in real terms with total plant cost. Variable O&M cost is assumed to remain constant in real terms.

Economic Life: The economic life of a landfill gas energy recovery plant is assumed to be 20 years; limited by the operating life of a reciprocating engine-generator and the productive life of a typical landfill.

Development potential: The remaining feasible development potential for landfill gas energy recovery facilities was derived from the U.S. EPA Landfill Methane Outreach Program database of candidate landfills for energy recovery[10]. EPA estimates of waste-in-place in candidate landfills in the four Northwest states were converted to estimated electricity production potential using values for gas generation potential and fuel energy content from an assessment of landfill energy recovery potential in Oregon prepared for the Energy Trust of Oregon (ETO, 2005). The reference plant heat rate of 10,060 Btu/kWh was substituted for the more optimistic heat rate of 9,000 Btu/kWh used in the ETO study. This yielded a remaining undeveloped electric energy potential of 69 average megawatts (Table I-7). This estimate should be viewed as having considerable uncertainty. On one hand, emplaced waste will continue to increase during the planning period, even with aggressive reuse and recycling programs. On the other, the competing alternative of direct injection of landfill-derived gas into the natural gas system is less expensive than on-site generation of electric power.

[10] http://www.epa.gov/lmop/proj/index.htm

Table I-7: Derivation of estimated undeveloped landfill gas energy recovery potential

	Waste in-place (tons)	Gas Generation Potential (MMscf/yr)	Fuel Energy (TBtu/yr)	Electric Energy (MWh/yr)	Developable Potential (MWa)
Idaho	2,000,000	400	0.18	17893	2
Montana	16,956,766	3391	1.53	151701	17
Oregon	25,022,845	5005	2.25	223862	26
Washington	23,656,412	4731	2.13	211638	24
Totals	**67636023**	**13527**	**6.09**	**605094**	**69**

Levelized cost summary: The estimated levelized lifecycle cost of delivered energy from landfill gas energy recovery power plants is shown in Table I-8. The cost estimates are based on investor-owned utility financing. 2010 service year cases include federal production tax credit.

Table I-8: Levelized Cost of Landfill Gas Energy Recovery Power Plants

Service Year	Plant Busbar ($/MWh)	Ancillary Services and Integration ($/MWh)	Transmission and Losses ($/MWh)	Emissions ($/MWh)	Total ($/MWh)
2010	$69.55	$0.97	$3.63	$0.00	$74
2015	$68.53	$0.99	$3.65	$0.00	$73
2020	$67.87	$0.99	$3.64	$0.00	$73
2025	$67.22	$0.99	$3.63	$0.00	$72
2030	$66.72	$1.00	$3.64	$0.00	$71

Animal Manure Energy Recovery

The energy value of certain agricultural and food wastes can be recovered by processing the waste materials in anaerobic digesters. This yields a combustible gas that can be used to fuel a thermal electric power generator. Reciprocating engine-generator sets are typically used for the power production. The most widely employed anaerobic digestion technology at present, uses animal manure in liquid or slurry form. The principal source of suitable feedstock is from manure handling systems at large concentrated animal feeding operations (CAFOs).

Reference Plant: The reference plant consists of a plug flow anaerobic digester supplied by liquid or slurry manure handling system at a large (500 head, or larger) CAFO dairy. The digester produces a low-Btu methane rich-gas that supplies an 850 kW reciprocating engine generating unit. Reject heat is recovered from the engine to maintain digester operating temperatures.

Fuel: The animal waste is supplied from an adjacent concentrated animal feeding operation. Anaerobic digesters and associated power generation equipment provide a solution to the problem of disposing of large quantities of animal waste from large concentrated feeding operations. The value of the raw manure/fuel is assumed to be zero for this analysis. In some cases the raw manure might be considered to have a negative value.

Heat rate: The heat rate of the reference plant is 10,250 Btu/kWh, derived as described for Landfill Gas Energy Recovery plants

Availability parameters: Plant availability parameters are as follows:

Scheduled maintenance outages - 14 days/yr

Equivalent forced outage rate - 8%

Mean time to repair - Not estimated (stochastic outages not modeled)

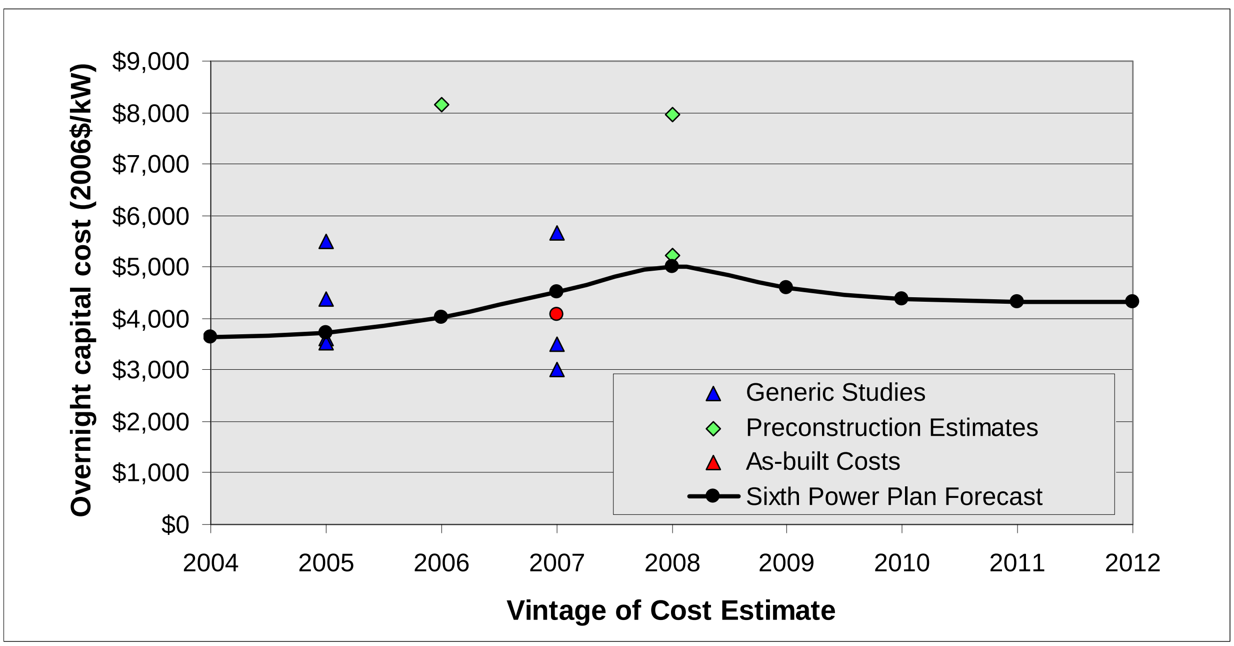
Equivalent annual availability - 88%

***Unit Commitment Parameters*:** Animal waste energy recovery plants operate as must-run units at an annual capacity factor of 75%, based on CEC (2007).

Total Plant Cost: The overnight total plant cost of the reference plant is $5000/kW installed capacity (2008 price year). This estimate is based on reported costs for one completed and three proposed plants and generic estimates from three sources. One of the generic sources provided a range estimate consisting of low and high bound costs and a second source included estimates for a range of plant sizes. These observations were normalized as described in the Capital Cost Analysis subsection of this appendix, and are plotted by vintage in Figure I-5. If the one 2006 outlier is omitted, the distribution, though based on a limited sample size, is reasonably satisfying, with a wide range. The wide range is likely attributable site-specific factors including a wide capacity range and the increased cost of manure handling facilities for plants serving several farms, compared to on-farm plants. Costs rise rapidly as plant capacity declines. A range of $4,500/kW for larger units (1 - 3 MW) to $8,000 for smaller units (400 - 500kW) is consistent with $5,000/kW for the reference 850 kW unit. The Sixth Plan forecast shown in the figure is consistent with the general increase in power plant costs observed from 2004 through 2008, the 2005 generic estimates (ETO, 2005) and the reported cost of the one completed plant from the sample (Bettencourt Dry Creek Dairy in Idaho).

Construction costs are forecast to decline by 8% (real) in 2009, and then continue to decline to market equilibrium conditions, represented by the average of 2004 and 2008 costs, by 2011. Construction costs are assumed to remain constant in real terms thereafter.

Figure I-5: Published and forecast capital costs of animal manure energy recovery plants



Development and Construction Schedule, Cash Flows: Development and construction schedule and cash flow assumptions for an animal waste energy recovery plant are as follows:

> **Development** (Feasibility study, permitting, geophysical assessment, engineering) - 12 mo., 2% of total plant cost
>
> **Construction** (Major equipment order, site preparation, delivery of major equipment, completion of construction and testing) - 12 mo., 98% of total plant cost

Operating and Maintenance Cost: Fixed O&M cost for animal waste energy recovery is taken as 0.9% of capital cost, based on Table 6 ("AD Dairy") of CEC (2007). This yields $72/kW/yr for small (450 kW) facilities, $45/kW/yr for mid-range (850 kW) facilities and $41/kW/yr for large (2.5 MW) facilities. Fixed O&M cost assumed to vary in real terms with total plant cost.

Variable O&M cost for animal waste energy recovery is taken as 0.3% of capital cost, based on Table 6 ("AD Dairy") of CEC (2007). This yields $24/MWh for small facilities, $15/kW/yr for mid-range facilities and $14/kW/yr for large facilities. Variable O&M cost is assumed to remain constant in real terms.

Economic Life: The economic life of an animal waste energy recovery plant is assumed to be 15 years.

Development potential: The remaining feasible development potential for animal manure energy recovery facilities at dairy operations in the Northwest is estimated to be 61 MWa with a possible range of 51 to 108 MWa. The derivation of this estimate is shown in Table I-9. Potentially feasible operations and mature head are reported by EPA for the top ten states, including Idaho and Washington. These are operations of 500 head, or more and employing slurry or liquid manure handling systems. The Oregon data are from ETO, 2005, and are based on dairy farms of 500 head or more. The Oregon estimates do not appear to have been screened for use of slurry of liquid manure handling systems, so may be high. The expected energy production potential was estimated from head count using the 3 kWh per mature head per day, described as "realistic" in (ETO, 2005). The low end of the range is based on the value of 2.6 kWh/head-day assumed in EPA[11] and the high end was based on "optimistic" 5 kWh/head-day of ETO (2005).

[11] 38.5 ft^3 methane per cow-day using plug flow digesters (EPA, p.31) x 66 kWh/1000 ft^3 methane (EPA, p.32).

Table I-9: Derivation of estimated undeveloped animal manure energy recovery potential

	Feasible Operations	Mature Head at Feasible Operations (000)	Electric Generation Potential (MWa)	Operating and Committed Generation (MWa)	Developable Potential (MWa)
Idaho[12]	185	285	36	7.9	29
Montana[13]	--	--	--	--	--
Oregon[14]	32	114	14	0.5	14
Washington[12]	122	135	17	2.9	14
Totals	**339**	**534**	**67**	**11.3**	**57**

Levelized cost summary: The estimated levelized lifecycle cost of delivered energy from animal waste energy recovery power plants is shown in Table I-10. The cost estimates are based on investor-owned utility financing. 2010 service year cases include federal production tax credit.

Table I-10: Levelized Cost of Animal Waste Energy Recovery Power Plants

Service Year	Plant Busbar ($/MWh)	Ancillary Services and Integration ($/MWh)	Transmission and Losses ($/MWh)	Emissions ($/MWh)	Total ($/MWh)
2010	$93.85	$0.97	$4.40	$0.00	$99
2015	$82.83	$0.99	$4.24	$0.00	$88
2020	$81.18	$0.99	$4.21	$0.00	$86
2025	$79.57	$0.99	$4.18	$0.00	$85
2030	$78.04	$1.00	$4.17	$0.00	$83

Waste Water Treatment Energy Recovery

Sludge collected in the clarification stage of waste water treatment is commonly processed in anaerobic digesters to remove volatile organic materials. Anaerobic digestion produces a low-Btu gas consisting largely of methane and carbon dioxide. This gas can be treated to remove moisture, siloxanes, hydrogen sulfide, and other impurities and used to fuel an electric generating plant. Reject heat from the engine is used to maintain optimum digester temperature.

Reference Plant: The reference plant is an 850-kilowatt reciprocating engine generating unit fuelled by gas from the anaerobic digestors of a wastewater treatment plant. Reject engine heat is captured and used to maintain optimal digester temperature. The plant includes gas processing equipment, the engine-generator, heat recovery equipment, interconnection equipment and associated infrastructure. The anaerobic digestors are assumed to be existing.

Fuel: The fuel of the reference plant is supplied from a wastewater treatment facility with existing anaerobic sludge digesters and associated gas collection system (for flaring). The facilities are assumed to be under common ownership and the raw fuel supplied free of charge.

---

[12] U.S. Environmental Protection Agency (Undated)
[13] No estimates were located for Montana. The number of large confined dairy operations in Montana is thught to be small.
[14] Energy Trust of Oregon (2005)

Heat rate: The heat rate of the reference plant is 10,250 Btu/kWh, derived as described for Landfill Gas Energy Recovery plants

Availability parameters: Plant availability parameters are as follows:

Scheduled maintenance outages - 7 days/yr

Equivalent forced outage rate - 4.7%

Mean time to repair - Not estimated (stochastic outages not modeled)

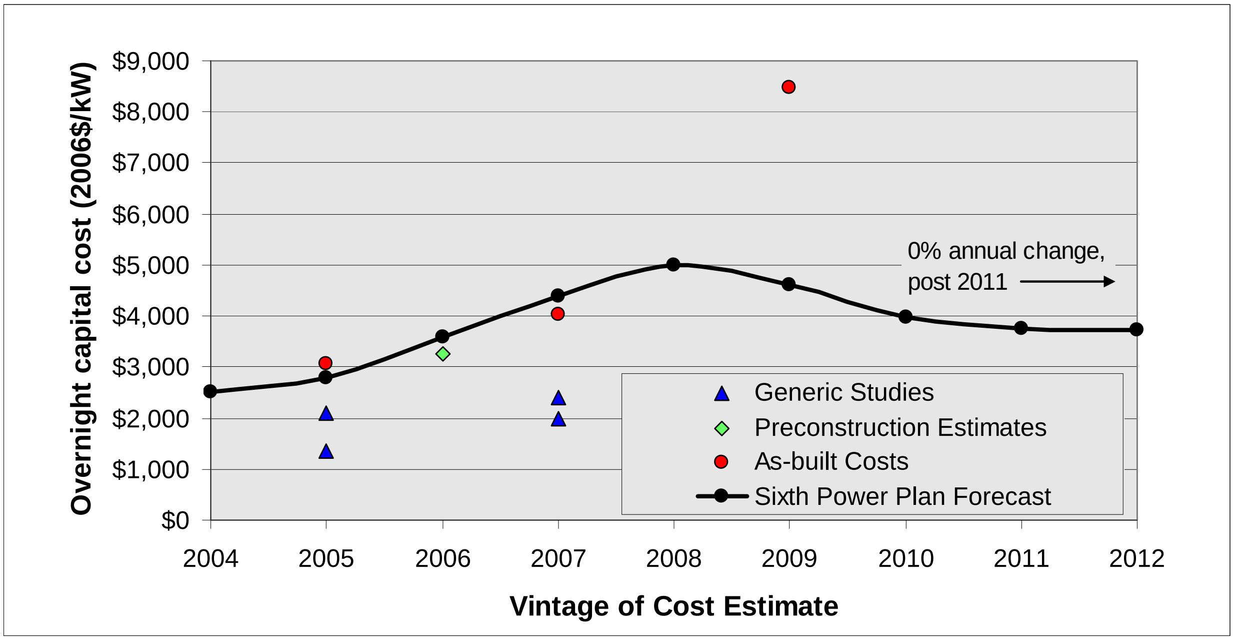
Equivalent annual availability - 93%

***Unit Commitment Parameters*:** Wastewater treatment energy recovery systems operate as must-run units at an annual capacity factor of 85%, based on CEC (2007).

Total Plant Cost: The "overnight" total plant cost of the reference plant is $5,000/kW installed capacity (2008 price year). This estimate is based on reported costs for one proposed and two completed plants (both a preconstruction and an as-built estimate is available for one of the latter). Generic estimates were obtained from three sources, one consisting of low and high bound costs. These observations were normalized as described in the Capital Cost Estimates section of this appendix, and are plotted by vintage in Figure I-6. The preconstruction and as-built costs are much higher than the generic estimates and show much stronger escalation in the 2004 - 08 period than do the generic costs. Because the underlying cost and plant configuration information for the 2005, 2006, and 2007 as-built and preconstruction estimates is reliable and representative, these strongly influenced the Sixth Power Plan estimate. The scope of the 2009 outlier is believed to be more extensive than a typical project, hence the much higher cost.

Construction costs are forecast to decline by 8% (real) in 2009, and then continue to decline to market equilibrium conditions, represented by the average of 2004 and 2008 costs, by 2011. Construction costs are assumed to remain constant in real terms thereafter.

Figure I-6: Published and forecast capital costs of waste water treatment energy recovery plants



Development and Construction Schedule, Cash Flows: Development and construction schedule and cash flow assumptions are as follows:

> **Development** (Feasibility study, permitting, geophysical assessment, preliminary engineering) - 24 mo., 8% of total plant cost.
>
> **Construction** (Final engineering, major equipment order, site preparation, delivery of major equipment, completion of construction and testing) - 12 mo., 92% of total plant cost.

Operating and Maintenance Cost: Fixed O&M cost, exclusive of property tax and insurance for wastewater treatment plant energy recovery ($40/kW/yr) is taken as 0.8% of capital cost, based on Table 6 ("Biomass - WWTP") of CEC (2007). Variable O&M ($30/MWh) is taken as 0.6% of capital cost, based on Table 6 ("Biomass - WWTP") of CEC (2007). Fixed O&M costs is assumed to vary in real terms with total plant cost. Variable O&M costs are assumed to remain constant in real terms.

Economic Life: The economic life of a wastewater treatment energy recovery plant is assumed to be 20 years; limited by the operating life of a reciprocating engine-generator.

Development potential: The remaining feasible development potential for wastewater treatment energy recovery facilities in the Northwest is estimated to be about 12 MWa. This estimate is based on a 2007 inventory of wastewater treatment plant energy recovery potential prepared by the U.S. Environmental Protection Agency (EPA, 2007), adjusted for existing development.

Levelized cost summary: The estimated levelized lifecycle cost of delivered energy from waste water treatment energy recovery power plants is shown in Table I-11. The cost estimates are based on investor-owned utility financing. 2010 service year cases include federal production tax credit.

Table I-11: Levelized Cost of Waste Water Treatment Energy Recovery Power Plants

Service Year	Plant Busbar ($/MWh)	Integration ($/MWh)	Transmission And Losses ($/MWh)	Emissions ($/MWh)	Total ($/MWh)
2010	$100.72	$0.97	$4.40	$0.00	$106
2015	$91.56	$0.99	$4.10	$0.00	$97
2020	$90.08	$0.99	$4.07	$0.00	$95
2025	$88.64	$0.99	$4.05	$0.00	$94
2030	$87.33	$1.00	$4.04	$0.00	$92

Woody Residue Power Plants

Woody residue includes mill residues, logging slash, urban construction and demolition debris, urban forest and landscaping debris, unmerchantable products of commercial forest management and ecosystem restoration and woody energy crops. Conventional steam-electric plants with or without CHP will be the chief technology for electricity generation using woody residue in the near-term. Modular biogasification plants are under development and may be introduced within the next several years. Modular units would open the possibility of “bringing the plant to the fuel” thereby expanding the potential fuel supply, reducing fuel transportation costs and improving the economics of plant operation.

Reference Plants: Two cases were modeled. A “Brownfield” case is sited to provide a cogeneration load, at a brownfield site with existing transportation, water, and transmission infrastructure. Locally available mill residue and other residue fuels are assumed sufficient to supply the plant’s fuel requirements. Refurbished salvaged equipment is available for the steam turbine-generator and other major equipment. This plant represents a favorable situation for development of new generating capacity using wood residues. The second, “Greenfield” case is a plant using new equipment, at a greenfield site and no cogeneration load. The plant is developed primarily to operate on woody residue from commercial forest thinning, harvest, and forest ecological restoration projects. This plant represents the longer-term marginal cost of expanding generation from woody residues. A third option based on smaller-scale, highly modular technology that could be periodically relocated to minimize fuel transportation costs and interconnect to local distribution lines is not commercially available, but may be introduced within the next several years. This concept could lower the marginal cost of expanding electricity generation from forest residue fuels.

The reference Brownfield plant is a 15 MW (gross), 13.2 MW (net) steam-electric plant with travelling grate furnace and extraction/condensing steam turbine-generator. 28.000 lb/hr of 150 psig steam is extracted for thermal applications. The plant is provided with mechanical draft condenser cooling. Overfire air, cyclones and precipitators are used for air emission control. Reconditioned equipment is used where feasible. The fuel supply largely consists of mill, logging and urban wood residues within a 50 to 75 mile radius, augmented by forest thinning and restoration residues.

The reference Greenfield plant is a 25 MW (nominal) fluidized bed steam-electric plant with a full condensing steam turbine-generator. The plant is provided with mechanical draft condenser cooling. Selective non-catalytic NOx reduction, cyclones and fabric filters are employed for air emission control. The plant consists largely of new equipment. The fuel supply largely consists of forest thinning and restoration residues within a 50 to 75 mile radius, augmented by mill, logging and urban wood residues.

Fuel: The fuel supply consists of various proportions of mill residues, logging slash and forest thinning residues. The delivered cost of these is assumed to be as follows:

Mill residues - $1.33/MMBtu

Logging slash - $3.00/MMBtu

Forest thinning - $3.30/MMBtu

The fuel supply of the Brownfield plant largely consists of mill, logging and urban wood residues, augmented by forest thinning residues with a net cost of $1.60/MMBtu. The fuel supply of the Greenfield plant largely consists of forest thinning residues, supplemented with limited quantities of mill residue and logging slash with a net cost of $3.00/MMBtu, declining at 1% (real) per year from improvements in fuel bundling and transportation equipment.

Heat rate: The overall heat rate of the reference CHP plant is 19,300 Btu/kWh. The heat rate of the stand-alone plant is 15,500 Btu/kWh.

Availability Parameters: Plant availability parameters are as follows:

Scheduled maintenance outages - 28 days/yr

Equivalent forced outage rate - 7%

Mean time to repair - 56 hours

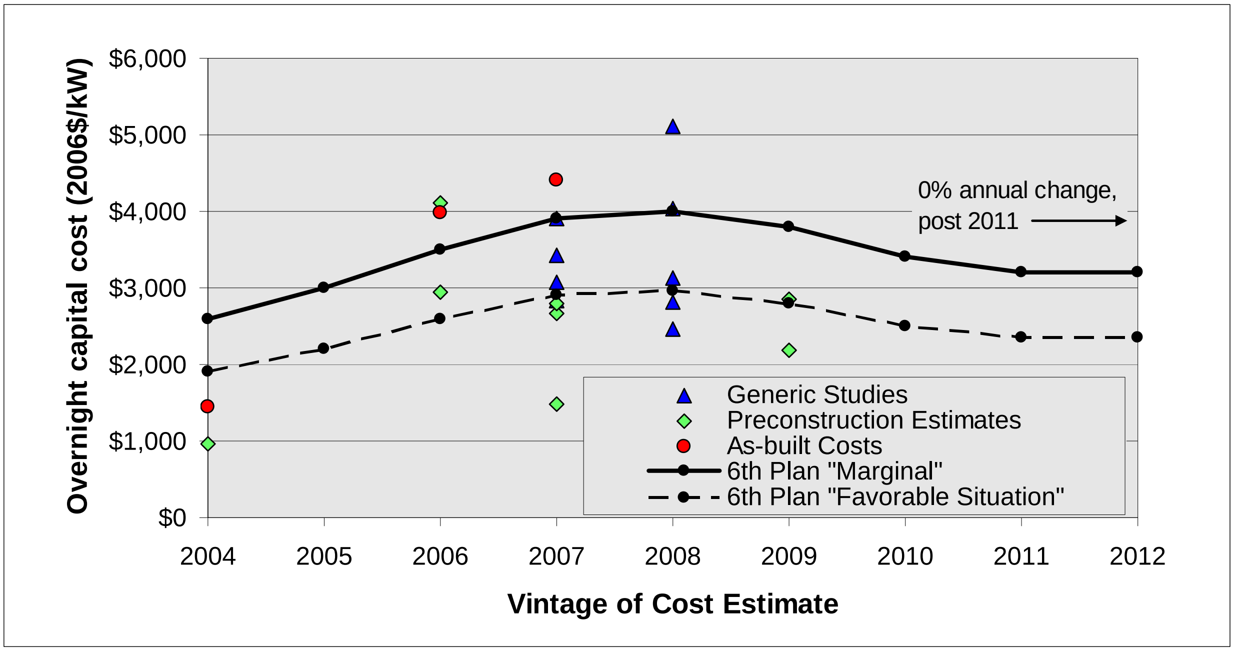
Equivalent annual availability - 86%

***Unit Commitment Parameters*:** Woody residue steam-electric plants are assumed to operate as must-run units at an annual capacity factor of 80%.

Total Plant Cost: The typical total plant cost of a plant developed under Brownfield conditions is estimated to be $3000/kW (net) capacity (2008 price year). The Greenfield plant representing longer-term marginal development conditions is estimated to cost $4,000/kW (net) installed capacity (2008 price year). These estimates were derived from six generic cost reports; preconstruction cost estimates from eight projects and as-built costs for three projects. The normalized cost estimates and resulting assumptions for the Sixth Power Plan are illustrated in Figure I-7. The Greenfield plant was used in the portfolio risk studies. The low-bound cost of -50% ($2000) represents the addition of a pressure drop steam turbine-generator to an existing industrial process steam system. The high bound cost of +25% ($5,000) represents greenfield construction of a new small plant.

Construction costs are forecast to decline by 5% (real) in 2009, and then continue to decline to market equilibrium conditions, represented by the average of 2004 and 2008 costs, by 2011. Construction costs are assumed to remain constant in real terms thereafter.

Figure I-7: Published and forecast capital costs of woody residue power plants



Development and Construction Schedule, Cash Flows: Development and construction schedule and cash flow assumptions are as follows:

> **Development** (Feasibility study, permitting, geophysical assessment, preliminary engineering) - 24 mo., 2% of total plant cost
>
> **Early Construction** (Final engineering, major equipment order, site preparation) - 12 mo., 45% of total plant cost
>
> **Committed Construction** (Delivery of major equipment, completion of construction and testing) - 12 mo., 53% of total plant cost.

Operating and maintenance costs: The estimated operating and maintenance costs for the reference Brownfield plant with CHP are $194/kW/yr fixed and $0.73/MWh variable. These costs are from Port of Port Angeles (2009), adjusted to the mid-2008 price point and 2006 dollars used for this plan. The estimated operating and maintenance costs for the reference Greenfield plant are $180/kW/yr fixed and $3.70/MWh variable. These are based on CEC (2007), adjusted to the mid-2008 price point and 2006 dollars used for this plan. Fixed O&M costs are forecast to decline to equilibrium values, and then stabilize as described for construction costs.   Variable O&M costs are assumed to remain constant in real terms.

Value of steam sales: Extracted 150 psi saturated steam is assumed to be values at $5.00/1000 lbs, based on Port of Port Angeles (2009).

Economic Life: Assumed to be 20 years. Though a new steam-electric plant can operate for 30 years, or more, the expected economic life of a steam-electric plant fuelled by woody residue and with cogeneration load is limited by uncertainties regarding continued fuel supply availability and the viability of the host facility.

Development potential: The estimated remaining regional development potential is 830 MW of capacity yielding 665 MWa of energy. This is based on estimates of woody residue supply developed for the Western Governor's Association (WGA, 2006). The derivation of the capacity and energy potential from the base WGA estimates of residue availability are shown in Table I-12.

Table I-12: Derivation of estimated undeveloped woody residue energy potential

	Forestry (MMODT)	MSW Biogenic (MMODT)	Total (MMODT)	Total (TButu/yr)[15]	Practical Potential (TBtu/yr)[16]	Energy[17] (aMW)	Capacity[18] (MW)
Idaho	2.05	0.43	2.47	43.0	17.2	127	158
Montana	1.83	0.50	2.33	40.6	16.2	119	149
Oregon	1.51	1.65	3.16	55.0	22.0	162	203
Washington	1.54	3.47	5.01	87.2	34.9	257	321
Total						**665**	**831**

Levelized cost summary: The estimated levelized lifecycle cost of delivered energy from two woody residue power plants cases is shown in Table I-13. The Brownfield case represents a best case situation. This case assumes the use of refurbished plant equipment, a brownfield site with existing transportation, water, wastewater and transmission infrastructure, a local supply of mill residue, urban wood residues or other low-cost fuel, and revenue from a cogeneration load. The Greenfield case represents the marginal cost of new woody residue power plants. This case assumes the use of new (though more efficient) plant equipment, a greenfield site, forest residue supplied from remote logging, pre-commercial thinning or ecological restoration operations, and no cogeneration load. The cost estimates are based on investor-owned utility financing. 2010 service year cases include federal production tax credit.

Table I-13: Levelized Cost of Woody Residue Power Plants

Case	Service Year	Plant Busbar ($/MWh)	Ancillary Services and Integration ($/MWh)	Transmission and Losses ($/MWh)	Emissions ($/MWh)	Total ($/MWh)
Brownfield	2010	$92.06	$0.97	$4.21	$0.00	$97
	2015	$83.30	$0.99	$4.08	$0.00	$88
	2020	$83.35	$0.99	$4.09	$0.00	$88
	2025	$83.43	$0.99	$4.09	$0.00	$89
	2030	$83.63	$1.00	$4.11	$0.00	$89
Greenfield	2010	$132.70	$0.97	$4.99	$0.00	$139
	2015	$118.83	$0.99	$4.77	$0.00	$125
	2020	$117.46	$0.99	$4.75	$0.00	$123
	2025	$116.66	$0.99	$4.74	$0.00	$122
	2030	$116.64	$1.00	$4.75	$0.00	$122

[15] Assumed average heat value of 17.4 MM Btu per oven dry ton.
[16] Assumed excess fuel supply ratio of 2.5 to ensure reliable long-term fuel supply.
[17] Assumed heat rate of 15,500 Btu/kWh.
[18] Assumed annual average plant capacity factor of 80%.

Geothermal

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

Reference Plant: The reference plant is a 40 megawatt (nominal) binary cycle plant comprised of three 13-megawatt (net) units. The plant is assumed to use closed loop organic Rankine cycle technology suitable for low geothermal fluid temperatures. The plant includes production and injection wells, geothermal fluid piping, power block, cooling towers, step-up transformers, switchgear and interconnection facilities, and security, control, and maintenance facilities. Wet cooling, resulting in higher plant efficiency, greater productivity, and lower cost, would likely be used at sites with sufficient water. Dry cooling could be employed at sites with insufficient cooling water availability, at additional cost and some sacrifice in efficiency and productivity.

Availability Parameters: Plant availability parameters are as follows:

Scheduled maintenance outages - 14 days/yr

Equivalent forced outage rate - 6.4%

Mean time to repair - 40 hours

Equivalent annual availability - 90%

Unit Commitment Parameters**:** Geothermal plants are assumed to operate as must-run units.

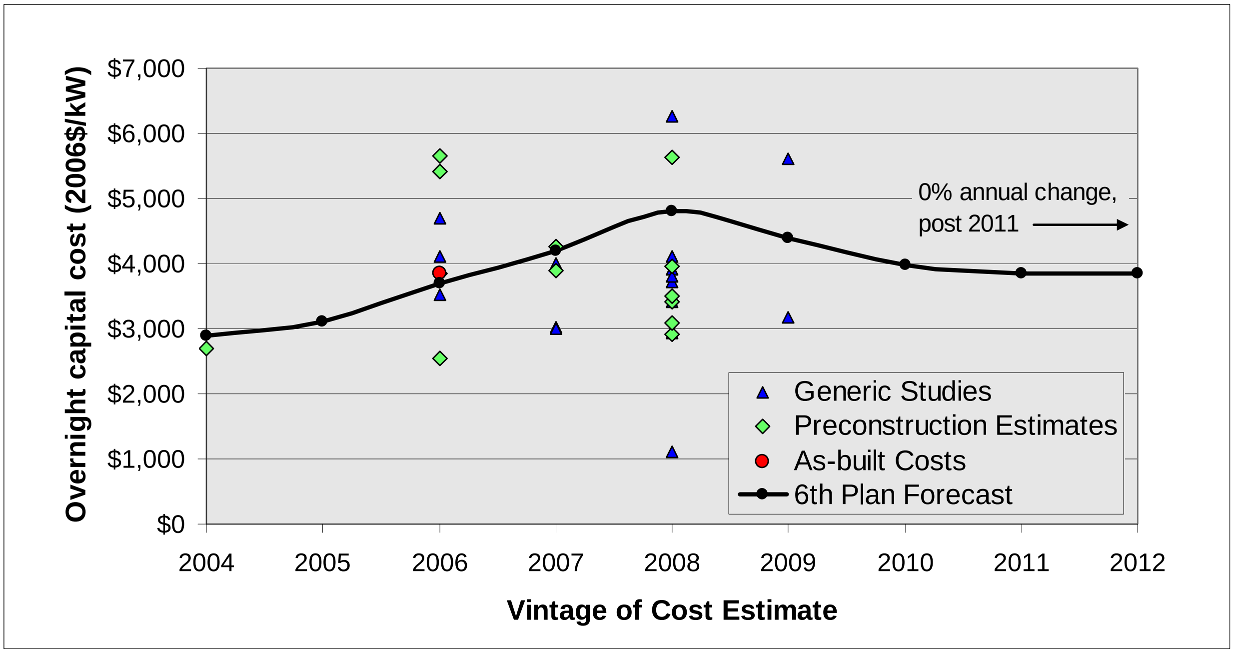
Capacity Factor: The average capacity factor over the life of the facility is assumed to be 90%.

Heat Rate: The average annual full load heat rate is 28,500 Btu/kWh, typical of an ORC binary plant operating on 300^{o}F geothermal fluid.

Total Plant Cost: The total plant cost of the reference geothermal plant is $4,800/kW installed capacity (2008 price year). This estimate is based on a sample of one reported as-built plant cost and 12 preconstruction estimates, including one estimate consisting of low and high bound costs. Ten generic estimates of geothermal plant development costs were also obtained. Five of these were range estimates consisting of low and high bound costs and one included low, mid-range, and high bound costs. Published costs, normalized as described in the Capital Cost Analysis subsection of this Appendix, are plotted by vintage in Figure I-8. A wide range of costs is evident and the general increase in power plant construction costs from 2004 through mid-2008 is poorly defined. The reference plant cost estimate of $4800/kW is based on a rough projection of average cost trends from 2004 through 2007 and lies on the high side of the 2008 cluster. The 2008 base year forecast does relate reasonably well to the 2009 generic estimates (the 2009 estimates are a range estimate representing a low-temperature deep resource (high cost) and a higher temperature shallower resource (low cost). A cost uncertainty of -33% ($3,200) to +17% ($5,600), for the portfolio model risk analysis, is based on the range of 2008 vintage costs, excluding the two extreme outlying values.

Total plant costs are forecast to decline by 8% (real) in 2009, and then continue to decline to market equilibrium conditions, represented by the average of 2004 and 2008 costs, by 2011. Total plant costs are assumed to remain constant in real terms thereafter.

Figure I-8: Published and forecast capital costs of geothermal power plants



Development and Construction Schedule, Cash Flows: The development and construction schedule and cash flow assumptions for a geothermal plant are as follows:

Development (Site option to completion of exploration) - 36 mo., 10% of total plant cost

Early Construction (Wellfield confirmation and development) - 12 mo., 35% of total plant cost

Committed Construction (Power plant, pipelines and infrastructure) - 24 mo., 55% of total plant cost

Operating and Maintenance Cost: Estimated operating and maintenance costs for the reference plant are $175/kW/yr fixed plus $4.50/MWh variable. This estimate is derived from eight published sources containing estimates of geothermal plant operating and maintenance costs. Each source is associated with a capital cost estimate, allowing O&M costs to be estimated in terms of percentage of capital cost, a common approach. The O&M cost estimates were first adjusted to 2006 dollar values. Some estimates include both fixed and variable components, some are fixed only, and others are in fully variable terms. Variable costs were converted to equivalent fixed values, assuming a 90% capacity factor. These were added to the fixed O&M component, if any, yielding total O&M cost in fixed terms, in 2006 year dollars. The resulting values were converted to percentages of total plant cost based on the associated normalized capital costs. This yielded an average value of 5% (omitting one extreme value associated with an unrepresentative low capital cost); $210/kW/yr using the capital cost of the reference plant. Fixed and variable components were derived from this estimate by assuming the variable component to be $4.50/MWh (the value from CEC, 2007). Deducting the fixed equivalent of $4.50/MWh at 90% capacity factor from $210/kW/yr yields the $175/kW/yr fixed component. Fixed O&M costs is assumed to vary in real terms with total plant cost. Variable O&M costs are assumed to remain constant in real terms.

Economic Life: The economic life of a geothermal plant is assumed to be 30 years; limited by wellfield viability and equipment life.

Development Potential: A recent U.S. Geological Survey assessment of moderate and high temperature hydrothermal resources[19] yielded a mean total electricity generating potential with 95% confidence of 266 MWe[20] of from currently identified resources and 1,103 MWe from currently undiscovered resources within the four Northwest states for a total of 1,369 aMW of energy potentially available with high confidence. However, factors including the limited development in the Northwest to date, the high frequency of dry holes encountered during earlier attempts to develop Northwest geothermal projects, siting resistance encountered in earlier efforts to develop Northwest geothermal resources, the high risk and long lead time associated with the confirmation of geothermal resources, and the relatively few sites currently under development all suggest that the Northwest resource potential during the period of this plan will be limited by development rate rather than ultimate availability. Based on geothermal development experience in Nevada, a state with similar types of geothermal resources as the Northwest, we assume that resources can be developed at a maximum rate of 14 MW per year in from 2011 through 2014, increasing to 24 MW per year, on average for the duration of the planning period. This would yield a maximum of 416 megawatts of hydrothermal resource over the term of the plan. At 90 percent capacity factor, this capacity would yield 374 average megawatts of energy. These assumptions are believed to be conservative and should be revisited at the biennial assessment of the Sixth Power Plan when it is expected that additional Northwest geothermal development experience will be available.

Levelized cost summary: The estimated levelized lifecycle cost of delivered energy from geothermal power plants is shown in Table I-14. The cost estimates are based on investor-owned utility financing. 2010 service year cases include federal production tax credit.

[19] United States Geological Survey. *Assessment of Moderate- and High-Temperature Geothermal Resources of the United States*. 2008.
[20] In this study, one MWe is defined as the capability of generating 8.77 GWh (one average megawatt) continuously for a period of 30 years.

Table I-14: Levelized Cost of Geothermal Power Plants

Service Year	Plant Busbar ($/MWh)	Ancillary Services and Integration ($/MWh)	Transmission and Losses ($/MWh)	Emissions ($/MWh)	Total ($/MWh)
2010	$83.93	$0.98	$3.79	$0.00	$89
2015	$76.22	$0.99	$3.68	$0.00	$81
2020	$76.10	$1.00	$3.69	$0.00	$81
2025	$76.17	$1.00	$3.70	$0.00	$81
2030	$76.22	$1.01	$3.71	$0.00	$80

Hydropower

The theoretical hydropower potential of the Northwest has been estimated to be about 68,000 megawatts of capacity and 40,000 average megawatts of energy. Nearly 33,000 megawatts of this potential capacity has been developed at about 360 projects. Though the remaining theoretical hydroelectric power potential is large, most economically and environmentally feasible sites have been developed and the remaining opportunities are a diversity of small-scale projects. These include equipment upgrades and capacity expansion at existing projects, projects on irrigation canal and conduit drops and high-head diversions on small headwater streams. As the technology improves and costs reduced, hydrokinetic turbines may see increased applications.

Reference Plant: Because of the diversity of remaining hydropower development opportunities, no single plant configuration is representative of the remaining development opportunities. Cost and performance assumptions were based on the characteristics of recently developed proposed hydropower plants in the WECC. For modeling purposes, the capacity of a typical new unit is assumed to be 10 MW.

Availability Parameters: Not evaluated. New hydropower plants are assumed to operate at the average capacity factor described below.

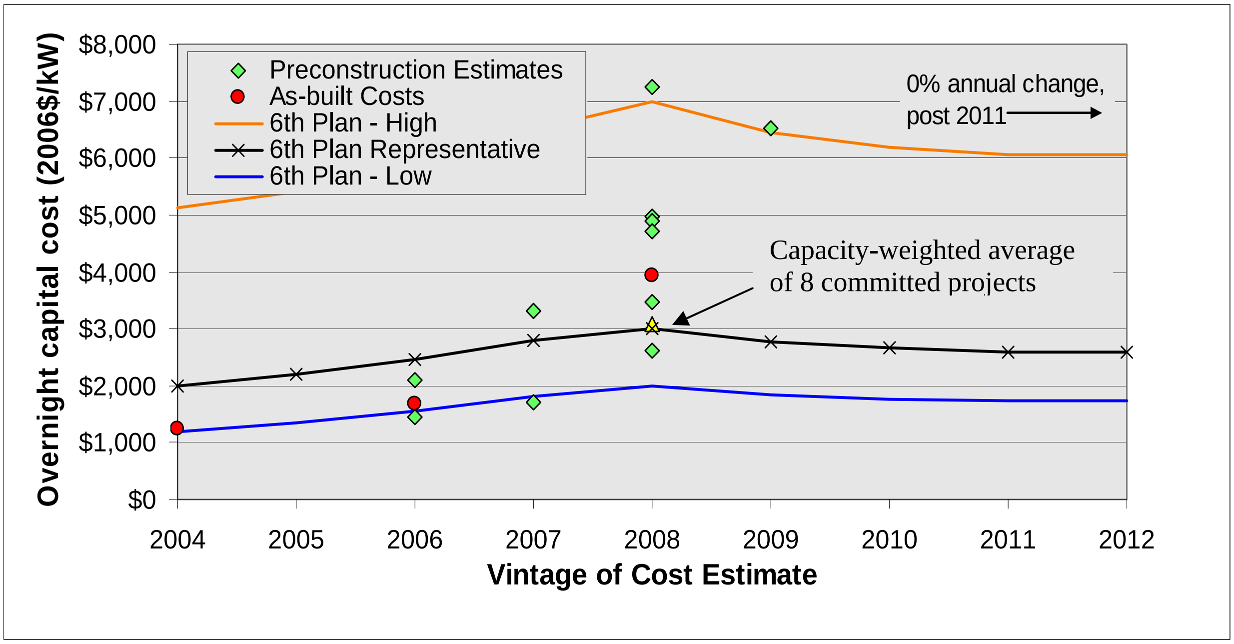
***Unit Commitment Parameters*:** Hydropower plants are assumed to operate as must-run units.

Capacity Factor: The average capacity factor over the life of the facility is assumed to be 50%. This is based on the average of the reported energy production of a sample of 15 recently developed and proposed hydropower plants in the WECC (49.4%), rounded to 50%.

Total Plant Cost: Cost information was located for 14 proposed and recently-constructed hydropower projects in the WECC region. No generic hydropower cost information was located. The costs of the 14 projects, normalized to overnight 2006 dollar values, are plotted by vintage in Figure I-9 (both preconstruction estimates and as-built costs were available for two of the projects). Partially because of the relatively little hydropower development in earlier years and a recent acceleration of development proposals, perhaps due to state renewable portfolio standards and similar BC energy policy, most of the costs are dated from 2008. An accelerating increase in project cost through 2008, similar to that observed for other generating technologies is evident. Also evident is a very wide spread of cost, particularly for 2008, likely due to wide variation in project configuration, size, and project scope. The latter ranges from rehabilitation of retired projects, through addition of power generation to existing water control structures to full new project construction.

The representative 2008 cost of $3,000/kW is the rounded capacity-weighted, escalation-adjusted average cost of eight "committed" (recently completed or under construction) projects. The low bound cost ($2,000/kW in 2008) was set so its historical curve includes the as-built costs of low-cost completed projects (Figure I-9). The high bound cost ($7,000/kW in 2008) includes all projects except for two outliers (one off the chart of Figure I-9). Much of the capital cost of the two outlying projects is associated with converting existing open irrigation ditches to piping for non-hydropower purposes of (controlling water loss).

Figure I-9: Published and forecast capital costs of new hydropower projects



Construction costs are forecast to decline by 8% (real) in 2009, and then continue to decline to market equilibrium conditions, represented by the average of 2004 and 2008 costs, by 2011. Construction costs are assumed to remain constant in real terms thereafter.

Development and Construction Schedule, Cash Flows: The development and construction schedule and cash flow assumptions for a typical small hydropower plant are as follows:

> **Development** (Issuance of preliminary permit to receipt of FERC license and selection of EPC contractor) - 48 mo., 12% of total plant cost
>
> **Construction** (Site preparation, construction and commissioning) - 24 mo., 88% of total plant cost

Operating and Maintenance Cost: Operating and maintenance costs are assumed to be 3% of overnight capital cost. This assumption yields $90/kW/yr for the representative case, $60/kW/yr for the low bound case and $210/kW/yr for the high bound case. The variable component is small and is included in the fixed O&M estimate. O&M cost is assumed to vary in real terms with total plant cost.

Economic Life: The economic life of a small hydropower plant is assumed to be 30 years; limited by major equipment life.

Development Potential: A comprehensive assessment of new hydropower potential has not been attempted by the Council since the Fourth Power Plan. In that plan, the Council estimated that about 480 megawatts of additional hydropower capacity was available for development at costs of 9.0 cents per kilowatt-hour or less. This capacity could produce about 200 megawatts of energy on average. Few projects have been developed in the intervening years, and it is likely that the Fourth Power Plan estimate remains representative. Because of increasing interest in the acquisition of renewable resources and expanding the diversity of renewable resource acquisitions, Bonneville and the Council are undertaking a new assessment of undeveloped hydropower potential.

Levelized cost summary: The estimated levelized lifecycle cost of delivered energy from the two new hydropower cases is shown in Table I-15. The cost estimates are based on investor-owned utility financing. 2010 service year cases include federal production tax credit.

Table I-15: Levelized Cost of New Hydropower Plants

Case	Service Year	Plant Busbar ($/MWh)	Ancillary Services and Integration ($/MWh)	Transmission and Losses ($/MWh)	Emissions ($/MWh)	Total ($/MWh)
Favorable Site	2010	$57.81	$0.98	$5.00	$0.00	$64
	2015	$54.30	$0.99	$5.00	$0.00	$60
	2020	$54.27	$1.00	$5.02	$0.00	$60
	2025	$54.31	$1.00	$5.04	$0.00	$60
	2030	$54.33	$1.01	$5.05	$0.00	$60
Typical Site	2010	$89.04	$0.98	$5.60	$0.00	$96
	2015	$81.45	$0.99	$5.53	$0.00	$88
	2020	$81.41	$1.00	$5.55	$0.00	$88
	2025	$81.47	$1.00	$5.56	$0.00	$88
	2030	$81.50	$1.01	$5.58	$0.00	$88

Utility-scale Solar Photovoltaic Plants

Though photovoltaics have been widely employed for many years to supply power to small remote loads, larger-scale and grid-connected photovoltaic installations have been few in number and capacity because of the high cost of the technology and low productivity relative to alternatives. Over the past several years, strong public and political support has lead to attractive financial incentives and multi-megawatt grid-connected installations are becoming increasingly common.

A wide variety of photovoltaic plant designs are possible with various combinations of cell, module, and mounting design. A basic tradeoff is energy conversion efficiency vs. cost. Thin-film photovoltaic cells mounted on fixed racks results in a (relatively) low cost, rugged design. Conversion efficiency is low, however, and thin-film cell output tends to deteriorate over time. Efficiency and durability can be increased by use of single-crystalline cells mounted on single axis tracking devices. The ultimate in efficiency can be achieved by use of concentrating lenses focused on multijunction cells sensitive to a wide spectral range, mounted on fully automatic dual axis trackers. But each increase in efficiency comes at a greater cost, and complexity. Moreover, the most efficient designs, those employing concentrating devices, operate only on direct solar radiation so are more suitable for Southwestern locations where clear skies prevail.

Reference Plant: The reference plant is 20 megawatt (net ac output) plant using flat plate (non-concentrating) single crystalline modules mounted on single-axis trackers. The 25 MW dc module output is converted to alternating current for grid interconnection using solid-state inverters. Inverter, cabling and transformer losses result in a net output of 20 MW ac. The plant also includes step-up transformers, switchgear and interconnection facilities and security, control and maintenance facilities. The deployment strategy would locate smaller individual plants at scattered locations within the better solar resource areas of the region. This should reduce instances of simultaneous ramping due to cloud movement, reduce environmental concerns and permitting issues, shorten lead time and reduce interconnection costs.

Availability Parameters: Not evaluated. Solar photovoltaic plants are assumed to operate at the average capacity factors described below.

***Unit Commitment Parameters*:** Solar photovoltaic plants are assumed to operate as must-run units.

Capacity Factors and Temporal Output: Annual capacity factor and seasonal daily and hourly output was estimated for five reference locations using the NREL Solar Advisor Model ((https://www.nrel.gov/analysis/sam/). Monthly average plant output and annual average capacity factors (ac rating to net ac output) are provided in Table I-16 and illustrated in Figure I-10. Example average hourly plant output for the Boise location is provided in Table I-17 and illustrated in Figure I-11.

The plant design assumptions used for this analysis are as follows:

Configuration - Flat plate, tracker-mounted, inverted to ac output, no storage

Array DC power - 25.3 MW (yielding nominal 20 MW ac output)

Modules - 12 x 10549 (126588) SunPower SPR-200-BLK(c-Si)

Mounting - Single-axis tracker

Inverters - (98) Xantrex GT250-480-POS

System degradation - 1%/yr, compounded

Internal derate factor - 84%, excluding inverter conversion efficiency

Overall performance ratio (dc rating > ac output) - 78%-79% (location-specific)

Table I-16: Estimated monthly net energy production (MWh) and annual capacity factors for utility-scale photovoltaic plant using flat plate single-crystalline modules on single-axis trackers (ac rating to net ac output)

	Billings, MT	Boise, ID	Burns, OR	Ely, NV	Yakima, WA
Jan	1722	1586	1722	2904	1255
Feb	2294	2244	2173	3083	1915
Mar	3566	3544	3323	4524	3391
Apr	3930	4404	4208	4914	3891
May	4977	5291	5180	5614	5245
Jun	5088	5656	5511	6121	5572
Jul	5837	6192	5859	6161	5941
Aug	5220	5637	5530	5461	5320
Sep	4059	4516	4421	5224	4258
Oct	2868	3389	3219	4086	2858
Nov	1905	1830	1540	2632	1279
Dec	1487	1421	1299	2579	1093
Annual	24.5%	26.4%	25.4%	30.4%	24.3%

Figure I-10: Estimated monthly net energy production for utility-scale photovoltaic plant using flat plate single-crystalline modules on single-axis trackers

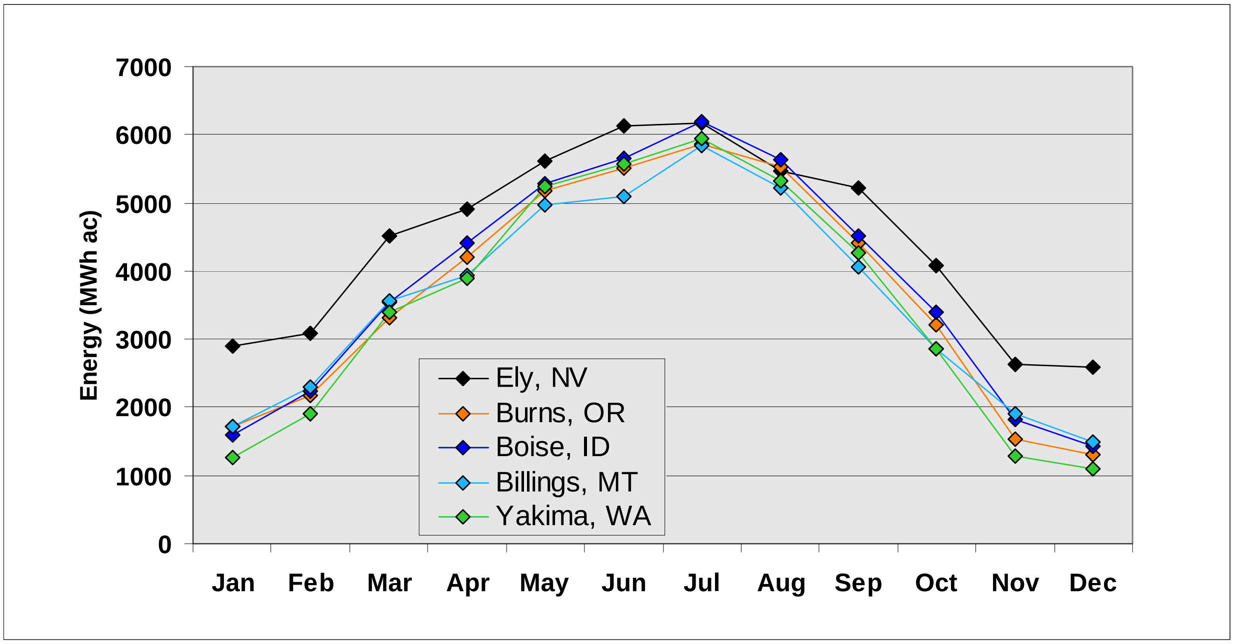
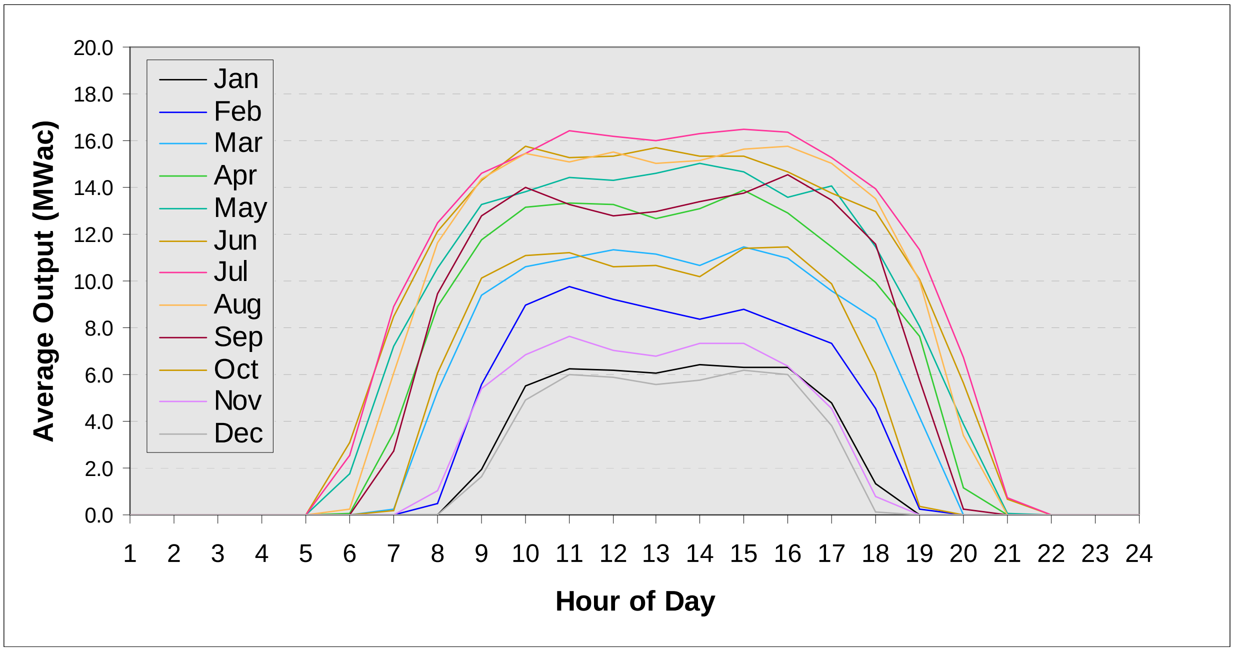


Table I-17: Average hourly energy output by month (Boise example)

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.08	1.78	3.10	2.54	0.22	0.00	0.00	0.00	0.00
7	0.00	0.00	0.25	3.53	7.22	8.50	8.90	6.09	2.70	0.16	0.00	0.00
8	0.00	0.47	5.29	8.90	10.55	12.15	12.50	11.61	9.45	6.09	1.02	0.00
9	1.95	5.58	9.37	11.77	13.25	14.32	14.62	14.34	12.79	10.14	5.37	1.65
10	5.52	8.99	10.63	13.16	13.81	15.73	15.46	15.46	13.98	11.06	6.85	4.92
11	6.27	9.75	11.00	13.33	14.44	15.28	16.44	15.09	13.25	11.22	7.61	5.97
12	6.20	9.24	11.35	13.30	14.33	15.34	16.17	15.54	12.76	10.61	7.03	5.89
13	6.05	8.82	11.17	12.69	14.60	15.71	15.98	15.01	12.95	10.68	6.82	5.59
14	6.45	8.37	10.65	13.11	15.00	15.33	16.33	15.17	13.41	10.19	7.36	5.77
15	6.28	8.82	11.47	13.86	14.64	15.36	16.46	15.62	13.78	11.39	7.31	6.17
16	6.32	8.08	10.97	12.88	13.58	14.70	16.37	15.76	14.54	11.46	6.37	5.99
17	4.81	7.30	9.58	11.48	14.04	13.74	15.28	15.05	13.46	9.91	4.52	3.82
18	1.36	4.52	8.39	9.97	11.46	12.94	13.92	13.51	11.55	6.06	0.79	0.11
19	0.00	0.26	4.19	7.62	8.08	10.08	11.31	9.98	5.74	0.39	0.00	0.00
20	0.00	0.00	0.03	1.13	3.86	5.63	6.76	3.40	0.22	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.05	0.66	0.74	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure I-11: Average hourly energy output by month (Boise location)



***Unit Commitment Parameters*:** Solar photovoltaic plants are assumed to operate as must-run units.

Total Plant Cost: The total plant cost is estimated to be $9000/kW (2008 price year) on a nominal ac rating basis. Publically-available cost information was located for 7 proposed or recently-constructed solar photovoltaic plants, ranging in size from 5 to 46 MWdc. Four generic cost estimates for projects greater than one megawatt were also located. These costs, normalized as total plant cost in 2006 dollars per net ac kW of capacity are plotted by the vintage of the cost data in Figure I-12. Also plotted in Figure I-12 are retail module prices for 2005 through 2008 compiled by the Energy Trust of Oregon. Total plant costs through time should bear a close relationship to module costs. The Sixth Power Plan representative cost curve is based on the costs of actual projects, especially those using tracking crystalline modules and the shape of the historical module cost curve. Less weight was placed on the three low-lying generic examples. Partly this was because the rating basis (ac or dc) of these examples was not reported, and if dc (as is often the case), the costs would be about 20% greater than plotted. Secondly, these examples lie below the retail module prices reported by the Energy Trust of Oregon. It is unlikely that even the discount associated with bulk orders would lead to the total plant costs of these three generic cases.

As shown in Figure I-12, module costs declined in real terms in 2008 with increases in production capacity. Preliminary information indicates that this decline continued in 2009 as demand slackened. Continuing real dollar declines in module costs over the long-term are anticipated with improvements in cell efficiency, increased production automation and increases in production capacity. Reduction in module costs and increases in plant size should lead to continued reduction in total plant costs. The long-term forecast of solar photovoltaic plant costs used for this plan are based on forecasts prepared by Navigant for the state of Arizona (Navigant, 2007) and Black and Veatch for Idaho Power (Black & Veatch, 2008). These, and the forecast used for this plan are shown in Figure I-13. Note that in contrast to Figure I-12, the horizontal axis of Figure I-13 is scaled to year of service for consistency with the Navigant and Black & Veatch forecasts. The vertical axis scale should be considered relative since the Black & Veatch estimates are not defined as to ac or dc basis.

Figure I-12: Published and forecast capital costs of utility-scale solar photovoltaic plants

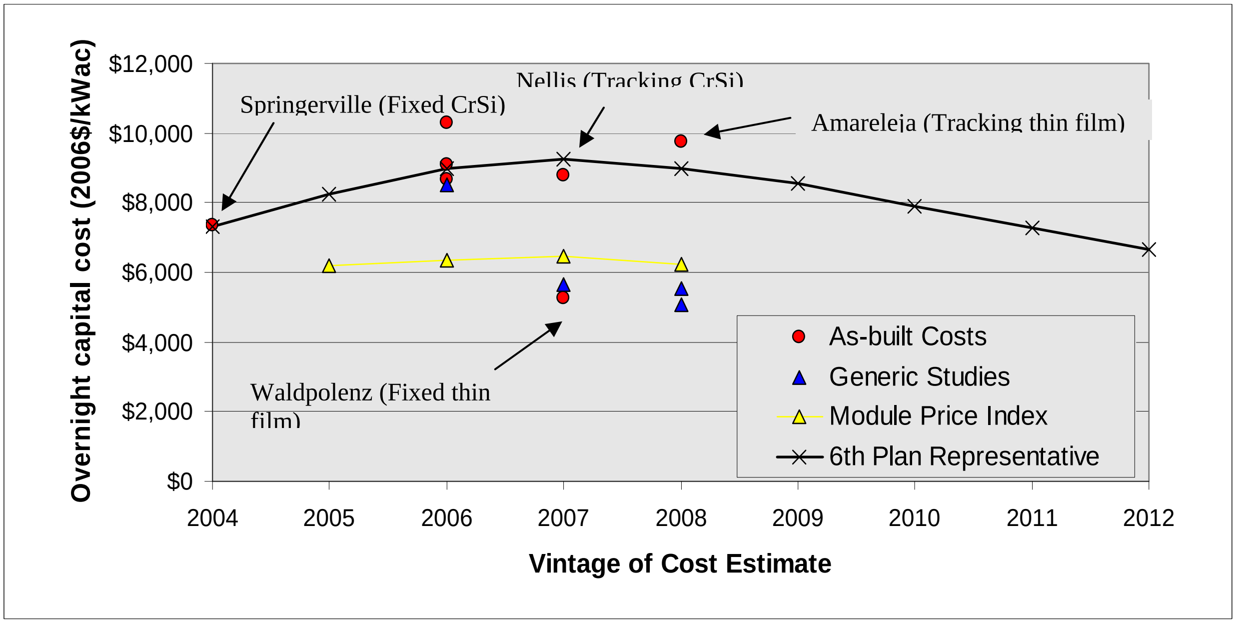
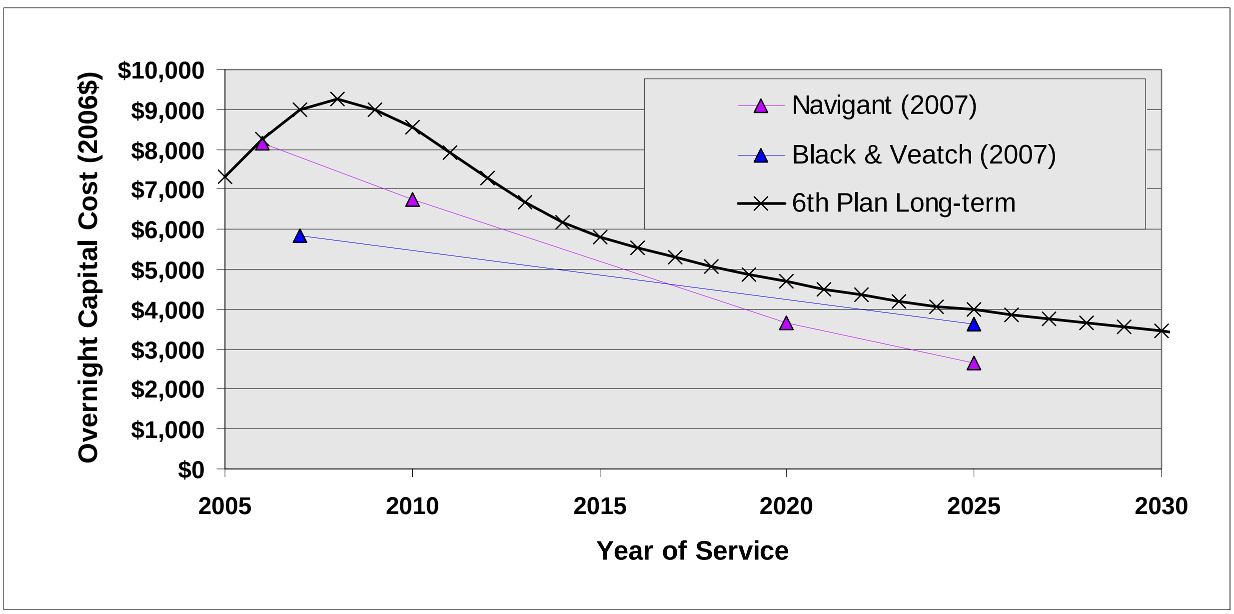


Figure I-13: Forecast long-term capital costs of utility-scale solar photovoltaic plants



Development and Construction Schedule, Cash Flows: The development and construction schedule and cash flow assumptions for representative utility-scale solar photovoltaic plant are as follows:

Development (Site acquisition, permitting) - 12 mo., 1% of total plant cost

Early Construction (Procurement and site preparation) - 12 mo., 14% of total plant cost

Committed Construction (Construction and commissioning) - 12 mo., 85% of total plant cost

Costs are assumed to be set one year in advance of completion.

Operating and Maintenance Cost: Operating and maintenance costs are assumed to be 0.4% of overnight capital cost. This is midway between reported O&M costs for the Arizona Public Service Springerville plant (0.26% of capital cost, including inverter replacement but using fixed mount modules), and International Energy agency estimates (0.5% of capital cost). This assumption yields $36/kW/yr (2008 base year). O&M costs are assumed to vary in real terms with total plant cost.

Integration cost: Photovoltaic plants are assumed to require integration and load following services. The forecast cost of supplying regulation and sub-hourly load-following services for operational integration is shown in Table I-5. The cost of longer-term shaping services is not included in this estimate.

Economic Life: The economic life of a utility-scale solar photovoltaic plant is assumed to be 25 years; limited by warranted cell life. One inverter replacement is likely to be required during the life of the plant.

Development Potential: Utility-scale solar photovoltaic development potential is likely to be substantial; however, an assessment has not been undertaken for the Northwest. Because of the high cost of electricity from photovoltaic plants in the Northwest, and the availability of more cost-effective renewable resources, an estimate of developable potential was not needed for this plan. An assessment of potential may be desirable in the future when the cost of electricity from photovoltaic plants approaches parity with other low-carbon resources.

Levelized cost summary: The estimated levelized lifecycle cost of delivered energy from a utility-scale solar photovoltaic power plant with a solar resource typical of southwestern Idaho and southeastern Oregon is shown in Table I-18. The cost estimates are based on investor-owned utility financing. 2010 service year cases include federal investment tax credit.

Table I-18: Levelized Cost of Utility-scale Solar Photovoltaic Power Plants (Boise site)

Service Year	Plant Busbar ($/MWh)	Ancillary Services and Integration ($/MWh)	Transmission and Losses ($/MWh)	Emissions ($/MWh)	Total ($/MWh)
2010	$376.36	$10.27	$14.53	$0.00	$401
2015	$254.40	$10.90	$12.31	$0.00	$278
2020	$205.13	$11.22	$11.38	$0.00	$228
2025	$174.45	$11.36	$10.81	$0.00	$197
2030	$150.75	$11.41	$10.39	$0.00	$173

Concentrating Solar Thermal Power Plant

Parabolic trough concentrating solar thermal power plants are a commercially proven technology with over 20 years of operating history. Existing plants use a synthetic oil primary heat transfer fluid and a supplementary natural gas boiler in the secondary water heat transfer loop for output stabilization and extended operation into the evening hours. Future plants are expected to benefit from higher collector efficiencies, higher operating temperatures (providing higher thermal efficiency and more economical storage) and economies of production.

Concentrating solar technologies (thermal and photovoltaic) require high direct normal solar irradiation for efficient operation. Though the most promising sites are in the desert southwest, potentially suitable areas may be present in Bonneville's Nevada service territory (http://www.nrel.gov/csp/images/3pct_csp_nv.jpg. Some evidence suggests possibly suitable sites in extreme southeastern Oregon.

Reference Plant: The reference plant is a 100-megawatt dry-cooled parabolic trough concentrating solar thermal plant located in east-central Nevada in the vicinity of Ely. Power would be delivered to southern Idaho via the north segment of the proposed Southwest Intertie Project and thence to the Boardman area via portions of the proposed Gateway West and the Boardman-to-Hemmingway transmission projects. Higher temperature heat transfer fluids such as molten salt are expected to be available by the earliest feasible date for energization of the necessary transmission (ca. 2015). The reference plant is assumed to be equipped with and a 2.5 solar multiplier collector field[21] and thermal storage sufficient to support six to eight hours of full power operation. This storage would allow output to be shifted to non-daylight hours, improve winter capacity factor, levelize output on intermittently cloudy days, and impart some firm capacity value. No natural gas backup is provided since natural gas service is not available in the vicinity of the reference site[22].

Capacity Factors and Temporal Output: Annual capacity factor and seasonal, daily and hourly output was estimated using the NREL Solar Advisor Model (https://www.nrel.gov/analysis/sam/) yields an annual average capacity factor of 35.5% for the Ely site. Output is highly seasonal, even with a collector field solar multiplier of 2.5. However, as shown in Table I-19 and Figure I-15, the storage facility effectively shifts output to approximate Northwest daily load shape (compare with photovoltaic output without storage in Table I-17 and Figure I-11). Periods of negative output in Table I-19 are plant parasitic loads in excess of gross solar output.

---

[21] A collector field with rated output 2.5 times the rated output of the power generation block. The surplus output of the collector field during peal solar hours serves to recharge the storage plant.

[22] The Ely vicinity was selected as a reference site because of the availability of reasonably favorable solar resource, suitable sites and the likelihood that the SWIP or a parallel transmission project would move forward. Subsequent analysis using the NREL Solar Advisor Model suggests possible alternatives including the Reno area with new transmission via the existing Alturas corridor. The Reno alternative may have somewhat better solar irradiation plus the advantage of natural gas service permitting use of natural gas backup.

Figure I-14: Estimated monthly net energy production for 100 MW parabolic trough plant with 2.5 solar multiplier and six hours of storage located near Ely, NV

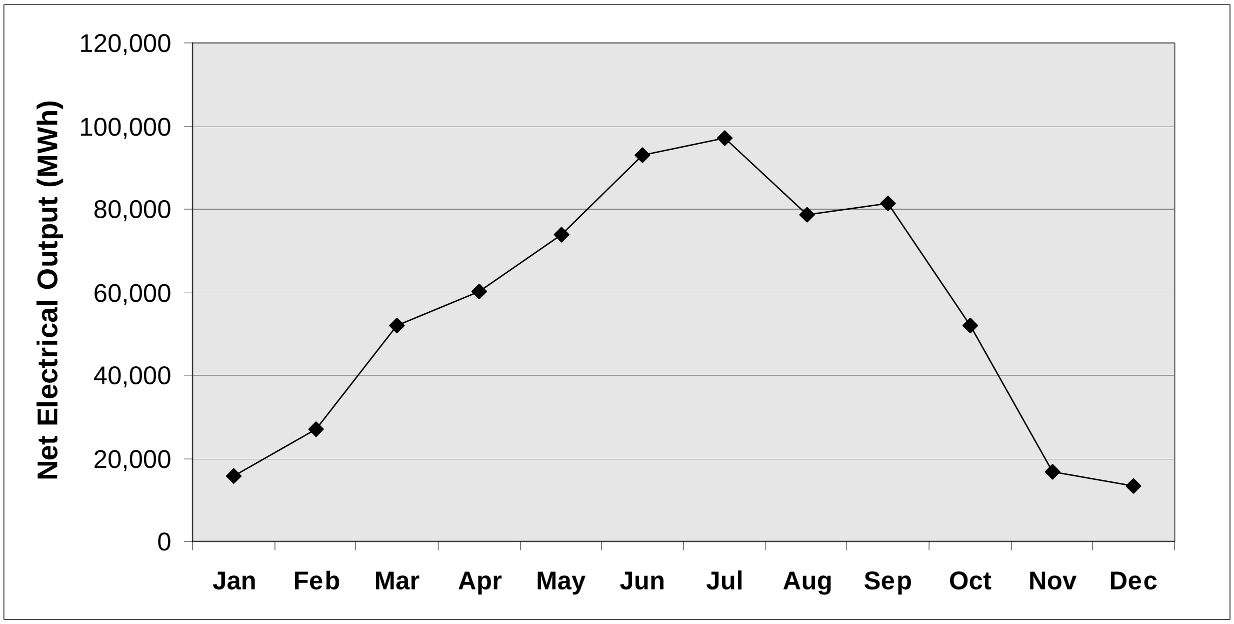
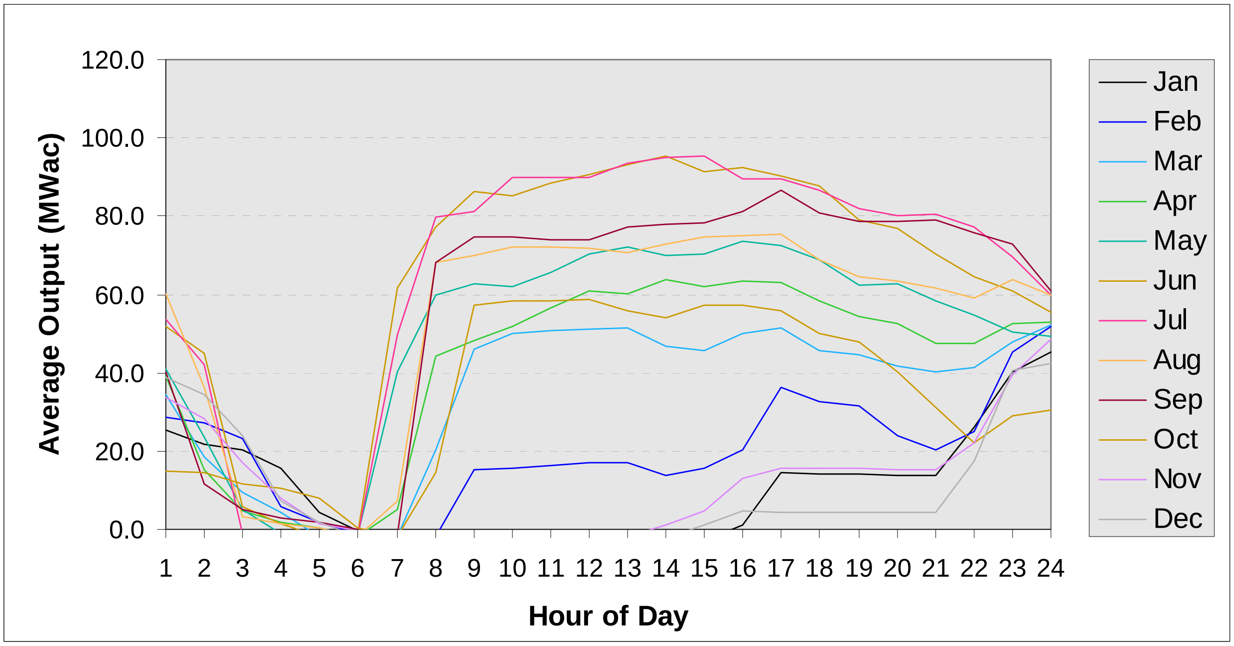


Table I-19: Average hourly energy output by month (MW) (Ely location)

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	25.3	28.8	34.6	39.0	41.0	51.8	53.6	60.2	40.3	14.9	33.9	38.7
2	21.8	27.3	18.6	15.1	23.5	45.0	42.1	36.1	11.6	14.4	28.2	34.6
3	20.2	23.3	9.5	4.6	5.0	5.8	-1.0	3.4	5.2	11.6	17.0	23.8
4	15.5	5.7	4.4	1.7	-1.1	1.4	-1.8	1.6	3.1	10.6	7.8	7.3
5	4.3	1.8	-1.8	0.3	-1.8	-1.8	-1.8	0.4	1.7	8.1	1.6	1.7
6	-0.3	-1.1	-1.8	-1.8	-1.6	-1.3	-1.6	-1.8	0.1	0.3	-0.4	-1.8
7	-1.8	-1.8	-1.8	5.2	40.3	61.5	49.6	7.4	-1.3	-1.8	-1.8	-1.8
8	-1.8	-1.7	20.4	44.1	59.7	77.2	79.9	68.2	68.3	14.3	-1.7	-1.8
9	-2.0	15.3	45.9	48.2	62.6	86.4	81.2	70.0	74.8	57.5	-2.2	-1.9
10	-2.5	15.5	49.9	51.8	61.9	85.1	89.9	72.3	74.6	58.2	-2.0	-2.1
11	-2.0	16.3	50.9	56.6	65.6	88.4	89.9	72.0	74.1	58.4	-2.0	-1.6
12	-1.8	16.9	51.1	60.8	70.4	90.7	90.1	71.6	73.9	58.7	-1.8	-1.6
13	-1.9	17.0	51.6	60.3	72.3	93.1	93.4	70.5	77.1	55.8	-2.0	-1.8
14	-2.2	13.6	46.8	64.0	70.1	95.3	94.8	72.7	77.9	54.0	1.2	-2.2
15	-2.7	15.4	45.7	61.9	70.2	91.4	95.3	74.5	78.3	57.2	4.7	1.1
16	1.3	20.3	50.0	63.6	73.5	92.3	89.6	75.1	81.3	57.1	12.9	4.7
17	14.6	36.4	51.4	63.1	72.6	90.4	89.4	75.5	86.5	55.9	15.7	4.5
18	14.2	32.5	45.8	58.4	69.0	87.8	86.6	68.7	80.8	50.2	15.6	4.4
19	14.0	31.5	44.6	54.5	62.3	78.9	81.8	64.4	78.8	47.9	15.5	4.3
20	13.9	24.0	41.7	52.6	62.6	77.0	80.0	63.6	78.6	40.4	15.4	4.3
21	13.8	20.2	40.4	47.4	58.2	70.2	80.3	61.7	78.9	31.1	15.3	4.4
22	26.0	24.9	41.4	47.3	54.6	64.5	77.2	59.1	75.8	22.0	22.1	17.3
23	40.3	45.3	47.8	52.5	50.4	61.1	69.6	63.6	72.7	28.9	39.7	40.7
24	45.5	52.0	52.3	53.0	49.3	55.4	59.8	60.0	61.0	30.6	48.5	42.6

Figure I-15: Average hourly energy output by month (Ely location)



***Unit Commitment Parameters*:** Concentrating solar thermal plants are assumed to operate as must-run units.

Total Plant Cost: The total plant cost of a representative parabolic trough concentrating solar plant is estimated to be $4,700/kW (2008 price year). Publically-available cost information was located for 3 proposed or recently-constructed parabolic trough concentrating solar plants, ranging in size from 64 to 250 MW. Two recent generic cost estimates for parabolic trough concentrating solar plants were also located. These costs, normalized as total plant cost per net kW capacity in 2006 dollars are plotted by the vintage of the cost data in Figure I-15. Though data are few, a reasonably clear trend of increasing costs from 2004 through 2007 is evident, marked in particular by the increasing estimates for Nevada Solar One. The trend is less clear beyond 2007 and could be interpreted as leveling off or even declining. Continued escalation through price year 2008 was chosen for the plan, because of the continued escalation during this period observed for other resource types and because the higher estimate for 2008 is for a plant employing dry cooling, whereas the lower estimate is for a plant employing evaporative cooling. Though evaporative cooling is less expensive than dry cooling, and results in more efficient plant operation, it is likely that plants located in arid areas (as is the representative plant) will increasingly employ dry cooling. Prices are shown declining in 2009 in accordance with the CERA near-term power plant capital cost index.

The forecast of future cost (Figure I-16) is based on the interaction of several factors including continued downward pressure in the near-term due to economic conditions, upward pressure in the near-term due to incorporation of thermal storage, and downward pressure through the planning period attributable to technological improvements, economies of scale, and economies of production. Figure I-16 illustrates the basic forecast described above, continuing to drop through 2011 when equilibrium prices are assumed to be achieved, consistent with other resource types. The horizontal line extending to the right from this point represents forecast capital costs if no further technological improvement or economies of scale are assumed. A long term forecast of the price effects of technological improvements and economies of scale and production for parabolic trough concentrating solar thermal plants appears in a renewable energy assessment prepared for the Arizona Public Service Company, Salt River Project and Tucson Electric Power Corporation (Black & Veatch, 2007). This forecast is plotted in Figure I-16 with interpolated values between the four forecast points (2011, 2015, 2020 and 2025). Because this forecast was prepared prior to the 2008 economic downturn, the shape, rather than the magnitude of the forecast is used to modify the "no technological improvement" curve to yield the combined forecast of future capital cost used for the final Sixth Power Plan.

Figure I-16: Published and forecast capital costs of parabolic trough concentrating solar power plants

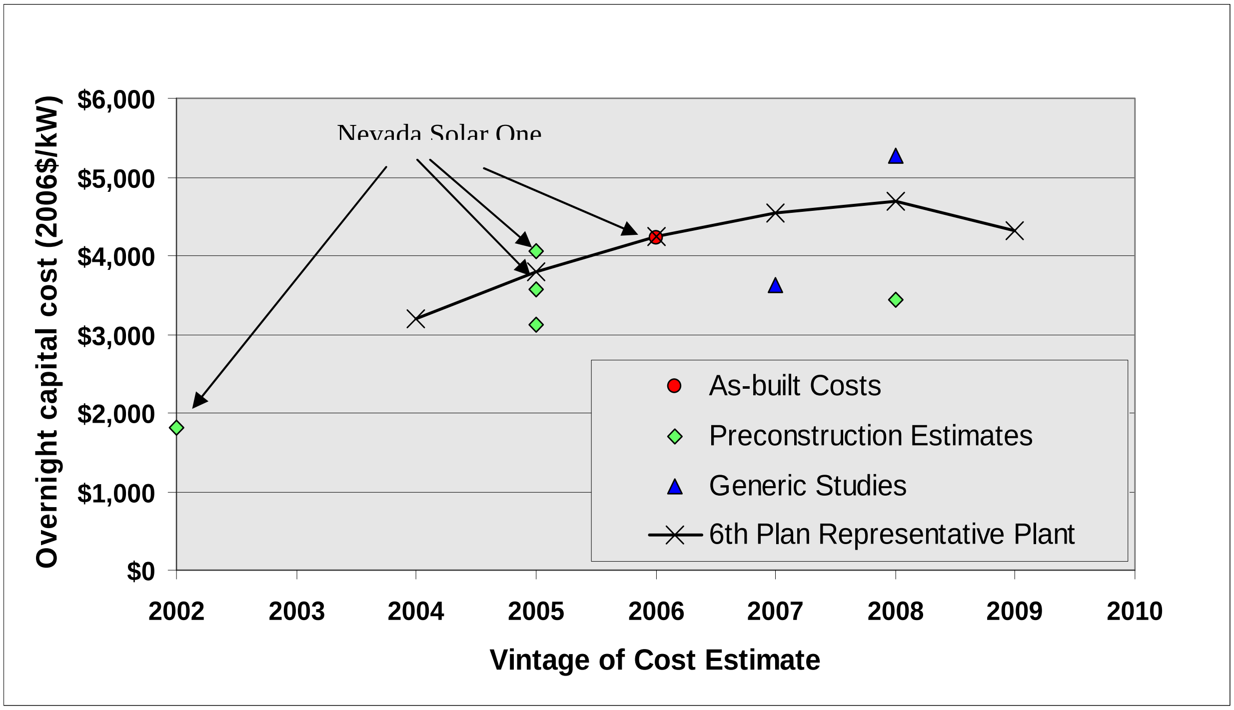
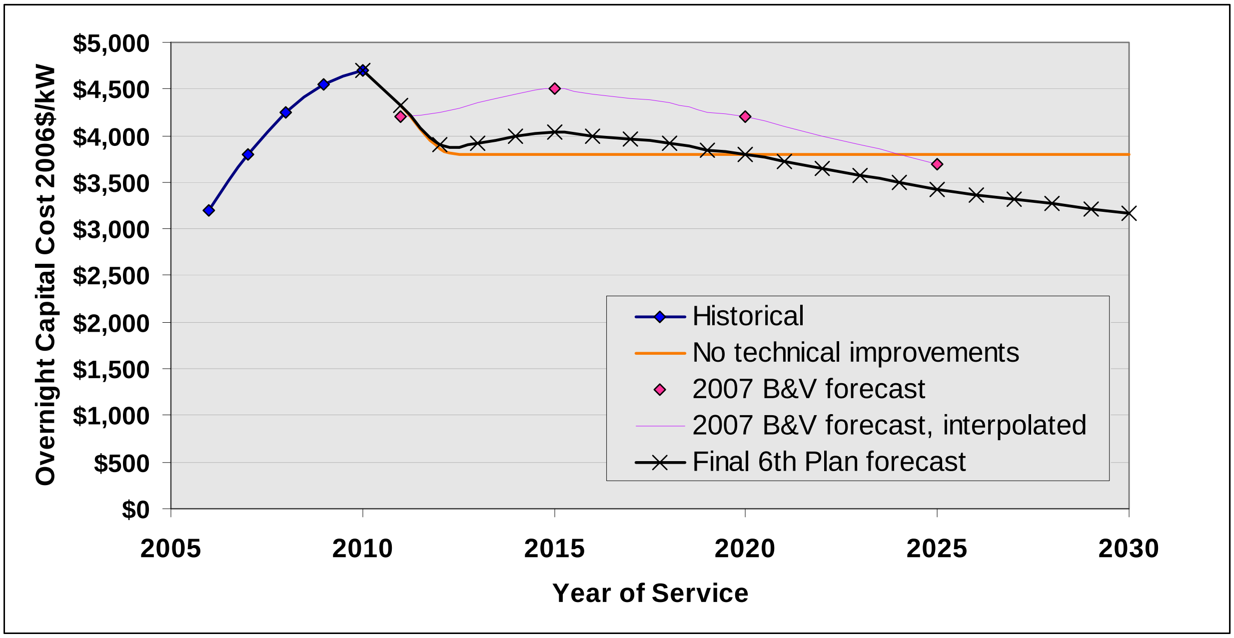


Figure I-17: Forecast long-term capital cost of parabolic trough concentrating solar power plants



Development and Construction Schedule, Cash Flows: The development and construction schedule and cash flow assumptions for representative utility-scale solar photovoltaic plant are as follows:

> **Development** (Site acquisition, permitting, preliminary engineering, interconnection agreement) - 24 mo., 2% of total plant cost
>
> **Early Construction** (Equipment order, site preparation, interconnection and infrastructure construction) - 8 mo. (possible 4 month overlap with development period, 19% of total plant cost
>
> **Committed Construction** (Major equipment installation, commissioning) - 20 mo., 79% of total plant cost

The construction period was based on CEC (2007). Total plant costs are assumed to be established two years in advance of completion

The combined development and construction schedule and cash flow for a solar thermal plant and the associated long-distance transmission is modeled in two phases. The first phase is coincidental development of the transmission line and 50% of the capacity potentially served by the transmission line. The transmission development schedule is controlling and the timing of solar thermal capacity development is assumed to be such that the generating capacity enters service coincidental with the transmission line. The second phase is optional buildout of the remaining 50% of solar thermal capacity potentially served by the transmission line in 250 MW increments.

Operating and Maintenance Cost: Operating and maintenance costs are based on values reported in Table 5-2 of NREL, 2006 for a 100 MW parabolic trough concentrating solar thermal plant with thermal storage. Labor (including administration), service contracts, equipment and materials, including capital replacement items are 1.3% of capital cost. This yields a fixed O&M cost (exclusive of property taxes and insurance) $60/kW/yr for the 2008 price year. Water treatment is assumed to be a variable cost and is rounded to $1.00/MWh. Fixed O&M cost is assumed to vary in real terms with total plant costs. Variable O&M cost is assumed to remain constant in real terms.

Integration Cost: The thermal storage capacity of the representative solar thermal plant is assumed to eliminate the need for the incremental regulation and load following.

Economic Life: The economic life of a parabolic trough concentrating solar thermal plant is assumed to be 30 years.

Transmission: New long-distance transmission would be required to deliver power to Northwest load centers from a solar thermal power plant near Ely, Nevada. Transmission configurations, alignments and basic cost assumptions are described in the Transmission section, above. Transmission costs and losses, including delivery within the region, are provided in Table I-20.

Table I-20: Transmission costs and losses (Ely location)

Load Center	Fixed Transmission Costs ($/kW/yr)	Variable Transmission Costs ($/MWh)	Transmission Losses
Southern Idaho	$102	$1.00	4.0%
Oregon & Washington	$189	$1.00	6.5%

Development Potential: Though environmental considerations will constrain land on which concentrating solar thermal plants can be developed, the development potential is likely to be very substantial. Because of the high cost of electricity from solar thermal plants, and the availability of more cost-effective renewable resources, an estimate of developable potential was not sought for this plan. The earliest availability of the resource to the Northwest is assumed to be 2015, constrained by transmission line development lead time.

Levelized cost summary: The estimated levelized lifecycle cost of delivered energy from concentrating solar thermal power plants is shown in Table I-21. The cost estimates are based on investor-owned utility financing. 2010 service year cases include federal investment tax credit.

Table I-21: Levelized Cost of Concentrating Solar Thermal Power Plants

Case	Service Year	Plant Busbar ($/MWh)	Ancillary Services and Integration ($/MWh)	Transmission and Losses ($/MWh)	Emissions ($/MWh)	Total ($/MWh)
NV > S. ID	2010	n/av	n/av	n/av	n/av	n/av
	2015	$146.20	$0.99	$41.95	$0.00	$189
	2020	$128.05	$1.00	$41.34	$0.00	$170
	2025	$116.24	$1.00	$40.98	$0.00	$158
	2030	$105.48	$1.01	$40.70	$0.00	$147
NV > OR/WA	2010	n/av	n/av	n/av	n/av	n/av
	2015	$146.20	$0.99	$79.38	$0.00	$227
	2020	$128.05	$1.00	$78.38	$0.00	$207
	2025	$116.24	$1.00	$77.82	$0.00	$195
	2030	$105.48	$1.01	$77.39	$0.00	$183

Wind Power Plants

Wind power is modeled by defining a reference wind plant then applying transmission costs and losses appropriate to the location of the wind resource and the load center served. Plant capacity factors are adjusted to reflect the quality of the various wind resource areas. Five wind resource areas were assessed, including the Columbia basin (eastern Washington and Oregon), southern Idaho, central Montana, southern Alberta, and eastern Wyoming. The combinations of wind resource areas, transmission, and points of delivery considered are shown in Table I-3 in the Transmission section.

Reference Plant: The 100 MW reference plant consists of arrays of conventional three-blade wind turbine generators, in-plant electrical and control systems, interconnection facilities and on-site roads, meteorological towers and support facilities.

Capacity Factors and Temporal Output: The annual average capacity factors used for the five resource areas are shown in Table I-22. These were taken from the Council's 2007 Biennial Monitoring Report (NPCC, 2007). The Biennial Monitoring Report values were based on assumptions of the Fifth Power Plan adjusted upward by 2% to reflect the introduction of larger, more efficient and reliable turbines, and improvements in turbine siting. The capacity factors shown in Table I-22 are net at the plant interconnection and are derated for transmission losses to the point of wholesale delivery using the transmission loss factors described in the transmission section. Hourly output estimates for the AURORA$^{xmp®}$ price forecasting model were developed from hourly wind output estimates for various subregional locations developed for the WECC Transmission Expansion Planning Policy Committee (TEPPC). The TEPPC hourly output estimates were based on mesoscale synthetic wind speed data developed by the National Renewable Energy Laboratory. The TEPPC hourly output values were not used directly, however, because the resulting annual capacity factors are substantially lower than historical capacity factors for Northwest sites. Rather, the TEPPC hourly output values were scaled upward to yield the capacity factors shown in Table I-22.

Table I-22: Wind average annual capacity factors

Wind Resource Area >	Columbia Basin	Southern Idaho	Central Montana	Southern Alberta	Eastern Wyoming
Average annual capacity factor (net plant output)	32%	30%	38%	38%	38%

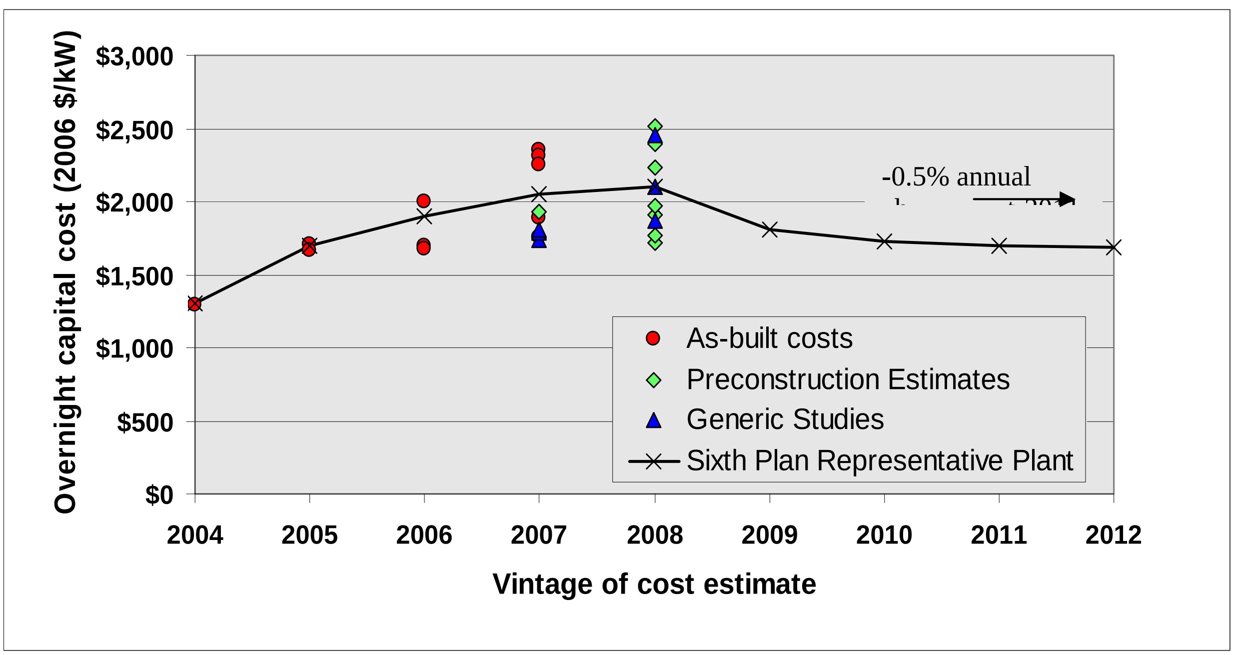
Firm Capacity Value: 5% of installed capacity as adopted by the Northwest Resource Adequacy Forum.

***Unit Commitment Parameters*:** Wind power plants are assumed to operate as must-run units.

Total Plant Cost: The total plant cost of the reference wind plant is $2,100/kW installed capacity (2008 price year). This estimate is based on a sample of 11 reported as-built plant costs and 8 published preconstruction estimates from 2004 through 2008. Five generic estimates of wind plant development costs were also obtained. Two of the latter were range estimates consisting of low and high bound costs. These costs, normalized as total plant cost per net kW capacity in 2006 dollars, are plotted by the vintage of the cost data in Figure I-18. A well-defined increase in construction costs from 2004 through mid-2008 is evident. Analysis of the factors underlying the increase in wind plant costs during this period is provided in the Biennial Monitoring Report (NPCC, 2007).

A cost uncertainty range from -19% to +24% ($1700 to $2500 in 2008) is used for Regional Portfolio Model studies. The range is based on the range of observations for 2008.

Figure I-18: Published and forecast capital costs of wind power plants



Costs are forecast to decline from 2008 highs through 2011, reaching an average of 2004 and 2008 costs. This price level is assumed to be in equilibrium. Thereafter, technological improvements are assumed to reduce total plant costs by 0.5% per year, on average, reflecting a 5% learning rate for wind technology.

Development and Construction Schedule, Cash Flows: The development and construction schedule and cash flow assumptions for a wind plant (exclusive of long-distance transmission, if any) are as follows:

> **Development** (Site options to completion of resource assessment): - 24 mo., 5% of total plant cost
>
> **Early Construction** (WTG order to first WTG shipment) - 12 mo., 16% of total plant cost
>
> **Committed Construction** (WTG shipment to commercial service) - 18 mo., 79% of total plant cost

The combined development and construction schedule and cash flow for a wind resource requiring long-distance transmission is modeled in two phases. The first phase is coincidental development of the transmission line and 50% of the installed wind capacity potentially served by the transmission line. The transmission development schedule is controlling and the timing of wind capacity development is assumed to be such that the wind capacity enters service coincidental with the transmission line. The second phase is optional build out of the remaining 50% of wind capacity potentially served by the transmission line in 250 MW increments.

Operating and Maintenance Cost: Fixed O&M costs include plant operation and maintenance costs and capital replacement costs, exclusive of property taxes and insurance. The estimated fixed O&M cost of $40/kW/yr is based on the fixed O&M cost for wind plants used for the Fifth Power Plan ($20/kWh/yr), escalated by observed 2004 - 2008 wind plant capital cost escalation (108% nominal) and rounded to $40/kW/yr to yield overall annual O&M costs (including property taxes and insurance) of 2.5% of total plant cost. This percentage is within the range of 2 - 3.5% of total energy cost and 20 - 25% of total energy costs over the life of the plant cited in IEA, 2008b. Fixed O&M cost is assumed to vary in real terms with total plant cost.

The variable O&M cost of $2.00/MWh is intended to represent land rent. Land rent is reported to typically range between 2 - 4% of the gross revenue from wind turbine generator (Wind Powering America, http://www.windpoweringamerica.gov/pdfs/wpa/34600_landowners_faq.pdf). $2.00 per MWh is approximately 2% of busbar revenue requirements at the current cost of wind. Because construction costs are expected to decline and variable O&M remains constant in the analysis, the low end value was selected.

Integration cost: The forecast cost of supplying regulation and sub-hourly load-following services for operational integration is shown in Table I-5. The cost of longer-term shaping services is not included in this estimate.

Economic Life: The economic life of a wind plant is assumed to be 20 years.

Development Potential: The estimated development potential for the various blocks of wind is shown in Table I-23. Capacity and energy shown as "available" is estimated developable capacity in excess of operating and committed (under construction) capacity as of February 2009.

The Columbia Basin resource potential for delivery to western Oregon and Washington load centers shown in Table I-23 is limited by new east - west transmission capacity that could be developed at current embedded transmission cost. This capacity is the sum of unconstructed projects with firm Bonneville transmission rights (estimated to be 1,250 MW) and new capacity created by the West of McNary, Little Goose and I-5 Corridor reinforcements (approximately 4,860 MW). This total was reduced by the capacity of unconstructed projects with announced long-term sales to California. (Projects selling to or owned by California utilities are assumed to hold firm transmission rights to California. It is not clear that this is necessarily so because California renewable portfolio standards and administrative rules allow delivery of energy any time within the calendar year, thus permitting use of conditional firm transmission.)

The Columbia basin potential for delivery to eastern Oregon and Washington load centers, and Idaho and Montana potential for local (sub-regional) delivery are each assumed to be limited to a maximum penetration of 20% of forecast local peak hourly load at the end of the planning period. The variable resource integration costs of Table I-5 are assumed sufficient to cover integration costs to this level of penetration.

The "remote" wind resource blocks using new long-distance transmission were provisionally limited by the capacity of a single transmission circuit, pending initial analysis of resource cost-effectiveness using the Resource Portfolio Model. In only one case (Low Conservation), did renewable resource development exceed the estimated availability of wind from sources not involving construction of new long-distance transmission. For this reason, further assessment of potential limits was not undertaken.

An issue needing further consideration is the prospect of additional long-term sales of Northwest wind to California utilities for compliance with California renewable portfolio standards. Various outcomes are possible, involving California renewable energy credit policy, the proposed increase in California renewable portfolio standard targets, current intertie capacity and the future competitiveness of Northwest wind vs. California and Southwestern solar from the perspective of California utilities.

Table I-23: Wind power development potential

Wind Resource Area	Load	Available Capacity (MW)	Available Energy (MWa)	Limiting Factors	Earliest Service
Columbia Basin	Westside OR/WA	4060	1300	New transmission to Westside @ embedded cost	2010
Westside OR/WA	Westside OR/WA	200	60	Allowance	2010

Columbia Basin	Eastside OR/WA	340	110	20% of 2029 peak load	2010
S. Idaho	S. Idaho	720	220	20% of 2029 peak load	2010
Montana	Montana	215	80	20% of 2029 peak load	2010
Montana	S. Idaho	1500	570	Per 500kV AC ckt	2015
Montana	OR/WA	1500	570	Per 500kV AC ckt	2015
Wyoming	S. Idaho	1500	570	Per 500kV AC ckt	2015
Wyoming	OR/WA	1500	570	Per 500kV AC ckt	2015
Alberta	OR/WA	2000	760	Per +/-500kV DC ckt	2015

Levelized cost summary: The estimated levelized lifecycle cost of delivered energy from the various wind resource areas to Northwest load centers is shown in Table I-24. The cost estimates are based on investor-owned utility financing. 2010 service year cases include federal production tax credit.

Table I-24: Levelized cost of Wind Power Plants

Case	Service Year	Plant Busbar ($/MWh)	Ancillary Services and Integration ($/MWh)	Transmission and Losses ($/MWh)	Emissions ($/MWh)	Total ($/MWh)
Wind (MT Local)	2010	$77.05	$10.62	$6.76	$0.00	$94
	2015	$71.20	$11.33	$6.75	$0.00	$89
	2020	$69.47	$11.70	$6.74	$0.00	$88
	2025	$67.81	$11.83	$6.72	$0.00	$86
	2030	$66.20	$11.89	$6.71	$0.00	$85
Wind (OR/WA Local)	2010	$93.24	$10.62	$8.02	$0.00	$112
	2015	$84.18	$11.33	$7.97	$0.00	$103
	2020	$82.13	$11.70	$7.95	$0.00	$102
	2025	$80.15	$11.83	$7.93	$0.00	$100
	2030	$78.24	$11.89	$7.92	$0.00	$98
Wind (S. ID Local)	2010	$100.08	$10.62	$8.56	$0.00	$119
	2015	$89.66	$11.33	$8.49	$0.00	$109
	2020	$87.47	$11.70	$8.46	$0.00	$108
	2025	$85.36	$11.83	$8.44	$0.00	$106
	2030	$83.32	$11.89	$8.43	$0.00	$104
Wind (MT> S. ID)	2010	n/av	n/av	n/av	n/av	n/av
	2015	$71.20	$10.84	$34.17	$0.00	$116
	2020	$69.47	$11.18	$34.17	$0.00	$115
	2025	$67.81	$11.31	$34.16	$0.00	$113
	2030	$66.20	$11.37	$34.25	$0.00	$112
Wind (MT > OR/WA via CTS upgrade)	2010	n/av	n/av	n/av	n/av	n/av
	2015	$71.20	$10.84	$46.46	$0.00	$128
	2020	$69.47	$11.18	$46.37	$0.00	$127
	2025	$67.81	$11.31	$46.28	$0.00	$125
	2030	$66.20	$11.37	$46.29	$0.00	$124
Wind (WY> S. ID)	2010	n/av	n/av	n/av	n/av	n/av
	2015	$71.20	$10.84	$38.98	$0.00	$121
	2020	$69.47	$11.18	$38.98	$0.00	$120
	2025	$67.81	$11.31	$38.98	$0.00	$118
	2030	$66.20	$11.37	$39.09	$0.00	$117
Wind (AB > OR/WA)	2010	n/av	n/av	n/av	n/av	n/av
	2015	$71.20	$10.84	$56.17	$0.00	$138
	2020	$69.47	$11.18	$56.21	$0.00	$137
	2025	$67.81	$11.31	$56.24	$0.00	$135
	2030	$66.20	$11.37	$56.44	$0.00	$134
Wind (MT > OR/WA via S. ID)	2010	n/av	n/av	n/av	n/av	n/av
	2015	$71.20	$10.84	$64.85	$0.00	$147
	2020	$69.47	$11.18	$64.87	$0.00	$146
	2025	$67.81	$11.31	$64.88	$0.00	$144
	2030	$66.20	$11.37	$65.08	$0.00	$143
Wind WY > OR/WA)	2010	n/av	n/av	n/av	n/av	n/av
	2015	$71.20	$10.84	$72.11	$0.00	$154
	2020	$69.47	$11.18	$72.13	$0.00	$153
	2025	$67.81	$11.31	$72.15	$0.00	$151
	2030	$66.20	$11.37	$72.37	$0.00	$150

Waste Heat Energy Recovery Cogeneration

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

Reference Plant: The reference plant is a 5 MW organic Rankine cycle (ORC) generating plant using 900^{o} F gas turbine exhaust heat from a natural gas pipeline compressor station as an energy source. The plant is provided with dry cooling.

Fuel: The operator of the waste heat recovery plant is assumed to pay a fee to the owner of the host facility for the usable energy content of the waste gas stream. This cost is included in Operating and Maintenance cost

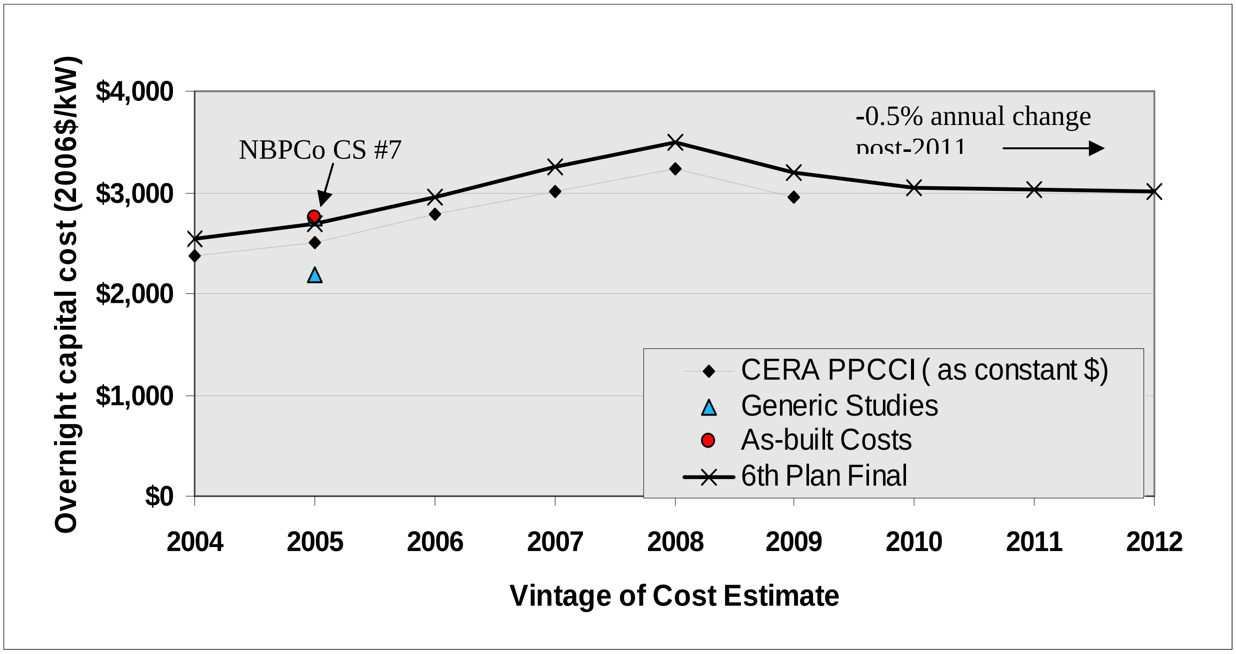
Heat Rate: The representative heat rate 38,000 Btu/kWh for an ORC plant operating with the reference plant assumptions (900^{o}F GT exhaust temperature, dry cooling) is based on the average annual performance of the ORC heat recovery project at the Northern Border Pipeline Compressor Station #7 (ORNL, 2007). Because the cost of the waste heat "fuel" is assumed to be a royalty payment based on electricity production, a heat rate assumption is not required for energy production cost calculations.

***Unit Commitment Parameters*:** CHP power plants are assumed to operate as must-run units at an average capacity factor of 80%. The expected annual energy production for Trailblazer Pipeline Peetz compressor station is 27,600 MWh (3.15 MWa) (Colorado Energy News, 2009). The installed capacity at this station is 4 MW, giving a 79% capacity factor. This was rounded to 80% for the reference plant. A higher (90%) capacity factor is reported for the Northern Border Compressor Station #7 plant, though the load factor in pipelines serving the Midwestern market may be higher than those of Western lines.

Total Plant Cost: The total plant cost of the reference plant is $3,500/kW installed capacity (2008 price year). This cost is based on the installed cost of the Basin Electric Project at the Northern Border Pipeline Company's Compressor Station #7 (ORNL, 2007). The cost of this project, normalized to overnight 2006 dollars, is plotted in Figure I-19 as the "as-built" cost point. A second source was located (INGAA, 2008) and is plotted as the generic costs in Figure I-19, however, the INGAA capital costs are based on the Basin Electric Project and are not adjusted for escalation despite the later date of the report. As illustrated in Figure I-19, the reference 2008 price year cost was derived by approximating the effect of the CERA Power Plant Construction Cost Index (excluding nuclear)[23] on the 2005 as-built cost of the Basin Electric Project.

Costs are forecast to decline from 2008 highs through 2011, reaching an average of 2004 and 2008 costs. This price level is assumed to be in equilibrium. Thereafter, technological improvements are assumed to reduce total plant costs by 0.5% per year, on average, reflecting a 5% learning rate for organic Rankine cycle technology.

Figure I-19: Published and forecast capital costs of representative waste heat recovery plants



Development and Construction Schedule, Cash Flows: The development and construction schedule and cash flow assumptions for the representative waste heat recovery plant are as follows:

> **Development** (Site acquisition, permitting, preliminary engineering, interconnection agreement) - 24 mo., 5% of total plant cost
>
> **Early Construction** (Final engineering, equipment order, site preparation, interconnection, infrastructure construction and installation of compressor turbine exhaust diversion valves and ducting) - 12 mo., 30% of total plant cost
>
> **Committed Construction** (Major equipment installation, commissioning) - 12 mo., 65% of total plant cost

23 http://www.cera.com/aspx/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=10429

The development and construction schedule is based on gas turbine assumptions, but with an extended development period reflecting the complexities of three-party development (developer, pipeline owner, and purchasing utility) and an extended early construction period including installation of compressor turbine exhaust diversion valves and ducting.

Operating and Maintenance Cost: O&M costs are estimated to be $8.00/MWh. Operating and maintenance costs (exclusive of property taxes and insurance) include plant O&M costs and payments to the pipeline owner for the use of the site and energy supply. INGAA, 2008 cites $0.005/kWh ($5/MWh) as typical pipeline company compensation and 0.002/kWh ($2/MWh) as a typical O&M cost . A range of possible O&M costs of $0.001 - 0.005/kWh ($1 - 5/MWh) is cited. The O&M costs were increased by 30% to account for general and administrative costs, and rounded up to the nearest dollar. No basis for disaggregating fixed and variable components was located. O&M costs are asssumed to remain constant in real terms.

Economic Life: The economic life of a heat recovery cogeneration plant is assumed to be 20 years; limited by uncertainty regarding host facility viability.

Development Potential: An inventory of potential Northwest opportunities for the development of recovered energy generation was not located. Opportunities are known to exist, for example, more than 50 natural gas pipeline compressor stations are located in the Northwest, none of which is known to have heat recovery generation installed. Recovered energy cogeneration facilities for trunkline compressor station applications are typically about five megawatts in capacity, suggesting a potential of tens to low hundreds of megawatts. Cement kilns, steel processing facilities, and glass furnaces offer additional possibilities.

Levelized cost summary: The estimated levelized lifecycle cost of delivered energy from waste heat energy recovery cogeneration power plants is shown in Table I-25. The cost estimates are based on investor-owned utility financing.

Table I-25: Levelized Cost of Waste Heat Energy Recovery Cogeneration Power Plants

Service Year	Plant Busbar ($/MWh)	Ancillary Services and Integration ($/MWh)	Transmission and Losses ($/MWh)	Emissions ($/MWh)	Total ($/MWh)
2010	$58.82	$0.99	$3.61	$0.00	$63
2015	$58.82	$0.99	$3.61	$0.00	$63
2020	$57.53	$0.99	$3.59	$0.00	$62
2025	$56.31	$0.99	$3.57	$0.00	$61
2030	$55.12	$1.00	$3.56	$0.00	$60

Coal-fired Steam-electric Plants

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 facility, a furnace and steam generator, and a steam turbine-generator. Coal is ground (e.g., pulverized) 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. Newer units are typically equipped with low-NOx burners, sulfur dioxide removal equipment, and electrostatic precipitators or baghouses for particulate removal. 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. Most western coal-fired plants are sited near the mine-mouth, though some plants are supplied with coal by rail at intermediate locations between mine-mouth and load centers.

Most existing 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. Several supercritical units 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. The majority of new North American coal capacity now supercritical technology.

Reference Plant: A single 450 MW net supercritical pulverized coal-fired power plant at a greenfield site. This plant is equipped with low-NOx burners, overfire air, and selective catalytic reduction for control of nitrogen oxides. The plant would be provided with flue gas de-sulfurization, fabric filter particulate control, and activated charcoal injection for reduction of mercury emissions. The capital costs include a switchyard and transmission interconnection.

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.

Fuel: The reference plant is assumed to be fuelled by western subbituminous coal. Coal price forecasts are described in Chapter 2 and Appendix A.

Heat Rate: The heat rate of 9,000 Btu/kWh is from Exhibit 3-5 of EPA, 2006 (Supercritical pulverized coal unit using subbituminous coal).

Availability Parameters: Availability parameters (lifecycle averages) are based on 2004 - 2008 NERC Generating Availability Data System (GADS) data for all coal units. They are as follows:

Scheduled maintenance outages - 35 days/yr

Equivalent forced outage rate - 7%

Mean time to repair - 40 hours

Equivalent annual availability - 85%

Unit Commitment Parameters: Coal steam-electric power plants are assumed to operate as base load units with limited dispatch capability. Unit commitment parameters used in the AURORA<u>xmp®</u> Electric Power Market Model are as follows:

Minimum load - 50%

Minimum run time - 24 hours

Minimum down time - 12 hours

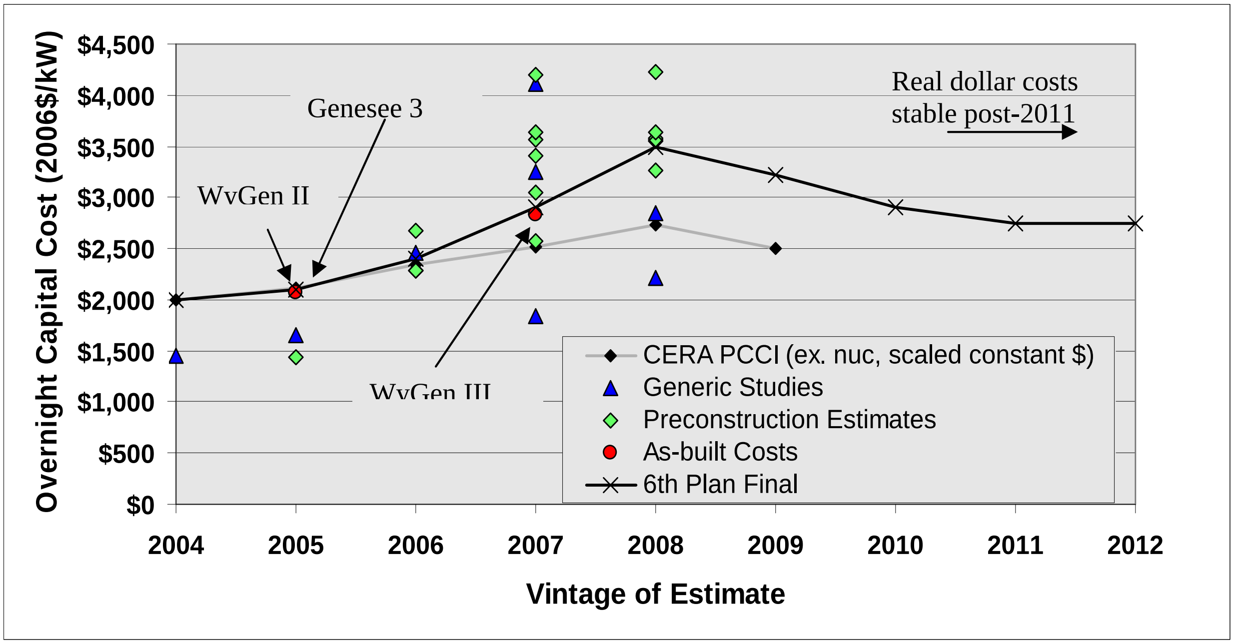
Ramp rate - 30%/hr maximum

Total Plant Cost: The "overnight" total plant cost of the reference pulverized coal-fired plant is estimated to be $3,500/kW installed capacity (2006 dollar values for the 2008 price year; or 2011 service year, assuming costs are fixed at the beginning of the committed construction period). This estimate is based on a sample of three reported as-built plant costs, 15 preconstruction cost estimates, and 8 generic cost estimates, from 2004, or later. These costs were normalized as described in the Capital Cost Analysis subsection of this Appendix and are plotted by vintage in Figure I-20. Also plotted is the CERA (non-nuclear) power plant capital cost index for 2004-09, normalized to real dollar values and scaled to match to 2008 reference cost selected by the Council. A wide range of costs is evident for 2007 and 2008, though the rapid increase in construction costs from 2004 through mid-2008 is well defined. The CERA index, while consistent with the earlier as-built cost examples, does not capture the more rapid escalation embodied in the 2007 and 2008 preconstruction cost estimates. The Sixth Power Plan final estimates follow the 2004 and 2005 CERA and as-built costs closely. The 2006 point corresponds to the cost reported in the 2007 National Engineering Technology Laboratory Report (NETL, 2007), which contains original and detailed cost estimates. The 2007 and 2008 points are heavily influenced by the preconstruction estimates dating from these years, rather than the generic estimates from these years, which appear to be secondary sources.

Total plant cost is forecast to decline from the 2008 high point to market equilibrium conditions by 2011, represented by the average of 2004 and 2008 costs. Total plant costs are assumed to remain constant, on average.

A cost uncertainty range of +20%/- 20% is used for Regional Portfolio Model studies.

Figure I-20: Overnight total plant costs of coal steam-electric power plants



Development and Construction Schedule, Cash Flows: The development and construction schedule and cash flow assumptions for the representative coal steam-electric power plant are as follows:

> **Development** (Site acquisition, environmental assessment, permitting, preliminary engineering, interconnection agreement, EPC selection) - 36 mo., 3% of total plant cost
>
> **Early Construction** (Final engineering, equipment order, site preparation, interconnection, infrastructure construction, foundations) - 12 mo., 11% of total plant cost
>
> **Committed Construction** (Major equipment delivery through commissioning) - 36 mo., 86% of total plant cost

Operating and Maintenance Costs: The fixed O&M cost for the reference plant are estimated to be $60/kW/yr (exclusive of property tax and insurance). This estimate is based on the fixed O&M costs for a supercritical unit (Case 11) appearing Exhibit 4-35 of NETL, 2007. The cost appearing in NETL was converted to a percentage of the Case 11 capital cost estimate. This percentage (1.8%) was then applied to the Sixth Power Plan price year capital cost described above and the result rounded, yielding $60/MWh.

The variable O&M cost for the reference plant is estimated to $2.75/MWh. This cost is the Case 11 variable O&M cost of NETL, 2007 (in 2006 year dollars), not adjusted for power plant construction cost escalation.

Escalation of fixed operating and maintenance costs is assumed to correspond to the forecast escalation of total plant costs. Variable O&M costs are assumed to vary only with general inflation.

Economic Life: The economic life of a coal-fired steam-electric plant is assumed to be 30 years.

Technology Variations: Cost and heat rate estimates for five technical variations on the reference plant are shown in Table I-26. The values of Table I-26 are based on estimates reported in Table 3-1 of MIT, 2007. The MIT study provides cost and performance estimates for a comprehensive set of coal-fired technologies. Though the costs and heat rate of the supercritical unit of the MIT study differ somewhat from the equivalent values developed for the Sixth Power Plan (the reference units of the MIT study assume use Midwestern bituminous coal, for example), the relative costs and heat rates of the MIT units should be roughly representative of the relative costs and heat rates of units suitable for Northwest conditions. The values of Table I-26 were derived by applying the ratios between the various technologies of Table 3-1 of MIT, 2007 to the reference supercritical values developed for the Sixth Plan.

Table I-26: Costs and performance of technical variations on the reference pulverized coal-fired steam-electric plant

Technology	Heat Rate (Btu/kWh, HHV)	Total Plant Cost ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)
Subcritical PC	10,080	$3360	$60	$2.75
Supercritical PC (Reference Plant)	9000	$3500	$60	$2.75
Ultra-supercritical PC	8010	$3570	$60	$2.75
Subcritical PC w/90% CO_2 Capture	13,770	$5880	$128	$5.86
Supercritical PC w/90% CO_2 Capture	11,880	$5635	$128	$5.86
Ultra-supercritical PC w/90% CO_2 Capture	10,170	$5495	$128	$5.86

Development Potential: New pulverized coal-fired power plants would be constructed 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. However, carbon dioxide performance standards in Montana, Oregon and Washington preclude construction of new coal-fired plants without significant reduction (roughly 50 percent) of the carbon dioxide production of conventional subcritical units. Reducing per-megawatt-hour carbon dioxide production from coal-fired plants can be achieved by increased thermal efficiency, fuel switching, and carbon dioxide capture and sequestration. For new construction, increasing the efficiency of combustion is the least cost and logical first step to reducing carbon dioxide production. Ultra-supercritical plants, for example, produce about 80 percent of the carbon dioxide of conventional subcritical units. Switching from sub-bituminous to certain bituminous coals can reduce carbon dioxide production from existing as well as new plants by several percent, but the economics and net impact on carbon dioxide production are case-specific because of coal production and transportation considerations. Co-firing biomass can reduce carbon dioxide production, but the biomass quantities and co-firing percentages are limited. Carbon capture and sequestration will be required to control carbon dioxide releases to the levels needed to achieve proposed greenhouse gas reduction targets if continued reliance on coal is desired. While carbon capture technology for coal gasification plants is commercially available, capture technology for steam-electric plants remains under development and is not expected to be commercially available for a decade, or more. Though legal issues remain, sequestration in depleted oil or gas fields is commercially proven. Suitable oil and gas reservoirs are limited in the Northwest and though other geologic alternatives are potentially available, including deep saline aquifers and possibly flood basalt sequestration, these remain to be proven and commercialized.

The earliest service years for new plants is assumed to be 2017 for units without CO_2 separation and sequestration and 2023 for units with CO_2 separation and sequestration.

Levelized cost summary: The estimated levelized lifecycle costs of delivered energy from four coal-fired steam-electric power plant cases are shown in Table I-27. Cases 1, 2 and 3 are plants using subcritical, supercritical and ultra-supercritical technology, respectively, and not provided with CO_2 separation. The cost estimates are based on plants sited in eastern Oregon or Washington supplied with Powder River Basin coal by rail. These plants would not comply with current Washington or Oregon CO_2 policy. Cases 4, 5 and 6 represent partial repowers of the Colstrip Transmission System with plants equipped with CO_2 separation. Separated CO2 would be transported to depleted oil or gas reservoirs, unmineable coal seams or deep saline reservoirs for sequestration. The plants would employ subcritical, supercritical and ultra-supercritical technology, respectively. These plants would comply with current Montana CO_2 policy. The cost estimates are based on investor-owned utility financing.

Table I-27: Levelized Cost of Coal-fired Steam-electric Power Plants

Case	Service Year	PlantBusbar ($/MWh)	Ancillary Services and Integration ($/MWh)	Transmission and Losses ($/MWh)	Emissions ($/MWh)	Total ($/MWh)
1. Subcritical (E. OR/WA)	2010	n/av	n/av	n/av	n/av	n/av
	2015	n/av	n/av	n/av	n/av	n/av
	2020	$63.46	$1.00	$4.53	$49.59	$119
	2025	$63.62	$1.00	$4.57	$50.82	$120
	2030	$63.72	$1.01	$4.59	$51.26	$121
2. Supercritical (E. OR/WA)	2010	n/av	n/av	n/av	n/av	n/av
	2015	n/av	n/av	n/av	n/av	n/av
	2020	$63.61	$1.00	$4.43	$44.28	$113
	2025	$63.75	$1.00	$4.46	$45.37	$115
	2030	$63.84	$1.01	$4.48	$45.77	$115
3. Ultra-supercritical (E. OR/WA)	2010	n/av	n/av	n/av	n/av	n/av
	2015	n/av	n/av	n/av	n/av	n/av
	2020	$62.82	$1.00	$4.33	$39.90	$108
	2025	$62.95	$1.00	$4.36	$40.88	$109
	2030	$63.03	$1.01	$4.38	$41.24	$110
4. Subcritical w/CO2 Capture (MT>E. OR/WA via CTS Repower)	2010	n/av	n/av	n/av	n/av	n/av
	2015	n/av	n/av	n/av	n/av	n/av
	2020	n/av	n/av	n/av	n/av	n/av
	2025	$103.41	$1.00	$17.65	$41.83	$164
	2030	$103.54	$1.01	$17.71	$42.06	$164
5. Supercritical w/CO2 Capture (MT>E. OR/WA via CTS Repower)	2010	n/av	n/av	n/av	n/av	n/av
	2015	n/av	n/av	n/av	n/av	n/av
	2020	n/av	n/av	n/av	n/av	n/av
	2025	$98.60	$1.00	$16.92	$36.09	$153
	2030	$98.71	$1.01	$16.97	$36.29	$153
6. Ultra-Supercritical w/CO2 Capture (MT>E. OR/WA via CTS Repower)	2010	n/av	n/av	n/av	n/av	n/av
	2015	n/av	n/av	n/av	n/av	n/av
	2020	n/av	n/av	n/av	n/av	n/av
	2025	$95.20	$1.00	$16.32	$30.90	$143
	2030	$95.31	$1.01	$16.37	$31.06	$144

Coal-fired Gasification Combined-cycle Plants

First demonstrated in 1670 by the Reverend John Clayton, coal gasification, as applied to electric power generation, allows the application of efficient gas turbine combined-cycle technology to coal-fired generation. This reduces fuel consumption, improves operating flexibility, and lowers carbon dioxide production. Integrated coal gasification combined-cycle plants (IGCCs) also offer the benefits of low-cost mercury removal, superior control of criteria air emissions, optional separation of carbon for sequestration using currently commercial processes, and optional co-production of synthetic natural gas, hydrogen, liquid fuel, or other chemicals. Numerous coal gasification project proposals were announced in North America during the early 2000s, including several in the Northwest. However, estimated costs have escalated significantly, and as designs have been refined, earlier forecasts of greatly improved criteria pollutant emission control capability and plant efficiency for IGCC plants compared to steam-electric coal plants appear optimistic. Current estimates suggest that emission control and efficiency would not be significantly better than supercritical steam electric plants. This appears to have dampened enthusiasm for coal gasification technology. Uncertainties regarding the timing and magnitude of greenhouse gas regulation and the availability of carbon sequestration facilities have further clouded the future of these plants and only a handful of proposals remain active. One project, the Duke Energy Edwardsport plant, is under construction for 2013 service. The key advantage of IGCC plants remains the commercial technology available for carbon capture.

Reference Plants: Assumptions for two reference IGCC plants were developed; one without and one with carbon capture. These are based, respectively on Cases 3 and 4 of NETL, 2007. The two plants use Conoco-Phillips (CoP) E-Gas oxygen-blown, two-stage, slurry-fed slagging gasifiers. The key advantage of the CoP gasifier from a Northwest perspective is that the commercial-scale CoP gasifiers successfully operated on western subbituminous coal at the 160 MW Dow Chemical coal gasification combined-cycle power plant in Plaquemine, Louisiana. The two-stage CoP design operates at somewhat greater efficiency and reduced oxygen requirement than other gasifier designs and produces only inert solid waste. The high operating temperatures result in a short refractory life, however, and the process produces more methane in the synthesis gas, reducing maximum potential carbon recovery.

The plant without carbon capture (Case 3 of NETL, 2007) includes an air separation unit, a coal preparation section, two gasification trains, syngas coolers, and a gas cleanup section for particulate, mercury and sulfur removal. The clean syngas is heated, humidified, and diluted with nitrogen from the air separation unit and supplied to a combined-cycle section. The combined-cycle section consists of two F-Class gas turbine generators, two heat recovery steam generators and a single steam turbine generator. Evaporative condenser cooling is used. Gross plant capacity is 742 MW and net output is 623 MW. The principal auxiliary loads are the air separation unit and oxygen compressor (55 MW) and the nitrogen dilutent compressor (35 MW).

The configuration of the reference plant with carbon capture (Case 4 of NETL) is similar to the plant without carbon capture with additional stages of syngas hydrolysis to convert the majority of the CO contained in the synthesis gas to CO_2. The CO_2 is stripped in a Selexol unit and compressed for export. CO_2 removal efficiency is 88% (most of the discharged CO_2 is produced in the gas turbines from combustion of CH_4 (methane) produced directly in the gasifier and thus not strippable. Gross plant capacity is 694 MW and net output is 518 MW. The principal auxiliary loads are the air separation unit and oxygen compressor (72 MW), the nitrogen dilutent compressor (36 MW), the Selexol CO2 stripping unit (15 MW) and the CO2 compressor (26 MW).

Fuel: Two cases are considered. One set of reference plants are assumed to be fuelled by 100% western subbituminous coal. A second set of plants is assumed to be fuelled by a mix of 50% pertroleum coke and 50% western subbituminous coal. Coal price forecasts are described in Chapter 2 and Appendix A. Petroleum coke is assumed to trade at a discount of 80% to western subbituminous coal based on 2008 and 2009 market data.

Heat Rate: The heat rate of the reference plant without carbon capture is 8,680 Btu/kWh and the heat rate of the plant with carbon capture is 10,760 Btu/kWh (NETL, 2007). The higher heat rate of the plant with carbon capture is largely attributable to the auxiliary loads of the carbon capture and compression equipment (the heating value of the carbon is recovered in both cases since the carbon is oxidized). Because the NETL examples are based on Illinois No 6 bituminous coal rather than western low-sulfur sub-bituminous coal, the NETL heat rates may be lower than encountered in practice in the Northwest. The higher moisture content and lower heating value of western subbituminous coal could increase both plant heat rate and plant capital costs. Detailed case studies of coal gasification combined-cycle plants using western subbituminous coal were not available for preparation of the power plan. Though heat rates for gasification plants using subbituminous coal provided in EPA, 2006, the EPA heat rates for bituminous coal are much lower than equivalent NETL heat rates, having been based on earlier, more optimistic studies. Moreover, the EPA study assumed use of GE-Texaco gasifiers, a design less suited to western subbituminous coals. The IGCC heat rates used for this plan should be viewed with caution and will be subject to periodic review.

Plant heat rate is forecast to decline 0.5% annually, consistent with forecast improvements in gas turbine technology.

Availability Parameters: With only two operating IGCC plants in North America, the NERC GADS database does not provide information regarding IGCC availability parameters. The following estimates are provided in NREL, 2007, as follows:

Scheduled maintenance outages - 30 days/yr

Equivalent forced outage rate - 10%

Mean time to repair - Not available.

Equivalent annual availability - 81%

Unit Commitment Parameters**:** Coal gasification power plants are assumed to operate as baseload units with limited dispatch capability. Unit commitment parameters specific to IGCC plants were not located. Because of the thermal mass of the gasifiers and synthetic gas cooler, the response rate of first-generation gasification plants is likely to be slow. Nuclear plant commitment parameters were used for interim assumptions until better information becomes available:

Minimum load - 70%

Minimum run time - 120 hours

Minimum down time - 24 hours

Ramp rate - 10%/hr maximum (hot operating conditions)

Total Plant Cost: The total plant cost of the reference plant without carbon capture is estimated to be $3,600/kW. The equivalent cost of the plant with carbon capture is $4,800/kW (2008 price year). Sixteen preconstruction estimates and eight generic estimates of IGCC capital costs dating from 2004, or later were located. No IGCC plants have been constructed since the mid-1990s, so as-built costs were not available. These costs were normalized as described in the Capital Cost Analysis subsection of this Appendix and are plotted by vintage in Figures I-21 (plants without carbon separation) and I-22 (plants with carbon separation). Also plotted in each figure is the CERA (non-nuclear) power plant capital cost index for 2004-09, normalized to real dollar values and scaled to match the normalized costs from the NETL report. Of the available estimates, The NETL estimates of total plant costs appear to be based on the most detailed, relevant and recent cost analysis. However, the cost of an IGCC plant using western subbituminous coal is likely to be higher than the NETL reference plant costs, based on the use of low moisture, higher Btu Midwestern bituminous coal. The Sixth Plan reference costs were therefore derived by increasing the NETL estimates by 5% and escalating to 2008 at approximately the CERA non-nuclear PCCI rate.

Total plant cost is forecast to decline from 2008 to market equilibrium conditions by 2011, represented by the average of 2004 and 2008 costs. Thereafter, total plant costs are forecast to decline 0.5% annually, consistent with forecast improvements in gas turbine technology.

A cost uncertainty range of +/- 30%, based on NETL (2007) is used for Regional Portfolio Model studies.

Figure I-21: Total plant costs of coal gasification power plants (without CO_2 capture)

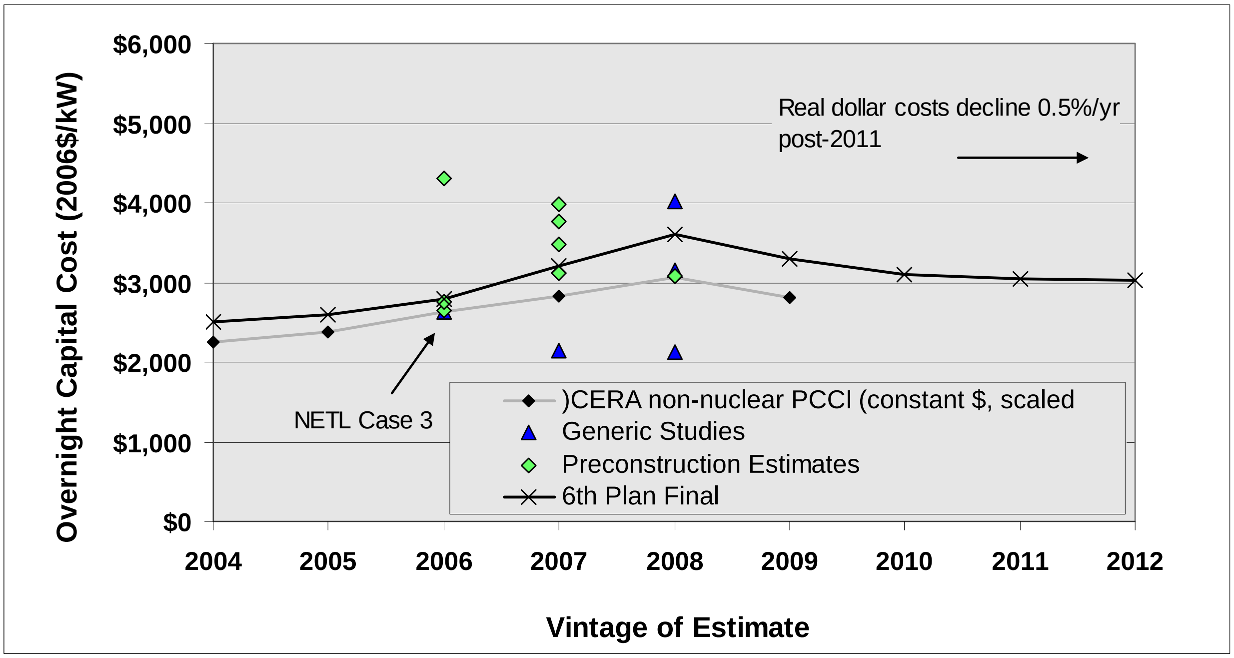
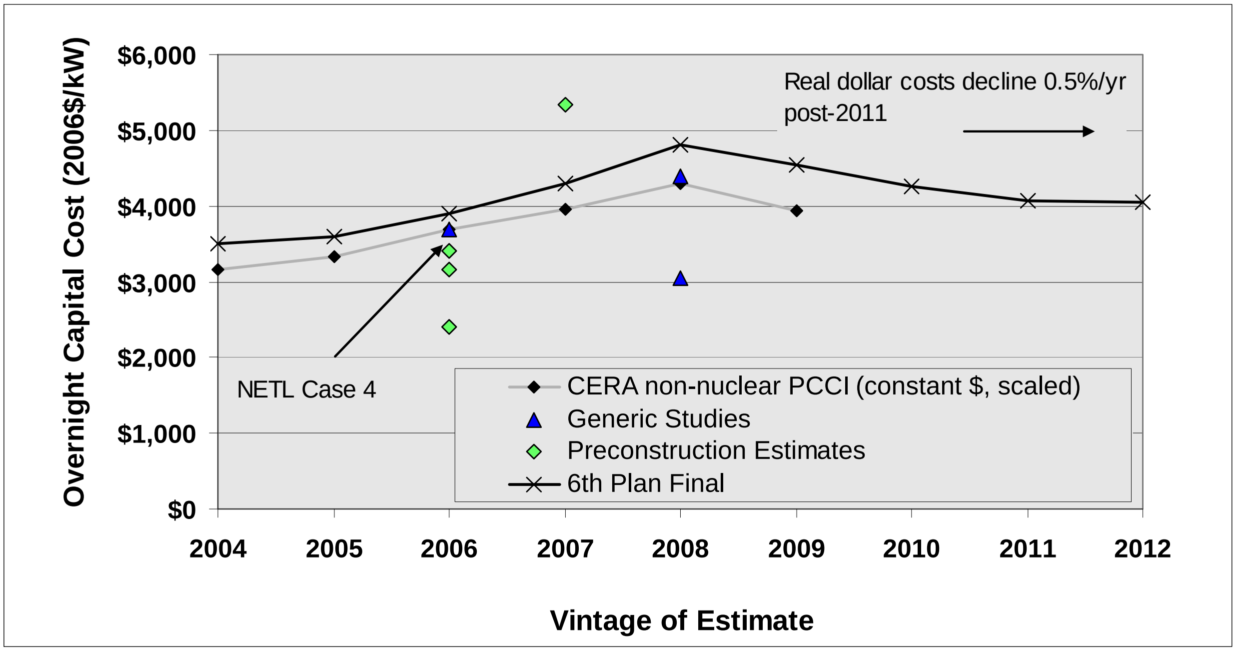


Figure I-22: Total plant costs of coal gasification power plants (with CO_2 capture)



Development and Construction Schedule, Cash Flows: The development and construction schedule and cash flow assumptions for both reference IGCC power plants are as follows:

> **Development** (Site acquisition, environmental assessment, permitting, preliminary engineering, interconnection agreement, EPC selection) - 36 mo., 2% of total plant cost
>
> **Early Construction** (Final engineering, equipment order, site preparation, interconnection, infrastructure construction, foundations) - 12 mo., 31% of total plant cost
>
> **Committed Construction** (Major equipment delivery through commissioning) - 36 mo., 67% of total plant cost

Operating and Maintenance Cost: Fixed O&M cost, exclusive of property tax and insurance is $45/kW/yr for the plant without carbon capture and $60/kW/yr for the plant with carbon capture. Variable O&M cost of $6.30/MWh for the plant without carbon capture and $8.50/MWh for the plant with carbon capture. Operating and maintenance costs for the plant with carbon capture include the cost of CO2 compression, but exclude transportation and sequestration costs. The cost of carbon sequestration is described in Carbon Sequestration section of this appendix. O&M costs are based on values appearing in NETL (2007). The NETL O&M costs were increased by the ratio of Sixth Plan total plant cost described above and the normalized total plant cost of NETL plants. Fixed O&M cost is assumed to escalate in real terms with total plant cost. Variable O&M cost is assumed to remain constant in real terms.

Economic Life: The economic life of a coal gasification combined-cycle plant is assumed to be 30 years.

Development Potential: New coal gasification combined-cycle plants would be constructed for the purposes of providing base load power and (optionally) synthetic fuels and chemicals. Coal supplies are adequate to meet any plausible Northwest needs over the period of this plan. However, carbon dioxide performance standards in Montana, Oregon and Washington preclude construction of new coal gasification combined-cycle power plants without capture and sequestration of about 50%, or more of the potential carbon dioxide. While the technology for capturing CO_2 from the synthesis gas of a gasification plant is commercially available, Case 2 commercial sequestration facilities are not. As described in the carbon sequestration section, the Council assumes that a commercial sequestration facility would not be available in the Northwest until 2023 at the earliest. The earliest service years for new plants is assumed to be 2017 for units without CO_2 separation and sequestration and 2023 for units with CO_2 separation and sequestration.

Levelized cost summary: The estimated levelized lifecycle costs of delivered energy from four gasification combined-cycle power plant cases are shown in Table I-28. Case 1 is a plant sited in eastern Oregon or Washington supplied with Powder River Basin coal by rail. Case 2 is a plant sited in western Oregon or Washington. 50% of its fuel would be Powder River Basin coal supplied by rail and 50% of its fuel would be petroleum coke supplied by rail or barge from north Puget Sound refineries. Neither plant would be allowed under current Washington or Oregon CO_2 policy. Cases 3 and 4 represent partial repowers of the Colstrip Transmission System with plants equipped with CO_2 separation. Separated CO2 would be transported to depleted oil or gas reservoirs, unmineable coal seams or deep saline reservoirs for sequestration. Case 3 would be fuelled with Powder River Basin coal. Case 4 would use a mix of 50% Powder River Basin Coal and 50% petroleum coke from eastern Montana refineries. These plants would comply with current Montana CO_2 policy. The cost estimates are based on investor-owned utility financing.

Table I-28: Levelized Cost of Coal-fired Gasification Combined-cycle Power Plants

Case	Service Year	Plant Busbar ($/MWh)	Ancillary Services and Integration ($/MWh)	Transmission and Losses ($/MWh)	Emissions ($/MWh)	Total ($/MWh)
1. 100% Coal (E. OR/WA)	2010	n/av	n/av	n/av	n/av	n/av
	2015	n/av	n/av	n/av	n/av	n/av
	2020	$71.88	$1.00	$4.67	$40.82	$118
	2025	$70.39	$1.00	$4.65	$40.79	$117
	2030	$68.95	$1.01	$4.62	$40.33	$115
2. 50% Coal/50% Pet Coke (W. OR/WA)	2010	n/av	n/av	n/av	n/av	n/av
	2015	n/av	n/av	n/av	n/av	n/av
	2020	$72.06	$1.00	$4.70	$42.07	$120
	2025	$70.56	$1.00	$4.68	$42.04	$118
	2030	$69.12	$1.01	$4.65	$41.57	$116
3. 100% Coal w/CSS (MT > E. OR/WA via CTS Repower)	2010	n/av	n/av	n/av	n/av	n/av
	2015	n/av	n/av	n/av	n/av	n/av
	2020	n/av	n/av	n/av	n/av	n/av
	2025	$90.25	$1.00	$16.44	$30.92	$139
	2030	$88.37	$1.01	$16.32	$30.47	$136
4. 50% Coal/50% PetCoke w/CSS (MT > E. OR/WA via CTS Repower)	2010	n/av	n/av	n/av	n/av	n/av
	2015	n/av	n/av	n/av	n/av	n/av
	2020	n/av	n/av	n/av	n/av	n/av
	2025	$89.24	$1.00	$16.44	$31.87	$139
	2030	$87.37	$1.01	$16.31	$31.41	$136

Natural Gas Simple-cycle Aeroderivative Gas Turbine Plant

Aeroderivative simple-cycle gas turbine power plants are based on jet engines developed for aircraft propulsion and adapted for stationary applications including electric power generation. Aeroderivative gas turbines feature high pressure (compression) ratios and light construction. Higher pressure ratios increase thermal efficiency and produce a more compact unit. Lighter construction improves operational flexibility including black start capability, short run-up, rapid cool-down, and overpower operation. Start times to full load of ten minutes or less allow these machines to provide "virtual" spinning reserve capacity (spinning reserve without the need to be operating).[24] Aeroderivative machines are highly modular and major maintenance can be accomplished by swapping out major components or the entire engine, shortening maintenance outages. Aeroderivative gas turbines are widely used to provide daily peaking capacity and operating reserves and can provide balancing services for variable resource integration. Aeroderivative units with heat recovery steam generators are often used for industrial cogeneration and are occasionally used as the prime mover for combined-cycle power plants. The lighter and more highly stressed components of aeroderivative machines result in higher per-kilowatt initial investment cost than heavy-duty (frame) simple-cycle turbines. Gas turbines require a high fuel supply pressure and fuel gas booster compressors may be required in locations away from natural gas mainlines. Typically electrically-driven, fuel gas booster compressors can consume several percent of the gas turbine generator output, reduce net capacity, and thermal efficiency.

Reference Plant: The reference aeroderivative simple-cycle gas turbine plant consists of twin gas turbine generator sets of 47 MW nominal capacity each. The net "new and clean" base load capacity of the plant under ISO conditions is 92 megawatts. This is based on the nominal capacity of a General Electric LM6000PD Sprint™ (Gas Turbine World, 2007), derated 3.1% for inlet, exhaust, auxiliary load, and main transformer losses. The new and clean heat rate is degraded a further 2.5% for maintenance-adjusted lifecycle aging effects to yield a lifecycle average baseload capacity of 90 MW (ISO conditions). The gas turbine generators are enclosed for weather protection and acoustic control, and are provided with inlet air filters and exhaust silencers. The plant also includes an injection water treatment system, lube oil, starting, fuel forwarding, and control systems; a control building, step-up transformers and a switchyard. Dry low-NOx combustors and selective catalytic reduction are used for NOx control and an oxidation catalyst for CO and VOC control. The plant is assumed to be located near a natural gas mainline with sufficient pressure for operation without fuel gas booster compression.

Fuel: Natural gas supplied on a firm transportation contract with capacity release capability. No backup fuel is provided. Fuel price forecasts are described in Chapter 2 and Appendix A.

Heat Rate: The full load, higher heating value heat rate under "new and clean" conditions is estimated to be 9,300 Btu/kWh[25]. This is based on the nominal lower heating value heat rate of a General Electric LM6000PD Sprint™ (water spray injection intercooling) (Gas Turbine World, 2007), converted to higher heating value and derated 3.1% for inlet, exhaust, auxiliary load and

---

[24] However, though physically capable of achieving full load in less than 10 minutes, emission limits are reported to have precluded the use of non-operating aeroderivative turbines for spinning reserves (Keyspan, 2007).

[25] Fuel gas compresssion, if needed, will further increase net heat rate, as will extended partial load operation. Startup inefficiencies will also increase heat rate, though the significance of the impact will depend on startup frequency.

transformer losses. The new and clean heat rate degraded a further 0.8% for maintenance-adjusted lifecycle aging effects to obtain a lifecycle average full load heat rate of 9,370 Btu/kWh.

Availability parameters: Availability parameters are based on 2004 - 2008 NERC Generating Availability Data System (GADS) data for all gas turbines, as follows:

Scheduled maintenance outages - 14 days/yr

Equivalent forced outage rate - 5%

Mean time to repair - 88 hours

Equivalent annual availability - 91%

Unit Commitment Parameters: Gas turbines are assumed to operate as dispatchable units. In the Northwest, these plants would normall provide capacity reserves. As such, they could serve peak loads, provide incremental and decremental load following and wind integration service and provide seasonal backup for low water years. Unit commitment parameters used in the AURORA^xmp®^ Electric Power Market Model are as follows:

Minimum load - 25%

Minimum run time - 1 hour

Minimum down time - 1 hour

Ramp rate - Cold start to full load in 10 minutes

Total Plant Cost: The overnight total plant cost of the reference plant is estimated to be $1,050/kW[26] in 2006 dollars for the 2008 price year. The estimate is based on a sample of 4 reported as-built plant costs, 10 preconstruction cost estimates, and 5 generic cost estimates (including one range estimate). The sample costs were normalized as described in the Capital Cost Analysis section of this appendix. Owner's costs, where not included in the estimate, were assumed to represent 12% of total plant costs. Single-unit plants were assumed to cost 130% of multiple-unit plants. The resulting normalized costs are shown in Figure I-23.

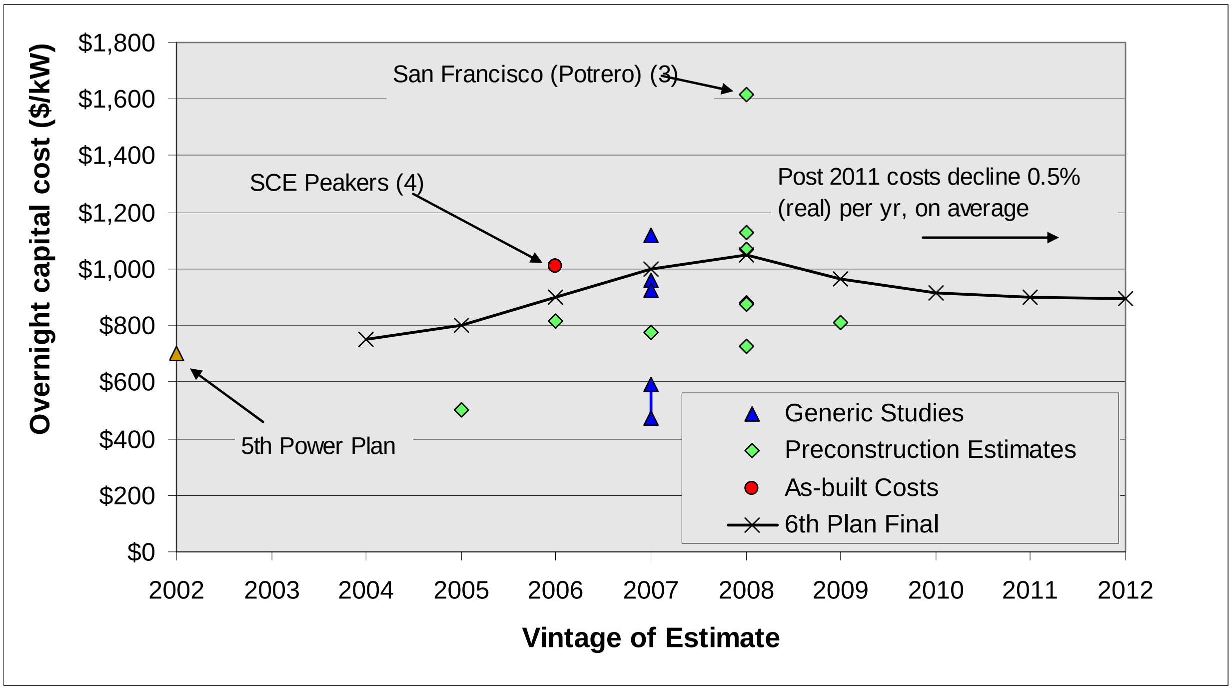
The normalized costs show evidence of the 2004 to 2008 escalation of power plant costs, but are scattered in 2007 and 2008. This may result from variation in plant designs or site conditions or imperfect information for normalization. The cost of the San Francisco Potrero plants is a noticeable high side outlier. Because of the controversial, highly urbanized location, extended schedule delays and challenging air quality constraints, this plant is unlikely to be representative of future Northwest projects. Because of the lack of usable project data for 2002 - 2004, the Sixth Plan cost curve is based off the 2002 vintage Fifth Power Plan generic estimates for aeroderivative gas turbines. The curve escalates to the 2008 peak, running on the high side the majority of the 2005 through 2008 samples and somewhat below the Southern California Edison projects. Total plant cost is forecast to decline from the 2008 high to market equilibrium

[26] "Lifecycle average" capacity basis. The average capacity over the life of a gas turbine-based power plant is estimated to be 97.5% of new and clean capacity. The total plant cost on the basis of new and clean capacity would be about $1025/kW.

conditions by 2011, represented by the average of estimated 2004 and 2008 cost. Following 2011, costs are assumed to decline, on average at 0.5% per year, reflecting a 5% learning rate for gas turbine technology.

A cost uncertainty range of +30%/-30% is used for Regional Portfolio Model studies.

Figure I-23: Total plant costs of aeroderivative gas turbine power plants



Development and Construction Schedule, Cash Flows: The development and construction schedule and cash flow assumptions for aeroderivative gas turbine plants are as follows:

> **Development** (Site acquisition, environmental assessment, permitting, preliminary engineering, interconnection agreement, EPC selection) - 18 mo., 5% of total plant cost
>
> **Early Construction** (Final engineering, equipment order, site preparation, interconnection, infrastructure construction, foundations) - 9 mo., 50% of total plant cost
>
> **Committed Construction** (Major equipment delivery through commissioning) - 6 mo., 45% of total plant cost

The overall duration of the development period and construction periods remains at the value used for the Fifth Power Plan. However, the Early Construction period is shorted from 12 to 9 months and the Committed Construction Period extended by 3 months. Level cash flows are assumed for the Development Period. Construction cash flows are based on a right-skewed cash flow from Phung, 1978, maximized at the initial month of the committed construction period.

Operating and Maintenance Cost: Fixed O&M cost is estimated to be $13/kW/yr. Fixed O&M includes operating and routine maintenance labor, maintenance materials, routine contract services, and administrative and general costs. Insurance and property taxes are excluded. The cost of fixed O&M is assumed to escalate in real terms with the cost of construction. Variable

O&M is estimated to be $4.00/MWh. Variable O&M includes operating hour or startup-based major maintenance labor and materials, unscheduled maintenance, SCR catalyst replacement, ammonia, water and other consumables. The O&M estimates are based on the NERA "Lower Hudson Valley" LM6000 case (Table A-3 of NERA, 2007), excluding site leasing costs, property tax and insurance. Fixed O&M costs are assumed to escalate in real terms with total plant costs. Variable O&M costs are assumed to remain constant in real terms.

Economic Life: The economic life of an aeroderivative gas turbine plant is assumed to be 30 years.

Developable Potential: No constraints were initially placed on the cumulative development potential for simple-cycle gas turbine plants pending initial portfolio model results. The portfolio for the Carbon Risk scenario includes a maximum of 170 MW of new simple-cycle gas turbine capacity, an amount that should not be constrained by gas supply, other infrastructure or air quality constraints.

Levelized cost summary: The estimated levelized lifecycle fixed capacity cost, and cost of delivered energy from a natural gas simple-cycle aeroderivative gas turbine power plant are shown in Table I-29. The cost estimates are based on investor-owned utility financing. Fixed capacity costs include the fixed costs of the plant, fuel supply and transmission. Energy costs are illustrative for 46% capacity factor (4000 hours per year) operation.

Table I-29: Levelized Cost of Natural Gas Simple-cycle Aeroderivative Gas Turbine Power Plants

Service Year	Capacity Cost ($/kW/yr)	Plant Busbar ($/MWh)	Ancillary Services and Integration ($/MWh)	Transmission and Losses ($/MWh)	Emissions ($/MWh)	Total ($/MWh)
2010	$166	$94.29	$0.98	$6.41	$17.81	$119
2015	$164	$98.92	$0.99	$6.68	$22.91	$130
2020	$162	$100.65	$1.00	$6.76	$24.08	$132
2025	$159	$100.98	$1.00	$6.78	$24.06	$133
2030	$157	$100.94	$1.01	$6.80	$24.03	$133

Natural Gas Simple-cycle Heavy-duty (Frame) Gas Turbine Plant

Heavy-duty (also called Frame or Industrial) gas turbines are designed specifically for stationary installations. Weight and physical size are not as constraining as they are for aeroderivative units. Heavy-duty machines are available in much larger sizes than aeroderivative units and are designed for long life and reliability. Pressure (compression) ratios are lower for aeroderivative machines, resulting in less demanding design conditions, but produce a bulkier, somewhat less efficient engine. More robust construction improves durability, but constrains operational flexibility. Start time to full load typically exceeds ten minutes so heavy-duty machines must be operating to provide spinning reserve capacity. Major maintenance is accomplished on site in contrast to the component swap out common for aeroderivative units. Because of economies of scale and less demanding design conditions, heavy duty machines cost less per-kilowatt capacity than aeroderivative units. Heavy-duty simple-cycle gas turbines are used to provide daily and seasonal peaking capacity, especially where infrequent, but extended operation may be required.

They are also used in plants where eventual conversion to combined-cycle configuration is planned. Like aeroderivative units, heavy-duty gas turbines require a high fuel supply pressure and fuel gas booster compressors may be needed in locations away from natural gas mainlines. The higher exhaust gas temperatures of some frame machines preclude the use of SCR for NOx and CO control. This may limit site availability and operating hours.

Reference Plant: The reference heavy-duty simple-cycle gas turbine plant consists of a single gas turbine generator set of 85 MW nominal capacity. The net "new and clean" capacity of the plant under ISO conditions is 83 megawatts. This is based on the nominal capacity of a General Electric MS7001EA (Gas Turbine World, 2007), derated 3.1% for inlet, exhaust, auxiliary load and main transformer losses. The new and clean heat rate is degraded a further 2.5% for maintenance-adjusted lifecycle aging effects to yield a lifecycle average baseload capacity of 81 MW (ISO conditions). The gas turbine generator is enclosed for weather protection and acoustic control, and is provided with inlet air filters and exhaust silencers. The plant also includes lube oil, starting, fuel forwarding, and control systems; a control building, step-up transformers and a switchyard. Dry low-NOx combustors are used for NOx emissions control. The plant is assumed to be located near a natural gas mainline with sufficient pressure for operation without fuel gas booster compression.

Fuel: Natural gas is supplied on a firm transportation contract with capacity release capability. No backup fuel is provided. Fuel price forecasts are described in Chapter 2 and Appendix A.

Heat Rate: The full load, higher heating value heat rate under "new and clean" conditions is estimated to be 11,870 Btu/kWh. This is based on the nominal lower heating value heat rate reported for a General Electric MS7001EA in Gas Turbine World (2007), converted to higher heating value and derated 3.1% for inlet, exhaust, auxiliary load, and transformer losses. The lifecycle average higher heating value full load heat rate is estimated to be 11,960 Btu/kWh, HHV. This is based on the new and clean heat rate degraded 0.8% for maintenance-adjusted lifecycle aging effects[27].

Availability parameters: Availability parameters are based on 2004 - 2008 NERC Generating Availability Data System (GADS) data, as described for aeroderivative gas turbine plants.

***Unit Commitment Parameters*:** Gas turbines are assumed to operate as dispatchable units. In the Northwest, these plants would normally provide capacity reserves. As such, they could serve peak loads, provide incremental and decremental load following and wind integration service and provide seasonal backup for low water years. Unit commitment parameters used in the AURORA$^{\underline{xmp}®}$ Electric Power Market Model, as described for aeroderivative gas turbine plants.

Total Plant Cost: The overnight total plant cost of the reference plant is estimated to be $610/kW[28] in 2006 dollars for the 2008 price year. This estimate is based on a sample of 3 reported as-built plant costs, 7 preconstruction cost estimates (including one range estimate), and 6 generic cost estimates (including two range estimates). The sample costs were normalized as

[27] Fuel gas compression, if needed, will further increase net heat rate, as will extended partial load operation. Startup inefficiencies will also increase heat rate, though the significance of the impact will depend on startup frequency.

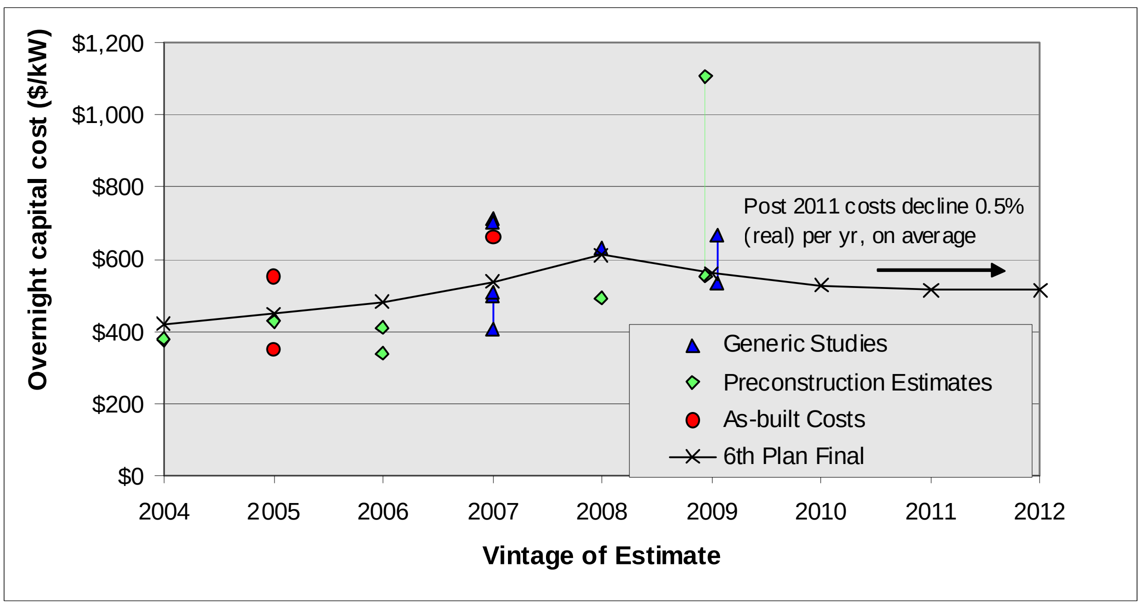
[28] "Lifecycle average" capacity basis. The average capacity over the life of a gas turbine-based power plant is estimated to be 97.5% of new and clean capacity. The total plant cost on the basis of new and clean capacity would be about $595/kW.

described in the Capital Cost Analysis section of this appendix. Owner's costs, where not included in the estimate, were assumed to represent 12% of total plant costs. Single-unit plants were assumed to cost 130% of multiple-unit plants. The examples included larger F-class as well as E-class machines because of the limited number of Frame E examples. Though unit scale economies were expected, this was not reflected in the data. Because normalized E-class examples lie above and below the curve chosen for the Sixth Plan, no unit scale adjustment was made. The resulting normalized costs are shown in Figure I-24. The range estimates are represented by connected point pairs in the Figure.

Except for the 2009 Pastoria range estimate, the samples are reasonably clustered for each year and clearly reflect the escalation of power plant costs from 2004 to 2008. The Pastoria estimate appears to assume that 2004 to 2008 rates of escalation would continue in 2009. The Sixth Power Plan cost curve is placed within all 2004 through 2008 samples. Total plant cost is forecast to decline from the 2008 high to market equilibrium conditions by 2011, assumed to be the average of estimated 2004 and 2008 costs. Following 2011, costs are assumed to decline, on average at 0.5% per year, reflecting a 5% learning rate for gas turbine technology.

A cost uncertainty range of +25%/- 25% is used for Regional Portfolio Model studies.

Figure I-24: Total plant costs of heavy-duty (frame) gas turbine power plants



Development and Construction Schedule: See discussion under Aeroderivative Simple-cycle Gas Turbine Plant

Economic Life: The economic life of a heavy-duty simple-cycle gas turbine power plant is assumed to be 30 years.

Operating and Maintenance Cost: Fixed O&M cost is estimated to be $11/kW/yr[29]. Fixed O&M includes operating and routine maintenance labor, maintenance materials, routine contract services, and administrative and general costs. Insurance and property taxes are excluded. The cost of fixed O&M is assumed to escalate in real terms with the cost of construction. Variable O&M is estimated to be $1.00/MWh. Variable O&M includes operating hour or startup-based major maintenance labor and materials, unscheduled maintenance, and consumables. The O&M estimates are based on the average of the NERA "Syracuse" and "Albany" GE7FA cases (Table A-3 of NERA, 2007), excluding site leasing costs, property tax, and insurance. The NERA fixed costs were adjusted by the ratio of GE7FA capacity to GE7EA capacity to account for expected unit scale economies, and further increased by 30% to normalize to a single unit installation. Fixed O&M costs are assumed to escalate in real terms with total plant costs. Variable O&M costs are assumed to remain constant in real terms.

Developable Potential: No constraints were initially placed on the cumulative development potential for simple-cycle gas turbine plants pending initial portfolio model results. The recommended (least risk) portfolio contains a cumulative maximum of 170 MW of new simple-cycle gas turbine capacity, an amount that should not be constrained by gas supply, other infrastructure or air quality constraints. Siting opportunities may be limited to non-sensitive attainment air quality areas because of the lack of SCR control of NOx and CO emissions.

Levelized cost summary: The estimated levelized lifecycle fixed capacity cost, and cost of delivered energy from a natural gas simple-cycle heavy-duty gas turbine power plant are shown in Table I-30. The cost estimates are based on investor-owned utility financing. Fixed capacity costs include the fixed costs of the plant, fuel supply and transmission. Energy costs are illustrative for 46% capacity factor (4000 hours per year) operation.

Table I-30: Levelized Cost of Natural Gas Simple-cycle Heavy-duty (Frame) Gas Turbine Power Plants

Service Year	Capacity Cost ($/kW/yr)	Plant Busbar ($/MWh)	Ancillary Services and Integration ($/MWh	Transmission And Losses ($/MWh)	Emissions ($/MWh)	Total ($/MWh)
2010	$132	$97.76	$0.98	$6.57	$22.74	$128
2015	$134	$104.93	$0.99	$6.92	$29.24	$142
2020	$134	$107.55	$1.00	$7.02	$30.73	$146
2025	$132	$108.36	$1.00	$7.05	$30.71	$147
2030	$131	$108.71	$1.01	$7.08	$30.67	$147

Natural Gas Simple-cycle Intercooled Gas Turbine Plant

Combustion air compression consumes about two-thirds of the total power produced by a gas turbine engine. This energy consumption can be reduced by intercooling - cooling the compressed air at intermediate stages of compression. Intercooling improves thermal efficiency by reducing the energy needed for air compression and increases power output for a given size

[29] An earlier fixed O&M estimate of $4/kW/yr, not normalized for the unit scale of the 7EA machine, or to a single unit plant, was used for portfolio model studies. The $11/kW/yr value increases the fixed cost of the reference plant by 3% from $128/kW/yr to $134/kW/yr. The levelized cost of energy at a 10% capacity factor, typical of a peaking unit would increase by 2% from $255/MWh to $261/MWh (IOU financing, 2015 service year).

turbine by increasing density of air flowing through the high pressure stages of the compressor and the power turbine. Intercooling can be accomplished by direct injection of water into the compressed air stream or by routing the compressed air through an external air cooler. Turbine designs such as the aeroderivative General Electric LM6000 Sprint™ use direct water spray injection. The sole commercial gas turbine using external intercooling is the General Electric LMS100™. The LMS100, introduced in 2004, is called a hybrid intercooled turbine because it uses both aeroderivative and heavy-duty gas turbine components and design practices. The combination of external intercooling and use of lightweight aeroderivative components improves both simple-cycle thermal efficiency and operating flexibility (flatter heat rate curve, fast ramping, fast cold start, and reduced cycling maintenance penalty). The external air cooler and cooling system add to the complexity and cost of the plant. Water consumption may be reduced compared to a spray-injected intercooled machine, especially if dry mechanical draft cooling is used to chill the intercooler.

Reference Plant: The reference intercooled simple-cycle gas turbine plant consists of a single gas turbine generator set of 99 MW nominal capacity, an external intercooler, an evaporative mechanical draft cooling system for the intercooler, lube oil, fuel forwarding and other ancillary equipment, a control building, and switchyard. Cost and performance characteristics are based on the General Electric LMS100PB (dry low-NOx combustors). Auxiliary loads for external intercooler technology will be greater than a conventional simple-cycle unit and the net “new and clean” capacity of the plant under ISO conditions is 96 megawatts. The new and clean heat rate is degraded a further 2.2% for maintenance-adjusted lifecycle aging effects to yield a lifecycle average baseload capacity of 94 MW (ISO conditions). The gas turbine generator is enclosed for weather protection and acoustic control, and is provided with inlet air filters and exhaust silencers. The plant also includes an outboard intercooler, a mechanical draft evaporative intercooler cooling system, a makeup cooling water treatment plant; lube oil, starting, fuel forwarding, and control systems; a control building and switchyard. Dry low-NOx combustors are used for NOx emissions control. The plant is assumed to be located near a natural gas mainline with sufficient pressure for operation without fuel gas booster compression.

Fuel: Natural gas is supplied on a firm transportation contract with capacity release capability. No backup fuel is provided. Fuel price forecasts are described in Chapter 2 and Appendix A.

Heat Rate: The full load, higher heating value heat rate under “new and clean” conditions is estimated to be 8,810 Btu/kWh. This is based on the nominal lower heating value heat rate reported for a General Electric LMS100PB in Gas Turbine World (2009), converted to higher heating value and derated 3.1% for inlet, exhaust, auxiliary load, and transformer losses. The lifecycle average higher heating value full load heat rate is estimated to be 8,870 Btu/kWh, HHV. This is based on the new and clean heat rate degraded 0.8% for maintenance-adjusted lifecycle aging effects[30].

Availability parameters: Because the first LMS100 entered service in 2006, long-term availability information is not available. Availability parameters are based on 2004 - 2008 NERC Generating Availability Data System (GADS) data for all gas turbines, and are as follows:

[30] Fuel gas compresssion, if needed, will further increase net heat rate, as will extended partial load operation. Startup inefficiencies will also increase heat rate, though the significance of the impact will depend on startup frequency.

Scheduled maintenance outages - 14 days/yr

Equivalent forced outage rate - 5%

Mean time to repair - 88 hours

Equivalent annual availability - 91%

***Unit Commitment Parameters*:** Gas turbines are assumed to operate as dispatchable units. In the Northwest, these plants would normally provide capacity reserves. As such, they could serve peak loads, provide incremental and decremental load following and wind integration service and provide seasonal backup for low water years. Unit commitment parameters used in the AURORA$^{xmp®}$ Electric Power Market Model are as follows:

Minimum load - 25%

Minimum run time - 1 hour

Minimum down time - 1 hour

Ramp rate - Cold start to full load in 10 minutes

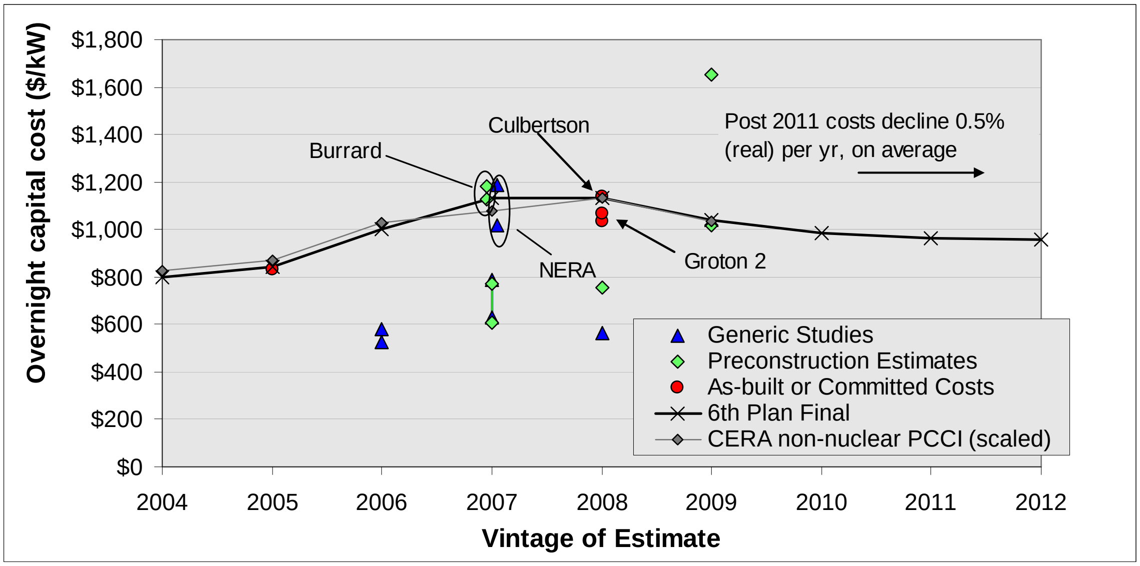
Total Plant Cost: The overnight total plant cost of the reference plant is estimated to be $1,130/kW[31] in 2006 dollars for the 2008 price year. This estimate is based on a sample of 1 reported as-built plant cost, 3 “as-committed” cost estimates, 7 preconstruction cost estimates (including one range estimate), and 5 generic cost estimates including two range estimates. The sample costs were normalized as described in the Capital Cost Analysis section of this appendix. Owner’s costs, where not included in the estimate were assumed to represent 12% of total plant costs. Single-unit plants were assumed to cost 30% more than multiple-unit plants (approximation from NERA, 2007, Figure II-3). The resulting normalized costs are shown in Figure I-25. The range estimates are represented by connected points in the figure.

The normalized estimates are scattered and the 2004 - 2008 escalation in construction costs is not clearly evident unless the two 2009 preconstruction estimates are considered. The high-lying 2009 preconstruction estimate may date prior to the peaking of construction costs in mid-2008. The recent introduction of the LMS100 further complicates estimating a 2008 price year and a market equilibrium cost. No estimates are available prior to 2005, and the 2005 estimate is the as-built cost of Groton 1, the first commercial LMS100. The cost of Groton 1 may not be representative. First-of-a-kind problems may have increased construction costs, while on the other hand, the manufacturer may have offered discount pricing, in-kind services, or special warranties to help place the first unit in the field. The curve chosen for the Sixth Power Plan is strongly influenced by the upper NERA (SCR) case (NERA, 2007), Groton 2, Burrard Replacement and Culbertson data points and the CERA non-nuclear PCCI (www.ihsindexes.com). These plant data are well-documented, reasonably representative of the reference unit and follow completion and initial operation of Groten 1 by two or more years. Total plant cost is forecast to decline from the 2008 high to market equilibrium conditions by

[31] “Lifecycle average” capacity basis. The average capacity over the life of a gas turbine-based power plant is estimated to be 97.5% of new and clean capacity. The total plant cost on the basis of new and clean capacity would be about $995/kW.

2011. Equilibrium conditions were assumed to be the average of estimated 2004 and 2008 price year costs. Following 2011, costs are assumed to decline, on average at 0.5% per year, reflecting a 5% learning rate for gas turbine technology.

Figure I-25: Total plant costs of intercooled gas turbine power plants



Development and Construction Schedule: See discussion under Aeroderivative Simple-cycle Gas Turbine Plant

Economic Life: The economic life of an intercooled hybrid simple-cycle gas turbine power plant is assumed to be 30 years.

Operating and Maintenance Cost: Fixed O&M cost is estimated to be $8/kW/yr. Fixed O&M includes operating and routine maintenance labor, maintenance materials, routine contract services, and administrative and general costs. Insurance and property taxes are excluded. The cost of fixed O&M is assumed to escalate in real terms with the cost of construction. Variable O&M is estimated to be $5.00/MWh. Variable O&M includes operating hour or startup-based major maintenance labor and materials, unscheduled maintenance, SCR catalyst replacement, ammonia, water, and other consumables. The O&M estimates are based on the NERA "Lower Hudson Valley" LMS100 case (Table A-3 of NERA, 2007), excluding site leasing costs, property tax and insurance. Fixed costs are increased by 30% to normalize to a single unit installation. Fixed O&M costs are assumed to escalate in real terms with total plant costs. Variable O&M costs are assumed to remain constant in real terms.

Developable Potential: No constraints were initially placed on the cumulative development potential for simple-cycle gas turbine plants pending initial portfolio model results. The portfolio for the Carbon Risk scenario includes a maximum of 170 MW of new simple-cycle gas turbine capacity, an amount that should not be constrained by gas supply, other infrastructure, or air quality constraints.

Levelized cost summary: The estimated levelized lifecycle fixed capacity cost, and cost of delivered energy from a natural gas simple-cycle intercooled gas turbine power plant are shown in Table I-31. The cost estimates are based on investor-owned utility financing. Fixed capacity costs include the fixed costs of the plant, fuel supply and transmission. Energy costs are illustrative for 46% capacity factor (4000 hours per year) operation.

Table I-31: Levelized Cost of Natural Gas Simple-cycle Intercooled Gas Turbine Power Plants

Service Year	Capacity Cost ($/kW/yr)	Plant Busbar ($/MWh)	Ancillary Services and Integration ($/MWh	Transmission and Losses ($/MWh)	Emissions ($/MWh)	Total ($/MWh)
2010	$168	$92.75	$0.98	$6.37	$16.86	$117
2015	$164	$96.83	$0.99	$6.62	$21.69	$126
2020	$162	$98.42	$1.00	$6.69	$22.79	$129
2025	$159	$98.68	$1.00	$6.71	$22.78	$129
2030	$157	$98.60	$1.01	$6.73	$22.75	$129

Natural Gas Reciprocating Engine Generator Plant

Reciprocating-engine generators (also known as internal combustion engines, ICs or gen-sets) consist of a compression or spark-ignition reciprocating engine driving a generator. Individual units are typically frame mounted and supplied as modular units. Unit sizes for power system applications range from about one to 17 megawatts. Reciprocating generators are used for small isolated power systems, emergency capacity at sites susceptible to transmission outages, and to provide emergency power and black start capacity at larger power plants. Other applications include units modified to operate on biogas from landfills or anaerobic digestion of waste biomass, industrial cogeneration, and mobile units for emergency service. Reciprocating units also provide backup power for hospitals, elevators and emergency lighting in high-occupancy buildings, and other critical loads. Except for biogas units, these applications typically use light fuel oil stored on site.

With improvements in emission control and thermal efficiency, reciprocating-engine generators increasingly have been incorporated into natural-gas fuelled multi-unit power generation stations for main grid applications. The high efficiency, flat heat rate curves and rapid response of contemporary reciprocating-engine generator sets make these plants especially suitable for peaking and intermediate load service and for the provision of balancing and other ancillary services. Because of lower fuel supply pressure requirements, fuel gas booster compressors are usually not required for commercial gas supplies. Lower fuel supply pressure requirements afford greater siting flexibility. A further advantage of reciprocating units, is that compared to gas turbines, power output falls off more slowly with increasing elevation and ambient temperature. Finally, a reciprocating engine plant comprised of several small units can be more efficient at part-load operation than a single gas turbine unit of equivalent size because of the ability to shut down units and load the remaining units at or near peak efficiency. On the other hand, lube oil consumption of reciprocating engines is high, leading to somewhat greater variable O&M cost than a comparable gas turbine.

Reference Plant: The reference reciprocating engine plant consists of twelve 8.25 MW capacity engine-generators comprising a plant of approximately 100 MW nominal capacity. The plant would normally include a generator and control building, reciprocating engine-generator units, fuel, electrical and control and instrumentation systems, closed-cycle (radiator) cooling, and a switchyard. Fuel is natural gas supplied on a firm transportation contract with capacity release capability. No backup fuel is provided. Air emission controls include selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC control.

Heat Rate: The full load, higher heating value heat rate under "new and clean" conditions is estimated to be 8,800 Btu/kWh. This is based on the guaranteed-to-grid heat rate for a plant employing Wartsila 20V34 engines. The lifecycle average higher heating value full load heat rate is estimated to be 8,850 Btu/kWh, HHV. This is based on the new and clean heat rate degraded 0.6% for maintenance-adjusted lifecycle aging effects.

Availability parameters: Availability parameters are based on 2004 - 2008 NERC Generating Availability Data System (GADS) data for diesel units, as follows:

Scheduled maintenance outages - 7 days/yr

Equivalent forced outage rate - 5%

Mean time to repair - 56 hours (per unit)

Equivalent annual availability - 93%

The GADS statistics for reciprocating units are from old units, on average, and may be low for contemporary plants.

***Unit Commitment Parameters*:** Reciprocating engines are assumed to operate as dispatchable units. In the Northwest, these plants would normally provide capacity reserves. As such, they could serve peak loads, provide incremental and decremental load following and wind integration service and provide seasonal backup for low water years. Unit commitment parameters (used in the AURORA$^{xmp®}$ Electric Power Market Model) are as follows:

Minimum load - 40% (all engines running) (Kirby, 2007). A 100 MW plant could provide 30 MW up regulation and 30 MW down regulation.

Minimum run time - 1 hour

Minimum down time - 1 hour

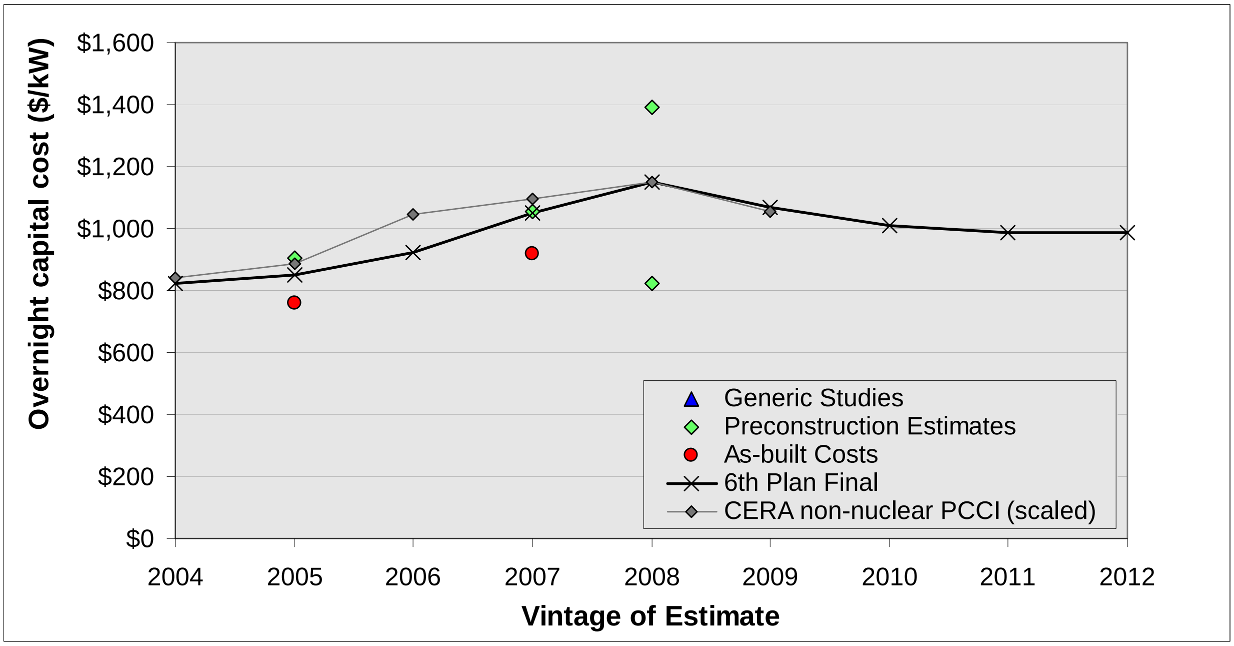
Ramp rate, warm start to full load - Less than 10 minutes (Kirby, 2007). Virtual spinning reserve under warm start conditions.

Total Plant Cost: The overnight total plant cost of the reference reciprocating engine plant is estimated to be $1,150/kW installed capacity (2008 price year). This estimate is based on a sample of two reported as-built plant costs and 4 preconstruction estimates from 2004, or later. No recent generic estimates of reciprocating engine-generator plant costs were located. Published costs, normalized as described in the Capital Cost Analysis subsection of this Appendix, are plotted by vintage in Figure I-26. A wide range of costs is evident for 2007 and

2008, though the general increase in power plant construction costs from 2004 through mid-2008 is well defined. The Sixth Plan cost estimate follows the shape of the CERA PPCCI curve and is positioned midway between the sample values.

Total plant cost is forecast to decline from the 2008 high point to market equilibrium conditions, represented by the average of 2004 and 2008 costs, by 2011. Total plant costs are assumed to remain constant in real terms thereafter.

Figure I-26: Published and forecast capital costs of reciprocating engine plants



Development and Construction Schedule, Cash Flows: The development and construction schedule and cash flow assumptions for reciprocating engine plant are the same as assumed for gas turbine plants, as follows:

> **Development** (Site acquisition, permitting, preliminary engineering, interconnection agreement) - 18 mo., 5% of total plant cost
>
> **Early Construction** (Final engineering, equipment order, site preparation, interconnection, infrastructure construction) - 9 mo., 50% of total plant cost
>
> **Committed Construction** (Major equipment installation, commissioning) - 6 mo., 45% of total plant cost

Fuel Price: Fuel price forecasts are described in Chapter 2 and Appendix A.

Operating and Maintenance Cost: Fixed O&M cost, excluding property tax and insurance is estimated to be $13/kW/yr. Fixed O&M includes operating labor and routine maintenance labor and materials, and administrative and general costs. Insurance and property taxes are excluded. The cost of fixed O&M is assumed to escalate in real terms with the cost of construction. Variable O&M is estimated to be $10.00/MWh. Variable O&M includes operating hour-based major maintenance labor and materials, unscheduled maintenance warranty, SCR catalyst replacement, ammonia, lube oil and other consumables. Variable O&M is assumed to remain constant in real terms through the life of the plant.

Economic Life: The economic life of a reciprocating engine plant is assumed to be 30 years; limited by the expected operating life of major equipment.

Developable Potential: In the Northwest, reciprocating engine plants will likely compete with simple and combined-cycle gas turbine technology for serving intermediate and peak loads and to provide regulation and load-following and other ancillary services. The recommended (least risk) resource portfolio contains a maximum of 1,000 MW of new combined-cycle and simple-cycle gas turbine capacity. A portion of this capacity may be served by reciprocating engine plants. This amount is unlikely to be constrained by gas supply or other infrastructure or air quality constraints.

Levelized cost summary: The estimated levelized lifecycle fixed capacity cost, and cost of delivered energy from natural gas reciprocating engine generator power plants are shown in Table I-32. The cost estimates are based on investor-owned utility financing financing. Fixed capacity costs include the fixed costs of the plant, fuel supply and transmission. Energy costs are illustrative for 46% capacity factor (4000 hours per year) operation.

Table I-32: Levelized Cost of Natural Gas Reciprocating Engine Generator Power Plants

Service Year	Capacity Cost ($/kW/yr)	Plant Busbar ($/MWh)	Ancillary Services and Integration ($/MWh)	Transmission and Losses ($/MWh)	Emissions ($/MWh)	Total ($/MWh)
2010	$180	$100.68	$0.98	$6.52	$16.91	$125
2015	$172	$105.39	$0.99	$6.80	$22.30	$135
2020	$171	$108.79	$1.00	$6.91	$24.03	$141
2025	$170	$110.92	$1.00	$6.98	$24.62	$144
2030	$168	$111.63	$1.01	$7.02	$24.84	$144

Natural Gas Combined-Cycle Plant

Gas turbine combined-cycle power plants consist of one or more gas turbine generators provided with exhaust heat recovery steam generators. Steam raised in the heat recovery units powers a steam-turbine generator. Capture of the energy of the gas turbine exhaust increases the overall thermal efficiency of a combined-cycle plant compared to a simple-cycle gas turbine generator. The reference combined-cycle unit, for example, has a base load efficiency of 48 percent compared to a full-load efficiency of 38 percent for the reference hybrid intercooled gas turbine. Combined-cycle plants can serve cogeneration steam load (at some loss of electricity production) by extracting steam at the needed pressure from the heat-recovery steam generator or steam turbine. Additional generating capacity (power augmentation) can be obtained at low cost by oversizing the steam turbine generator and providing the heat recovery steam generator with natural gas burners (duct firing). The resulting capacity increment operates at somewhat lower electrical efficiency than the base plant and is usually reserved for peaking operation, the incremental efficiency, however, is comparable to that of simple-cycle gas turbines. Because they often operate at or near market clearing prices, combined-cycle plants can be an economical source of system balancing reserves. With high reliability, high efficiency, low capital cost, short lead-time, operating flexibility, and low air emissions, gas-fired combined-cycle plants have been the bulk power generation resource of choice since the early 1990s.

Reference Plant: The reference plant is a single train (1x1) natural gas-fired combined-cycle plant consisting of a "G-class" gas turbine generator, a fired heat recovery steam generator and a steam turbine generator. The "new and clean" net base load capacity under ISO conditions is 395 megawatts with 25 megawatts of peaking power augmentation. The net baseload capacity is based on the nominal capacity of a 1x1 Mitsubishi 501G combined-cycle unit (Gas Turbine World, 2009), derated 0.9% for SCR and main transformer losses. The new and clean heat rate is degraded a further 2.7% for maintenance-adjusted lifecycle aging effects to yield a lifecycle average baseload capacity of 385 MW. 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.

Fuel: Natural gas supplied on a firm transportation contract with capacity release capability. No backup fuel is provided. Fuel price forecasts are described in Chapter 2 and Appendix A.

Heat Rate: The higher heating value heat rate at full baseload under "new and clean" conditions is estimated to be 6,790 Btu/kWh. This is the reported heat rate for the Port Westward plant (Mitsubishi MHI 501G). The lifecycle average higher heating value heat rate at full baseload is estimated to be 6,930 Btu/kWh, HHV. This is based on the new and clean heat rate degraded 2.1% for maintenance-adjusted lifecycle aging effects[32]. The incremental heat rate of supplemental (duct fired) capacity is estimated to be 9,500 Btu/kWh (Fifth Plan assumption).[33]

Availability parameters: Availability parameters are based on 2004 - 2008 NERC GADS data for all combined-cycle plants, and are as follows:

Scheduled maintenance outages - 21 days/yr

Equivalent forced outage rate - 6%

Mean time to repair - 32 hours

Equivalent annual availability - 89%

Unit Commitment Parameters**:** Combined-cycle gas turbines are assumed to operate as dispatchable units. In the Northwest, combined-cycle plants normally provide firm capacity, and intermediate and baseload energy production. The baseload section of these plants can be engineered to provide incremental and decremental load following and wind integration service. The duct firing capability provides additional capacity reserves. Duct firing can serve peak

[32] Fuel gas compression, if needed, will further increase net heat rate, as will extended partial load operation. Startup inefficiencies will also increase heat rate, though the significance of the impact will depend on startup frequency.

[33] A base load heat rate of 7110 Btu/kWh for new combined-cycle plants was estimated using an erroneous spreadsheet early in the development of the Sixth Power Plan. This value was carried forward to subsequent wholesale price forecasts and Regional Portfolio Model studies for the final plan. A heat rate of 7110 Btu/kWh would increase the levelized cost of power from a combined-cycle unit operated in baseload mode (80% capacity factor) by 2% (less than $2/MWh).

loads, provide incremental and decremental load following and wind integration service, and seasonal backup for low water years. Unit commitment parameters used in the AURORA$^{xmp®}$ Electric Power Market Model are as follows:

Minimum load - 70% of base load capacity

Minimum run time - 6 hours

Minimum down time - 12 hours

Ramp rate - greater than 100%/hr (hot operating conditions)

Fuel Price: Fuel price forecasts are described in Chapter 2 and Appendix A.

Economic Life: The economic life of a combined-cycle plant is assumed to be 30 years.

Total Plant Cost: The overnight total plant cost of the reference plant is estimated to be $1,120/kW[34] in 2006 dollars for the 2008 price year. This estimate is based on an estimated cost of base load capacity of $1,160/kW and an estimated cost of supplementary (fired HSRG) capacity of $465/kW. These estimates were derived from 6 reported as-built plant costs, 16 preconstruction cost estimates (one with low and high bound estimates), and 4 generic cost estimates (one including low and high bound costs) from 2004, or later. The sample costs were normalized as described in the Capital Cost Analysis section of this Appendix to represent a base a single-train (1x1) plant with evaporative cooling. For normalization to base load-only cost, supplementary firing capacity was assumed to cost 40% of base load capacity. Single-train plants were assumed to cost 10% more than plants using multiple gas turbine configurations and owner's costs were assumed to represent 20% of total plant costs. The resulting normalized costs are shown in Figure I-27.

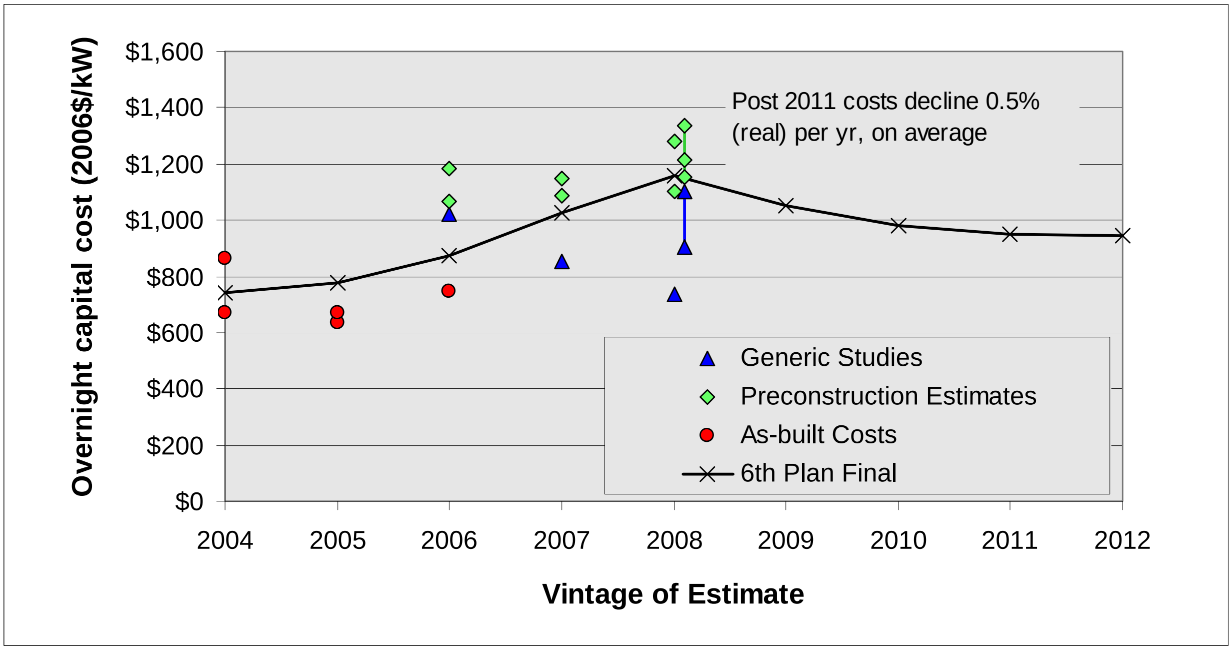
The averages of the two 2004 as-built examples and the intersection of the range of preconstruction and generic cost estimates establish the 2004 and 2008 points of the Sixth Plan cost curve. The fairing of the curve between these years is influenced by the 2005 and 2006 as-built cost examples and the 2007 preconstruction example. Total plant cost is forecast to decline from the 2008 high to market equilibrium conditions by 2011, represented by the average of estimated 2004 and 2008 cost. Thereafter, costs are assumed to decline at 0.5% per year, reflecting a 5% learning rate for gas turbine technology.

The total plant cost for the reference plant is the sum of the capacity-weighted base load and supplementary firing capacity costs.

A cost uncertainty range of +30%/- 30% was used for Regional Portfolio Model studies.

[34] "Lifecycle average" capacity basis. The average capacity over the life of a gas turbine-based power plant is estimated to be 97.3% of new and clean capacity. The total plant cost on the basis of new and clean capacity would be $1090/kW.

Figure I-27: Total plant costs of combined-cycle power plants



Development and Construction Schedule, Cash Flows: The development and construction schedule and cash flow assumptions for the reference combined-cycle plant are as follows:

> **Development** (Site acquisition, environmental assessment, permitting, preliminary engineering, interconnection agreement, EPC selection) - 24 mo., 4% of total plant cost
>
> **Early Construction** (Final engineering, equipment order, site preparation, interconnection, infrastructure construction, foundations) - 12 mo., 42% of total plant cost
>
> **Committed Construction** (Major equipment delivery through commissioning) - 18 mo., 54% of total plant cost

Development and Early Construction schedules are the values used in the Fifth Power Plan. The overall construction period was extended from 24 to 30 months at the recommendation of the Council's Generating Resources Advisory Committee (GRAC) to reflect recent construction experience. Level cash flows are assumed for the Development Period. Construction cash flows are based on a right-skewed cash flow from Phung, 1978, maximized at the initial month of the committed construction period.

Operating and Maintenance Cost: Fixed O&M cost, exclusive of property tax and insurance is $14/kW/yr. Variable O&M is $1.70/MWh. These values are based on NETL (2007), escalated in proportion to the difference in the normalized combined-cycle capital cost of NETL (2007) and the Sixth Plan total plant cost described above. Fixed O&M cost is assumed to escalate in real terms with total plant cost. Variable O&M is assumed to remain constant in real terms.

Economic Life: The economic life of a combined-cycle plant is assumed to be 30 years.

Development Potential: No constraints were initially placed on the cumulative development potential for combined-cycle gas turbine plants pending initial portfolio model results. The portfolio for the Carbon Risk scenario includes a maximum of 830 MW (two units) of new combined-cycle gas turbine capacity. This amount should not be constrained by gas supply, other infrastructure or air quality constraints.

Levelized cost summary: The estimated levelized lifecycle fixed capacity cost, and cost of delivered energy from a natural gas combined-cycle power plant are shown in Table I-33. Baseload costs represent the costs associated with the baseload section of the plant (385 MW, degraded lifecycle capacity for the reference plant). Incremental duct-firing costs are the incremental costs associated with the supplementary peaking capacity (25 MW for the reference unit) of the plant. The cost estimates are based on investor-owned utility financing. The baseload energy costs are based on 85% (of baseload capacity) capacity factor operation. The incremental duct firing energy costs are illustrative for 46% capacity factor (4000 hours per year) operation of supplemental firing. Fixed capacity costs include the fixed costs of the plant, fuel supply and transmission.

Table I-33: Levelized Cost of Natural Gas Combined-cycle Power Plants

Resource	Service Year	Capacity ($/kW/yr)	Plant Busbar ($/MWh)	Ancillary Services and Integration ($/MWh)	Transmission and Losses ($/MWh)	Emissions ($/MWh)	Total ($/MWh)
Baseload	2010	$170	$61.76	$0.98	$3.74	$13.24	$80
	2015	$166	$65.36	$0.99	$3.93	$17.12	$87
	2020	$163	$66.63	$1.00	$3.98	$17.99	$90
	2025	$160	$66.98	$1.00	$4.00	$17.97	$90
	2030	$158	$66.49	$1.01	$3.99	$17.77	$89
Incremental Duct-firing	2010	$105	$76.40	$0.98	$6.07	$18.15	$102
	2015	$113	$85.23	$0.99	$6.44	$23.94	$117
	2020	$115	$89.55	$1.00	$6.57	$25.80	$123
	2025	$116	$92.51	$1.00	$6.66	$26.43	$127
	2030	$117	$93.91	$1.01	$6.71	$26.66	$128

Advanced Nuclear Plant

Commercial nuclear plants in the United States are "Generation II" designs based on light water reactor (LWR) technology developed in the 1950s for the naval nuclear program. In light water reactors (LWRs), energy released by fission of U_{235} and the Pu^{239} in the reactor core produces steam, either directly (boiling water reactors) or indirectly (pressurized water reactors with intermediate steam generators). The steam powers a steam turbine generator to produce electricity.

Following a three decade hiatus in planning for new nuclear plants, U.S. developers, as of late 2009, have submitted applications to the Nuclear Regulatory Commission for combined construction and operating licenses for 27 new units at 17 sites, largely in the southeast. The proposed plants would all employ Generation III (Advanced) LWR designs. Generation III designs feature increased standardization, passively operated safety systems, improved resistance to external impact, reduced probability of core melt events, factory-assembled modular components, extended plant life, extended fuel life and higher fuel burn-up and improved load-following capability. These features are intended to improve safety and reliability, reduce construction lead time, reduce construction and operating costs, to improve fuel use efficiency and reduce spent fuel production, and improve operating flexibility.

A consortium of countries is developing "Generation IV" reactor designs. Several technological alternatives are under development, but all would operate at higher temperatures to improve thermodynamic efficiency. Several would be optimized for hydrogen production and several would incorporate closed fuel cycles to improve fuel utilization, minimize potential for diversion and to minimize waste. In addition, interest has increased in small modular reactors (SMRs) with greater extent of factory fabrication, shorter construction times, smaller capital investment and better fit to individual utility systems. Several SMR concepts, based on both Generation III and Generation IV technologies, are under development.

Reference Plant: The reference plant is an 1,117 MW net electrical output "Generation III+" unit based on the Toshiba-Westinghouse AP1000. The AP1000 is a two-loop pressurized light water reactor with standardized plant design, simplified, passively-activated safety systems, and extensive use of modular construction techniques. The first four AP1000 units are under construction in China, with the first unit slated for 2013 service. The AP1000 design has received its U.S. NRC design certification, but in response to a request for an amendment to the original design certification, NRC has requested modifications and testing to increase shield structure strength. The impact of this requirement on the schedules of the 14 AP1000 units proposed for US construction is uncertain. However, site preparation work for four Florida units has been suspended as of this writing because of regulatory and economic uncertainties. The reference plant would consist of the nuclear containment structure, turbine building, cooling towers, cooling water supply and discharge systems, auxiliary structures, transportation access, switchyard and transmission interconnection. It is assumed to be developed as a single unit at an existing nuclear plant site.

Heat Rate: The full-load heat rate 10,400 Btu/kWh (33% thermal efficiency) (Westinghouse, 2003).

Availability parameters: Advanced nuclear units are designed for improved reliability and reduced scheduled maintenance time. However, until more specific information becomes available the Council assumes that new and existing nuclear power plants will operate at availabilities consistent with the recent performance of existing commercial units. The availability parameters are based on NERC Generating Availability Data System (GADS) data (www.nerc.com).[35]

Scheduled maintenance and refueling outages - 28 days/yr (average)

Equivalent forced outage rate - 4.2%

Mean time to repair - 112 hours

[35] Earlier values, developed prior to the availability of 2004 - 2008 GADS data were used for portfolio model studies. These were as follows: Scheduled maintenance and refueling outages - 20 days (average) per year; equivalent forced outage rate - 5%; and, mean time to repair - 200 hours. These values yield the same equivalent availability (90%) as the final values derived from 2004 - 2008 GADS data.

Equivalent annual availability - 90%

Capacity-weighted 2004-08 averages for all nuclear units of 1,000MW and larger were used in deriving scheduled and maintenance outages and mean time to repair. In practice, nuclear units are typically refueled on an 18 or 24 month schedule so maintenance outages will vary from year-to-year.

***Unit Commitment Parameters*:** Advanced nuclear units may provide increased operating flexibility compared to current plants. However, until specific information is available, the Council assumes that new and existing nuclear power plants will operate as base load units with limited dispatch capability. Unit commitment parameters used in the AURORA[xmp®] Electric Power Market Model are as follows:

Minimum load - 70%

Minimum run time - 120 hours

Minimum down time - 24 hours

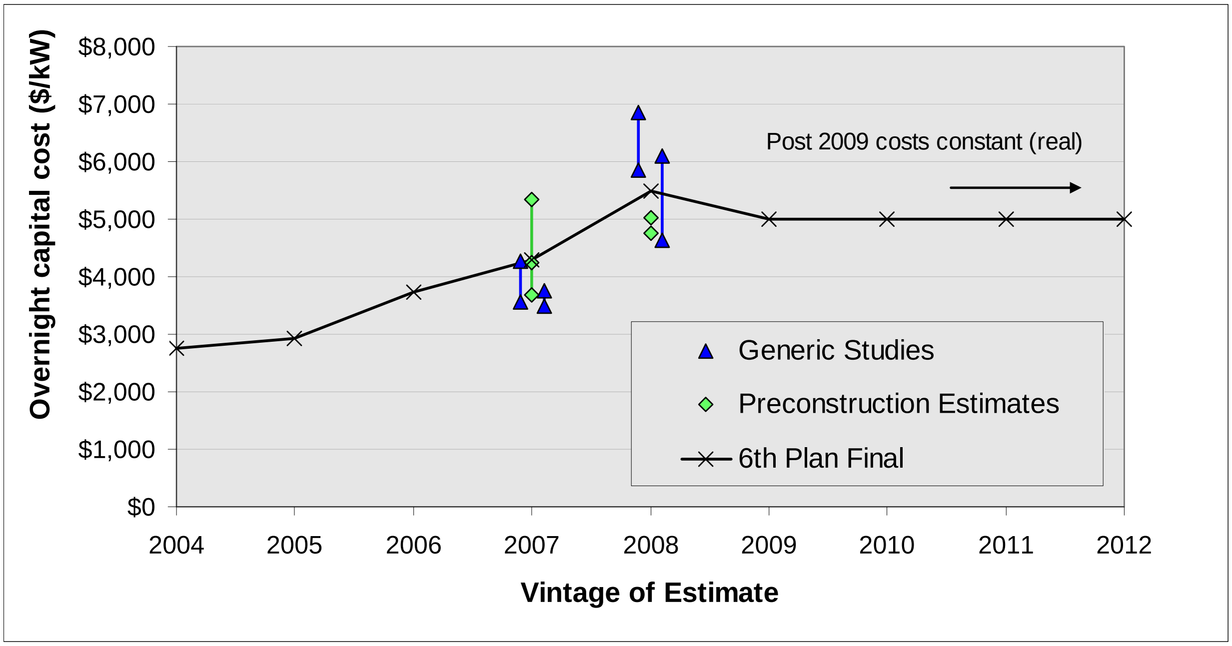
Ramp rate - 10%/hr (maximum)

Total Plant Cost: The overnight total plant cost of the reference plant is estimated to be $5,500/kW in 2006 dollar values for the 2008 price year. This estimate was derived from 2007 and 2008 published estimates for new AP1000 units. These included 3 preconstruction cost estimates (one with expected, low and high bound estimates) and 4 generic cost estimates (each comprised of low and high bound costs). The sample costs were normalized as described in the Capital Cost Analysis section of this appendix to represent a new single unit at the site of an existing nuclear unit. The preconstruction estimates are for new two-unit plants, two at existing plant sites and one at a greenfield site. The cost estimates for plants located at existing nuclear sites were increased by 10% to account for cost savings associated with multiple-unit configurations. The estimated cost of the greenfield plant was not adjusted. Where not included, owner's costs of 22.5% of total plant costs were added to the estimates. The resulting normalized costs are shown in Figure I-28.

The rapid escalation of construction cost estimates for new nuclear units is evident from the 2007 and 2008 clusters and the 2004 - 2007 points of the Sixth Power Plan curve (based on the CERA nuclear plant historical construction cost index). The escalation rate for new nuclear units is more rapid than the general escalation of new power plant construction costs because of further detailed engineering of specific new nuclear units and globally limited production capability for large nuclear components. The 2008 Sixth Plan base year estimate was chosen to approximate the average of normalized cost estimates for 2008. The points for earlier years were derived by deescalating the 2008 cost using the CERA nuclear plant historical construction cost index. Nuclear construction costs are forecast to decline by 9% between 2008 and 2009, based on preliminary data from CERA. This decline is attributable to global softening of the heavy construction market, prospective expansion of global fabrication capacity for large nuclear components and deferral of planned completion dates for several proposed nuclear units. Post-2009 nuclear construction costs are shown as flat in real terms. Technological learning gained from construction of new units is expected to be offset by additional costs as detailed engineering, construction, startup, and shakedown of new units proceeds.

A capital cost uncertainty of +/-30%, roughly corresponding to the observed spread of normalized 2008 estimates, was used for the portfolio model risk analysis.

Figure I-28: Total plant costs of advanced nuclear power plants



Development and Construction Schedule: The development and construction schedule and associated cash flows used for the Regional Portfolio Model studies are based on a ten-year overall schedule, from initial development of the NRC Combined Construction and Operating License Application (COLA) to commercial operation. Development and construction activities are assumed to overlap to the extent practical to minimize the overall project lead time. For example, site preparation and construction of facilities not subject to NRC jurisdiction is assumed to commence as soon as state and local permits are received. The extent of assumed overlap is consistent with current practice.

> **Development** (Preparation of COLA to receipt of combined construction and operation license) - 60 mo. (final 12 mo. concurrent with Early Construction). 5% of total plant cost for the 48 months not concurrent with Early Construction.
>
> **Early Construction** (Final engineering, major equipment order, site preparation, interconnection, infrastructure construction, start construction of non-NRC jurisdictional facilities) - 24 mo., 30% of total plant cost
>
> **Committed Construction** (NRC jurisdictional construction to commercial operation) - 48 mo., 65% of total plant cost

Fuel Price: Currently operating commercial light water reactors in the United States are normally fuelled with a mixture of about 3 percent fissionable U-235 and 97 percent non-fissionable, but fertile U-238. The U-238 is transmuted to fissionable Pu-239 within the reactor by absorption of a neutron, internally extending the supply of fuel. Though reactors using thorium and “bred” plutonium have been developed in anticipation of eventual shortages of natural uranium, it appears that the industry can rely on abundant supplies of natural uranium for the foreseeable future. The price of fabricated nuclear fuel is forecast by EIA (EIA, 2008) to be stable through the planning period. The base price is $0.64/MMBtu in 2008, increasing slowly in real terms at an average of 0.8%/yr to $0.75 by 2030 (Table I-34).

Table I-34: Forecast nuclear fuel prices (2006$/MMBtu)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
$0.64	$0.68	$0.70	$0.70	$0.70	$0.69	$0.69	$0.70	$0.70	$0.71	$0.72	$0.73
2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	
$0.74	$0.75	$0.76	$0.77	$0.77	$0.77	$0.76	$0.76	$0.76	$0.75	$0.75	

Operating and Maintenance Costs: The fixed O&M cost for the reference plant is estimated to be $90/kW/yr (inclusive of decommissioning fund and exclusive of property tax and insurance). The non-fuel variable O&M cost is $1.00/MWh. The O&M costs are based on the average 2007 operating and maintenance costs for operating U.S. nuclear units reported by the Nuclear Energy Institute (www.nei.org). The spent fuel disposal fee (a variable cost) was subtracted from the reported total O&M costs to obtain the fixed cost component. The spent fuel disposal fee was converted to 2006$/MWh and rounded to the nearest dollar to obtain the variable cost component. The remaining fixed component was converted to $/kW/yr units assuming an 85% capacity factor. To this was added the estimated decommissioning fund contribution using the high-end plant decommissioning estimate ($500 million) reported on the NEI website and the conservative assumption of decommissioning at 40 years. The resulting sum was rounded up to the nearest dollar to obtain estimated fixed O&M costs.[36]

Fixed costs are assumed to vary with total plant costs in real terms. Variable O&M costs are assumed to remain constant in real terms.

Economic Life: The economic life of a new nuclear unit is assumed to be 30 years. This is likely to be a conservative assumption as the design operating lifetime of new nuclear units is 60 years and the original 40-year operating licenses of existing units are, in most cases, being extended to 60 years.

Developable Potential: In terms of fuel supply and suitable sites, new nuclear units could serve all new electrical needs of the Northwest through the planning period, including scenarios where a substantial portion of existing coal capacity is curtailed or retired to reduce CO2 production. The principal limiting factor would be the earliest date that new nuclear capacity could be brought into service. A combined construction and development period of less than ten years is unlikely, so the earliest plausible service year is 2020. As a practical matter, committed construction of a Northwest unit is unlikely in advance of successful completion and operation of at least one of the proposed new units elsewhere in the United States, an established federal policy regarding spent fuel and aggressive development of equally cost-effective conservation and renewable resources. These conditions would likely preclude operation of a new conventional nuclear plant in the Northwest prior to the early to mid-2020s. 2023 was used as the earliest service year for portfolio studies.

[36] Following the development of the nuclear O&M estimates, it was learned that the NEI values are based on FERC Form 1 reporting and may not include administrative and general costs nor interim capital replacement costs.

Levelized cost summary: The estimated levelized lifecycle cost of delivered energy from advanced nuclear power plants is shown in Table I-35. The cost estimates are based on investor-owned utility financing and and 85% capacity factor.

Table I-35: Levelized Cost of Advanced Nuclear Power Plants

Service Year	Plant Busbar ($/MWh)	Ancillary Services and Integration ($/MWh)	Transmission and Losses ($/MWh)	Emissions ($/MWh)	Total ($/MWh)
2010	n/av	n/av	n/av	n/av	n/av
2015	n/av	n/av	n/av	n/av	n/av
2020	n/av	n/av	n/av	n/av	n/av
2025	$102.53	$1.00	$4.34	$0.00	$108
2030	$102.53	$1.01	$4.35	$0.00	$108

GLOSSARY

Definitions of terms used in this appendix. The definitions below are generally consistent with usage within the industry. In certain cases, however, the definitions used in the Plan may differ somewhat from the definitions as used elsewhere in the industry because of the nature of the Council's models or the societal cost perspective of the Power Plan.

Engineering, Procurement and Construction (EPC) Costs: EPC costs include direct and indirect costs of plant construction, engineering, procurement and fees, often covered under a single contract. Direct construction costs include the costs of field labor, equipment, materials and supplies for construction. Indirect construction costs include construction supervision, payroll burdens, tools, facilities and field engineering.

Gas Turbine: A gas turbine (also known as a combustion turbine) is a rotating continuous flow internal combustion engine based on an open Brayton thermodynamic cycle. A gas turbine consists of a rotating air compressor to increase the pressure of incoming air; a fuel combustor to increase the temperature of the compressed air, and a gas turbine through which the heated, compressed air is expanded to produce mechanical energy. A portion of the mechanical energy produced by the gas turbine is used to power the inlet air compressor and the remaining portion is used to drive a load. In a gas turbine used for electric power generation, the load is an electric power generator.

Heat Rate: A measure of thermal efficiency, in British thermal units of fuel energy consumed per kilowatt-hour of electricity produced (Btu/kWh). A kilowatt-hour of electricity is equivalent to 3413 Btu, so a plant with a heat rate of 7000 Btu/kWh would operate at a thermal efficiency of 48.8%. Unless otherwise indicated, in this report, heat rate is expressed on the basis of the higher heating value (HHV) of the fuel.

Owner's Costs: Costs incurred directly by the project developer. Owners Costs include including permits and licenses, land and right-of-way acquisition, economic and other social justice costs, project development costs, legal fees, owners engineering, project and construction management staff, startup costs, site infrastructure (transmission, road, water, rail, waste water disposal, etc.), taxes, spares, and furnishings. Because the Council's planning models test the cost-effectiveness of resource options at different points in time, the escalation and interest incurred during construction are not included in the base year Owners Costs.

Overnight Costs: Plant construction costs exclusive of escalation and interest incurred during construction. The cost of construction as if incurred instantaneously. Sometimes called instantaneous costs.

Total Plant Cost: The sum of direct and indirect engineering, procurement and construction (EPC) costs, contingencies and Owner's Costs, exclusive of escalation and interest during construction.

Total Plant Investment: The sum of engineering, procurement and construction costs, owner's costs, financing costs, escalation and interest during construction. Total Plant Investment costs will be in nominal (current) dollars and will vary by year of plant service.

REFERENCES

Black & Veatch. *Arizona Renewable Energy Assessment*. Prepared for Arizona Public Service Company, Salt River Project and Tucson Electric Power Corporation. September 2007.

Black & Veatch. *Solar Generation Technology Assessment*. Prepared for Idaho Power Company. September 2008.

Bonneville Power Administration (BPA). *Open Access Transmission Tariff*. October 2008

Bonneville Power Administration (BPA). 2010 *Transmission and Ancillary Service Rate Schedules*. October 2009.

California Energy Commission (CEC). Comparative Costs of California Central Station Electricity Generation Technologies. December 2007.

Colorado Energy News . "Tri-State partners on heat recovered energy generation". June 25, 2009.

EcoSecurities Consulting Limited. *CO2 Capture and Storage - An Overview of Information Available for the Western U.S.* Prepared for the Northwest Power and Conservation Council. January 2009.

Energy Trust of Oregon (ETO). Sizing and Characterizing the Market for Oregon Biopower Projects. April 2005.

Gas Turbine World. Gas Turbine World. *2009 GTW Handbook*. 2009.

Gas Turbine World. Gas Turbine World. *2007-08 GTW Handbook*. 2007.

Idaho Statesman. "In Ada county, landfill turns trash to cash." January 1, 2009.

IHS CERA. "IHS CERA Power capital costs index shows construction costs falling for all Types of new power plants" Press release June 23, 2009.

International Energy Agency. Prospects for CO2 Capture and Storage. 2004.

International Energy Agency (2008a). *CO2 Capture and Storage*. 2008.

International Energy Agency (2008b). *Energy Technology Perspectives*. 2008.

Interstate Natural Gas Association of America (INGAA). Waste Energy Recovery Opportunities for Interstate Natural Gas Pipelines. February 2008.

Keyspan. Comments of Keyspan Ravenswood, Initial NERA/Sergent and Lundy Presentation to the NYISO ICAPWG, December 21, 2006. Letter dated January 8, 2007.

Kirby, Brendon. *Ancillary Services: Technical and Commercial Insights*. Prepared for Wartsila. July 2007.

Lazard. Levelized Cost of Energy Analysis - Version 2.0. June 2008.

Massachusetts Institute of Technology (MIT). The Future of Coal. 2007.

National Energy Technology Laboratory (NETL). *Cost and Performance Baseline for Fossil Energy Plants* DOE/NETL-2007/1281. Revision 1, August 2007

National Renewable Energy Laboratory (NREL). Economic, Energy, and Environmental Benefits of Concentrating Solar Power in California. NREL/SR-550-39291. April 2006

Navigant Consulting. *Arizona Solar Electric Roadmap Study*. Prepared for Arizona Department of Commerce. January 2007.

NERA Economic Consulting. Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator. August 2007.

Northwest Power and Conservation Council (NPCC). *Fifth Northwest Electric Power and Conservation Plan* (Document 2005-7). May 2005.

Northwest Power and Conservation Council (NPCC). *Biennial Monitoring Report on the Fifth Power Plan* (Document 2007-4). January 2007.

Northwest Power Pool Northwest Transmission Assessment Committee (NTAC). *Canada-Northwest-California (C-N-C) Study Group Options Analysis Workbook.* May 2006. (http://www.nwpp.org/ntac/publications.html)

Northwest Power Pool Northwest Transmission Assessment Committee (NTAC). *Montana Transmission Study Group Montana-NW Equal Angle Study Final Report.* October 2005. (http://www.nwpp.org/ntac/publications.html)

Nuclear Energy Institute (NEI). The Cost of New Generating Capacity in Perspective. August 2008.

Oak Ridge National Laboratory (ORNL). Subcontractor Report: National Account Energy Alliance Final Report for the Basin Electric Project at Northern Border Pipeline Company's Compressor Station #7, North Dakota ORNL/TM-2007/158. December 2007.

Oregon State University. Oregon-NASA Space Grant Consortium. *Columbia River Flood Basalt Province, Idaho, Washington, Oregon, USA* . http://volcano.oregonstate.edu/vwdocs/volc_images/north_america/crb.html

Phung, Duon. *A Method for Estimating Escalation and Interest During Construction* ORAU/IEA-78-7(M). Oak Ridge Associated Universities Institute for Energy Analysis. 1978.

Port of Port Angeles. Biomass Cogeneration Feasibility Study. March 2009.

TransCanada. NorthernLights HVDC Project: WECC Comprehensive Progress Report. November 2008.

U.S. Army Corps of Engineers (USACE). *Civil Works Construction Cost Index System (CWCCIS) EM1110-2-1304*, Table A-3. March 2000, revised March 2008.

U.S. Department of Energy Energy Information Administration (EIA). *Annual Energy Outlook 2008* DOE/EIA-0383(2008). June 2008.

U.S. Department of Energy Office of Fossil Energy. 2008 Carbon Sequestration Atlas of the United States and Canada - Second Edition. October 2008.

U.S. Environmental Protection Agency (USEPA). Market Opportunities for Biogas Recovery Systems EPA-430-8-06-004. (Undated)

U.S. Environmental Protection Agency. Opportunities for and Benefits of Combined Heat and Power at Wastewater Treatment Facilities. April 2007.

U.S. Environmental Protection Agency. Environmental Footprints and Costs of Coal-based Integrated Gasification, Combined Cycle and Pulverized Coal Technologie EPA-430/R-06/006. July 2006.

Western Electricity Coordinating Council (WECC). *TEPPC Renewable Energy Cases.* September 2008.

Western Governors' Association (WGA). Clean and Diversified Energy Initiative Biomass Task Force Report Supply Addeddum. January 2006.

Westinghouse Electric Co. The Westinghouse AP1000 Advanced Nuclear Plant. 2003.