2012 BPA Rate Case
Customer Workshop

Marginal Demand Price Signal

May 26, 2010

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Tiered Rate Methodology Language

- 5.3.6 Demand Rate

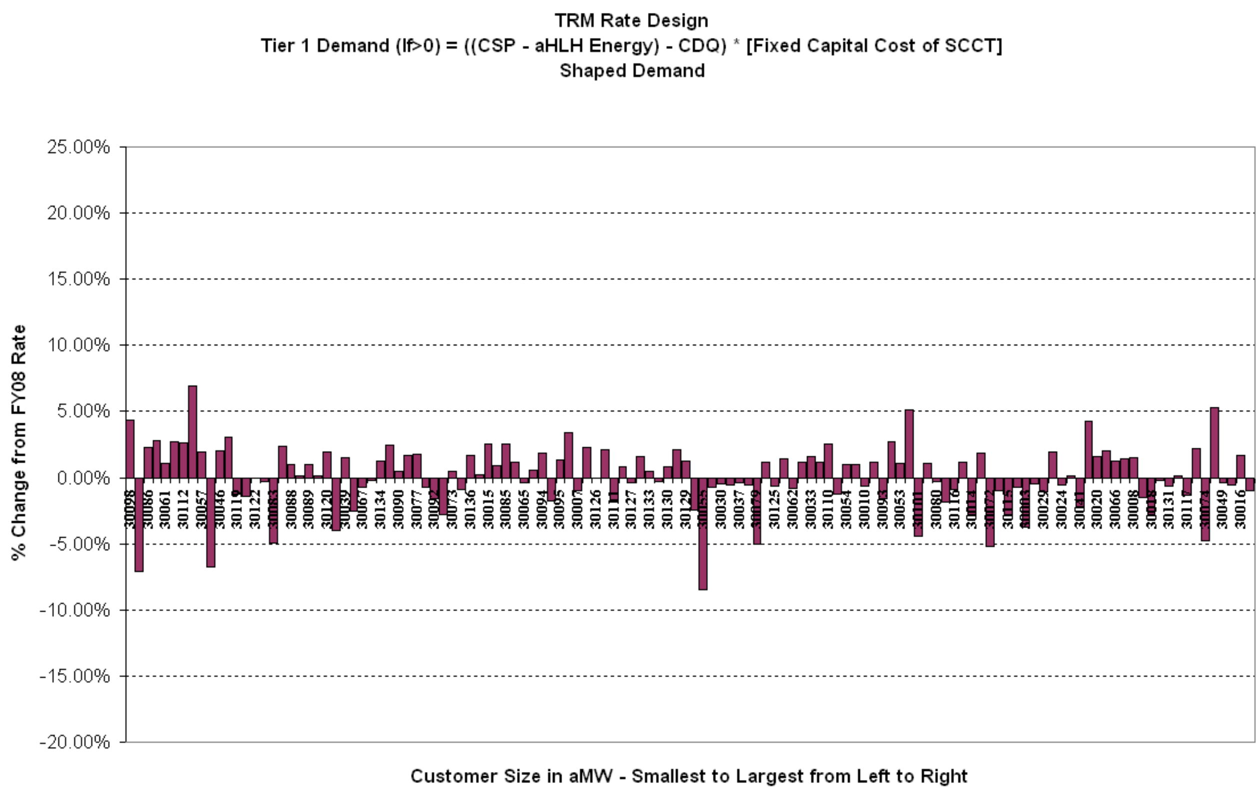
  BPA will base the Demand Rate on the annual fixed costs (capital and O&M) of the marginal capacity resource as determined in each 7(i) Process. BPA will identify the marginal capacity resource and the annual fixed costs associated with that resource for each Rate Period. To determine the Demand Rate, BPA will spread such annual fixed costs to months in proportion to the monthly Heavy Load Hour energy prices used to set the Load Shaping Rates. Such marginal capacity resource may be based on BPA's Resource Program and/or costs of BPA's recent capacity additions. Or it may be based on third-party sources, which may include, but are not limited to, the Energy Information Administration, EPRI Technical Assessment Guide, the Northwest Power and Conservation Council, and Integrated Resource Plans of Pacific Northwest electric utilities. The shape of the Demand Rate may be subject to a dampening methodology proposed in each 7(i) Process if there proves to be significant volatility in the shape of the Demand Rate from Rate Period to Rate Period. Alternatively, BPA may base the Demand Rate on the market price for capacity if a viable capacity market develops in the Pacific Northwest.

Tiered Rate Methodology Language (continued)

- 8 RESOURCE SUPPORT SERVICES AND RESOURCE SHAPING CHARGE:
  Unless a different pricing approach is specifically set forth in section 8.4, the capacity component of each RSS service will be priced at the Demand Rate, and the energy component will be priced at the market price of energy for the appropriate time period for the particular RSS service.

TRM Rate Design and Rate Impacts

In 2007, BPA conducted multiple rate impact tests to illuminate how different TRM rate designs impacted our different customers. The graph below was the last rate impact conducted and represents the rate design captured in the TRM. An average monthly demand rate of $8.50/kW/mo was used for this analysis. Absent cost changes, the customers and BPA attempted to create a TRM rate design that kept the majority of customer rate impacts within plus or minus 5% when compared to the WP-07 rate design.



Helpful Definitions to Create Apples-to-Apples Comparisons

- Understanding the cost of new generating capacity and its output requires careful analysis of what is in any set of figures.
  - **Engineering-Procurement-Construction (EPC Cost) -** the bare plant
  - **Owner's Cost** - land, cooling infrastructure, administration and associated buildings, site works, switchyards, project management, licenses, cost escalation and inflation. (Owner's costs may include transmission infrastructure, though strictly this is extrinsic.)
  - **Overnight Cost -** EPC cost plus owner's costs and excluding financing, escalation due to increased material and labor costs, and inflation.
  - **All-in Cost -** adds to overnight cost any escalation and interest during construction and up to the start of construction. It is expressed in the same units as overnight cost and is useful for identifying the total cost of construction and for determining the effects of construction delays.

Source: http://www.world-nuclear.org/info/inf02.html

Helpful Definitions to Create Apples-to-Apples Comparisons (continued)

- **Instant Cost -** sometimes referred to as **overnight cost** [**emphasis added**], is the initial capital expenditure. The instant costs do not include the costs incurred during construction (see installed cost). Instant costs include all costs: the component cost, land cost, development cost, permitting cost, connection equipment such as transmission, and environmental control costs.

- **Installed Cost -** [sometimes referred to as **all-in costs**,] is the total cost of building a power plant. It includes not only the instant costs, but also the costs associated with the fact that it takes time to build a power plant. Thus, it includes a building loan, sales taxes, and the costs associated with escalation of costs during construction.

Source: January 2010 CEC-200-2009-07SF

PUBLISHED INSTANT COST / INSTALLED COSTS

U. S. Energy Information Administration Assumptions to the Annual Energy Outlook 2010

Table 8.2. Cost and Performance Characteristics of New Central Station Electricity Generating Technologies

Technology	Online Year[1]	Size (mW)	Leadtime (Years)	Base Overnight Cost in 2009 ($2008/kW)	Contingency Factors: Project Contingency Factor[2]	Contingency Factors: Technological Optimism Factor[3]	Total Overnight Cost in 2009[4] (2008 $/kW)	Variable O&M[5] ($2008 mills/kWh)	Fixed O&M[5] ($2008/kW)	Heatrate[6] in 2009 (Btu/kWhr)	Heatrate nth-of-a-kind (Btu/kWr)
Scrubbed Coal New[7]	2013	600	4	2,078	1.07	1.00	2,223	4.69	28.15	9,200	8,740
Integrated Coal-Gasification Combined Cycle (IGCC)[7]	2013	550	4	2,401	1.07	1.00	2,569	2.99	39.53	8,765	7,450
IGCC withCarbon Sequestration	2016	380	4	3,427	1.07	1.03	3,776	4.54	47.15	10,781	8,307
Conv Gas/Oil Comb Cycle	2012	250	3	937	1.05	1.00	984	2.11	12.76	7,196	6,800
Adv Gas/Oil Comb Cycle (CC)	2012	400	3	897	1.08	1.00	968	2.04	11.96	6,752	6,333
ADVCC with Carbon Sequestion	2016	400	3	1,720	1.08	1.04	1,932	3.01	20.35	8,613	7,493
Conv Combustion Turbine[8]	2011	160	2	653	1.05	1.00	685	3.65	12.38	10,788	10,450
Adv Combustion Turbine	2011	230	2	617	1.05	1.00	648	3.24	10.77	9,289	8,550

4 Overnight Capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2009.

5 O&M = Operations and Maintenance

Portland General Electric Marginal Capacity

PORTLAND GENERAL ELECTRIC
SCCT Proxy Cost

SCCT Proxy Capital Cost $/kW

1	SCCT Installed Cost	$/kW	$1,171
2	Real Carrying Charge		11.20%
3	Annualized SCCT Cost	$/kW-yr	$131.25
4	Fixed O&M	$/kW-yr	$3.11
5	Fixed Gas Transport	$/kW-yr	$36.34
6	Reserve Margin (12%)	$/kW-yr	$20.48
7	Total	$/kW-yr	$191.18

Source: Page 6 of PGE Exhibit 1504 from UE-215 General Rate Case 2011

BPA's Load Price Signal – Demand Rate

PGE is using the LMS100 in its current rate case as the proxy long-run marginal cost of future capacity. PGE uses the marginal cost of capacity to allocate production costs across rate schedules.

BPA's Resource Price Signal – RSS Capacity Valuation

PGE also used the LMS100 in its 2009 IRP for backing up renewable resources.

- Renewables – we will model RPS compliance in all years of the analysis. RPS resources are generally backed up by flexible natural-gas fired resources (377 MW by 2030). For modeling purposes, we used an LMS100 simple-cycle turbine, which has a heat rate of 9165 and can reach full capability within an hour.

Source: PGE 2009 Integrated Resource Plan

New York Independent System Operator, Inc.
Proposed NYISO Installed Capacity (ICAP) Demand Curves
Capability Years 2008/2009, 2009/2010 and 2010/2011

- The Commission finds that NYISO's proposal to use the LMS-100 peaking unit for NYC and LI is reasonable. The 7FA is not a viable peaking unit for NYC and LI because it does not satisfy NOx requirements.

- The Commission finds that NYISO's proposal to use the 7FA peaking unit for developing the capital cost estimate for NYCA is reasonable.

Source: Docket No. ER08-283-000

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

Table II-3 — Capital Investment Costs for Greenfield Site (2007 $)

	NYC 2 x LM6000 With SCR	NYC 2 x LMS100 With SCR	Long Island 2 x LM6000 With SCR	Long Island 2 x LMS100 With SCR	LHV 2 x LM6000 With SCR	LHV 2 x LMS100 With SCR
Direct Costs	109,552,000	193,841,000	106,870,000	189,976,000	92,757,000	168,473,000
Owner's Costs	13,052,000	23.324,000	12,129,000	21,274,000	10,329,000	18,655,000
Financing Costs During Construction	5,579,000	9,881,000	5,415,000	9,612,000	4,690,000	8,515,000
Working Capital and Inventories	2,191,000	3,877,000	2,137,000	3,800,000	1,855,000	3,369,000
Total	130,374,000	230,923,000	126,551,000	224,662,000	109,631,000	199,012,000
Net Degraded ICAP MW	87.56	188.72	87.57	188.75	87.06	187.59
$/kW	$1,489	$1,224	$1,445	$1,190	$1,259	$1,061

The direct costs are the costs typically within the scope of engineer, procure, and construct (EPC) contracts, and do not include owner's costs, financing costs, or working capital and inventories. SCR = Selective Catalytic Reduction

Comparative Costs of California Central Station Electricity Generation – California Energy Commission (CEC) January 2010

All projects are assumed to have selective catalytic reduction (SCR) for control of nitrogen oxides emissions and an oxidation catalyst for control of carbon monoxide emissions.

Table 14: Plant Cost Data—Average Case

Plant Cost Data Start Year = 2009 (2009 Dollars)	Gross Capacity (MW)	Instant Costs ($/kW)			Construction Period (%/Year)						Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)
		Base	Environmental Compliance	Total	Year-0	Year-1	Year-2	Year-3	Year-4	Year-5		
Small Simple Cycle	49.9	1,277	15	1,292	100%	0%	0%	0%	0%	0%	23.94	4.17
Conventional Simple Cycle	100	1,204	27	1,231	100%	0%	0%	0%	0%	0%	17.40	4.17
Advanced Simple Cycle	200	801	26	827	75%	25%	0%	0%	0%	0%	16.33	3.67
Conventional Combined Cycle (CC)	500	1,044	51	1,095	75%	25%	0%	0%	0%	0%	8.62	3.02

Table 15: Plant Cost Data—High Case

Plant Cost Data Start Year = 2009 (2009 Dollars)	Gross Capacity (MW)	Instant Costs ($/kW)			Construction Period (%/Year)						Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)
		Base	Environmental Compliance	Total	Year-0	Year-1	Year-2	Year-3	Year-4	Year-5		
Small Simple Cycle	49.9	1,567	11	1,578	75%	25%	0%	0%	0%	0%	42.44	9.05
Conventional Simple Cycle	100	1,495	23	1,518	75%	25%	0%	0%	0%	0%	42.44	9.05
Advanced Simple Cycle	200	919	23	942	50%	40%	10%	0%	0%	0%	39.82	8.05
Conventional Combined Cycle (CC)	500	1,349	40	1,389	50%	40%	10%	0%	0%	0%	12.62	3.84

Comparative Costs of California Central Station Electricity Generation – CEC January 2010 (continued)

All projects are assumed to have selective catalytic reduction (SCR) for control of nitrogen oxides emissions and an oxidation catalyst for control of carbon monoxide emissions.

Table 16: Plant Cost Data—Low Case

Plant Cost Data Start Year = 2009 (2009 Dollars)	Gross Capacity (MW)	Instant Costs ($/kW)			Construction Period (%/Year)						Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)
		Base	Environmental Compliance	Total	Year-0	Year-1	Year-2	Year-3	Year-4	Year-5		
Small Simple Cycle	49.9	914	21	935	100%	0%	0%	0%	0%	0%	6.68	0.88
Conventional Simple Cycle	100	842	33	875	100%	0%	0%	0%	0%	0%	6.68	0.88
Advanced Simple Cycle	200	693	31	724	100%	0%	0%	0%	0%	0%	6.27	0.79
Conventional Combined Cycle (CC)	500	777	59	836	100%	0%	0%	0%	0%	0%	5.76	2.19

Comparative Costs of California Central Station Electricity Generation – CEC January 2010

Table C-24: Raw Cost Data for Simple Cycle Projects

Project Name	State	Size (MW)`	Raw Cost ($/kW)	Year	As-Built? (Y/N)
LMS100 Advanced Gas Turbine Projects					
Groton 1	SD	95	$726	2006	Y
Panoche Energy Center	CA	400	$750	2008	N
Sentinel CPV Ph I	CA	728	$604	2007	N
Walnut Energy Park	CA	515	$544	2007	N

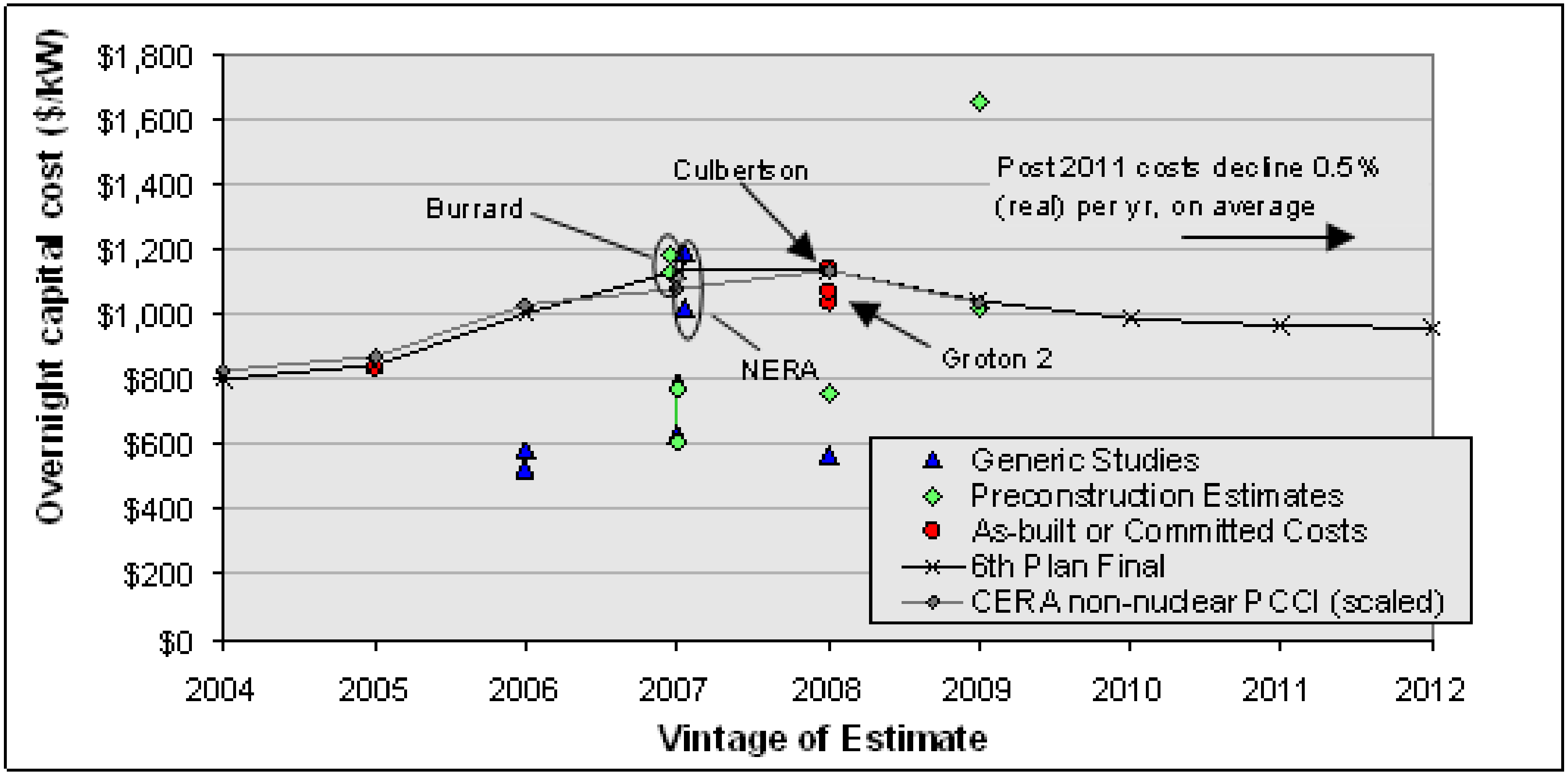
Source: Energy Commission, NWPCC, CRS

Raw Cost = Announced instant cost or as-built installed cost

No new or revised information requests were completed for the new power plants built or starting operation since the 2007 *IEPR* (Integrated Energy Policy Report) information request. However, a large amount of additional capital and operating cost data was gathered through third-party sources, **with the vast majority of this third-party collected cost data coming from Jeff King of the Northwest Power and Conservation Council (NWPCC)** and Stan Kaplan of the Congressional Research Service (CRS).

NWPPC 6th Power Plan

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



Note: NWPPC sampling of resource costs includes information from the NERA Economic Consulting to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator

NWPPC and CEC Methods for Creating Comparable Cost Estimates

Table C-17: State Adjustment Factors

State	Index	State	Index	State	Index	State	Index	State	Index
AL	0.90	HI	1.18	MA	1.18	NM	0.94	SD	0.87
AK	1.21	ID	0.97	MI	1.04	MY	1.15	TN	0.87
AZ	0.95	IL	1.11	MN	1.15	NC	0.84	TX	0.86
AR	0.88	IN	1.00	MS	0.89	ND	0.92	UT	0.94
CA	**1.18**	IA	0.96	MO	1.02	OH	1.04	VT	0.96
CO	0.98	KS	0.94	MT	0.96	OK	0.85	VA	0.96
CT	1.20	KY	0.98	NE	0.97	OR	1.09	WA	1.07
DE	1.12	LA	0.88	NV	1.09	PA	1.09	WV	1.03
FL	0.91	ME	0.98	NH	1.05	RI	1.15	WI	1.07
GA	0.89	MD	0.98	NJ	1.20	SC	0.85	WY	0.91

Source: ACOE, March 2008 (note 2009 values have been published, but, due to at least one apparent major error in the 2009 index, the 2008 index has been used in this evaluation)

Table C-18: Power Plant Cost Index

Year	Index	Year	Index
1998	0.91	2004	1.24
1999	0.95	2005	1.37
2000	1	2006	1.56
2001	1.05	2007	1.71
2002	1.11	2008	1.82
2003	1.17	2009	1.75

Source: CERA, 2008, with 2009 also based on evaluation of PPI index.

Note: In addition to location and annual index cost adjustments, both NWPPC and CEC made size and design adjustments

PUBLISHED FIXED O&M

Comparative Costs of California Central Station Electricity Generation – CEC January 2010

Table C-29: Comparison of O&M Cost Estimates

	Fixed O&M	Variable O&M	Total O&M
	$/KW-yr	$/MWh	$/kW-Yr
Advanced CT			
2009 CEC Cost of Generation (200 MW)-High Cost	***$39.82***	***$8.05***	***$46.81***
2009 CEC Cost of Generation (200 MW)-Average	***$16.33***	***$3.56***	***$19.55***
PJM CONE CT 2008 (Siemens Flexplant 10)	$19.03	NA	$19.03
PJM CONE CT 2008 (LMS 100)	$17.40	NA	$17.40
2007 EIA Assumptions Annual Energy Outlook	$11.15	$3.35	$14.09
2007 UCS RPS analysis (2005) EIA case	$11.14	$3.38	$14.10
2007 UCS RPS analysis (2005) UCS case-Ave. CEC	$7.20	$3.04	$9.86
LMS 100 Confidential (Submitted 2009)	$7.00	$2.50	$9.19
2009 CEC Cost of Generation (200 MW)-Low Cost	***$6.27***	***$0.79***	***$6.95***

Note: The high and low values for the 2009 analysis are based on the 5 percentile and 95 percentile values for the evaluated projects.
Source: Energy Commission review of noted documents.

Table C-27: Fixed O&M

Technology	Average	High	Low
Small Simple Cycle	23.94	42.44	6.68
Conventional Simple Cycle (SC)	17.40	42.44	6.68
Advanced Simple Cycle	16.33	39.82	6.27
Conventional Combined Cycle (CC	8.62	12.62	5.76
Conventional CC W/ Duct Firing	8.30	12.62	5.76
Advanced CC	7.17	10.97	5.01

Source: Energy Commission

NWPPC 6th Power Plan

- Operating and Maintenance Cost:
  - Fixed O&M cost is estimated to be $8/kW/yr ($2006). Fixed O&M includes operating and routine maintenance labor, maintenance materials, routine contract services, and administrative and general costs.

- 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.

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

	Long Island	NYC	Hudson Valley	Albany	Syracuse	Long Island	NYC	Hudson Valley	Albany	Syracuse	Albany	Syracuse
Combustion Turbine Model	LM6000	LM6000	LM6000	LM6000	LM6000	LMS100	LMS100	LMS100	LMS100	LMS100	GE 7FA	GE 7FA
Fixed O&M (2 Units, $/year)												
Labor - Routine O&M	902,720	902,720	728,000	728,000	728,000	902,720	902,720	728,000	728,000	728,000	728,000	728,000
Materials and Contract Services - Routine	237,000	237,000	237,000	237,000	237,000	305,000	305,000	305,000	305,000	305,000	365,000	365,000
Administrative and General	206,000	206,000	206,000	206,000	206,000	206,000	206,000	206,000	206,000	206,000	206,000	206,000
Subtotal Fixed O&M	1,345,720	1,345,720	1,171,000	1,171,000	1,171,000	1,413,720	1,413,720	1,239,000	1,239,000	1,239,000	1,299,000	1,299,000
$/kW-year	15.37	15.37	13.45	13.51	13.59	7.49	7.49	6.60	6.63	6.68	4.33	4.35
Other Fixed Costs (2 Units, $/year)												
Site Leasing Costs	73,500	427,000	59,500	59,500	59,500	73,500	427,000	59,500	59,500	59,500	59,500	59,500
Subtotal Fixed O&M	1,419,220	1,772,720	1,230,500	1,230,500	1,230,500	1,487,220	1,840,720	1,298,500	1,298,500	1,298,500	1,358,500	1,358,500
$/kW-year	16.21	20.25	14.13	14.19	14.28	7.88	9.75	6.92	6.95	7.00	4.52	4.55

U. S. Energy Information Administration Assumptions to the Annual Energy Outlook 2010

Table 8.2. Cost and Performance Characteristics of New Central Station Electricity Generating Technologies

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4 Overnight Capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2009.

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Portland General Electric SCCT Proxy Cost

	SCCT Proxy Capital Cost $/kW		
1	SCCT Installed Cost	$/kW	$1,171
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5	Fixed Gas Transport	$/kW-yr	$36.34
6	Reserve Margin (12%)	$/kW-yr	$20.48
7	Total	$/kW-yr	$191.18

Source: Page 6 of PGE Exhibit 1504 from UE-215 General Rate Case 2011

CALCULATING A $/KW/YR COST FROM INSTALLED COST

Financing Assumptions

Table 18: Capital Cost Structure

	% Equity	Equity Rate	Debt Rate	WACC
Average Case				
Merchant Fossil	60.0%	14.47%	7.49%	10.46%
Merchant Alternatives	40.0%	14.47%	7.49%	8.45%
Default IOU	52.0%	11.85%	5.40%	7.70%
Default POU	0.0%	0.0%	4.67%	4.67%
High Case				
Merchant Fossil	80.0%	18.00%	10.00%	15.59%
Merchant Alternatives	60.0%	18.00%	10.00%	13.17%
Default IOU	55.0%	15.00%	9.00%	10.65%
Default POU	0.0%	0.0%	7.00%	7.00%
Low Case				
Merchant Fossil	40.0%	14.47%	7.49%	8.45%
Merchant Alternatives	35.0%	14.00%	6.00%	7.21%
Default IOU	50.0%	10.00%	6.00%	6.78%
Default POU	0.0%	0.0%	4.00%	4.00%

Source: Energy Commission

	% Equity	Equity Rate	Debt Rate	WACC
Merchant	40%	13.70%	7.10%	8.04%
Regulated IOU	50%	10.20%	7.10%	7.23%
POU	0	0	5.10%	5.10%

Source: NWPPC MicroFin Model

	% Equity	Equity Rate	Debt Rate	WACC
Merchant	50%	12.00%	7.00%	7.90%

Source: NERA Economic Consulting to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator

Note: WACC is equal to nominal after-tax and the tax assumptions in each are different based on the location of focus for each study.

Plant Life & Financing Period

Table 19: Life Term Assumptions

Technology	Debt Term (Years)			Book Life (Years)	Equipment (Years)	Depreciation (Years)	
	Average	High	Low			Federal	State
Small Simple Cycle	12	10	20	20	20	15	15
Conventional Simple Cycle	12	10	20	20	20	15	15
Advanced Simple Cycle	12	10	20	20	20	15	15
Conventional Combined Cycle (CC)	12	10	20	20	20	20	20

Source: Energy Commission

	Debt Term (Years)	Equipment (Years)
Public	30	30
Regulated IOU	30	30
Merchant	15	30

Source: NWPPC MicroFin Model

“ 1) For each of the 20 years the LMS100 is assumed to operate…”

Source: PORTLAND GENERAL ELECTRIC UE 215 PGE Response to OPUC Data Request Dated April 30, 2010 Question No. 381

	Debt Term (Years)	Equipment (Years)
Merchant NYC	15.5	30
Merchant Long Island & ROS	11.5	30

Source: NERA Economic Consulting to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator

BPA STAFF CONCLUSION AND STARTING SPOT FOR DEMAND RATE WORKSHOP CONVERSATION

PUD Financing w/o Fixed Gas

Start Year of Operation (FY)	2012	
Cost of Debt	5.70%	/3
Inflation Rate	2.6%	
Insurance Rate	0.25%	/1
Debt Finance Period (years)	20	
Plant Lifecycle (years)	20	
All-in Nominal Capital Cost LMS100 $/kW	$ 1,070.00	/1
Fixed O&M $/kW/yr	$ 17.26	/2

Calendar Year	Chained GDP IPD	
2004	93.72	
2005	96.85	
2006	100.00	
2007	102.86	
2008	105.06	
2009	106.31	
	102.6%	5-year Ave.

Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product

Month	Load Shaping Rate HLH $/MWh	Demand Shaping Factor	Monthly Demand Rate $/kW/mo
Oct	$ 44.14	8.44%	$ 9.37
Nov	$ 45.09	8.62%	$ 9.57
Dec	$ 44.39	8.49%	$ 9.43
Jan	$ 48.04	9.18%	$ 10.19
Feb	$ 48.43	9.26%	$ 10.28
Mar	$ 44.06	8.42%	$ 9.35
Apr	$ 41.53	7.94%	$ 8.82
May	$ 26.22	5.01%	$ 5.56
Jun	$ 33.64	6.43%	$ 7.14
Jul	$ 46.97	8.98%	$ 9.97
Aug	$ 50.53	9.66%	$ 10.73
Sep	$ 50.03	9.56%	$ 10.62
	Average $/kW/mo		$ 9.25

End of Fiscal Year	Midyear Assessed Value	Debt Payment	Fixed O&M	Insurance	Cash Expense Each Year
2012	$ 1,043.25	$91.03	$ 17.26	$ 2.61	$ 110.90
2013	$ 989.75	$91.03	$ 17.70	$ 2.47	$ 111.20
Rate Period Average Expense $/kW/year					$ 111.05

/1 Source NWPCC Microfin Model with 100% PUD ownership with plant in service 2012

/2 Source California Energy Commission - Comparative Costs of California Central Station Electricity Generation [CEC-200-2009-07SF] average 2009 estimate escalated to 2012 using inflation rate

/3 Source Table 7 BPA FY 2010 Third-Party Taxable Borrowing Rate Forecast 20-year

PUD Financing w/ Fixed Gas

Start Year of Operation (FY)	2012	
Cost of Debt	5.70%	/3
Inflation Rate	2.6%	
Insurance Rate	0.25%	/1
Debt Finance Period (years)	20	
Plant Lifecycle (years)	20	
Heat Rate MMBtu/kWh	0.00877	
Pipeline Tariff $/MMBtu/day	$ 0.37984	/5
All-in Nominal Capital Cost LMS100 $/kW	$ 1,070.00	/1
Fixed O&M $/kW/yr	$ 17.26	/2
Fixed Fuel $/kW/yr	$ 29.18	

Calendar Year	Chained GDP IPD	
2004	93.72	
2005	96.85	
2006	100.00	
2007	102.86	
2008	105.06	
2009	106.31	
	102.6%	5-year Ave.

Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product

Month	Load Shaping Rate HLH $/MWh	Demand Shaping Factor	Monthly Demand Rate $/kW/mo
Oct	$ 44.14	8.44%	$ 11.84
Nov	$ 45.09	8.62%	$ 12.09
Dec	$ 44.39	8.49%	$ 11.91
Jan	$ 48.04	9.18%	$ 12.87
Feb	$ 48.43	9.26%	$ 12.99
Mar	$ 44.06	8.42%	$ 11.81
Apr	$ 41.53	7.94%	$ 11.13
May	$ 26.22	5.01%	$ 7.03
Jun	$ 33.64	6.43%	$ 9.02
Jul	$ 46.97	8.98%	$ 12.59
Aug	$ 50.53	9.66%	$ 13.55
Sep	$ 50.03	9.56%	$ 13.41
		Average $/kW/mo	$ 11.69

End of Fiscal Year	Midyear Assessed Value	Debt Payment	Fixed O&M	Insurance	Fixed Fuel	Cash Expense Each Year
2012	$ 1,043.25	$91.03	$ 17.26	$ 2.61	$ 29.18	$140.08
2013	$ 989.75	$91.03	$ 17.70	$ 2.47	$ 29.18	$140.38
					Rate Period Average Expense $/kW/year	$ 140.23

/1 Source NWPCC Microfin Model with 100% PUD ownership with plant in service 2012

/2 Source California Energy Commission - Comparative Costs of California Central Station Electricity Generation [CEC-200-2009-07SF] average 2009 estimate escalated to 2012 using inflation rate

/3 Source BPA FY 2010 Third-Party Taxable Borrowing Rate Forecast 20-year

/4 Source Williams Northwest Pipeline Tariff - http://www.northwest.williams.com/NWP_Portal/extLoc.action?Loc=FilesNorthwesttariff&File=tariff6.html

IPP Financing w/o Fixed Gas

Start Year of Operation (FY)	2012	
Debt Ratio	60.0%	/1
Equity Ratio	40.0%	/1
Cost of Debt	7.1%	/1
After-Tax Cost of Equity	13.7%	/1
Inflation Rate	2.6%	
Marginal Federal Tax Rate	35.0%	/1
Marginal State Tax Rate	5.0%	/1
Property Tax Rate	1.4%	/1
Insurance Rate	0.25%	/1
Equity Finance Period (years)	20	
Debt Finance Period (years)	20	
Plant Lifecycle (years)	20	
1st-year Tax Depreciation MACRS	6.6%	/3
2nd-year Tax Depreciation MACRS	7.0%	/3
All-in Nominal Capital Cost LMS100 $/kW	$ 1,084.00	/1
Fixed O&M $/kW/yr	$ 17.26	/2

Calendar Year	Chained GDP IPD	
2004	93.72	
2005	96.85	
2006	100.00	
2007	102.86	
2008	105.06	
2009	106.31	
	102.6%	5-year Ave.

Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product

Month	Load Shaping Rate HLH $/MWh	Demand Shaping Factor	Monthly Demand Rate $/kW/mo
Oct	$ 44.14	8.44%	$ 13.93
Nov	$ 45.09	8.62%	$ 14.23
Dec	$ 44.39	8.49%	$ 14.01
Jan	$ 48.04	9.18%	$ 15.15
Feb	$ 48.43	9.26%	$ 15.29
Mar	$ 44.06	8.42%	$ 13.90
Apr	$ 41.53	7.94%	$ 13.11
May	$ 26.22	5.01%	$ 8.27
Jun	$ 33.64	6.43%	$ 10.61
Jul	$ 46.97	8.98%	$ 14.82
Aug	$ 50.53	9.66%	$ 15.95
Sep	$ 50.03	9.56%	$ 15.78
		Average $/kW/mo	$ 13.75

End of Fiscal Year	Midyear Assessed Value	Equity Payment	Equity Return	Debt Payment	Interest Payment	Fixed O&M	Federal Income Tax	State Income Tax	Property Tax	Insurance	Cash Expense Each Year
2012	$ 1,056.90	$ 64.34	$ 59.40	$61.87	$46.18	$ 17.26	$ 4.79	$ 0.72	$ 14.80	$ 2.64	$ 166.42
2013	$ 1,002.70	$ 64.34	$ 58.73	$61.87	$45.06	$ 17.70	$ 2.83	$ 0.43	$ 14.04	$ 2.51	$ 163.71
										Rate Period Average Expense $/kW/year	$ 165.07

/1 Source NWPCC Microfin Model with 100% IPP ownership and plant in service 2012

/2 Source California Energy Commission - Comparative Costs of California Central Station Electricity Generation [CEC-200-2009-07SF] average 2009 estimate escalated to 2012 using inflation rate

/3 Source IRS Publication 946 Table A-2 Mid-Quarter Convention Placed in Service in 1st Quarter - Modified Accelerated Cost Recovery System (MACRS)

IPP Financing w/ Fixed Gas

Start Year of Operation (FY)	2012	
Debt Ratio	60.0%	/1
Equity Ratio	40.0%	/1
Cost of Debt	7.1%	/1
After-Tax Cost of Equity	13.7%	/1
Inflation Rate	2.6%	
Marginal Federal Tax Rate	35.0%	/1
Marginal State Tax Rate	5.0%	/1
Property Tax Rate	1.4%	/1
Insurance Rate	0.25%	/1
Equity Finance Period (years)	20	
Debt Finance Period (years)	20	
Plant Lifecycle (years)	20	
1st-year Tax Depreciation MACRS	6.6%	/3
2nd-year Tax Depreciation MACRS	7.0%	/3
Heat Rate MMBtu/kWh	0.00877	
Pipeline Tariff $/MMBtu/day	$ 0.37984	/4
All-in Nominal Capital Cost LMS100 $/kW	$ 1,084.00	/1
Fixed O&M $/kW/yr	$ 17.26	/2
Fixed Fuel $/kW/yr	$ 29.18	

Calendar Year	Chained GDP IPD	
2004	93.72	
2005	96.85	
2006	100.00	
2007	102.86	
2008	105.06	
2009	106.31	
	102.6%	5-year Ave.

Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product

Month	Load Shaping Rate HLH $/MWh	Demand Shaping Factor	Monthly Demand Rate $/kW/mo
Oct	$ 44.14	8.44%	$ 16.39
Nov	$ 45.09	8.62%	$ 16.74
Dec	$ 44.39	8.49%	$ 16.49
Jan	$ 48.04	9.18%	$ 17.83
Feb	$ 48.43	9.26%	$ 17.99
Mar	$ 44.06	8.42%	$ 16.36
Apr	$ 41.53	7.94%	$ 15.42
May	$ 26.22	5.01%	$ 9.73
Jun	$ 33.64	6.43%	$ 12.49
Jul	$ 46.97	8.98%	$ 17.44
Aug	$ 50.53	9.66%	$ 18.76
Sep	$ 50.03	9.56%	$ 18.57
		Average $/kW/mo	$ 16.18

End of Fiscal Year	Midyear Assessed Value	Equity Payment	Equity Return	Debt Payment	Interest Payment	Fixed O&M	Federal Income Tax	State Income Tax	Property Tax	Insurance	Fixed Fuel	Cash Expense Each Year
2012	$ 1,056.90	$ 64.34	$ 59.40	$61.87	$46.18	$ 17.26	$ 4.79	$ 0.72	$ 14.80	$ 2.64	$ 29.18	$ 195.60
2013	$ 1,002.70	$ 64.34	$ 58.73	$61.87	$45.06	$ 17.70	$ 2.83	$ 0.43	$ 14.04	$ 2.51	$ 29.18	$ 192.90
										Rate Period Average Expense $/kW/year		$ 194.25

/1 Source NWPCC Microfin Model with 100% IPP ownership and plant in service 2012

/2 Source California Energy Commission - Comparative Costs of California Central Station Electricity Generation [CEC-200-2009-07SF] average 2009 estimate escalated to 2012 using inflation rate

/3 Source IRS Publication 946 Table A-2 Mid-Quarter Convention Placed in Service in 1st Quarter - Modified Accelerated Cost Recovery System

/4 Source Williams Northwest Pipeline Tariff - http://www.northwest.williams.com/NWP_Portal/extLoc.action?Loc=FilesNorthwesttariff&File=tariff6.html