Northwest Power Planning Council
New Resource Characterization for the Fifth Power Plan

Natural Gas Combined-cycle Gas Turbine Power Plants

August 8, 2002

This paper describes the technical characteristics and cost and performance assumptions to be used by the Northwest Power Planning Council for new natural gas combined-cycle gas turbine power plants. The intent is to characterize a facility typical of those likely to be constructed in the Western Electricity Coordinating Council (WECC) region over the next several years, recognizing that each plant is unique and that actual projects may differ from these assumptions. These assumptions will be used in our price forecasting and system reliability models and in the Council's periodic assessments of system reliability. The Council may also use these assumptions in the assessment of other issues where generic information concerning natural gas combined-cycle power plants is needed. Others may use the Council's technology characterizations for their own purposes.

A combined-cycle gas turbine power plant consists of one or more gas turbine generators equipped with heat recovery steam generators to capture heat from the gas turbine exhaust. Steam produced in the heat recovery steam generators powers a steam turbine generator to produce additional electric power. Use of the otherwise wasted heat in the turbine exhaust gas results in high thermal efficiency compared to other combustion-based technologies. Combined-cycle plants currently entering service can convert about 50 percent of the chemical energy of natural gas into electricity (HHV basis[1]). Additional efficiency can be gained in combined heat and power (CHP) applications (cogeneration), by bleeding steam from the steam generator, steam turbine or turbine exhaust to serve direct thermal loads[2].

A single-train combined-cycle plant consists of one gas turbine generator, a heat recovery steam generator (HSRG) and a steam turbine generator ("1 x 1" configuration). Using "FA-class" combustion turbines - the most common technology in use for large combined-cycle plants - this configuration can produce about 270 megawatts of capacity at reference ISO conditions[3]. Increasingly common are plants using two or even three gas turbine generators and heat recovery steam generators feeding a single, proportionally larger steam turbine generator. Larger plant sizes result in economies of scale for

[1] The energy content of natural gas can be expressed on a higher heating value or lower heating value basis. Higher heating value includes the heat of vaporization of water formed as a product of combustion, whereas lower heating value does not. While it is customary for manufacturers to rate equipment on a lower heating value basis, fuel is generally purchased on the basis of higher heating value. Higher heating value is used as a convention in Council documents unless otherwise stated.
[2] Though increasing overall thermal efficiency, steam bleed for CHP applications will reduce the electrical output of the plant.
[3] International Organization for Standardization reference ambient conditions: 14.7 psia, 59^{o} F, 60% relative humidity.

construction and operation, and designs using multiple combustion turbines provide improved part-load efficiency. A 2 x 1 configuration using FA-class technology will produce about 540 megawatts of capacity at ISO conditions. Other plant components include a switchyard for electrical interconnection, cooling towers for cooling the steam turbine condenser, a water treatment facility and control and maintenance facilities.

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

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

The principal environmental concerns associated with gas-fired combined-cycle gas turbines are emissions of nitrogen oxides (NOx) and carbon monoxide (CO). Fuel oil operation may produce sulfur dioxide. Nitrogen oxide abatement is accomplished by use of "dry low-NOx" combustors and a selective catalytic reduction system within the HSRG. Limited quantities of ammonia are released by operation of the NOx SCR system. CO emissions are typically controlled by use of an oxidation catalyst within the HSRG. No special controls for particulates and sulfur oxides are used since only trace amounts are produced when operating on natural gas. Fairly significant quantities of water are required for cooling the steam condenser and may be an issue in arid areas. Water consumption can be reduced by use of dry (closed-cycle) cooling, though with cost and efficiency penalties. Gas-fired combined-cycle plants produce less carbon dioxide per unit energy output than other fossil fuel technologies because of the relatively high thermal efficiency of the technology and the high hydrogen-carbon ratio of methane (the primary constituent of natural gas).

Because of high thermal efficiency, low initial cost, high reliability, relatively low gas prices and low air emissions, combined-cycle gas turbines have been the new resource of choice for bulk power generation for well over a decade. Other attractive features include significant operational flexibility, the availability of relatively inexpensive power augmentation for peak period operation and relatively low carbon dioxide production. Combined-cycle power plants are an increasingly important element of the Northwest power system, comprising about 87 percent of generating capacity currently under construction. Completion of plants under construction will increase the fraction of gas-fired combined-cycle capacity from 6 to about 11 percent of total regional generating capacity.

Proximity to natural gas mainlines and high voltage transmission is the key factor affecting the siting of new combined-cycle plants. Secondary factors include water availability, ambient air quality and elevation. Initial development during the current construction cycle was located largely in eastern Washington and Oregon with particular focus on the Hermiston, Oregon crossing of the two major regional gas pipelines. Development activity has shifted to the I-5 corridor, perhaps as a response to east-west transmission constraints and improving air emission controls.

Issues associated with the development of additional combined-cycle capacity include uncertainties regarding the continued availability and price of natural gas, volatility of natural gas prices, water consumption and carbon dioxide production. A secondary issue has been the ecological and aesthetic impacts of natural gas exploration and production. Though there is some evidence of a decline in the productivity of North American gas fields, the continental supply appears adequate to meet needs at reasonable price for at least the 20-year period of the Council's power plan. Importation of liquefied natural gas from the abundant resources of the Middle East and the former Soviet states and could enhance North American supplies and cap domestic prices. The Council forecasts that US wellhead gas prices will escalate at an annual rate of about 0.9% (real) over the period 2002 - 21. Though expected to remain low, on average, natural gas prices have demonstrated both significant short-term volatility and longer-term, three to four year price cycles. Both effects are expected to continue. Additional discussion of natural gas availability and price is provided in the Council issue paper Draft Fuel Price Forecasts for the Fifth Power Plan (Document 2002-07). The conclusions of the paper with respect to natural gas prices are summarized in Appendix A of this document.

Water consumption for power plant condenser cooling appears to be an issue of increasing importance in the west. As of this writing, water permits for two proposed combined-cycle projects in northern Idaho have been recently denied, and the water requirement of a proposed central Oregon project is highly controversial. Significant reduction in plant water consumption can be achieved by the use of closed-cycle (dry) cooling, but at a cost and performance penalty. Over time it appears likely that an increasing number of new combined-cycle projects will use dry cooling.

Carbon dioxide, a greenhouse gas, is an unavoidable product of combustion of any power generation technology using fossil fuel. The carbon dioxide production of a gas-fired combined-cycle plant on a unit output basis is much lower than that of other fossil fuel technologies. The reference plant, described below, would produce about 0.8 lb CO_2 per kilowatt-hour output, whereas a new coal-fired power plant would produce about 2 lb CO_2 per kilowatt-hour. To the extent that new combined-cycle plants substitute for existing coal capacity, they can substantially reduce average per-kilowatt-hour CO_2 production.

The proposed reference plant is based on the General Electric 7FA gas turbine generator in 2 x 1 combined-cycle configuration. The baseload capacity is 540 megawatts and the plant includes an additional 70 MW of power augmentation using duct burners. The plant is fuelled with pipeline natural gas using a firm gas transportation contract with capacity release provision. No backup fuel is provided. Air emission controls include dry low-NOx combustors and selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC control. Condenser cooling is wet mechanical draft. Specific characteristics of the reference plant are shown in Table 1.

Table 1
Resource characterization: Natural gas combined-cycle gas turbine power plant

Facility description and basic assumptions		
Facility	Natural gas-fired combined-cycle gas turbine power plant. 2 GT x 1 ST configuration. 7FA gas turbine technology. 540 MW new & clean baseload output @ ISO conditions, plus 70 MW of capacity augmentation (duct-firing). No cogeneration load. Dry SCR for NOx control, CO catalyst for CO control. Wet mechanical draft cooling.	
Fuel	Pipeline natural gas. Firm transportation contract with capacity release provisions.	See Appendix A for a summary of the gas price forecast and structure.
Project developer	Consumer-owned utility: 5% Investor-owned utility: 5% Independent power producer: 90%	See Appendix B for project financing assumptions.
Technology base year	2000	Representative of projects entering service in 2002 (2000 vintage equipment).
Price base year	2002	Representative of projects entering service in 2002.
Year dollars	2000	5th Plan year dollars.
Service life	30 years	

Technical Performance		
Net power	New & clean: 540 MW (baseload), 610 MW (peak) Lifetime average: 528 MW (baseload), 597 MW (peak)	Lifetime average based on 1 % degradation per year, 98.75% recovery at hot gas path inspection or major overhaul. GE data.
Operating limits	Minimum load: 40 %. Cold start: 3 hours Ramp rate: 7 %/min	Minimum load: One GT in service, point of minimum constant firing temperature operation.
Scheduled outages	Scheduled outage factor: 4% (15 days/yr).	Based on a planned maintenance schedule of a 7-day annual inspection, a 10-day hot gas path inspection & overhaul every third year and a 28-day major overhaul every sixth year. Planned maintenance intervals are GE baseline recommendations for baseload service. In addition, assumes two additional 28-day scheduled outages and one 90-day plant rebuild during the 30-year plant life.
Forced outages	Forced outage rate: 4% Mean time to repair: 24 hours	NERC Generating Availability Data System (GADS) weighted average equivalent forced outage rate for combined-cycle plants, reduced to account for improving availability of combined-cycle plants. Mean time to repair is GADS average for full outages.
Availability	92%	Estimated lifetime average equivalent annual availability at the busbar.
Heat rate (HHV, net, ISO conditions)	New & clean (Btu/kWh): 6880 (baseload); 9290 (incremental duct firing); 7180 (full power) Lifetime average (Btu/kWh): 7030 (baseload); 9500 (incremental duct firing); 7340 (full power)	Baseload is current new & clean rating for GE 207FA. Lifetime average is new & clean value derated by 2.2%. Degradation estimates are from GE. Duct firing heat rate is GRAC recommendation.
Vintage heat rate improvement.	2002-25 annual average: -0.6%.	Assume 7B technology full commercial by 2005; 7H by 2010; asymptotic to ultimate potential by 2060.

Seasonal power output	Seasonal power output factors for selected WECC locations are shown in Figure 1.	Based on power output ambient temperature curve for GE STAG combined-cycle plant using 30-year monthly average temperatures.
Elevation adjustment for power output	See Table 2 for power output elevation correction factors for selected WECC locations.	Based on standard gas turbine altitude correction curve.

Costs & development schedule		
Development & construction cost	Baseload configuration: $565/kW (overnight); 621 $/kW (all-in). Power augmentation configuration: $525/kW (overnight); 577 $/kW (all-in).	Excludes financing fees and interest during construction. Assumes "equilibrium" market conditions. Normalized cost of a 1x1 plant estimated to be 110% of example plant costs. Incremental cost of power augmentation using duct burners $225/kW. Values are based on new and clean rating.
Lead time	Development: 24 months Construction: 24 months	
Development and construction annual cash flow	1%/1%/59%/39%	
Capital replacement cost	$1.60/kW/yr[1]	Levelized equivalent of 10% of initial capital investment in Year 15. Value is based on new and clean rating.
Fixed operating costs	Baseload configuration: $7.25/kW/yr. Power augmentation configuration: $6.50/kW/yr.	Includes operating labor, routine maintenance, general & overhead, fees, contingency and an allowance for startup costs and average sales tax. Excludes property taxes and insurance (separately calculated in the Council's models). Normalized fixed O&M cost for a 1x1 plant estimated to be 167% of that for the example 2x1plant. Values are based on new and clean rating.
Variable operating costs	$2.80/MWh	Includes consumables, SCR catalyst replacement, makeup water and wastewater disposal costs, long-term major equipment service agreement, contingency and an allowance for sales tax. Excludes any

		greenhouse gas fees.
Interconnection and regional transmission costs	$15.00/kW/yr	Bonneville point-to-point transmission rate (PTP-02) plus Scheduling, System Control and Dispatch, and Reactive Supply and Voltage Control ancillary services, rounded. Omit for busbar calculations. Value is based on new and clean rating.
In-region transmission losses	1.9%	Omit for busbar calculations.
Vintage cost reduction	2002-25 annual average: -0.6% (capital and fixed O&M costs)	Assumes cost reductions related to increase in gas turbine specific work by factor of 0.3. Assumes 7B technology full commercial by 2005; 7H by 2010; asymptotic to ultimate potential by 2060.

Emissions (Plant site, excluding gas production & delivery)		
Particulates (PM-10)	Typical actual: 0.007 T/GWh	Typical permit limits, baseload operation: 0.02 T/GWh
SOx	Typical actual: 0.002 T/GWh	Typical permit limits, baseload operation: 0.02 T/GWh
NOx	Typical actual: 0.039 T/GWh	Typical permit limits, baseload operation: 0.04 T/GWh
CO	Typical actual: 0.005 T/GWh	Typical permit limits, baseload operation: 0.04 T/GWh
Hydrocarbons/VOC	Typical actual: 0.0003 T/GWh	Typical permit limits, baseload operation: 0.01 T/GWh
Ammonia	Typical actual: 0.0000006 T/GWh	Slip from catalyst. Typical permit limits, baseload operation: 0.004 T/GWh
CO_2	411 T/GWh (baseload operation) 429 T/GWh (full power operation)	Based on EPA standard fuel carbon content assumptions and lifecycle average heat rates.
Availability for future development		
Site Availability 2001 - 2020	Initially not limited.	Extent of future development to be tested in AURORA runs. If the resulting development significantly exceeds the inventory of currently or likely permitted sites in any load-resource area this issue will be revisited.

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

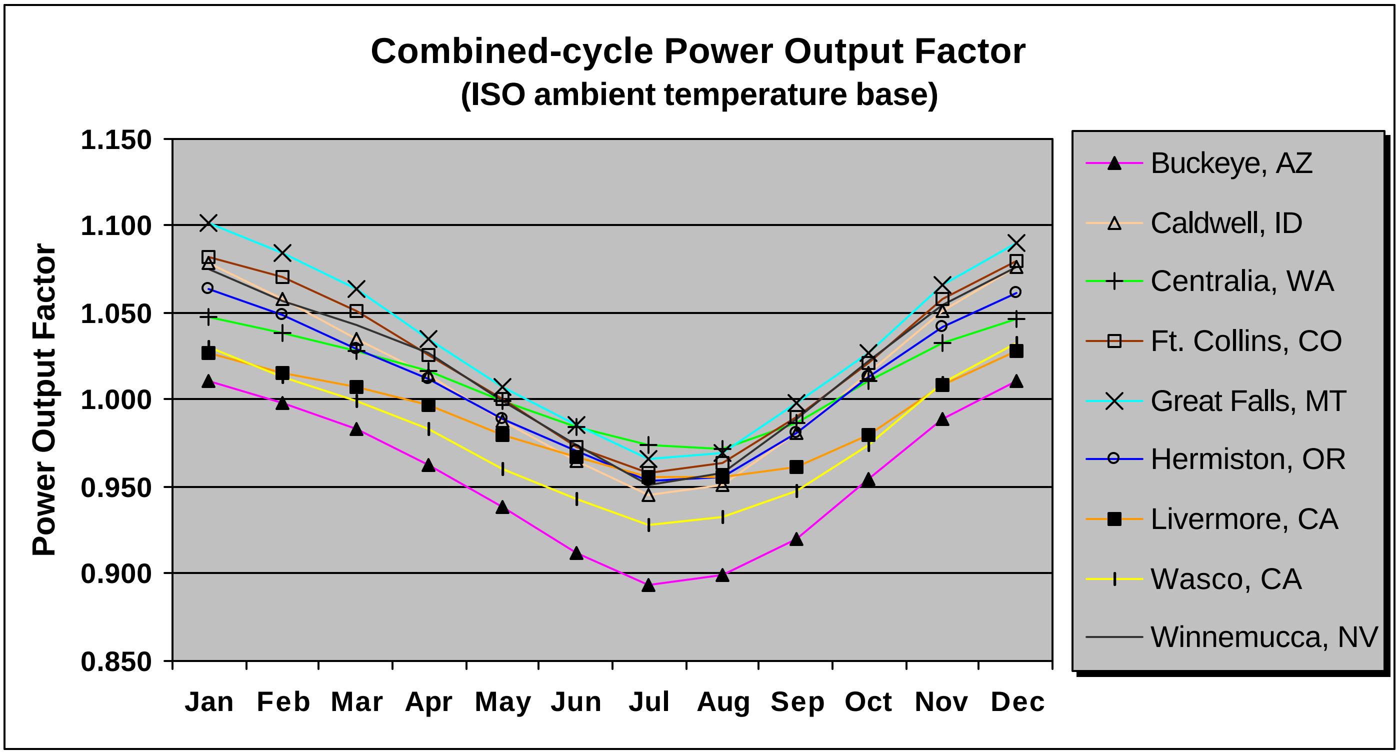

Table 2
Gas turbine power output elevation correction factors for selected locations

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

APPENDIX A
SUMMARY OF THE NATURAL GAS PRICE FORECAST

This appendix summarizes the natural gas price forecast used by the Council for modeling the cost of power from combined-cycle power plants. More detail is provided in the Council's issue paper *Draft Fuel Price Forecasts for the 5th Northwest Conservation and Electric Power Plan (Document 2002 - 07)*.

The natural gas prices used by the Council are based on forecast average U.S. wellhead prices. The forecast wellhead price is adjusted by a series of basis differentials to yield delivered gas prices for various geographic areas of western North America. Figure A-1 shows the relationships between wellhead price forecasts and the various pricing points.

Figure A-1
Structure used to establish delivered natural gas prices
(Medium case, 2005, rolled-in pipeline capacity costs, 2000$ per MMBtu)

	Basis Differential	Delivery Cost	2005 Price
Wellhead			$3.00
Henry Hub	$0.12		$3.12
AECO (AB)	($0.45)		$2.67
Station 2	$0.10[4]		$2.77
Sumas (BC)		$0.26	$3.03
West-side PNW		$0.68[5]	$3.45
East-side PNW		$0.39[6]	$3.06
Northern CA		$0.80	$3.47
San Juan	($0.26)		$2.86
CO		$0.36	$3.22
Rockies	($0.40)		$2.72
UT		$0.35	$3.07
WY		$0.40	$3.12
MT		$0.33	$3.05
Southern ID		$0.35	$3.07
Permian	($0.17)		$2.95
CA Border		$0.33	$3.28
Southern CA& Baja		$0.05	$3.33
AZ		$0.32	$3.27
NM		$0.24	$3.19
NV		[illegible]	[illegible]

[4] Annual average differential. Typically $0.20 during winter season and $0.00 during summer season.
[5] Incremental pipeline capacity pricing (applied to new power projects). Differential for rolled-in pricing (applied to existing) is $0.63, yielding delivered price of $3.40.

Price forecast cases

The wellhead prices shown in Figure A-1 are from the medium case forecast for 2005. Wellhead prices for all five forecasts cases are shown in Table A-1.

Table A-1
U.S. Average wellhead natural gas price forecasts
(2000$ Per MMBtu)

Year	Low	Med-Lo	Medium	Med-Hi h	High
2000	3.60	3.60	3.60	3.60	3.60
2001	4.03	4.03	4.03	4.03	4.03
2002	2.35	2.45	2.70	2.80	2.90
2003	2.80	3.00	3.20	3.35	3.50
2004	2.70	2.90	3.10	3.25	3.30
2005	**2.50**	**2.80**	3.00	**3.15**	**3.24**
2006	2.46	2.76	3.00	3.16	3.27
2007	2.42	2.72	3.00	3.17	3.30
2008	2.38	2.68	3.00	3.18	3.34
2009	2.34	2.64	3.00	3.19	3.37
2010	**2.30**	**2.60**	3.00	**3.20**	**3.40**
2011	2.32	2.62	3.03	3.23	3.44
2012	2.34	2.64	3.06	3.26	3.48
2013	2.36	2.66	3.09	3.29	3.52
2014	2.38	2.68	3.12	3.32	3.56
2015	**2.40**	**2.70**	3.15	**3.35**	**3.60**
2016	2.42	2.74	3.16	3.38	3.64
2017	2.44	2.78	3.17	3.41	3.68
2018	2.46	2.82	3.18	3.44	3.72
2019	2.48	2.86	3.19	3.47	3.76
2020	**2.50**	**2.90**	3.20	**3.50**	**3.80**
2021	2.52	2.92	3.22	3.52	3.84
2022	2.54	2.94	3.24	3.54	3.88
2023	2.56	2.96	3.26	3.56	3.92
2024	2.58	2.98	3.28	3.58	3.96
2025	**2.60**	**3.00**	3.30	**3.60**	**4.00**

The Henry Hub-to-AECO basis differential changes with forecast case (Table A-2). The other differentials are constant over the five forecast cases.

[6] Incremental pipeline capacity pricing (applied to new power projects). Differential for rolled-in pricing (applied to existing) is $0.36, yielding delivered price of $3.03.

Table A-2
Henry Hub to AECO Basis Differential
(2000$ Per MMBtu)

Low	$-.60
Medium Low	$-.55
Medium	$-.45
Medium High	$-.30
High	$-.20

All differentials are assumed to be seasonally constant except for the Station 2-to-AECO differential. The Station 2 price will be $ 0.20 higher than AECO during the winter season, and about equal in summer. The annual average Station 2-to-AECO basis differential is assumed to be $0.10. Though as of this writing we are assuming no seasonality of wellhead prices, the seasonal characteristics of wellhead prices is being investigated.

All differentials are assumed to be constant over time, except for the Pacific Northwest eastside and Westside delivery differentials, where we seek greater modeling detail. For the Northwest, we assume that operators of existing power plants see rolled-in pipeline capacity costs, whereas developers of new plants would see incremental pipeline capacity costs. (Pipeline capacity costs comprise most, but not all of the delivery costs shown in Figure 1. Other cost components include the pipeline commodity charge and in-kind transportation fuel costs). Rolled-in capacity costs are assumed to be constant through time. Incremental capacity costs are assumed to escalate slightly through time. Incremental Pacific Northwest pipeline capacity costs (eastside and westside) are forecast to escalate at an average annual rate of 0.66% for the period 2006 - 2025.

Example delivered prices

Net delivered prices for the Pacific Northwest Westside (Western Washington and Oregon) and Eastside (Eastern Washington and Oregon and Northern Idaho) areas are shown in Table A-3. The prices of Table A-3 are based on incremental pipeline capacity costs, as assumed for new power projects.

Table A-3
Net Pacific Northwest delivered natural gas prices (incremental pipeline capacity)
(Medium case, 2000$ Per MMBtu)

	U.S. Wellhead	AECO Price	Station 2 Price	West-Side Delivered	East-Side Delivered
2000	3.60	3.37	3.47	4.13	3.75
2001	4.03	4.05	4.15	4.85	4.48
2002	2.70	2.37	2.47	3.09	2.75
2003	3.20	2.87	2.97	3.61	3.26
2004	3.10	2.77	2.87	3.56	3.16
2005	3.00	2.67	2.77	3.45	3.06
2006	3.00	2.67	2.77	3.55	3.15
2007	3.00	2.67	2.77	3.56	3.15
2008	3.00	2.67	2.77	3.56	3.15
2009	3.00	2.67	2.77	3.57	3.16
2010	3.00	2.67	2.77	3.57	3.16
2011	3.03	2.70	2.80	3.60	3.19
2012	3.06	2.73	2.83	3.64	3.23
2013	3.09	2.76	2.86	3.68	3.26
2014	3.12	2.79	2.89	3.71	3.29
2015	3.15	2.82	2.92	3.75	3.33
2016	3.16	2.83	2.93	3.76	3.34
2017	3.17	2.84	2.94	3.78	3.35
2018	3.18	2.85	2.95	3.79	3.37
2019	3.19	2.86	2.96	3.81	3.38
2020	3.20	2.87	2.97	3.82	3.39
2021	3.22	2.89	2.99	3.85	3.42
2022	3.24	2.91	3.01	3.87	3.44
2023	3.26	2.93	3.03	3.90	3.47
2024	3.28	2.95	3.05	3.93	3.49
2025	3.30	2.97	3.07	3.95	3.51

Fixed cost component

The prices shown above are expressed in variable cost terms (Btu/kWh). In actuality, a portion of the fuel price will be fixed, and will have to be paid whether or not the plant is operating. We assume that the firm pipeline transportation component of the fuel price is a fixed payment, but that a portion of this payment can be recaptured through the capacity release market. Thus the only fixed portion of the fuel price with respect to plant dispatch decisions is the portion of the fuel transportation cost that is not recoverable in the capacity release market.

We assume that the total firm transportation costs comprise 90 percent of the delivery costs shown in Figure A-1. We assume that 10 percent of this cost can typically be recaptured in the capacity release market.

APPENDIX B
PROJECT FINANCING ASSUMPTIONS: COMBINED-CYCLE PROJECTS

Developer:	**Consumer-owned Utility**	**Investor-owned Utility**	**Independent Developer**
General			
General inflation	2.5%		
Debt financing fee	2.0%		
Project financing terms			
Debt repayment period	20 years	20 years	20 years[7]
Capital amortization period		20 years	20 years
Debt/Equity ratio	100%	50%/50%	Development: 0%/100% Construction: 60%/40% Long-term: 60%/40%
Interest on debt (real/nominal)			Development: n/a Construction: 6.3%/9.0% Long-term financing: 6.1%/8.7%
Return on equity (real/nominal)			14.4/17.3%
After-tax cost-of-capital (real/nominal)	3.9%/6.5%	5.2%/7.9%	7.5%/10.2%
Discount Rate (real/nominal)	3.9%/6.5%	5.2%/7.9%	7.5%/10.2%
Taxes & insurance assumptions			
Federal income tax rate	n/a	34%	34%
Federal investment tax credit	n/a	0%	0%
Tax recovery period	n/a	20 years	20 years
State income tax rate	n/a	3.7%	3.7%
Property tax	0%	1.4%	1.4%
Insurance	0.3%	0.3%	0.3%

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[7] Long-term debt. Construction debt is assumed to be refinanced at completion of construction.