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COMPARATIVE COSTS OF CALIFORNIA CENTRAL STATION ELECTRICITY GENERATION TECHNOLOGIES

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ABSTRACT

This 2007 report updates the cost of generating electricity for California-located technologies. California Energy Commission staff provides levelized costs, including the cost assumptions, for 8 conventional and 20 alternative central station generation technologies. These levelized costs are useful in evaluating the financial feasibility of a generation technology and for comparing the cost of one technology against another. These cost of generation estimates represent one of the first such efforts based substantially on empirical data collected from operating facilities. The combined cycle and simple cycle costs are the result of a comprehensive survey of actual costs from the power plant developers in California who built power plants between 2001 and 2006. The other costs are based on actual costs and surveys of expected costs from experts in the field. For this reason, staff expects these estimates to have improved accuracy relative to other such estimates. The Energy Commission's Cost of Generation Model is also unique in that it has two features not commonly found in cost of generation models: screening curves and cost sensitivity analysis curves. The Energy Commission also uses the fixed-cost data of the Cost of Generation Model with the variable cost information of a production cost market simulation model to produce wholesale electricity costs, which are necessary to many related resource planning studies at the Energy Commission, including Retail Electricity Price Forecasts, Global Warming Evaluations and Electric Vehicle Studies for the AB 1007 Report.

Keywords: cost of generation, Cost of Generation Model, Model, levelized costs, instant cost, installed cost, fixed operation and maintenance, fixed O&M, variable operation and maintenance, variable O&M, heat rate, generation technology cost, annual costs, fixed cost, variable cost, alternative technologies, combined cycle, simple cycle, combustion turbine, integrated gasification combined cycle, coal cost, fuel cost, natural gas cost, nuclear fuel cost, heat rate degradation, financial variables, capital cost structure

Executive Summary

This Cost of Generation report provides levelized cost of generation estimates for various central station generation technologies. These levelized costs are useful in evaluating the financial feasibility of a generation technology and for comparing the cost of one technology against another. Since most studies involving new generation or transmission require an assessment of costs, accurate and readily available cost of generation estimates are essential to much of the California Energy Commission's (Energy Commission) work.

Care must be taken not to misuse these levelized costs. They are nominal values, not precise estimates. They are for a specific set of assumptions that might not be completely applicable for the study in question. Comparing one levelized cost against another may be useful where levelized costs are of significantly different magnitudes, but problematic where levelized costs are close. Most importantly, these estimates do not predict how the units will actually operate in an electric system, how the units will affect the operation of one another, or their effect on system costs. Such estimates require a more sophisticated model such as a market model. Finally, these cost estimates do not address environmental, system diversity or risk factors which are a vital planning aspect of all resource development.

The levelized costs herein were developed using the Energy Commission's staff Cost of Generation Model. The Energy Commission's Cost of Generation Model was first used to produce cost of generation estimates for the *2003 Integrated Energy Policy Report*, which at that time consisted of 25 separate models. Because of the usefulness of the resulting cost estimates and many requests for this type of information, the staff revised the Cost of Generation Model to be more compact, accurate and user-friendly. Staff combined the 25 separate cost of generation models of the 2003 version into one Cost of Generation Model with drop-down menus. In addition, the Cost of Generation Model has been completely reorganized to make it more flexible and more transparent.

Energy Commission staff comprehensively updated the component costs that are used as inputs to the Cost of Generation Model. Staff revised the simple cycle and combined cycle units based on a survey of the power plant developers for all units built in California since 2001. The remaining unit costs are based on a combination of actual costs collected from the power plant developers and experts in the field.

The staff added a number of analytical functions to the Cost of Generation Model, including screening curves and sensitivity curves to allow users to evaluate the effect of the various cost factors used in developing levelized costs.

The Cost of Generation Model, working together with the Marketsym model, can now develop wholesale electricity price forecasts. This feature estimates the fixed cost component and applies the variable cost factors from the production cost or

market model to produce a wholesale electricity price forecast. Wholesale electricity price forecasts are necessary for many of the resource planning studies.

Energy Commission staff improved the documentation and created a comprehensive user's guide to facilitate the use of the Cost of Generation Model. Both the Cost of Generation Model and the user's guide will be made available on the web site.

The Cost of Generation Model and a June 2007 Draft Report were the subject of a June 12, 2007 workshop. Several comments were received and incorporated into the Model and this Report.

The Report is organized as follows:

- Chapter 1 reports the levelized cost estimates – the output of the Model. It provides the levelized cost estimates for 8 standard technologies and 20 alternative technologies. The levelized costs, as well as the component costs, are provided for three classes of developers: merchant, investor-owned utilities (IOU) and publicly owned utilities (POU) – often referred to as municipal utilities.

- Chapter 2 summarizes the inputs to the Model: data assumptions, and the collection and analysis process for the improved data. It also compares the effect of the present assumptions to those used in the *2003 Integrated Energy Policy Report*, *(2003 IEPR)* forecast, as well as comparing the present estimates to the EIA estimates.

- Chapter 3 provides a general description of the California Energy Commission's (Energy Commission) Model, provides instructions on how to use the Model and also describes the various unique new features of the Model, such as screening and sensitivity curves.

- Appendix A provides a list of contacts if further information about the Model is needed.

- Appendix B provides the power point slides from the June 12, 2007 workshop that describe the details of the alternative technologies, advanced nuclear and clean coal.

- Appendix C provides the comments of interested parties who reviewed the report and/or the Model, followed by staff responses to these comments.

- Appendix D provides a summary of the changes in levelized cost relative to the draft report.

- Appendix E provides a summary of the levelized fixed cost for a simple cycle unit in $/kW-Yr.

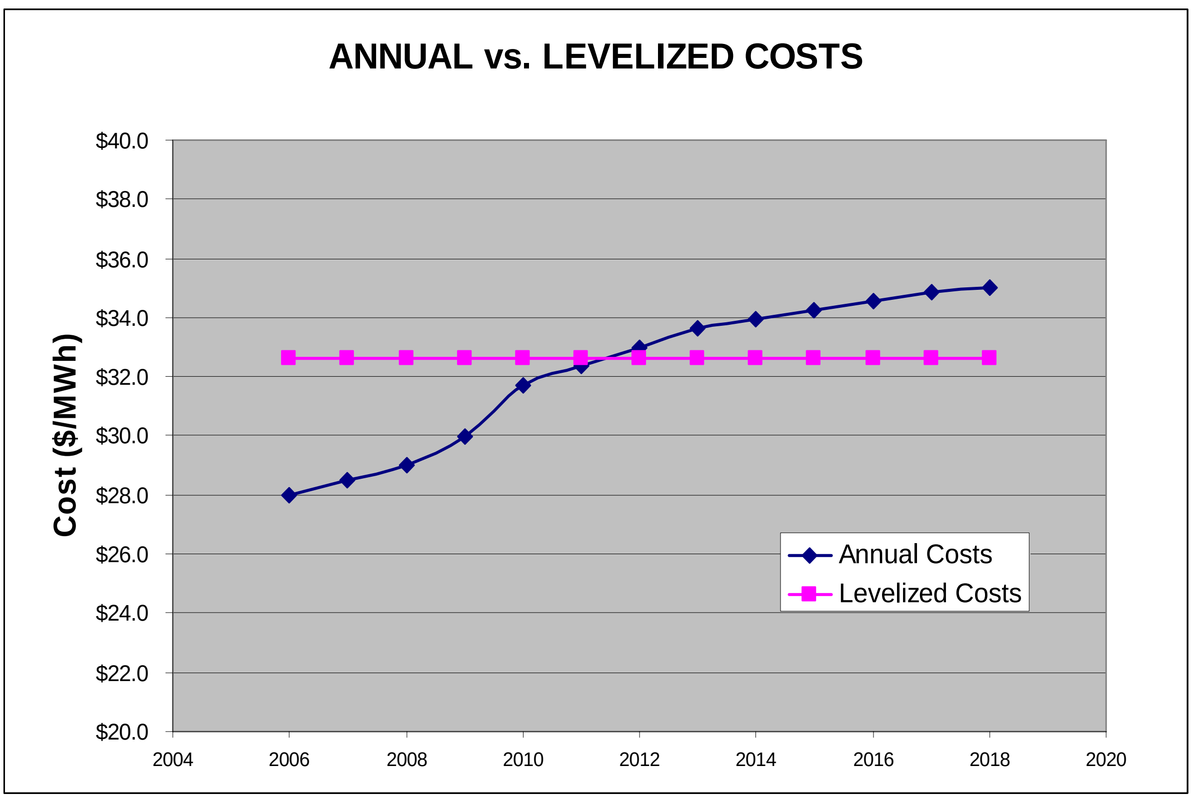
CHAPTER 1: Summary of Technology Costs

This chapter defines levelized cost, delineates the cost components of levelized cost, and summarizes the levelized costs of the technologies considered in this report. These costs are reported for nuclear, fossil fuel, and various alternative technologies.

Definition of Levelized Cost

Levelized cost is the constant annual cost that is equivalent on a present-value basis to the actual annual costs, which are themselves variable. **Figure 1** is a fictitious illustration of this relationship, which is defined by the fact that the present worth of the annualized levelized cost values is equal to the present worth of the actual annual costs. This annualized cost value allows for the comparison of one technology against the other, whereas the differing annual costs are not easily compared.

Figure 1: Illustration of Levelized Cost



Source: Energy Commission

Levelized Cost Categories

Levelized costs are reported for fixed and variable cost components as shown in **Table 1**.

Table 1: Summary of Levelized Cost Components

Fixed Cost
Capital and Financing – The total cost of construction, including financing the plant
Insurance – The cost of insuring the power plant
Ad Valorem – Property taxes
Fixed O&M – Staffing and other costs that are independent of operating hours
Variable Costs
Fuel Cost – The cost of the fuel used
Variable O&M – Operation and maintenance costs that are a function of operating hours

Source: Energy Commission

All of these costs vary depending on whether the project is a merchant facility, an IOU, or a POU. In addition, the costs can vary with location because of differing land costs, fuel costs, construction costs, operational costs, and environmental licensing costs. These costs are discussed in detail in Chapter 2, but are defined briefly as follows.

Capital and Financing Costs

The capital cost includes the total costs of construction, including land purchase, land development, permitting, interconnection, environmental control equipment, and component costs. The financing costs are those incurred through debt and equity financing and are incurred by the developer annually, similar in structure to financing a home. These annual costs, therefore, are essentially levelized by this cost structure.

Insurance Cost

Insurance is the cost of insuring the power plant, similar to the insuring of a home. The annual costs are based on an estimated first-year cost and are then escalated by nominal inflation throughout the book life period. The first-year cost is estimated as a percentage of the installed cost per kilowatt for a merchant facility and POU plant. For an IOU plant, the first-year cost is a percentage of the book value.

Ad Valorem

Ad valorem costs are annual property tax payments that are paid as a percentage of the assessed value and usually transferred to local governments. POU power plants are generally exempt from these taxes but may pay in-lieu fees. The assessed values for power plants are set by the State Board of Equalization (BOE) as a percentage of book value for an IOU and as depreciation-factored value for a merchant facility.

Fixed Operating and Maintenance

Fixed O&M costs are shown as costs that occur regardless of how much the plant operates. These are not uniformly defined by all interested parties but generally include staffing, overhead and equipment (including leasing), regulatory filings, and miscellaneous direct costs.

Corporate Taxes

Corporate taxes are state and federal taxes, which are not applicable to a POU. The calculation of these taxes is different for a merchant facility and an IOU. Neither lends itself to a simple explanation, but in general the taxes depend on depreciated values and are adjusted for interest on debt payments. The federal taxes are adjusted for the state taxes similar to adjustment rates for a homeowner.

Fuel Cost

Fuel cost is the cost of fuel, most commonly expressed in dollars per megawatt hour. For a thermal power plant, it is the heat rate (Btu/kWh) multiplied by the cost of the fuel ($/MMBtu). This includes start-up fuel costs as well as the online operating fuel usage. Allowance must be made for the degradation of the heat rate over time.

Variable Operations and Maintenance

Variable O&M costs are a function of the hours of operation of the power plant. Most importantly, this includes yearly maintenance and overhauls. Variable O&M also includes repairs for forced outages, consumables, water supply, and annual environmental costs.

Summary of Levelized Costs

Table 2 summarizes the calculated levelized costs for the various generation technologies as developed by merchant facilities, IOUs, and POUs. They are provided in the two most common formats, $/MWh and $/kW-Yr. All costs are in 2007 nominal dollars and are for a generation unit that begins operation in 2007. Although levelized costs commonly vary with location and are captured accordingly in the Model, only average California levelized costs are shown in this table and the remainder of the report. Similarly, only average California gas prices are used in reporting levelized costs for gas-fired technologies, even though the Model can produce levelized costs for each natural gas area.

Figure 2 provides this same information in graphical form. To present the information in a less busy representation, **Figure 3** shows the same data for the merchant facilities arranged in ascending order of cost.

The levelized costs include tax credits and any other benefits attributable to the technology, such as tipping fees for the biomass anaerobic digester dairy.

The IOU plants are less expensive than the merchant facilities due to lower financing costs. This is in marked contrast to the *2003 IEPR* when merchant financing costs were at least comparable to those for the IOUs. The change is a reflection of the outcome from the 2000-2001 energy crisis. The publicly owned plants are the least expensive because of lower financing costs and freedom from taxes.

Component Costs

Tables 3, **4,** and **5** show the cost components for each developer category, merchant facility, IOU and POU. **Figures 4**, **5,** and **6** show this same data graphically.

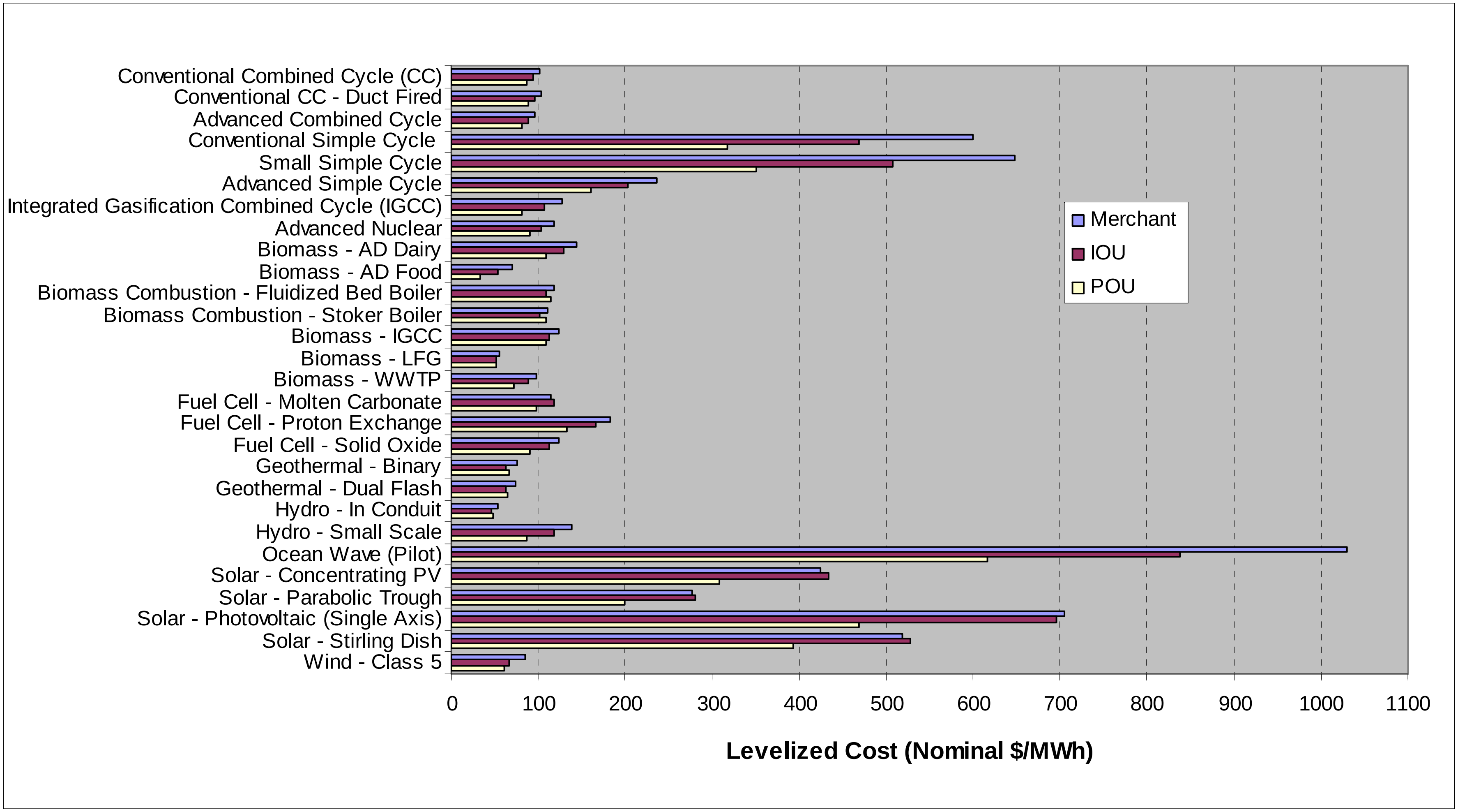
Staff has provided all the noted above levelized tables and graphs as this data is commonly used and commonly requested by various entities. It should be kept in mind, as will be explained in more detail later in the report, that all these levelized costs are nominal values based on the most likely assumptions. Since these nominal assumptions might not apply to individual studies, they are to be used with caution. In addition, these estimates show no deference to how these units will operate in a particular system or how they will affect the operation of that system and the corresponding system costs, so no conclusions should be drawn in this regard.

Table 2: Summary of Levelized Costs

In-Service Year =2007 (Nominal 2007$)	Size	Merchant			IOU			POU		
	MW	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh
Conventional Combined Cycle (CC)	500	505.82	102.19	10.22	466.86	94.47	9.45	428.32	86.84	8.68
Conventional CC - Duct Fired	550	512.39	103.52	10.35	472.40	95.59	9.56	432.97	87.78	8.78
Advanced Combined Cycle	800	476.97	96.36	9.64	438.22	88.68	8.87	399.62	81.02	8.10
Conventional Simple Cycle	100	250.43	599.57	59.96	195.59	468.46	46.85	132.84	318.33	31.83
Small Simple Cycle	50	270.36	647.28	64.73	212.08	507.98	50.80	146.70	351.55	35.15
Advanced Simple Cycle	200	295.96	236.12	23.61	253.22	202.10	20.21	201.13	160.60	16.06
Integrated Gasification Combined Cycle (IGCC)	575	566.58	126.51	12.65	476.15	106.32	10.63	361.52	80.72	8.07
Advanced Nuclear	1000	862.70	118.25	11.83	757.78	103.87	10.39	664.78	91.12	9.11
Biomass - AD Dairy	0.25	924.52	143.61	14.36	826.57	128.39	12.84	800.93	109.77	10.98
Biomass - AD Food	2	450.97	70.05	7.00	350.30	54.41	5.44	218.82	33.99	3.40
Biomass Combustion - Fluidized Bed Boiler	25	866.25	118.72	11.87	793.99	108.82	10.88	839.92	115.12	11.51
Biomass Combustion - Stoker Boiler	25	810.99	111.15	11.12	745.45	102.17	10.22	799.74	109.61	10.96
Biomass - IGCC	21.25	849.18	123.66	12.37	768.58	111.92	11.19	744.82	108.46	10.85
Biomass - LFG	2	382.50	56.11	5.61	345.95	50.86	5.09	352.73	52.36	5.24
Biomass - WWTP	0.5	514.65	97.34	9.73	466.63	88.84	8.88	366.54	71.78	7.18
Fuel Cell - Molten Carbonate	2	886.11	114.66	11.47	910.60	117.83	11.78	754.94	97.69	9.77
Fuel Cell - Proton Exchange	0.03	1409.63	182.41	18.24	1281.28	165.80	16.58	1025.67	132.72	13.27
Fuel Cell - Solid Oxide	0.25	955.64	123.66	12.37	868.61	112.40	11.24	695.29	89.97	9.00
Geothermal - Binary	50	477.23	75.85	7.58	396.31	63.53	6.35	394.23	65.55	6.56
Geothermal - Dual Flash	50	453.91	73.66	7.37	379.23	62.07	6.21	384.36	65.26	6.53
Hydro - In Conduit	1	213.72	52.84	5.28	183.96	45.68	4.57	188.71	47.78	4.78
Hydro - Small Scale	10	567.71	138.74	13.87	481.05	118.08	11.81	347.96	87.09	8.71
Ocean Wave (Pilot)	0.75	1239.92	1030.50	103.05	1005.64	837.65	83.76	733.96	617.12	61.71
Solar - Concentrating PV	15	620.48	424.84	42.48	631.79	434.00	43.40	442.11	308.09	30.81
Solar - Parabolic Trough	63.5	497.33	277.30	27.73	504.17	281.37	28.14	355.71	199.31	19.93
Solar - Photovoltaic (Single Axis)	1	1035.07	704.98	70.50	1019.48	695.59	69.56	681.74	468.87	46.89
Solar - Stirling Dish	15	855.55	518.89	51.89	868.93	527.00	52.70	648.77	393.47	39.35
Wind - Class 5	50	245.94	84.24	8.42	196.08	67.16	6.72	179.19	61.38	6.14

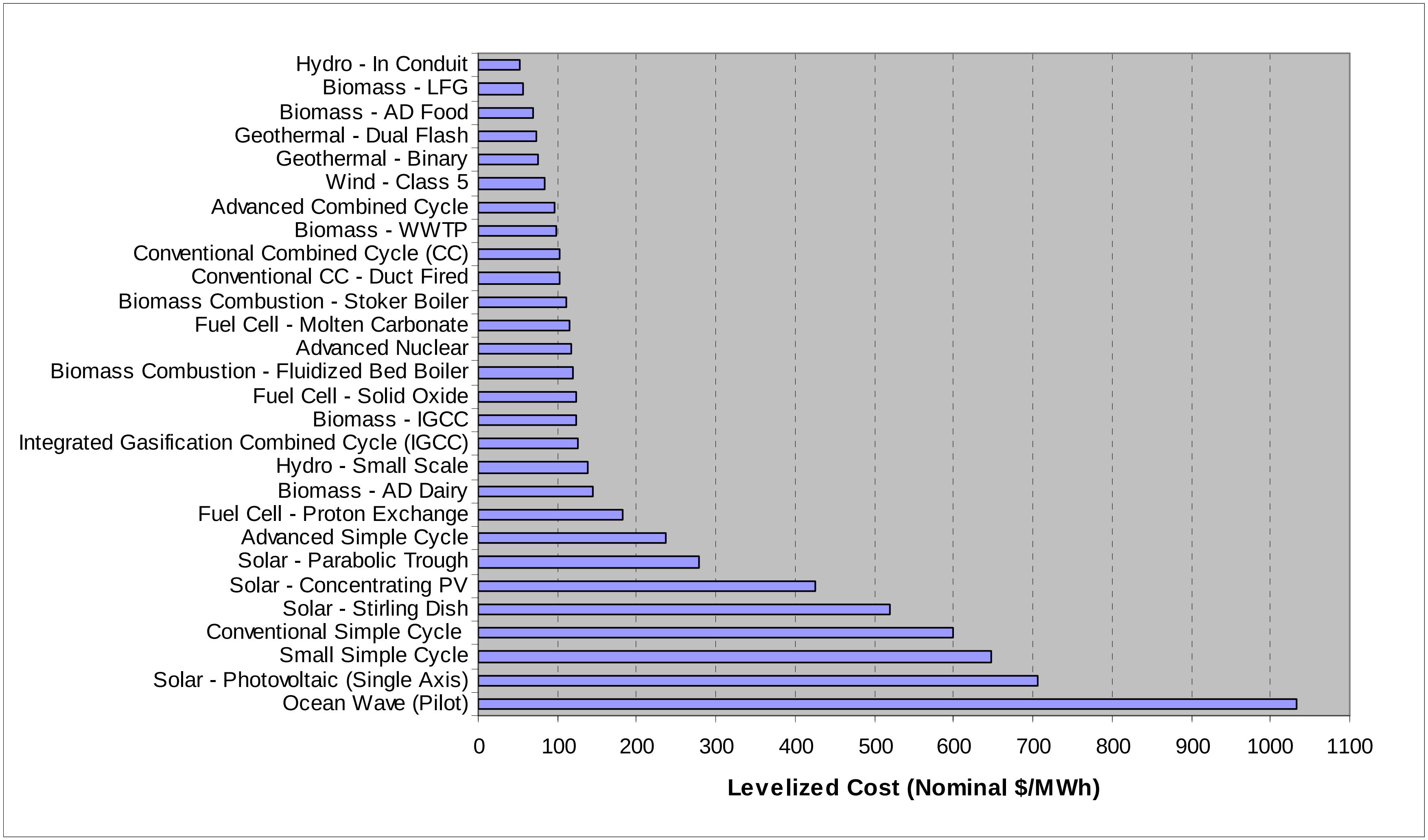
Source: Energy Commission

Figure 2: Summary of Levelized Costs



Source: Energy Commission

Figure 3: Total Levelized Costs – Merchant Plants Only



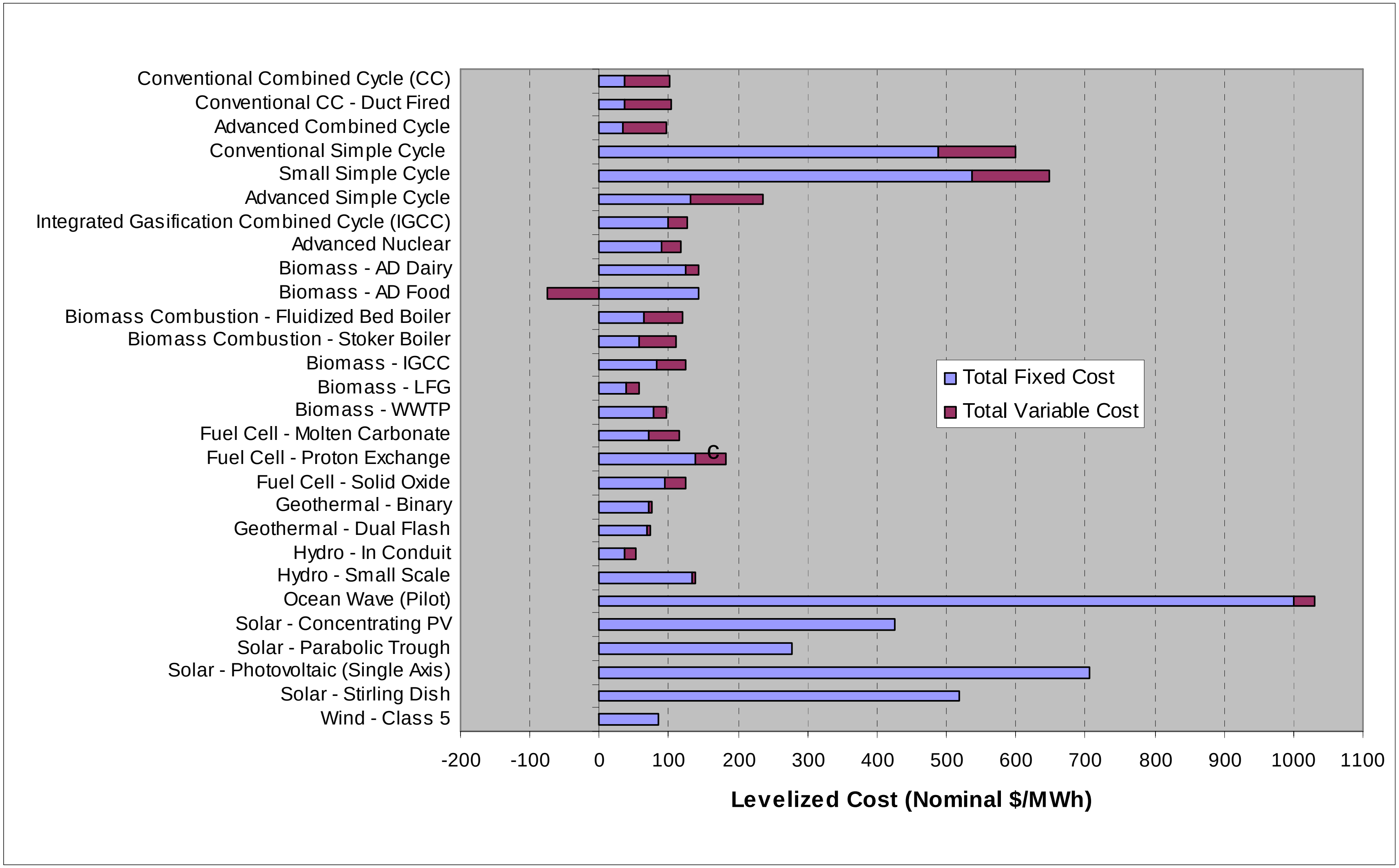
Source: Energy Commission

Table 3: Levelized Cost Components – Merchant Plants

		$/MWh (Nominal 2007$)										¢/kWh
In-Service Year =2007	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	**Total Levelized Cost**	**Total Levelized Cost**
Conventional Combined Cycle (CC)	500	23.28	1.48	1.16	2.30	7.85	**36.07**	60.86	5.27	**66.12**	**102.19**	**10.22**
Conventional CC - Duct Fired	550	23.81	1.52	1.19	2.22	8.03	**36.77**	61.64	5.11	**66.75**	**103.52**	**10.35**
Advanced Combined Cycle	800	22.85	1.46	1.14	1.96	7.71	**35.13**	56.68	4.56	**61.24**	**96.36**	**9.64**
Conventional Simple Cycle	100	327.02	20.82	16.31	30.49	94.43	**489.08**	79.66	30.83	**110.49**	**599.57**	**59.96**
Small Simple Cycle	50	347.88	22.15	17.35	48.75	100.20	**536.33**	79.66	31.29	**110.96**	**647.28**	**64.73**
Advanced Simple Cycle	200	89.52	5.70	4.46	6.59	25.88	**132.15**	73.51	30.46	**103.97**	**236.12**	**23.61**
Integrated Gasification Combined Cycle (IGCC)	575	64.47	6.79	4.44	10.58	12.15	**98.44**	24.00	4.06	**28.07**	**126.51**	**12.65**
Advanced Nuclear	1000	56.79	5.14	3.70	24.18	0.64	**90.45**	21.50	6.30	**27.80**	**118.25**	**11.83**
Biomass - AD Dairy	0.25	110.17	7.82	6.33	9.58	-9.05	**124.84**	0.00	18.77	**18.77**	**143.61**	**14.36**
Biomass - AD Food	2	110.21	7.82	6.33	28.74	-9.05	**144.05**	0.00	-74.00	**-74.00**	**70.05**	**7.00**
Biomass Combustion - Fluidized Bed Boiler	25	48.67	4.40	3.17	25.91	-18.44	**63.72**	51.09	3.91	**55.00**	**118.72**	**11.87**
Biomass Combustion - Stoker Boiler	25	44.70	4.04	2.91	23.23	-18.74	**56.15**	51.09	3.91	**55.00**	**111.15**	**11.12**
Biomass - IGCC	21.25	53.27	4.82	3.47	28.48	-7.62	**82.42**	37.32	3.91	**41.23**	**123.66**	**12.37**
Biomass - LFG	2	40.49	2.87	2.33	3.62	-11.70	**37.61**	0.00	18.50	**18.50**	**56.11**	**5.61**
Biomass - WWTP	0.5	63.60	4.51	3.65	4.67	2.41	**78.84**	0.00	18.50	**18.50**	**97.34**	**9.73**
Fuel Cell - Molten Carbonate	2	72.48	5.14	4.16	0.34	-10.63	**71.50**	0.00	43.17	**43.17**	**114.66**	**11.47**
Fuel Cell - Proton Exchange	0.03	116.92	8.30	6.71	2.87	4.44	**139.24**	0.00	43.17	**43.17**	**182.41**	**18.24**
Fuel Cell - Solid Oxide	0.25	79.28	5.63	4.55	1.60	3.01	**94.06**	0.00	29.60	**29.60**	**123.66**	**12.37**
Geothermal - Binary	50	67.75	4.78	3.87	13.73	-19.84	**70.30**	0.00	5.55	**5.55**	**75.85**	**7.58**
Geothermal - Dual Flash	50	64.12	4.53	3.67	16.02	-20.12	**68.21**	0.00	5.45	**5.45**	**73.66**	**7.37**
Hydro - In Conduit	1	43.02	3.97	2.86	0.00	-13.97	**35.88**	0.00	16.96	**16.96**	**52.84**	**5.28**
Hydro - Small Scale	10	113.39	10.47	7.54	4.14	-0.71	**134.83**	0.00	3.91	**3.91**	**138.74**	**13.87**
Ocean Wave (Pilot)	0.75	777.27	54.07	43.81	30.77	93.75	**999.65**	0.00	30.85	**30.85**	**1030.50**	**103.05**
Solar - Concentrating PV	15	414.12	0.00	25.88	39.14	-54.30	**424.84**	0.00	0.00	**0.00**	**424.84**	**42.48**
Solar - Parabolic Trough	63.5	252.23	0.00	16.77	43.65	-35.34	**277.30**	0.00	0.00	**0.00**	**277.30**	**27.73**
Solar - Photovoltaic (Single Axis)	1	726.35	0.00	47.29	21.31	-89.97	**704.98**	0.00	0.00	**0.00**	**704.98**	**70.50**
Solar - Stirling Dish	15	422.09	0.00	28.06	128.97	-60.23	**518.89**	0.00	0.00	**0.00**	**518.89**	**51.89**
Wind - Class 5	50	75.51	6.83	4.92	13.40	-16.41	**84.24**	0.00	0.00	**0.00**	**84.24**	**8.42**

Source: Energy Commission

Figure 4: Fixed and Variable Costs – Merchant Plants



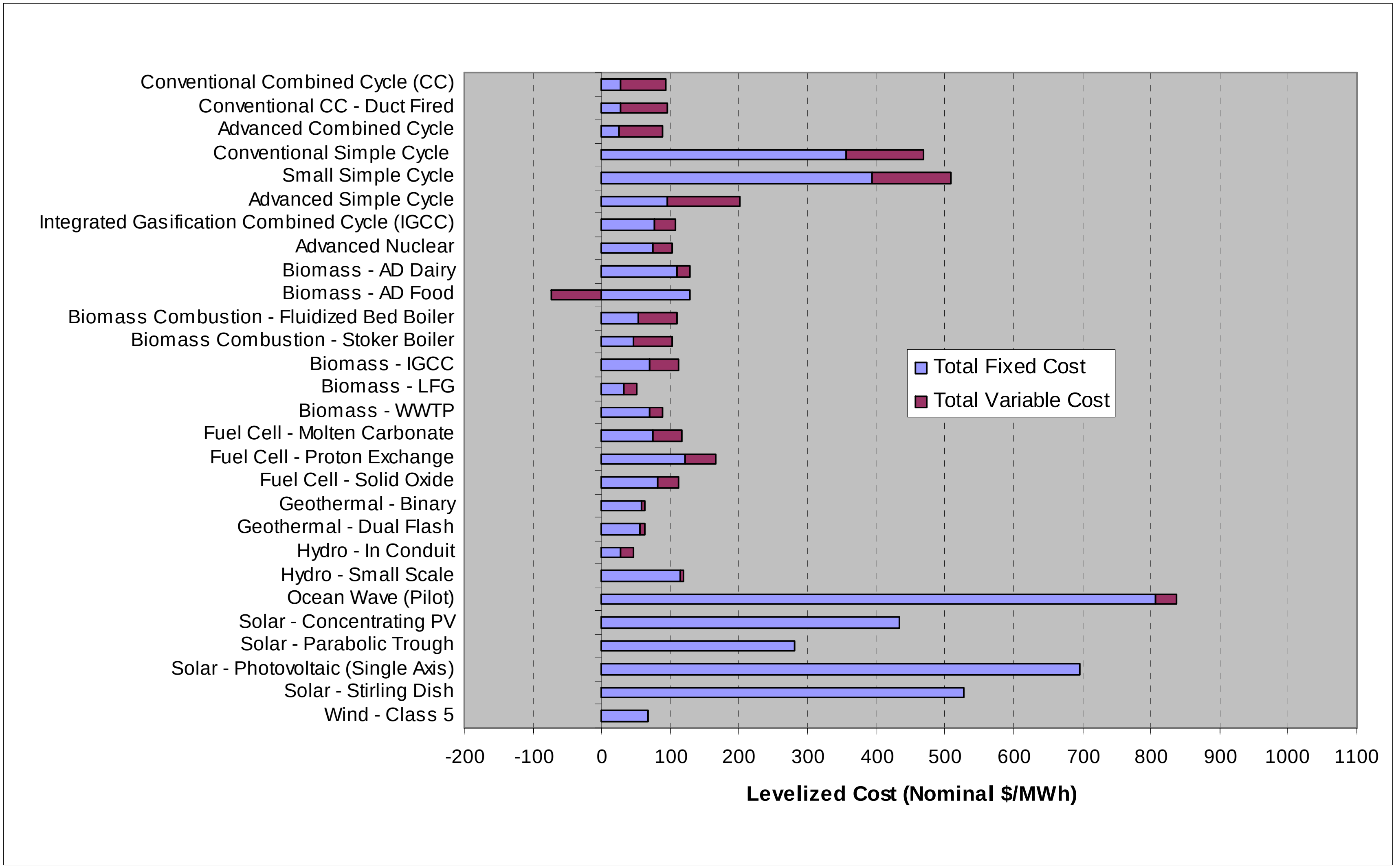
Source: Energy Commission

Table 4: Levelized Cost Components – IOU Plants

		$/MWh (Nominal 2007$)										¢/kWh
In-Service Year =2007	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	**Total Levelized Cost**	**Total Levelized Cost**
Conventional Combined Cycle (CC)	500	18.23	1.18	0.66	2.35	4.03	**26.46**	62.63	5.38	**68.02**	**94.47**	**9.45**
Conventional CC - Duct Fired	550	18.65	1.21	0.68	2.27	4.13	**26.93**	63.44	5.23	**68.66**	**95.59**	**9.56**
Advanced Combined Cycle	800	17.90	1.16	0.65	2.01	3.97	**25.68**	58.33	4.66	**62.99**	**88.68**	**8.87**
Conventional Simple Cycle	100	254.22	16.45	9.23	31.13	44.08	**355.10**	81.89	31.47	**113.36**	**468.46**	**46.85**
Small Simple Cycle	50	270.43	17.50	9.82	49.77	46.62	**394.14**	81.89	31.95	**113.84**	**507.98**	**50.80**
Advanced Simple Cycle	200	69.59	4.50	2.53	6.72	12.10	**95.44**	75.56	31.10	**106.66**	**202.10**	**20.21**
Integrated Gasification Combined Cycle (IGCC)	575	52.71	4.59	2.58	10.77	6.94	**77.59**	24.59	4.14	**28.72**	**106.32**	**10.63**
Advanced Nuclear	1000	47.31	3.69	2.07	24.46	-2.12	**75.41**	22.08	6.37	**28.46**	**103.87**	**10.39**
Biomass - AD Dairy	0.25	97.97	6.30	3.54	9.63	-7.93	**109.52**	0.00	18.88	**18.88**	**128.39**	**12.84**
Biomass - AD Food	2	98.01	6.30	3.54	28.90	-7.93	**128.83**	0.00	-74.42	**-74.42**	**54.41**	**5.44**
Biomass Combustion - Fluidized Bed Boiler	25	41.42	3.23	1.81	26.21	-19.46	**53.22**	51.65	3.96	**55.60**	**108.82**	**10.88**
Biomass Combustion - Stoker Boiler	25	38.03	2.97	1.67	23.50	-19.60	**46.56**	51.65	3.96	**55.60**	**102.17**	**10.22**
Biomass - IGCC	21.25	45.15	3.52	1.98	28.81	-9.23	**70.23**	37.73	3.96	**41.68**	**111.92**	**11.19**
Biomass - LFG	2	36.08	2.32	1.30	3.65	-11.09	**32.26**	0.00	18.61	**18.61**	**50.86**	**5.09**
Biomass - WWTP	0.5	56.89	3.66	2.05	4.72	2.91	**70.24**	0.00	18.61	**18.61**	**88.84**	**8.88**
Fuel Cell - Molten Carbonate	2	64.34	4.14	2.32	0.34	3.29	**74.42**	0.00	43.41	**43.41**	**117.83**	**11.78**
Fuel Cell - Proton Exchange	0.03	103.77	6.68	3.75	2.89	5.30	**122.39**	0.00	43.41	**43.41**	**165.80**	**16.58**
Fuel Cell - Solid Oxide	0.25	70.36	4.53	2.54	1.61	3.59	**82.63**	0.00	29.77	**29.77**	**112.40**	**11.24**
Geothermal - Binary	50	59.41	3.84	2.16	13.92	-21.39	**57.95**	0.00	5.58	**5.58**	**63.53**	**6.35**
Geothermal - Dual Flash	50	56.22	3.64	2.04	16.25	-21.56	**56.59**	0.00	5.48	**5.48**	**62.07**	**6.21**
Hydro - In Conduit	1	37.30	2.92	1.64	0.00	-13.33	**28.53**	0.00	17.15	**17.15**	**45.68**	**4.57**
Hydro - Small Scale	10	98.31	7.70	4.32	4.21	-0.43	**114.12**	0.00	3.96	**3.96**	**118.08**	**11.81**
Ocean Wave (Pilot)	0.75	672.25	43.49	24.41	31.01	35.47	**806.62**	0.00	31.02	**31.02**	**837.65**	**83.76**
Solar - Concentrating PV	15	362.76	0.00	14.65	39.63	16.96	**434.00**	0.00	0.00	**0.00**	**434.00**	**43.40**
Solar - Parabolic Trough	63.5	217.94	0.00	9.58	44.18	9.66	**281.37**	0.00	0.00	**0.00**	**281.37**	**28.14**
Solar - Photovoltaic (Single Axis)	1	619.97	0.00	27.16	21.60	26.87	**695.59**	0.00	0.00	**0.00**	**695.59**	**69.56**
Solar - Stirling Dish	15	364.38	0.00	16.02	130.44	16.16	**527.00**	0.00	0.00	**0.00**	**527.00**	**52.70**
Wind - Class 5	50	64.25	5.01	2.81	13.55	-18.47	**67.16**	0.00	0.00	**0.00**	**67.16**	**6.72**

Source: Energy Commission

Figure 5: Fixed and Variable Costs – IOUs



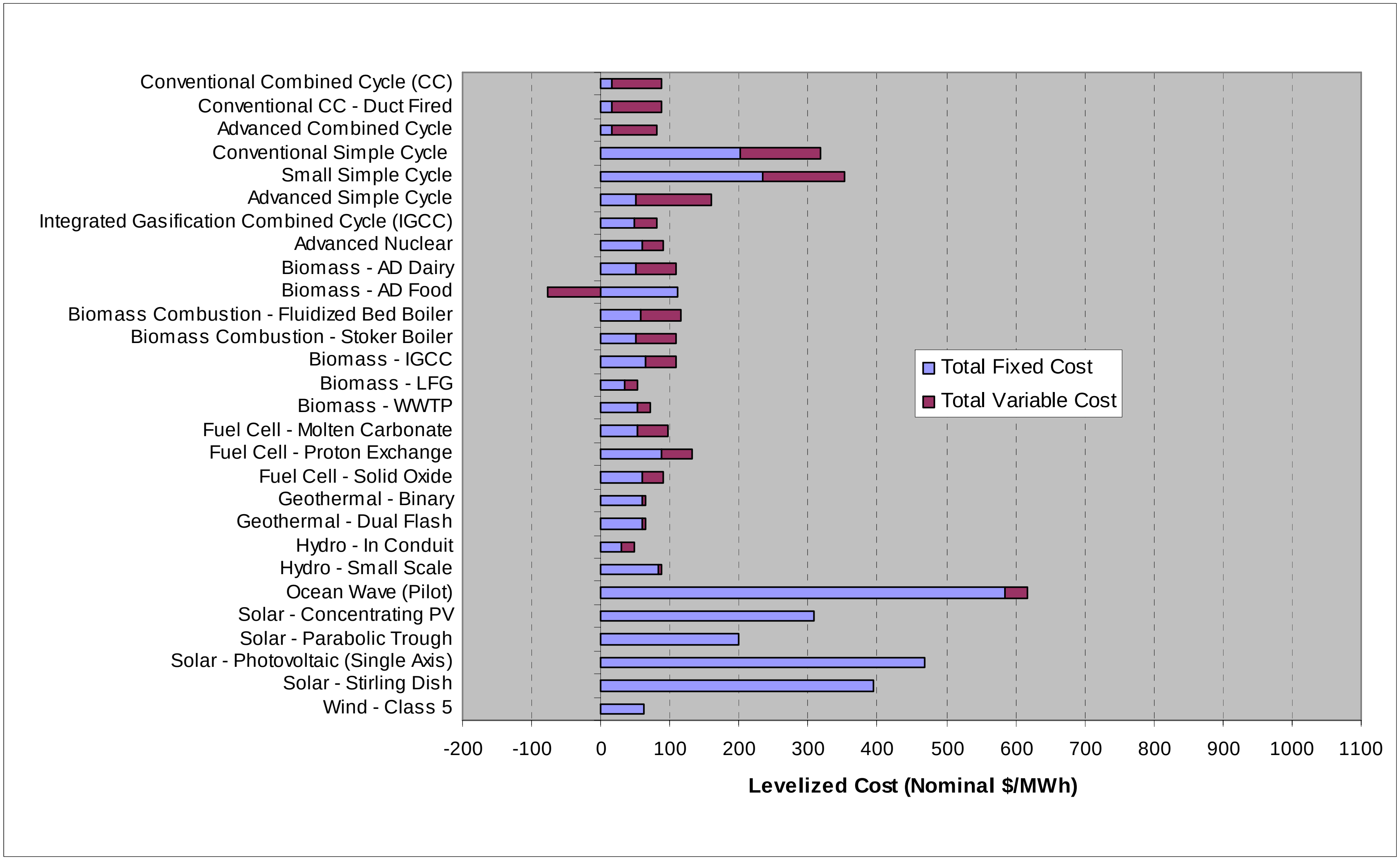
Source: Energy Commission

Table 5: Levelized Costs – Publicly Owned Plants

In-Service Year =2007	Size MW	$/MWh (Nominal 2007$) Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	Total Fixed Cost	Fuel	Variable O&M	Total Variable Cost	Total Levelized Cost	¢/kWh Total Levelized Cost
Conventional Combined Cycle (CC)	500	11.98	1.00	1.11	2.41	0.00	**16.50**	64.82	5.52	**70.34**	**86.84**	**8.68**
Conventional CC - Duct Fired	550	12.27	1.03	1.14	2.33	0.00	**16.77**	65.65	5.36	**71.01**	**87.78**	**8.78**
Advanced Combined Cycle	800	11.74	0.98	1.09	2.06	0.00	**15.88**	60.36	4.78	**65.14**	**81.02**	**8.10**
Conventional Simple Cycle	100	144.11	12.08	13.39	31.88	0.00	**201.47**	84.62	32.23	**116.86**	**318.33**	**31.83**
Small Simple Cycle	50	155.71	13.05	14.47	50.97	0.00	**234.20**	84.62	32.72	**117.34**	**351.55**	**35.15**
Advanced Simple Cycle	200	37.21	3.12	3.46	6.89	0.00	**50.67**	78.09	31.85	**109.93**	**160.60**	**16.06**
Integrated Gasification Combined Cycle (IGCC)	575	28.96	3.77	4.36	11.71	0.00	**48.80**	27.42	4.50	**31.92**	**80.72**	**8.07**
Advanced Nuclear	1000	27.62	3.04	3.46	25.73	0.00	**59.84**	24.58	6.70	**31.28**	**91.12**	**9.11**
Biomass - AD Dairy	0.25	24.21	2.66	3.04	24.82	-3.32	**51.41**	54.19	4.18	**58.36**	**109.77**	**10.98**
Biomass - AD Food	2	69.01	5.79	6.41	29.59	-0.60	**110.20**	0.00	-76.21	**-76.21**	**33.99**	**3.40**
Biomass Combustion - Fluidized Bed Boiler	25	26.32	2.89	3.29	27.57	-3.31	**56.77**	54.19	4.16	**58.35**	**115.12**	**11.51**
Biomass Combustion - Stoker Boiler	25	24.17	2.66	3.02	24.72	-3.31	**51.26**	54.19	4.16	**58.35**	**109.61**	**10.96**
Biomass - IGCC	21.25	28.25	3.11	3.53	30.30	-0.47	**64.72**	39.58	4.16	**43.74**	**108.46**	**10.85**
Biomass - LFG	2	25.61	2.15	2.38	3.77	-0.60	**33.31**	0.00	19.05	**19.05**	**52.36**	**5.24**
Biomass - WWTP	0.5	41.09	3.44	3.82	4.98	-0.60	**52.73**	0.00	19.05	**19.05**	**71.78**	**7.18**
Fuel Cell - Molten Carbonate	2	44.94	3.77	4.18	0.35	0.00	**53.23**	0.00	44.46	**44.46**	**97.69**	**9.77**
Fuel Cell - Proton Exchange	0.03	72.49	6.08	6.74	2.96	0.00	**88.26**	0.00	44.46	**44.46**	**132.72**	**13.27**
Fuel Cell - Solid Oxide	0.25	49.15	4.12	4.57	1.64	0.00	**59.48**	0.00	30.49	**30.49**	**89.97**	**9.00**
Geothermal - Binary	50	41.83	3.51	3.89	14.78	-4.17	**59.84**	0.00	5.72	**5.72**	**65.55**	**6.56**
Geothermal - Dual Flash	50	39.56	3.32	3.68	17.25	-4.17	**59.64**	0.00	5.61	**5.61**	**65.26**	**6.53**
Hydro - In Conduit	1	24.09	2.65	3.01	0.00	0.00	**29.75**	0.00	18.03	**18.03**	**47.78**	**4.78**
Hydro - Small Scale	10	63.49	6.98	7.94	4.51	0.00	**82.93**	0.00	4.16	**4.16**	**87.09**	**8.71**
Ocean Wave (Pilot)	0.75	473.75	39.72	44.02	32.04	-4.17	**585.37**	0.00	31.76	**31.76**	**617.12**	**61.71**
Solar - Concentrating PV	15	243.29	0.00	26.76	41.69	-3.65	**308.09**	0.00	0.00	**0.00**	**308.09**	**30.81**
Solar - Parabolic Trough	63.5	138.58	0.00	17.35	46.68	-3.31	**199.31**	0.00	0.00	**0.00**	**199.31**	**19.93**
Solar - Photovoltaic (Single Axis)	1	399.33	0.00	49.96	22.90	-3.31	**468.87**	0.00	0.00	**0.00**	**468.87**	**46.89**
Solar - Stirling Dish	15	230.77	0.00	28.87	137.14	-3.31	**393.47**	0.00	0.00	**0.00**	**393.47**	**39.35**
Wind - Class 5	50	40.84	4.49	5.11	14.26	-3.31	**61.38**	0.00	0.00	**0.00**	**61.38**	**6.14**

Source: Energy Commission

Figure 6: Fixed and Variable Costs – Publicly Owned Plants



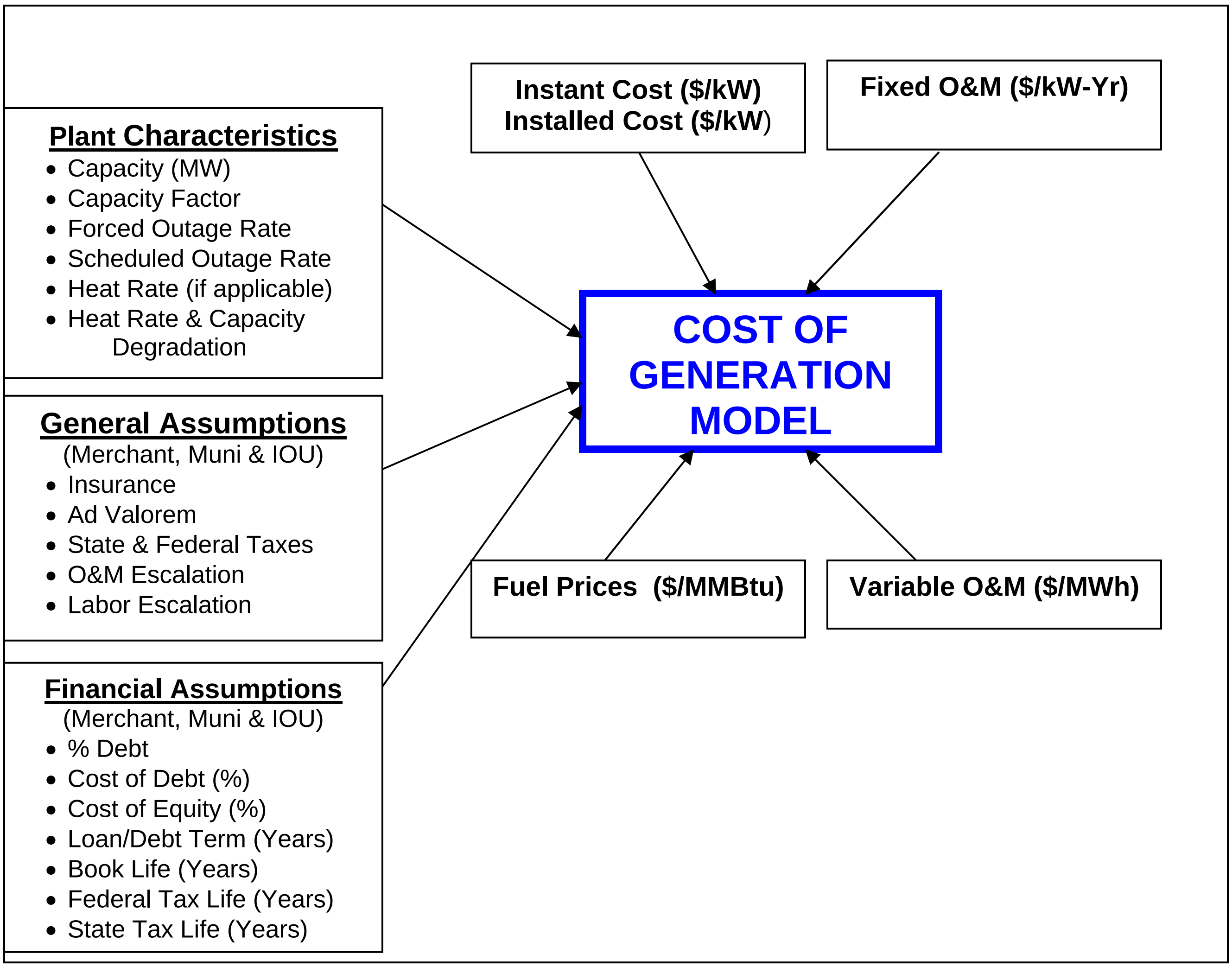
Source: Energy Commission

CHAPTER 2: Assumptions

This chapter summarizes the assumptions, the data collection and interpretation process, and a comparison to *2003 IEPR* assumptions.

Figure 7 shows a simplified block diagram of the Model's input assumptions.

Figure 7: Flow Chart of Cost of Generation Model Inputs



Source: Energy Commission

Summary of Assumptions

Tables 6 and **7** summarize the most common input assumptions. All costs are for 2007 and are in nominal dollars.

Table 6: Common Assumptions

Technology (All costs in Nominal 2007$)	Gross Capacity (MW)	Capacity Factor (%)	HHV Heat Rate (Btu/kWh)	Instant Cost ($/kW)	Installed Cost ($/kW)			Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)
					Merchant	IOU	Muni		
Conventional Combined Cycle (CC)	500	60.00%	6,990	781	844	849	779	9.86	4.42
Conventional CC - Duct Fired	550	60.00%	7,080	798	863	868	798	9.53	4.28
Advanced Combined Cycle	800	60.00%	6,510	766	828	834	763	8.42	3.83
Conventional Simple Cycle	100	5.00%	9,266	925	1000	1000	793	11.00	25.72
Small Simple Cycle	50	5.00%	9,266	974	1053	1053	846	17.65	26.10
Advanced Simple Cycle	200	5.00%	8,550	756	817	817	610	7.13	25.57
Integrated Gasification Combined Cycle (IGCC)	575	60.00%	8,979	2,198	3,007	2,941	2,569	36.27	3.11
Advanced Nuclear	1000	85.00%	10,400	2,950	3,754	3,662	3,177	140.00	5.00
Biomass - AD Dairy	0.25	75.00%	12,407	5,800	5,923	5,911	5,837	51.81	15.77
Biomass - AD Food	2	75.00%	17,060	5,803	5,925	5,913	5,840	155.44	-62.18
Biomass Combustion - Fluidized Bed Boiler	25	85.00%	15,509	3,156	3,223	3,217	3,177	150.26	3.11
Biomass Combustion - Stoker Boiler	25	85.00%	15,509	2,899	2,960	2,954	2,917	134.72	3.11
Biomass - IGCC	21.25	85.00%	10,663	3,121	3,320	3,301	3,181	155.44	3.11
Biomass - LFG	2	85.00%	11,566	2,254	2,302	2,296	2,263	20.73	15.54
Biomass - WWTP	0.5	75.00%	12,407	2,743	2,801	2,794	2,748	20.73	15.54
Fuel Cell - Molten Carbonate	2	90.00%	8,322	4,488	4,678	4,659	4,546	2.18	36.27
Fuel Cell - Proton Exchange	0.03	90.00%	13,127	7,239	7,545	7,515	7,332	18.65	36.27
Fuel Cell - Solid Oxide	0.25	90.00%	8,530	4,908	5,116	5,096	4,972	10.36	24.87
Geothermal - Binary	50	95.00%	N/A	3,093	3,548	3,501	3,227	72.54	4.66
Geothermal - Dual Flash	50	93.00%	N/A	2,866	3,287	3,244	2,988	82.90	4.58
Hydro - In Conduit	1	51.40%	N/A	1,547	1,612	1,606	1,567	0.00	13.47
Hydro - Small Scale	10	52.00%	N/A	4,125	4,299	4,282	4,178	13.47	3.11
Ocean Wave (Pilot)	0.75	15.00%	N/A	7,203	7,662	7,617	7,342	31.09	25.91
Solar - Concentrating PV	15	23.00%	N/A	5,156	5,372	5,352	5,222	46.63	0.00
Solar - Parabolic Trough	63.5	27.00%	N/A	4,021	4,190	4,175	4,073	62.18	0.00
Solar - Photovoltaic (Single Axis)	1	22.14%	N/A	9,611	9,678	9,672	9,632	24.87	0.00
Solar - Stirling Dish	15	24.00%	N/A	6,187	6,446	6,423	6,266	168.92	0.00
Wind - Class 5	50	34.00%	N/A	1,959	2,000	1,997	1,972	31.09	0.00

Source: Energy Commission

Table 7: Emission Factors

Technology	Emission Factors (Lbs/MWh)					
	NOx	VOC	CO	CO2	SOx	PM10
Conventional Combined Cycle (CC)	0.056	0.017	0.049	817.62	0.007	0.035
Conventional CC - Duct Fired	0.064	0.018	0.050	828.14	0.007	0.028
Advanced Combined Cycle	0.046	0.016	0.046	761.47	0.007	0.026
Conventional Simple Cycle	0.093	0.023	0.093	1083.84	0.009	0.065
Small Simple Cycle	0.093	0.023	0.093	1083.84	0.009	0.065
Advanced Simple Cycle	0.076	0.019	0.053	886.63	0.008	0.053
Integrated Gasification Combined Cycle (IGCC)	0.530	0.000	0.000	1928.00	0.300	0.000
Advanced Nuclear	0.000	0.000	0.000	0.000	0.000	0.000
Biomass - AD Dairy	1.700	0.000	0.000	0.000	0.390	0.000
Biomass - AD Food	1.700	0.000	0.000	0.000	0.420	0.000
Biomass Combustion - Fluidized Bed Boiler	1.240	0.000	0.000	0.000	0.700	0.000
Biomass Combustion - Stoker Boiler	1.240	0.000	0.000	0.000	0.700	0.000
Biomass - IGCC	0.850	0.000	0.000	0.000	0.700	0.000
Biomass - LFG	1.700	0.000	0.000	0.000	0.340	0.000
Biomass - WWTP	1.700	0.000	0.000	0.000	0.390	0.000
Fuel Cell - Molten Carbonate	0.010	0.000	0.000	0.000	0.003	0.000
Fuel Cell - Proton Exchange	0.100	0.000	0.000	0.000	0.000	0.000
Fuel Cell - Solid Oxide	0.050	0.000	0.000	0.000	0.000	0.000
Geothermal - Binary	0.000	0.000	0.000	0.000	0.000	0.000
Geothermal - Dual Flash	0.000	0.000	0.000	60.000	0.350	0.000
Hydro - In Conduit	0.000	0.000	0.000	0.000	0.000	0.000
Hydro - Small Scale	0.000	0.000	0.000	0.000	0.000	0.000
Ocean Wave (Pilot)	0.000	0.000	0.000	0.000	0.000	0.000
Solar - Concentrating PV	0.000	0.000	0.000	0.000	0.000	0.000
Solar - Parabolic Trough	0.000	0.000	0.000	0.000	0.000	0.000
Solar - Photovoltaic (Single Axis)	0.000	0.000	0.000	0.000	0.000	0.000
Solar - Stirling Dish	0.000	0.000	0.000	0.000	0.000	0.000
Wind - Class 5	0.000	0.000	0.000	0.000	0.000	0.000

Source: Energy Commission

Capacity Factor

The capacity factor (CF) is a measure of how much the power plant operates. More precisely, it is equal to the energy generated by the power plant during the year divided by the energy it could have generated if it had run at its dependable capacity throughout the entire year (8,760 hours).

Instant Cost

Instant cost, sometimes referred to as overnight cost, is the initial expenditure, which does not include the costs incurred during construction (see installed cost) – that is, it assumes that the plant could have been constructed in an instant requiring no construction loan or associated expenses. Instant costs include the component cost, land cost, development cost, permitting cost, linears, and environmental control costs.

Installed Cost

Installed cost 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.

Fixed Operations and Maintenance

Conceptually, fixed O&M comprises those costs that occur regardless of how much the plant operates. What is included in this category is not always consistent from one assessment to the other but always includes labor costs and the associated overhead. Other costs that are not consistently included are equipment (and leasing of equipment), regulatory filings, and miscellaneous direct costs. The Energy Commission staff recently changed to a convention that includes all of these components in the fixed O&M costs.

Variable Operations and Maintenance

Operations and maintenance are a function of the operation of the power plant and includes:

- Scheduled outage maintenance – annual maintenance and overhauls
- Forced outage maintenance
- Water supply costs
- Environmental costs

Scheduled outage maintenance, which includes annual maintenance and overhaul costs, is by far the largest expenditure.

Capital and Financing Assumptions

Capital and financing assumptions cover the entire cost of building and financing the construction of the power plant. These costs include the amortization of the loan, both principal and interest. These costs vary depending upon the developer because of the different interest rates available for IOUs, POUs, and merchants. Capital costs are described later in the report. **Table 8** summarizes the financial assumptions being used in the Model. Note that the debt to equity split is different for merchant gas-fired plants than non gas-fired plants (clean coal, advanced nuclear, and alterative technologies). The financial assumptions for gas-fired plants are available from the BOE and are known with a high degree of certainty. The corresponding assumption for the other plants is based on Navigant Consulting Inc. (Navigant) estimates.

Table 8: Financial Assumptions

	Merchant Gas-Fired	Merchant Non Gas-Fired	IOU	POU
% Debt	40.0%	60.0%	50.0%	100.0%
% Equity	60.0%	40.0%	50.0%	0.0%
Cost of Debt (%)	6.5%	6.5%	5.73%	4.35%
Cost of Equity (%)	15.19%	15.19%	11.74%	0.0%

Source: Energy Commission

Insurance

Insurance is calculated differently depending on the type of developer. For an IOU, the cost is based on the book value. For a merchant facility or publicly owned plant, the cost is calculated as a fraction of the installed cost. The fraction used in the Model is 0.6 percent, and the annual cost then escalates with nominal inflation.

Ad Valorem

In California, ad valorem (property tax) is different depending on the developer. The merchant-owned facility tax is based on the market value assessed by the BOE. The value reflects the market value of the asset but may not increase in value at a rate faster than 2 percent per annum per Proposition 13. The Model assumes an initial rate of 1.07 multiplied by the installed cost of the power plant and a property tax depreciation factor. The utility-owned plant tax is based on the value assessed by the BOE and is set to the net depreciated book value. The Model assumes an initial cost of $1.07 multiplied by the book value. Counties are allocated property tax revenues based on the share of rate base within each county. Publicly owned plants are exempt from paying property taxes but may pay a negotiated in-lieu fee.

Corporate Taxes

Corporate taxes are state and federal taxes. Again, these taxes depend on the developer type. A POU is exempt from state and federal taxes. The calculation of taxes for a merchant facility or IOU power plant is based on the taxable income. The rates are shown in **Table 9**.

Table 9: Tax Rates

Tax	Rate
Federal Tax	35.0%
CA State Tax	8.84%
Total Tax Rate	40.7%

Source: Energy Commission

Fuel Prices

The fuel prices used in this report are summarized in **Table 10**. The natural gas prices are a preliminary estimate developed from the *2005 IEPR* gas prices by modifying the first two years using forward gas prices. As of this time, there is no official *2007 IEPR* gas price series. The nuclear and coal fuel prices were developed from *2007 IEPR* data, and biomass fuel prices were developed by Navigant.

Description of Data Gathering and Analysis

Staff conducted two separate data gatherings: one for the combined cycle and simple cycle (combustion turbines) and one for the alternative technologies, clean coal, and nuclear.

Combined and Simple Cycle Data Collection

Initially, staff attempted to gather the modeling input information using the Energy Commission's Application for Certification (AFC) filings but discovered that the available capital cost data from AFC filings were inadequate. Cost estimates appeared to be inconsistent with one another and unrealistically low. Based on a preliminary assessment, the actual capital costs for building new combined cycle power plants over the last five years were approximately 25 percent higher than the estimated capital costs in recent AFC filings. Simple cycle estimates appeared to be even more inadequate. Additionally, the AFC filings did not contain useful operating cost data.

Table 10: Fuel Prices

Deflator Series 2007=1	Year	PG&E	SCE	SDG&E	SMUD	LADWP	IID	CA - Avg.	Uranium	Coal	Biomass
1.00	2007	8.30	8.23	8.74	8.50	8.50	8.50	8.34	0.63	1.47	2.57
1.02	2008	6.72	6.76	7.32	6.81	7.07	7.07	6.82	0.75	1.68	2.63
1.04	2009	6.80	6.80	7.11	6.92	7.06	7.06	6.87	0.89	1.70	2.69
1.07	2010	5.46	5.71	6.20	5.42	6.09	6.09	5.69	1.05	1.72	2.74
1.09	2011	7.04	7.25	7.74	7.05	7.66	7.66	7.26	1.26	1.71	2.80
1.11	2012	6.69	6.84	7.25	6.72	7.22	7.22	6.87	1.50	1.83	2.85
1.13	2013	8.08	8.28	8.59	8.04	8.57	8.57	8.26	1.77	1.90	2.91
1.15	2014	7.39	7.57	7.88	7.36	7.86	7.86	7.56	2.11	1.97	2.97
1.17	2015	8.52	8.61	8.65	8.57	8.90	8.90	8.63	2.58	2.04	3.02
1.20	2016	8.58	8.72	8.82	8.59	9.01	9.01	8.72	2.63	2.12	3.08
1.22	2017	8.63	8.82	8.99	8.60	9.12	9.12	8.80	2.68	2.19	3.14
1.24	2018	9.16	9.42	9.62	9.12	9.77	9.77	9.38	2.73	2.27	3.20
1.26	2019	9.71	10.04	10.28	9.65	10.45	10.45	9.98	2.78	2.35	3.25
1.29	2020	9.91	10.21	10.41	9.87	10.60	10.60	10.16	2.83	2.43	3.32
1.31	2021	10.12	10.38	10.54	10.09	10.75	10.75	10.34	2.89	2.52	3.38
1.34	2022	10.58	10.91	11.10	10.54	11.33	11.33	10.86	2.94	2.59	3.44
1.36	2023	11.06	11.47	11.69	11.00	11.94	11.94	11.39	3.00	2.70	3.51
1.39	2024	11.53	11.87	12.01	11.47	12.28	12.28	11.81	3.05	2.73	3.57
1.41	2025	12.01	12.28	12.35	11.95	12.63	12.63	12.23	3.11	2.83	3.64
1.44	2026	12.44	12.72	12.80	12.37	13.09	13.09	12.67	3.17	2.94	3.71
1.47	2027	12.91	13.21	13.28	12.83	13.58	13.58	13.15	3.23	3.02	3.78
1.49	2028	13.44	13.75	13.79	13.35	14.12	14.12	13.68	3.29	3.12	3.85
1.52	2029	13.96	14.28	14.30	13.87	14.65	14.65	14.21	3.35	3.23	3.92
1.55	2030	14.48	14.80	14.78	14.38	15.16	15.16	14.73	3.41	3.33	3.99
1.58	2031	15.05	15.36	15.31	14.94	15.71	15.71	15.28	3.48	3.44	4.07
1.61	2032	15.65	15.97	15.89	15.53	16.31	16.31	15.89	3.54	3.56	4.14
1.64	2033	16.27	16.59	16.47	16.15	16.92	16.92	16.50	3.61	3.67	4.22
1.67	2034	16.91	17.21	17.05	16.78	17.52	17.52	17.13	3.67	3.77	4.30
1.70	2035	17.57	17.87	17.66	17.43	18.16	18.16	17.78	3.74	3.90	4.38
1.73	2036	18.26	18.55	18.30	18.10	18.83	18.83	18.46	3.81	3.97	4.46
1.77	2037	18.97	19.26	18.96	18.80	19.52	19.52	19.16	3.88	4.04	4.54
1.80	2038	19.72	20.00	19.65	19.53	20.25	20.25	19.90	3.96	4.12	4.63
1.83	2039	20.49	20.77	20.36	20.29	20.99	20.99	20.66	4.03	4.20	4.72
1.87	2040	21.29	21.56	21.09	21.08	21.76	21.76	21.44	4.11	4.27	4.80
1.90	2041	22.12	22.38	21.86	21.90	22.56	22.56	22.26	4.18	4.35	4.89
1.94	2042	22.99	23.24	22.65	22.75	23.39	23.39	23.12	4.26	4.44	4.99
1.97	2043	23.90	24.13	23.47	23.64	24.25	24.25	24.00	4.34	4.52	5.08
2.01	2044	24.83	25.05	24.31	24.56	25.13	25.13	24.92	4.42	4.60	5.17
2.05	2045	25.80	26.01	25.19	25.51	26.06	26.06	25.87	4.51	4.69	5.27

Source: Energy Commission

Staff then decided to request this information directly from the power plant developers. All the combined cycle (but not cogeneration) and simple cycle power plants that were certified by the Energy Commission starting in 1999 and on-line since 2001 through the first quarter of 2006 received a data request. These plants are summarized in **Table 11**, together with the in-service year and county location.

Table 11: Surveyed Power Plants

Combined Cycle Plants (19)			Simple Cycle Plants (15)		
Plant Name	**County**	**Operating**	**Plant Name**	**County**	**Operating**
Los Medanos	Contra Costa	2001	Wildflower Larkspur [2]	San Diego	2001
Sutter	Sutter	2001	Wildflower Indigo [2]	Riverside	2001
Delta	Contra Costa	2002	Drews Alliance [2]	San Bernardino	2001
Moss Landing	Monterey	2002	Century Alliance [2]	San Bernardino	2001
La Paloma	Kern	2003	Hanford [2]	Kings	2001
High Desert	San Bernardino	2003	Calpeak Escondido [2]	San Diego	2001
MID Woodland [1,2]	Stanislaus	2003	Calpeak Border [2]	San Diego	2001
Sunrise	Kern	2003	Gilroy [2]	Santa Clara	2002
Blythe I	Riverside	2003	King City [2]	Monterey	2002
Elk Hills	Kern	2003	Henrietta	Kings	2002
Von Raesfeld [1]	Santa Clara	2005	Los Esteros	Santa Clara	2003
Metcalf	Santa Clara	2005	Tracy Peaker	San Joaquin	2003
Magnolia [1]	Los Angeles	2005	Kings River Peaker [1,2]	Fresno	2005
Malburg [1]	Los Angeles	2005	Ripon	San Joaquin	2006
Pastoria	Kern	2005	Riverside	Riverside	2006
Mountainview [3]	San Bernardino	2006			
Palomar	San Diego	2006			
Cosumnes	Sacramento	2006			
Walnut	Stanislaus	2006			

Notes:
1 – Muni-owned facility
2 – Emergency Siting or SPPE Cases
3 – IOU-owned facility

Source: Energy Commission

Capital cost information was requested from all 34 plants, while operating costs were requested from plants that began regular operations in 2005 or earlier. The data requests for the combined cycle and simple cycle units were divided into capital costs and operating and maintenance costs, as summarized in **Table 12**.

Table 12: Summary of Requested Data

Capital Cost Parameters	**Operating & Maintenance Cost Parameters**
Gas Turbine and Combustor Make/Models	Total Annual Operating Costs
Steam Turbine Make/Model	Operating Hours
Total Capital Cost of Facility	Startup/Shutdown Hours
Gas Turbine Cost	Natural Gas Sources
Steam Turbine Cost	Duct Burner Natural Gas Use
Air Inlet Treatment Cost	Water Supply Source/Cost/Consumption
Cooling Tower/Air Cooled Condenser Cost	Labor (Staffing and Cost)
Water Treatment Facilities	Non-Fuel Annual Operating Costs (Consumables, etc.)
Site Footprint and Land Cost	Annual Regulatory Costs (Filings, Consumables, etc.)
Total Construction Costs (Labor/Equipment/etc.)	Major Scheduled Overhaul Frequency/Cost
Cost of Site Grading	Normal Annual Maintenance Costs
Cost of Pipeline Linear Construction	Reconciliation of QFER data (MW generation and total fuel use)
Cost of Transmission Linear Construction	
Cost of Licensing/Permitting Project	
Air Pollution Control Costs	
Cost of Air Quality Offsets	

Source: Energy Commission

Each power plant received an information request tailored according to the design of that plant. For example, simple cycle facilities did not receive questions about steam turbines and duct burners.

The responses were reviewed, and additional data or clarification of data was requested, as appropriate for each power plant, to complete and validate the information to the extent possible. As much of this data was gathered under confidentiality agreements, the details can be presented and discussed only in general, collective terms.

Spreadsheet analysis and comparison of relative costs as a function of various variables enabled determination of a suitable base cost plus adders to atypical configurations for the following four categories.

Combined Cycle Capital Costs

By making cost adjustments to each of the combined cycle cost components, all the units could be reduced to a common base case configuration, which is shown in **Table 13.**

Table 13: Base Case Configuration - Combined Cycle

Combined Cycle Base Configuration
1) 500 MW Plant W/O Duct Firing
2) 2 Turbines W/ 1 Steam Generator
3) GE 7F Gas Turbines
4) Wet Cooling
5) Greenfield Site
6) Non-Urban Land Cost
7) Reclaimed Water Source
8) Evaporative Coolers/Foggers
9) Selective Catalytic Reduction (SCR) & Oxidation Catalyst
10) Zero Liquid Discharge (ZLD)
11) Not Co-Located W/ Other Power Facilities
12) 12-Month Licensing Process

Source: Energy Commission

These base case costs were then averaged to develop the base installed costs shown in **Table 14**. These costs include equipment, land, development, air emission control equipment, water treatment, and water cooling costs. The total installed costs are then calculated by estimating the linears (transmission, gas supply, water, and sewer), permits (building and environmental) and emission reduction credits (ERCs). The linear and the permit costs are estimated from the survey data. The ERC costs are based on emission factors developed by Energy Commission staff and are calculated by the Model for each of the California air districts. The value shown here is an average California value, calculated by the Model.

Table 14: Base Case Installed Costs for Combined Cycles

500 MW Combined Cycle Unit (Nominal 2007$)	**Merchant ($/kW)**	**IOU ($/kW)**	**Muni ($/kW)**
Base Installed Cost	**747**	**753**	**716**
Linears	**66**	**66**	**33**
Permits	**11**	**11**	**11**
ERCs (California Average)	**20**	**20**	**20**
Total Installed Cost	**844**	**849**	**779**

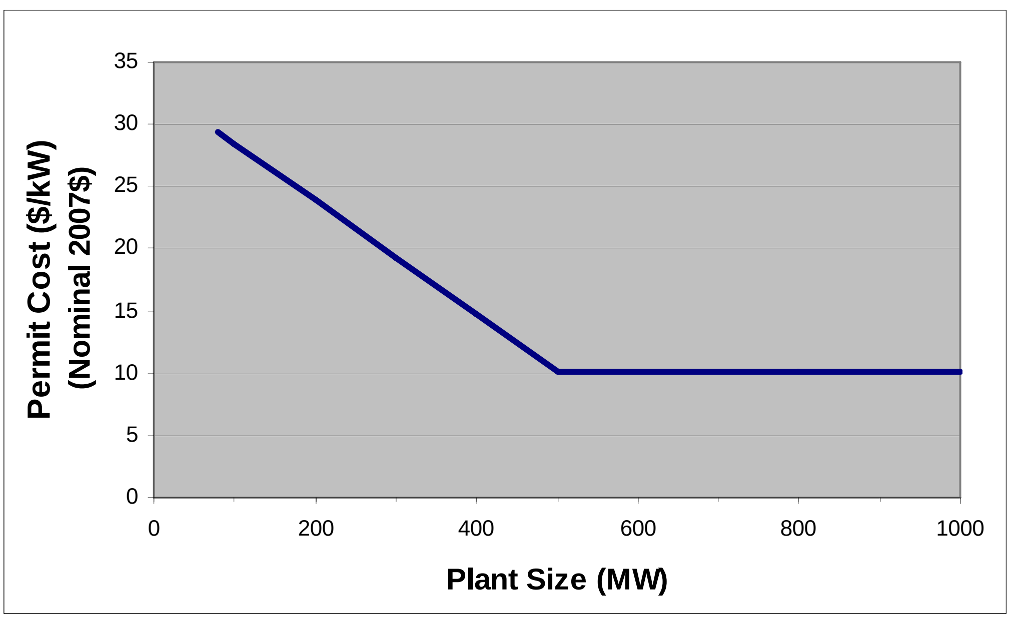
Source: Energy Commission

The above adders are shown as single values, however, permit and ERC costs are variable. Permits were found to be a function of plant size ($Size_{MW}$) and are entered in the Model accordingly:

- 500 MW and above: ***10.2***
- Below 500 MW: (***33 – 0.0456*** $\boldsymbol{Size_{MW}}$ ***)***

Figure 8 shows this graphically.

Figure 8: Combined Cycle Permit Costs



Source: Energy Commission

The ERCs in the table above are a single average California value but are a function of the location of the power plant. The cost of ERCs is constantly changing for all areas in California, but ERCs are clearly more costly in some areas than others. The staff anticipates that these costs will increase disproportionately over time and need to be critically evaluated regularly. One particular issue is the impact of the priority reserve credit costs for the South Coast Air Basin when the South Coast Air Quality Management District finalizes the priority reserve Rule 1309.1.

Table 15 shows the total installed costs for the standard combined cycle configurations available in the Model, including the above 500 MW unit. As before, it assumes permit costs and California average ERCs.

Table 15: Total Installed Costs for All Combined Cycle Units

Various Combined Cycle Units (Nominal 2007$)	**Merchant ($/kW)**	**IOU ($/kW)**	**Muni ($/kW)**
Conventional 500 MW CC without Duct Firing	844	849	779
Conventional 550 MW CC with Duct Firing	863	868	798
Advanced 800 MW CC without Duct Firing	828	834	763

Source: Energy Commission

The base installed costs are for a 2-on-1 configuration – two turbines and one steam generator, but the survey determined that the cost was dependent on the configuration. The Model has a selection option to incorporate survey data, which reduces cost approximated at $81/kW for each additional turbine and increases cost by $81/kW for a single turbine plant.

Cost adders for less common component costs were also calculated from the survey data that are not incorporated directly into the Model, but can be entered exogenously into the Model. These adders are shown in **Table 16**.

Combined Cycle Operating Costs

The operating costs consist of three components: fixed O&M, variable O&M, and fuel. Fuel costs were discussed earlier.

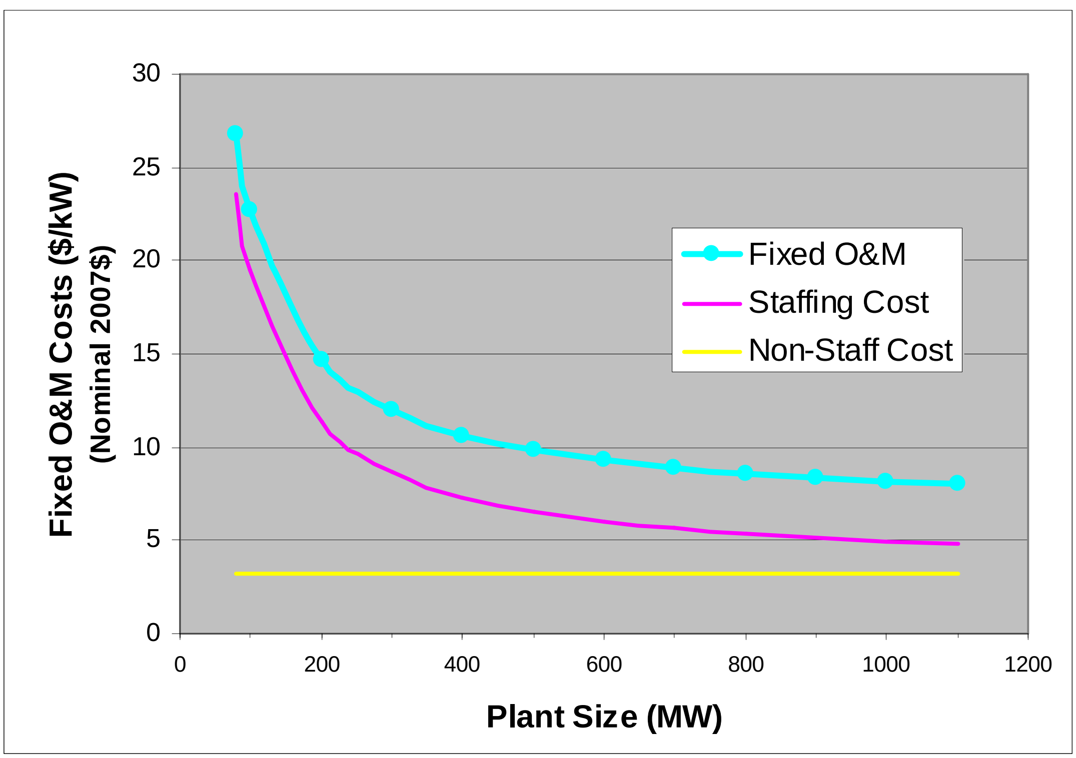
Fixed O&M is composed of two components: staffing costs and non-staffing costs. Non-staffing costs are equipment, regulatory filings, and other direct costs. The staffing cost, and thus the total fixed cost, varies with plant size as shown in **Figure 9**.

Table 16: Installed Cost Adders for Combined Cycles

Combined Cycle Units (Nominal 2007$)	**$/kW**
Dry Cooling	48
Chillers	11
Plume Abated Cooling Tower	6
No Oxidation Catalyst	-4
Urban Site	11
Co-located facility (Muni only)	-43
Alternative Gas Turbine Type	
SW 501	-32
Alstom GT-24	21
GE 7E	48
Alstom GTX100	53
GE LM6000	16

Source: Energy Commission

Figure 9: Combined Cycle Fixed O&M Costs



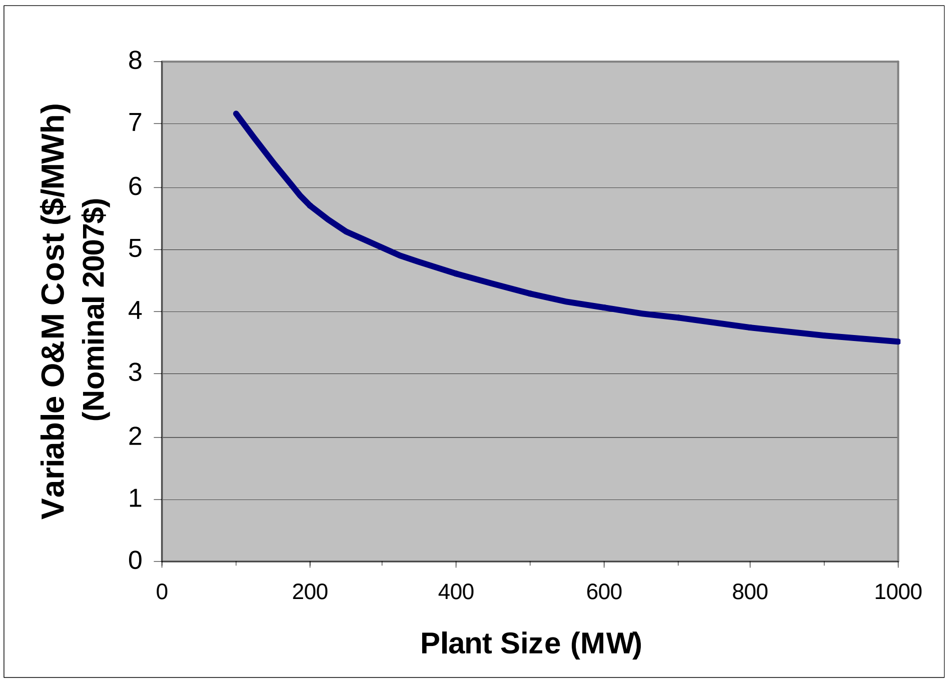
Source: Energy Commission

Variable O&M is composed of the following components:

- Scheduled outage maintenance – annual maintenance and overhauls
- Forced outage maintenance
- Consumables maintenance
- Water supply costs
- Environmental costs

Figure 10 shows the total variable O&M as a function of plant size. Of all the components, the scheduled and overhaul maintenance is the largest: about 75 to 90 percent of the total cost, depending on the year in question.

Figure 10: Combined Cycle Variable O&M



Source: Energy Commission

Simple Cycle Capital Costs

Similar to the combined cycle units, adjustments were made to each of the simple cycle units so that they could be reduced to a common base configuration, which is shown in **Table 17**. These base case costs were then averaged to develop the base installed costs shown in **Table 18**. These costs include equipment, land, development, air emission control equipment, water treatment, and water cooling costs.

The total installed costs are then calculated by estimating the linears (transmission, gas supply, water, and sewer), permits (building and environmental) and ERCs.

The linears and the permits are estimated from the survey data; permits were estimated at $21/kW except for units under 50 MW, which were estimated as $11/kW. The ERC costs are based on data developed by Energy Commission staff and calculated by the Model based on that information. The Model is able to calculate ERCs for each of the California air districts. The value shown here is an average California value, calculated by the Model.

Table 17: Base Case Configuration – Simple Cycle

1) 100 MW Merchant Plant
2) 2 LM6000 Turbines
3) Wet Cooling Or Dry Cooling
4) Brownfield Site
5) Non-Urban Land Cost
6) Potable Water Source
7) Evaporative Coolers/Foggers
8) Oxidation Catalyst Used
9) ZLD
10) Not Co-Located W/ Other Power Facilities

Source: Energy Commission

Table 18: Base Case Installed Costs for Simple Cycle

100 MW Simple Cycle Unit (Nominal 2007$)	**Merchant ($/kW)**	**IOU ($/kW)**	**Muni ($/kW)**
Base Installed Cost	**942**	**942**	**735**
Linears	34	34	34
Permits	21	21	21
ERCs (California Average)	3	3	3
Total Installed Cost	**1000**	**1000**	**793**

Source: Energy Commission

Table 19 shows the total installed costs for the standard simple cycle configurations available in the Model, including the above 100 MW unit. As before, this includes permit costs and California average ERCs.

Table 19: Total Installed Costs for Simple Cycle Units

Various Simple Cycle Units (Nominal 2007$)	**Merchant ($/kW)**	**IOU ($/kW)**	**Muni ($/kW)**
Conventional 50 MW SC	1053	1053	846
Conventional 100 MW SC	1000	1000	793
Advanced 200 MW SC	817	817	610

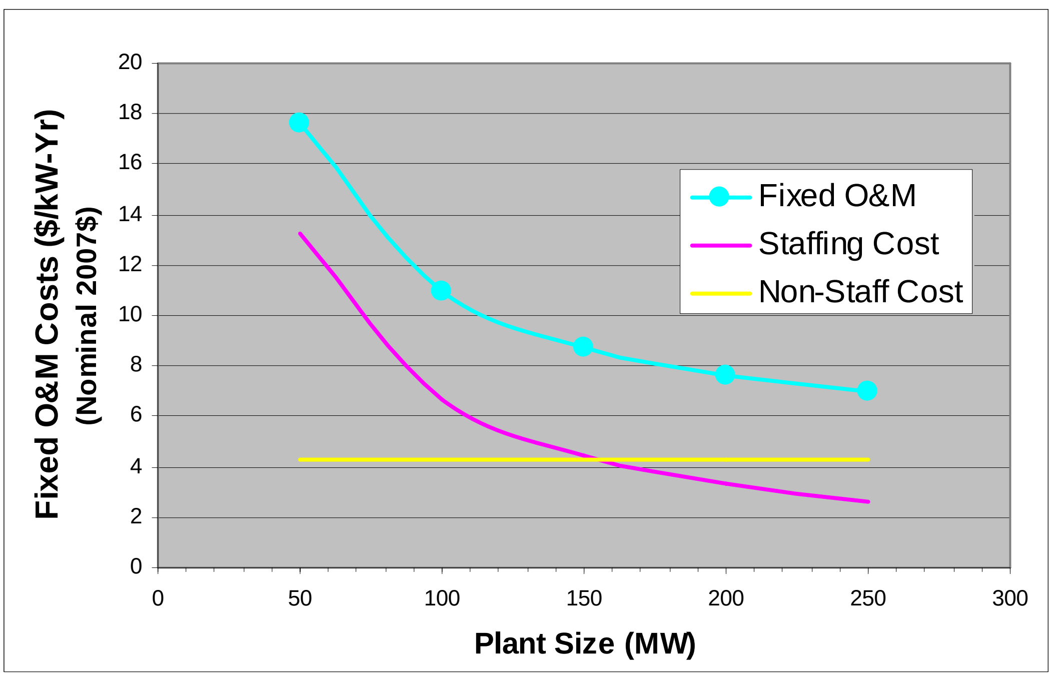
Source: Energy Commission

Simple Cycle Operating Costs

The operating costs consist of two components: fixed O&M and variable O&M.

Fixed O&M is composed of two components: staffing costs and non-staffing costs. Non-staffing costs are comprised of equipment, regulatory filings, and other direct costs. As with the combined cycle fixed costs, staffing costs for simple cycle units, and thus total fixed O&M, were found to vary with plant size as shown in **Figure 11**.

Figure 11: Simple Cycle Fixed O&M Costs



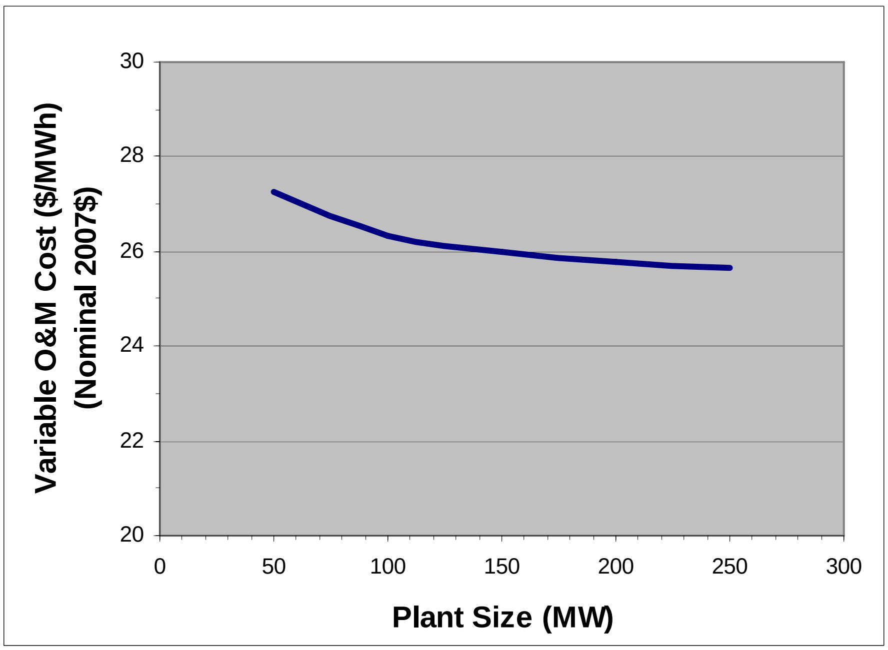
Source: Energy Commission

Variable O&M is composed of the following components:

- Scheduled outage maintenance – annual maintenance and overhauls
- Forced outage maintenance
- Consumables maintenance
- Water supply costs
- Environmental costs

Figure 12 shows the total Variable O&M as a function of plant size. Of the three components, the scheduled and overhaul maintenance is the largest: about 75 to 90 percent of the total cost, depending on the year in question.

Figure 12: Simple Cycle Variable O&M Cost



Source: Energy Commission

Miscellaneous Operating Variables

Heat Rate – Heat rates are a measure of the efficiency of a power plant. An imagined power plant with 100 percent efficiency would have a heat rate of 3413 Btu/KWh. The efficiency of a real power plant can be calculated as 3413 divided by the plant's heat rate. In this report, heat rates are estimated for four categories of thermal power plants:

- Conventional combined cycle
- Advanced combined cycle
- Conventional simple cycle
- Advanced simple cycle

The heat rates for all of these plant types were estimated based on actual data taken from the Energy Commission's Quarterly Fuels and Energy Report (QFER) database. The conventional units were developed by running a statistical regression of the monthly QFER data from 2001 to 2005 for 10 combined cycle and 12 simple cycle facilities. The advanced units were taken from the Energy Information Administration (EIA) 2006 forecast. **Table 20** summarizes the resulting formulas and heat rates for capacity factors of 60 percent for conventional and advanced combined cycles and 5 percent for conventional simple cycle units and 15 percent for advanced simple cycle units.

Table 20: Summary of Heat Rates

Technology	Heat Rate Formulas	Heat Rate (Btu/kWh)
Conventional Combined Cycle (CC)	***HR =8871+1050*0+2209*CF-4140*CF^.5***	6990
Conventional CC W/ Duct Firing	***HR =8871+1050*.091+2209*CF-4140*CF^.5***	7080
Advanced Combined Cycle	***HR= Conventional CC Heat Rate * (6333/6800)***	6510
Conventional Simple Cycle (SC)	***HR = Regression of QFER data***	9266
Advanced SC	***HR = 2006 EIA estimate***	8550

Source: Energy Commission

Heat Rate Degradation – Heat rate degradation is the percentage that the heat rate will increase per year. For this report, the heat rate degradation estimates are:

- For simple cycle units: 0.05 percent per year.
- For combined cycle units: 0.2 percent per year.

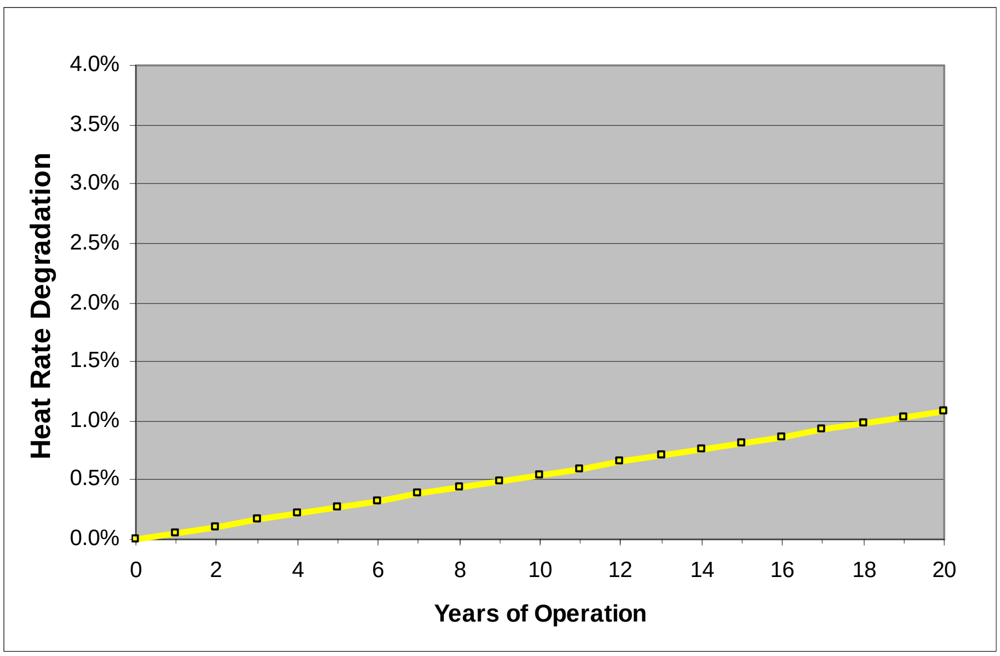
These values were estimated using General Electric data provided under the Aspen data survey. The rule for simple cycle units (combustion turbines) is that they degrade 3 percent between overhauls, which is every 24,000 hours. The actual time between overhauls, therefore, is a function of capacity factor as shown in **Table 21**. The staff elected to use a 5 percent capacity factor based on the capacity factors observed in the survey data and calculated degradation of 0.05 percent per year. **Figure 13** shows the results, designated as "Equivalent SC Degradation."

Table 21: Annual Heat Rate Degradation vs. Capacity Factor

Technology	Assumed Capacity Factor	Years Between Overhauls
Simple Cycle Units	5%	55
Simple Cycle Units	10%	27
Combined Cycle Units	50%	5.5
Combined Cycle Units	60%	4.6
Combined Cycle Units	70%	3.9
Combined Cycle Units	80%	3.4

Source: Energy Commission

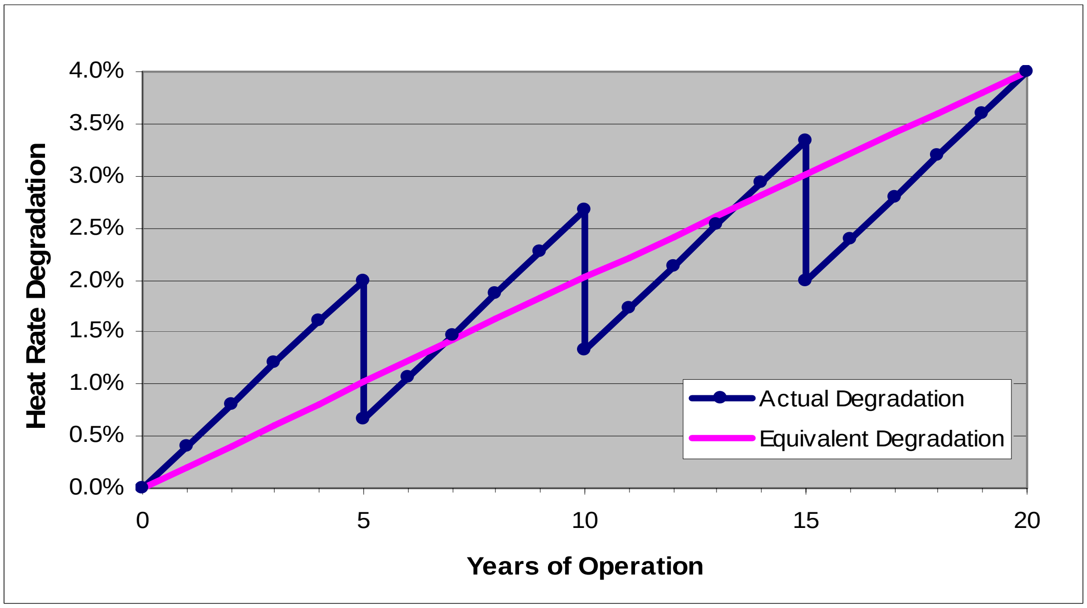
Figure 13: Simple Cycle Heat Rate Degradation



Source: Energy Commission

The computation for the combined cycle units is more complex due to its higher capacity factor, estimated herein to be roughly 60 percent based on the QFER data and other historical information. The 60 percent capacity factor calls for an overhaul every 4.6 years. The staff simplified this assumption by using five years. This results in three major overhauls during its 20-year book life, as shown in **Figure 14**. Since the steam generator portion remains essentially stable, the overall system deteriorates two-thirds of the 3 percent of the simple cycle during the five-year period, which is 2 percent; and recovers two-thirds of its deterioration during the overhaul, which is four-thirds of 1 percent. The details of this can be found in the Model User's Guide.

Figure 14: Combined Cycle Heat Rate Degradation



Source: Energy Commission

Parasitic Losses – These are sometimes defined as "station service losses." This is the power consumed by the power plant as a part of its normal operation. It can also be defined as the difference between the power generated and the power that arrives at the bus bar. The QFER database was used to estimate parasitic losses, which for combined cycle units was estimated to be 2.7 percent.

Transmission and Transformer Losses – Transformer losses are the losses in uplifting the power from the low voltage side of the transformer (generator voltage) to the high voltage side of the transformer (transmission voltage). Transmission losses represent the power lost in getting the power from the high side of the transformer to the load center (hearing designation is "GMM to Load Center"). Staff used assumptions established in the California Public Utility Commission (CPUC) 2005/2006 market price referents (MPRs), which are summarized in **Table 22**.

Table 22: Transformer and Transmission Losses Assumptions

LOCATION	LOSSES (%)	POWER (MW)	ENERGY (GWh)
Busbar	**--**	1.0000	8.059200
High-side of Transformer	0.5%	0.9950	8.018904
Load Center	1.43%	0.9808	7.904234

Source: Energy Commission

Nuclear, Clean Coal, and Alternative Technologies

This data was gathered by Navigant, based on earlier work, document searching, and phone calls to knowledgeable people in the field. The source of the data and other questions can be answered by contacting the expert noted in Appendix A.

Navigant provided input data for 22 technologies, 20 alternative technologies, nuclear, and integrated gasification combined cycle. The staff processed this data for use in the Model. The processed data is summarized in Chapter 2, and the resulting levelized costs are summarized in Chapter 1.

Navigant‘s instant costs are inherently incomplete, in that Navigant is not including ERC costs. Navigant provided the estimated emission factors (lbs/MWh) applicable to each technology. The staff used estimated cost of emissions ($/ton) in the Model to calculate the cost in dollars. These costs are added to the instant cost provided by Navigant to calculate the total instant cost. The Model converts the instant cost to installed cost and calculates the levelized cost. **Table 23** summarizes the Navigant instant costs and Energy Commission staff instant cost calculation.

Table 23: Instant Cost Adjustments

Technology (All costs in Nominal 2006$)	Gross Capacity (MW)	Navigant Instant Cost w/o ERCs ($/kW)	CEC Total Instant Cost ($/kW)
Integrated Gasification Combined Cycle (IGCC)	575	2050	2198
Advanced Nuclear	1000	2400	2950
Biomass - AD Dairy	0.25	5300	5800
Biomass - AD Food	2	5300	5803
Biomass Combustion - Fluidized Bed Boiler	25	2750	3156
Biomass Combustion - Stoker Boiler	25	2500	2899
Biomass - IGCC	21.25	2800	3121
Biomass - LFG	2	1850	2254
Biomass - WWTP	0.5	2400	2743
Fuel Cell - Molten Carbonate	2	4350	4488
Fuel Cell - Proton Exchange	0.03	7000	7239
Fuel Cell - Solid Oxide	0.25	4750	4908
Geothermal - Binary	50	3000	3093
Geothermal - Dual Flash	50	2750	2866
Hydro - In Conduit	1	1500	1547
Hydro - Small Scale	10	4000	4125
Ocean Wave (Pilot)	0.75	6985	7203
Solar - Concentrating PV	15	5000	5156
Solar - Parabolic Trough	63.5	3900	4021
Solar - Photovoltaic (Single Axis)	1	9321	9611
Solar - Stirling Dish	15	6000	6187
Wind - Class 5	50	1900	1959

Source: Energy Commission

Effect of Tax Credits on Cost

Table 24 shows the cost of technologies with and without tax credits. The difference between these quantifies the tax credit. The last column shows the tax credit as a percentage of the cost (in the absence of the tax credit). **Figure 15** shows this same data graphically.

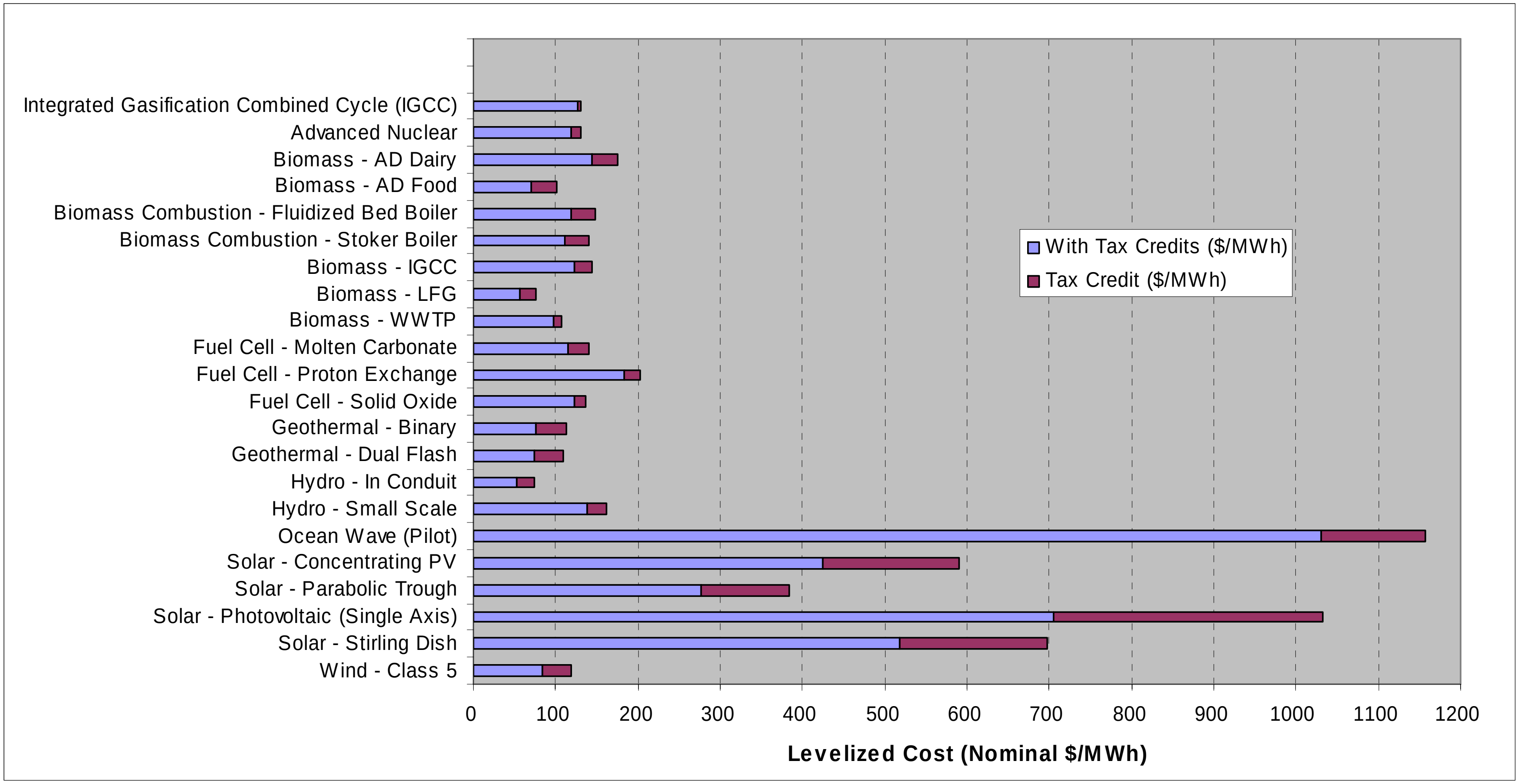
Table 24: Effect of Tax Credits on Costs

Levelized Costs (2007$)	With Tax Credits ($/MWh)	W/O Tax Credits ($/MWh)	Tax Credit ($/MWh)	As a % of Cost
Integrated Gasification Combined Cycle (IGCC)	126.51	130.43	3.92	3%
Advanced Nuclear	118.25	130.81	12.56	10%
Biomass - AD Dairy	143.61	175.09	31.49	18%
Biomass - AD Food	70.05	101.89	31.84	31%
Biomass Combustion - Fluidized Bed Boiler	118.72	148.57	29.84	20%
Biomass Combustion - Stoker Boiler	111.15	140.36	29.21	21%
Biomass - IGCC	123.66	143.74	20.08	14%
Biomass - LFG	56.11	76.18	20.07	26%
Biomass - WWTP	97.34	108.08	10.74	10%
Fuel Cell - Molten Carbonate	114.66	140.28	25.62	18%
Fuel Cell - Proton Exchange	182.41	202.15	19.74	10%
Fuel Cell - Solid Oxide	123.66	137.05	13.39	10%
Geothermal - Binary	75.85	112.22	36.37	32%
Geothermal - Dual Flash	73.66	109.43	35.77	33%
Hydro - In Conduit	52.84	74.95	22.11	30%
Hydro - Small Scale	138.74	160.81	22.07	14%
Ocean Wave (Pilot)	1030.50	1158.06	127.56	11%
Solar - Concentrating PV	424.84	590.06	165.22	28%
Solar - Parabolic Trough	277.30	383.45	106.14	28%
Solar - Photovoltaic (Single Axis)	704.98	1032.72	327.74	32%
Solar - Stirling Dish	518.89	697.59	178.70	26%
Wind - Class 5	84.24	118.54	34.30	29%

Source: Energy Commission

The tax credits for the alternative technologies were taken from the Database of State & Federal Incentives for Renewables & Efficiency. The link to the website is: http://www.dsireusa.org/Index.cfm?EE=0&RE=1

Figure 15: Effect of Tax Credits on Costs – Merchant Plants



Source: Energy Commission

Comparison to *2003 IEPR* Assumptions

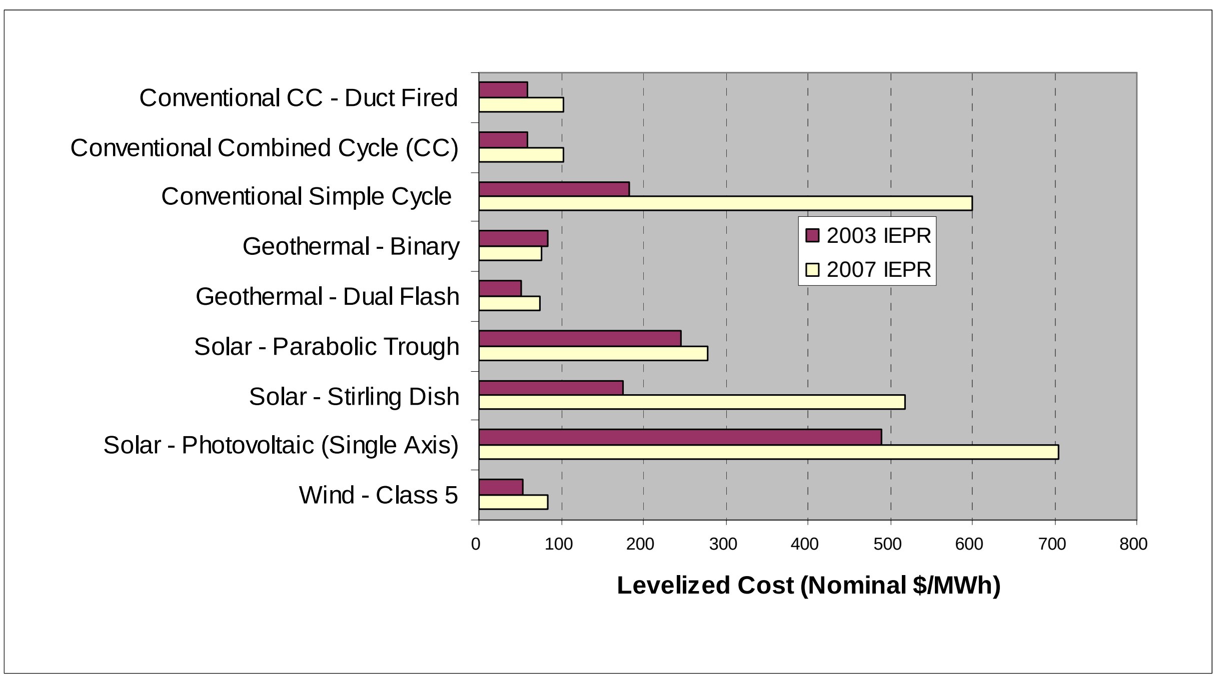
The staff compared the preliminary *2007 IEPR* costs to the *2003 IEPR* costs to see how the estimates have changed and to see if the differences are reasonable. **Table 25** makes this comparison of the total levelized costs. **Figure 16** presents the levelized cost data graphically.

Table 25: 2007 IEPR vs. 2003 IEPR

Technology (Costs in Nominal 2007$)	**2003 IEPR**			**2007 IEPR**			**2003 IEPR**		**2007 IEPR**	
	Gross Capacity (MW)	Levelized Cost ($/MWh)	Capacity Factor (%)	Gross Capacity (MW)	Levelized Cost ($/MWh)	Capacity Factor (%)	Instant Cost ($/kW)	Installed Cost ($/kW)	Instant Cost ($/kW)	Installed Cost ($/kW)
Conventional CC - Duct Fired	550	$59.73	91.6	550	$103.52	60.0	608	664	798	863
Conventional Combined Cycle (CC)	500	$59.50	91.6	500	$102.19	60.0	620	677	781	844
Conventional Simple Cycle	100	$182.62	9.4	100	$599.57	5.0	477	522	925	1000
Geothermal - Binary	35	$83.40	98.5	50	$75.85	95.0	3673	4140	3089	3562
Geothermal - Dual Flash	50	$51.85	96.0	50	$73.66	93.0	2435	2758	3093	3548
Solar - Parabolic Trough	110	$246.40	22.0	63.5	$277.30	27.0	2975	3203	4021	4190
Solar - Stirling Dish	15	$175.86	36.3	15	$518.89	24.0	3742	4028	6187	6446
Solar - Photovoltaic (Single Axis)	50	$488.84	23.8	1	$704.98	22.2	7614	8197	9611	9678
Wind - Class 5	100	$52.93	36.3	50	$84.24	34.0	1015	1093	1959	2000

Source: Energy Commission

Figure 16: Levelized Cost 2007 IEPR vs. 2003 IEPR



Source: Energy Commission

For some of the technologies, the differences in levelized cost were so dramatic that staff undertook a study to rationalize these differences. An exact comparison is difficult since so many factors have changed since the *2003 IEPR*, but staff was able in general to show that these differences can be explained. Staff selected three technologies that were comparable between the two IEPRs and had dramatic differences in costs: combined cycle, simple cycle, and solar stirling dish.

Combined Cycle with Duct Firing[1]

The *2007 IEPR* levelized cost is approximately 70 percent higher than that in the *2003 IEPR*. **Table 26** and the equivalent graphical representation in **Figure 17** show the cumulative effect on the levelized cost of changing present assumptions to match those of the *2003 IEPR* assumptions.

If the capacity factor in the *2007 IEPR* (60 percent) is adjusted to the *2003 IEPR* value (91.6 percent), the levelized cost decreases from $103.52/MWh to $89.54/MWh, which is a reduction of 13 percent. Additionally, if the *2007 IEPR* gas prices, which are about 40 percent higher, are replaced with the *2003 IEPR* gas prices, the levelized cost decreases from $88.54/MWh to $74.79, which is an additional 17 percent reduction. If the *2007 IEPR* installed cost, which is 27 percent higher than the 2003 cost, is adjusted to the 2003 value, then the levelized cost decreases from $74.79/MWh to $69.29/MWh, which is another 7 percent. The correction for the capital cost structure and fixed and variable O&M accounts for only a small percentage of difference. The remaining difference is to be expected due to modeling improvements made since the *2003 IEPR*, mostly in tax accounting.

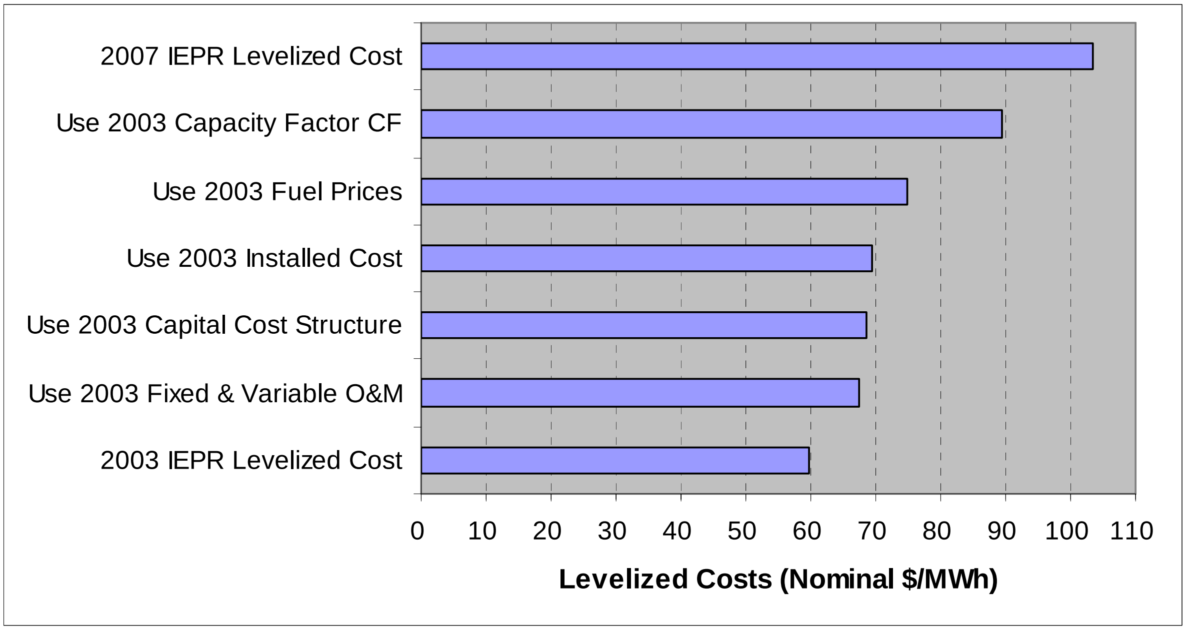
Table 26: 2007 IEPR vs. 2003 IEPR – Combined Cycle W/ DF

Effect of Change (Nominal 2007$)	$/MWh
2007 IEPR Levelized Cost	103.52
Use 2003 Capacity Factor CF	89.54
Use 2003 Fuel Prices	74.79
Use 2003 Installed Cost	69.29
Use 2003 Capital Cost Structure	68.71
Use 2003 Fixed & Variable O&M	67.48
2003 IEPR Levelized Cost	59.73

Source: Energy Commission

[1] Duct Firing: A combined cycle plant peaking technology that adds heat to the heat recovery steam generator section of a combined cycle plant to increase steam and power output. Duct burners can be small adding less than 5 percent additional load or very large adding 20 percent or more to the base load power output.

Figure 17: 2007 IEPR vs. 2003 IEPR – Combined Cycle



Source: Energy Commission

Simple Cycle

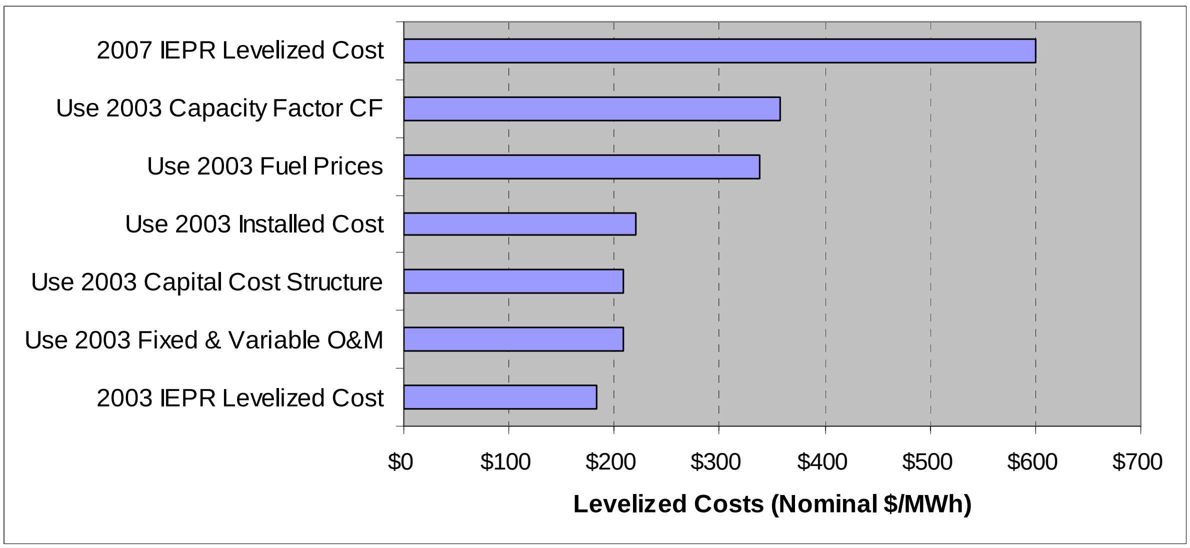
The *2007 IEPR* levelized cost is more than three times (3.3) higher than in the *2003 IEPR*. At first blush this difference seems inexplicable, but the difference can also be explained similar to the combined cycle unit above as shown in **Table 27** and **Figure 18.** If the capacity factor in the *2007 IEPR* emulation (5 percent) is adjusted to the *2003 IEPR* value (9.4 percent), the levelized cost decreases about 40 percent. Additionally, if the *2007 IEPR* gas prices, which are about 40 percent higher, are replaced with the *2003 IEPR* gas prices, the levelized cost decreases by another 5 percent – the difference is small due to the small amount of gas used at these lower capacity factors. If the *2007 IEPR* installed cost ($1,000/kW) is replaced with the 2003 cost ($522/kW), the levelized cost decreases another 35 percent. Using the 2003 financial assumptions and the fixed and variable O&M assumptions bring the levelized cost within 12 percent of the target *2003 IEPR* levelized cost, which again is to be expected due to the new modeling structure, most importantly the handling of taxes.

Table 27: 2007 IEPR vs. 2003 IEPR – Simple Cycle

Effect of Change (Nominal 2007$)	$/MWh
2007 IEPR Levelized Cost	599.57
Use 2003 Capacity Factor CF	357.01
Use 2003 Fuel Prices	337.94
Use 2003 Installed Cost	220.67
Use 2003 Capital Cost Structure	208.67
Use 2003 Fixed & Variable O&M	207.92
2003 IEPR Levelized Cost	182.62

Source: Energy Commission

Figure 18: 2007 IEPR vs. 2003 IEPR – Simple Cycle



Source: Energy Commission

Solar Stirling Dish

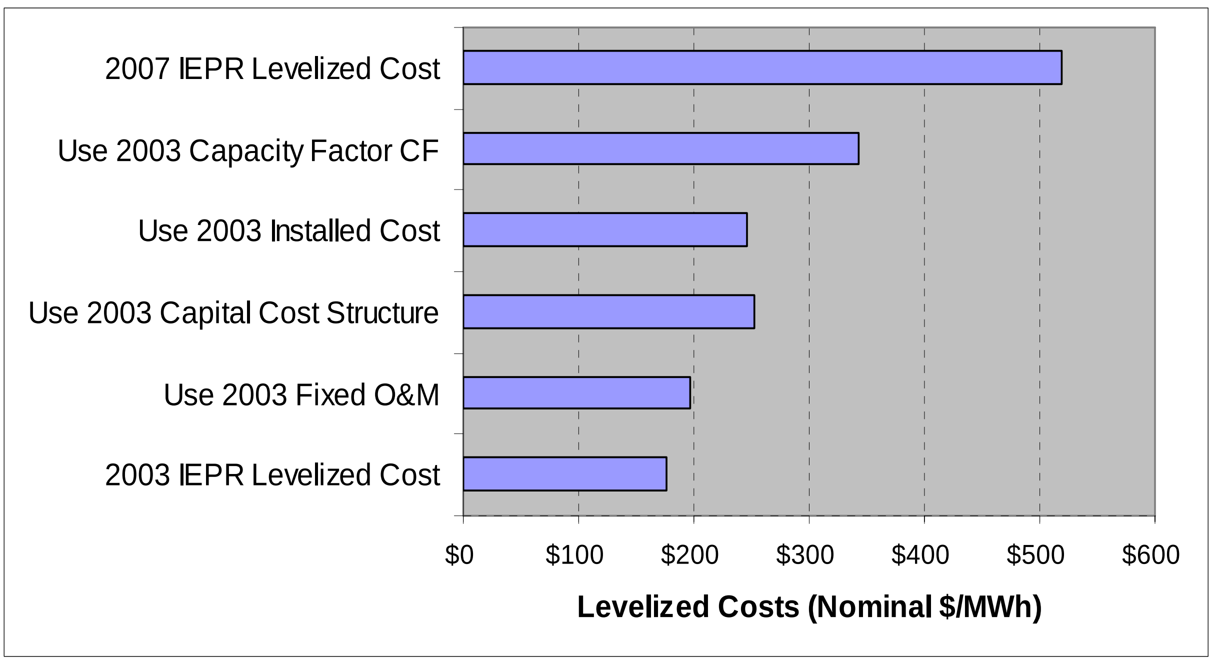
The *2007 IEPR* levelized cost is almost three times (2.95) that of the *2003 IEPR*. **Table 28** and **Figure 19** rationalize the differences similarly to the above analyses. If the capacity factor in the *2007 IEPR* (24 percent) is adjusted to the *2003 IEPR* value (36.3 percent), the levelized cost decreases 34 percent. If the 2007 installed cost $6446/kW is replaced by the 2003 installed cost of $4,028/kW (Both in 2007$), the levelized cost decreases 28 percent. If the 2003 cost of capital are used, the levelized cost increases slightly. If the *2007 IEPR* fixed O&M cost ($169/kW-Yr) is replaced by the *2003 IEPR* fixed cost ($53/kW-Yr), it reduces the levelized cost another 23 percent. The remaining 10 percent difference seems small considering the differences in tax credits and the modeling improvements.

Table 28: 2007 IEPR vs. 2003 IEPR – Solar Stirling Dish

Effect of Change (2007$)	$/MWh
2007 IEPR Levelized Cost	518.89
Use 2003 Capacity Factor CF	342.85
Use 2003 Installed Cost	245.99
Use 2003 Capital Cost Structure	253.02
Use 2003 Fixed O&M	196.07
2003 IEPR Levelized Cost	175.86

Source: Energy Commission

Figure 19: 2007 vs. 2003 IEPR – Solar Stirling Dish



Source: Energy Commission

Comparison to Energy Information Administration Assumptions

To gain additional perspective on the *2007 IEPR* levelized forecast, staff compared the input assumptions against those of the 2007 EIA estimate. **Table 29** makes this comparison for the main assumptions.

In general, the staff cost data is significantly higher than EIA information, with the notable exception of fixed O&M and some variable O&M. For example, EIA is estimating an instant cost for simple cycle units at $447/kW, which is much lower than staff's $925/kW estimate – approximately one-half of staff's estimate. Some of these differences can be explained by the higher construction costs in California compared to the nationwide costs used by the EIA. Also, EIA is not accounting for California's ERC costs, and staff believes that they are not accounting for linears. However, staff feels that part of this difference is that EIA is simply underestimating the instant cost of some of these technologies.

Staff also feels that the EIA estimates for capacity factors are not reasonable for California. The EIA is estimating an 87 percent capacity factor for conventional combined cycles and 30 percent for simple cycles, where staff is estimating 60 and 5 percent respectively. Staff also feels that the EIA heat rate of 10,450 Btu/kWh for a simple cycle unit is much too high compared to the staff estimate of 9,266 Btu/kWh based on actual operating statistics.

On the other hand, staff has ultimately deferred to the EIA estimated advanced simple cycle heat rate of 8550 Btu/kWh and has incorporated it into this final report. Staff, however, has not incorporated the corresponding EIA capacity factor of 30 percent but has elected to use a smaller capacity factor of 15 percent based on Energy Commission Marketsym simulations.

Table 29: 2007 IEPR vs. EIA Assumptions

Technology	Size (Gross MW)		Instant Cost ($/kW)			Fixed O&M ($/kW-Yr)			Variable O&M ($/MWh)			Capacity Factor (%)		Heat Rate (Btu/kWh)	
(Nominal 2007$)	CEC	EIA	CEC	EIA	Ratio	CEC	EIA	Ratio	CEC	EIA	Ratio	CEC	EIA	CEC	EIA
Combined Cycle (CC)	500	250	781	641	1.22	9.86	12.49	0.79	4.42	2.07	2.91	60%	87%	6,990	6,800
Advanced CC	800	400	766	632	1.21	8.42	11.70	0.72	3.83	2.00	2.70	60%	87%	6,510	6,333
Simple Cycle (SC)	100	160	925	447	2.07	11.00	12.12	0.9	25.72	3.57	13.5	5%	30%	9,266	10,450
Advanced SC	200	230	756	423	1.79	7.13	10.53	0.7	25.57	3.17	13.8	15%	30%	8,550	8,550
IGCC	575	550	2192	1585	1.38	36.27	38.68	0.2	3.11	2.92	14.5	60%	85%	8,979	6,800
Adv Nuclear	1000	1350	2950	2213	1.33	140.00	67.92	0.8	5.00	0.49	2.5	85%		10,400	10,400
Fuel Cell (Molten Carbonate)	2	10	4488	5085	0.88	2.18	5.65	0.4	36.27	47.95	0.8	90%		8,322	8,832
Geothermal - Binary	50	50	3093	1999	1.55	72.54	164.72	0.4	4.66	0.00	-	95%	90%		
Wind	50	50	1959	1282	1.53	31.09	30.31	1.0	0.00	0.00	-	34%	34.1%		
Photovoltaic	1	5	9678	5051	1.92	24.87	11.68	1.1	0.00	0.00	-	17.3%			

Source: Energy Commission

CHAPTER 3: Cost of Generation Model

This chapter describes:

- Model overview
- Model structure
- Model improvements since *2003 IEPR*
- Model limitations
- The Model's screening curve function
- The Model's sensitivity curve function
- The Model's wholesale electricity price forecast function

Model Overview

A simplified flow chart of the Model is shown in **Figure 20.**

Using the inputs on the left side of the flow chart, which are described in detail later in this chapter, the Model can produce the outputs shown on the right side of the flow chart. The top set of output boxes show the levelized costs:

- Levelized fixed costs
- Levelized variable costs
- Total levelized costs (Fixed + Variable)

These are typical results from most cost of generation models. These results are used in almost any study that involves the cost of generation technologies. They can be used to evaluate the cost of a generation technology as a part of a feasibility study or to compare the differences between generation technologies. They also can be used for system generation or transmission studies.

This Model is more unique than the traditional model since it can create three other outputs not commonly provided:

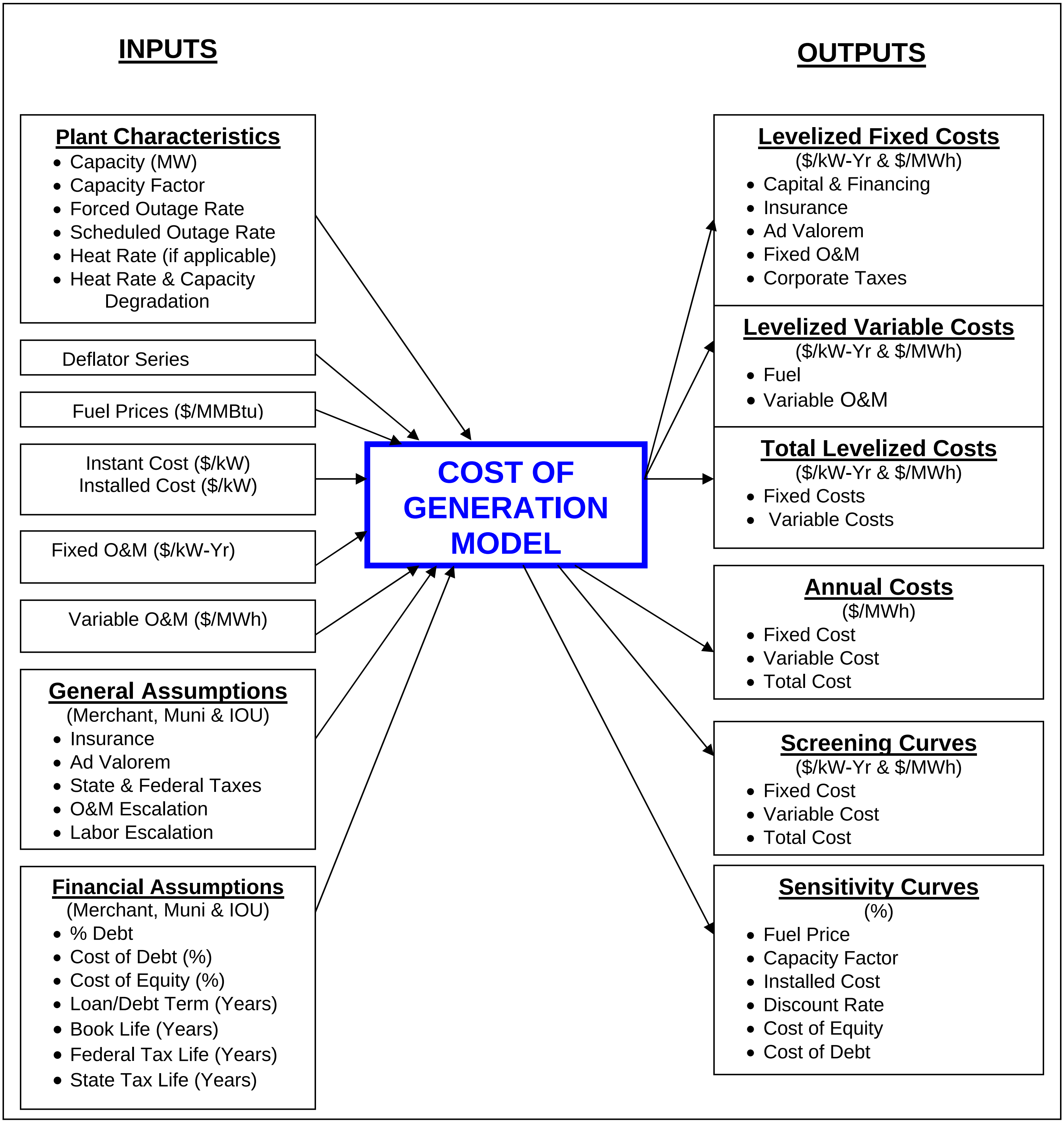
- Annual costs, which are not traditionally displayed in both a table and a graph.

- Screening curves, which show the relationship between levelized cost and capacity factor – an addition that makes the Model much more useful in evaluating cost of generation costs and comparing different technologies.

- Sensitivity curves, which show the percentage change in outputs (levelized cost) as various input variables are changed.

The fixed cost portion of the Model also can be used to forecast the cost of wholesale electricity, which is explained later in the chapter.

Figure 20: Flow Chart for Cost of Generation Model



Source: Energy Commission

Model Structure

The Model is a spreadsheet model that calculates levelized costs for 28 different technologies. These include nuclear, combined cycle, integrated gasification combined cycle, simple cycle and various alternative technologies. The Model is designed to accommodate additional technologies and includes a function for storing the results of scenario runs for these technologies.

The Model is contained within a single Excel file or workbook using Microsoft terminology. This workbook consists of 18 spreadsheets or worksheets using Microsoft terminology, but 4 of these are informational and do not contribute to the calculations.

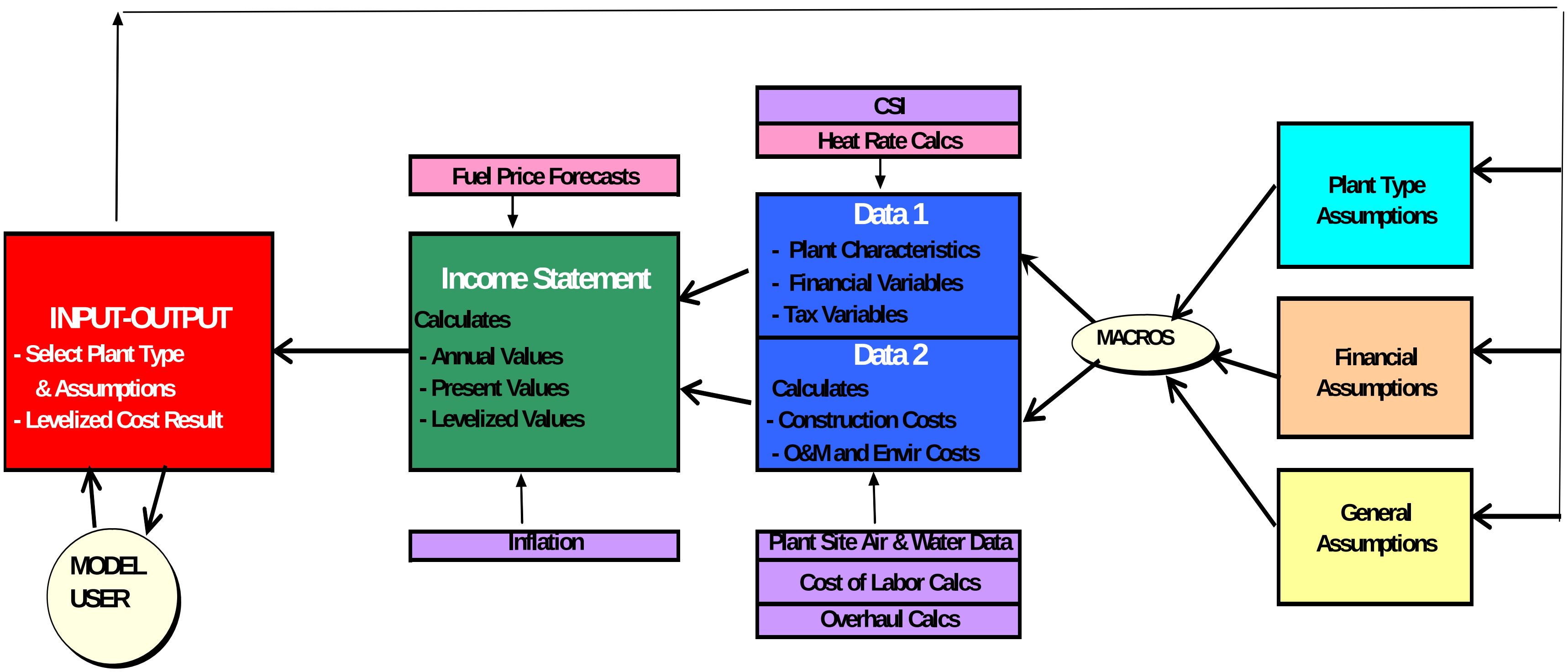
Changes	Tracks Model modifications using version numbers.
Instructions	General Instructions & Model Description.
WEP Forecast	Estimates Wholesale Electric Price Forecast
Adders	Provides Adder Costs that can be entered exogenously for the combined cycle & simple cycle units.
Input-Output	User selects Assumptions - Levelized Costs are reported along with some key data values.
Data 1	Plant, Financial & Tax Data are summarized - User can override data for unique scenarios.
Data 2	Construction, O&M Costs are calculated in base year dollars.
Income Statement	Calculates Annual Costs and Levelizes those Costs - Shows Annual Cash Flows of Costs & Revenues.
Plant Type Assumptions	Data Assumptions summary for each Plant Type.
Financial Assumptions	Data Assumptions summary of all Financial Data.
General Assumptions	General Assumptions summary such as Inflation Rates & Tax Rates.
Plant Site Air & Water Data	Regional Air Emissions & Water Costs - Used by Data 2 Worksheet.
Overhaul Calcs	Calculates Overhaul & Equipment Replacement Costs - Used by Data 2 Worksheet.
Inflation	Calculates Historical & Forward Inflation Rates based on GDP Price Deflator Series - Used by Income Statement Worksheet.
Fuel Price Forecasts	Fuel Price Forecast - Used by the Income Statement Worksheet.
Heat Rate Table	Shows the regression and provides the Heat Rate factors.
Labor Table	Calculates the Labor Cost components.
CSI	Shows the California Solar Initiative.

Source: Energy Commission

The relationship of these worksheets is illustrated in **Figure 21**.

One way to better understand the Model is to visualize the “Income Statement Worksheet” as the Model, the “Input-Output Worksheet” as the control module, which also summarizes the results, and the remaining worksheets as data inputs. Data 1 and 2 could be considered the data set (broken into two parts) that is derived from the “Assumptions Worksheets” and the remaining worksheets (auxiliary data).

Figure 21: Block Diagram for Cost of Generation Model



Source: Energy Commission

Input-Output Worksheet

Figure 22 shows the key interface worksheet, where the user selects the generation technology and characteristics and reads the final result. Through the use of drop-down windows, the user selects the power plant type, the financial assumptions, the general assumptions, fuel price, and regional location of the power plant. The user enters the start year.

Figure 22: Technology Assumptions Selection Box

Plant Type Assumptions (Select)	**Combined Cycle Standard - 2 Turbines, No Duct Firing**
Financial (Ownership) Assumptions (Select)	**Merchant Gas-Fired**
Ownership Type For Scenarios	**Merchant**
General Assumptions (Select)	**Default**
Base Year (All Costs In 2005 Dollars)	**2005**
Fuel	**Natural Gas**
Data Source	*CEC 2007 IEPR Survey (Will Walters, Aspen)*
Start (Inservice) Year (Enter)	**2007**
Fuel Price Forecast (Select)	**CA - Avg.**
Plant Site Region (Air & Water) (Select)	**CA - Avg.**
Study Perspective (Select)	**At Load Center**
Reported Construction Cost Basis (Select)	**Installed**
Turbine Configuration (Select)	**2**

Source: Energy Commission

The remaining options are more complex and require further description. The study perspective sets the location of the calculation (busbar or load center) – that is, the load center option allows for transformer and transmission losses incurred getting to the delivery point. All data reported in this Model are based on load center. The reported construction cost basis allows the user to enter the data as instant or installed. The turbine configuration allows for non-standard configurations for the combined cycle units. The standard configuration is two combustion turbine units and one steam generator – thus the number “2.”

The Model collects the relevant data as directed by the selection box and delivers it to the data worksheets. The income statement then uses the data worksheets to calculate the levelized costs and reports those costs back to the input-output worksheet to the table shown in **Figure 23**.

Figure 23: Levelized Cost Output

SUMMARY OF LEVELIZED COSTS Combined Cycle Standard - 2 Turbines, No Duct Firing		
Start Year = 2007 (2007 Dollars)	**$/kW-Yr**	**$/MWh**
Capital & Financing - Construction	$115.21	$22.69
Insurance	$5.75	$1.13
Ad Valorem Costs	$7.34	$1.44
Fixed O&M Costs	$11.58	$2.28
Corporate Taxes (w/Credits)	$35.38	$6.97
Fixed Costs	**$175.25**	**$34.52**
Fuel Costs	$309.57	$60.98
Variable O&M	$26.27	$5.17
Variable Costs	**$335.85**	**$66.15**
Total Levelized Costs	**$511.10**	**$100.67**

Source: Energy Commission

Figure 24 also shows the annual costs both in tabular and graphical form.

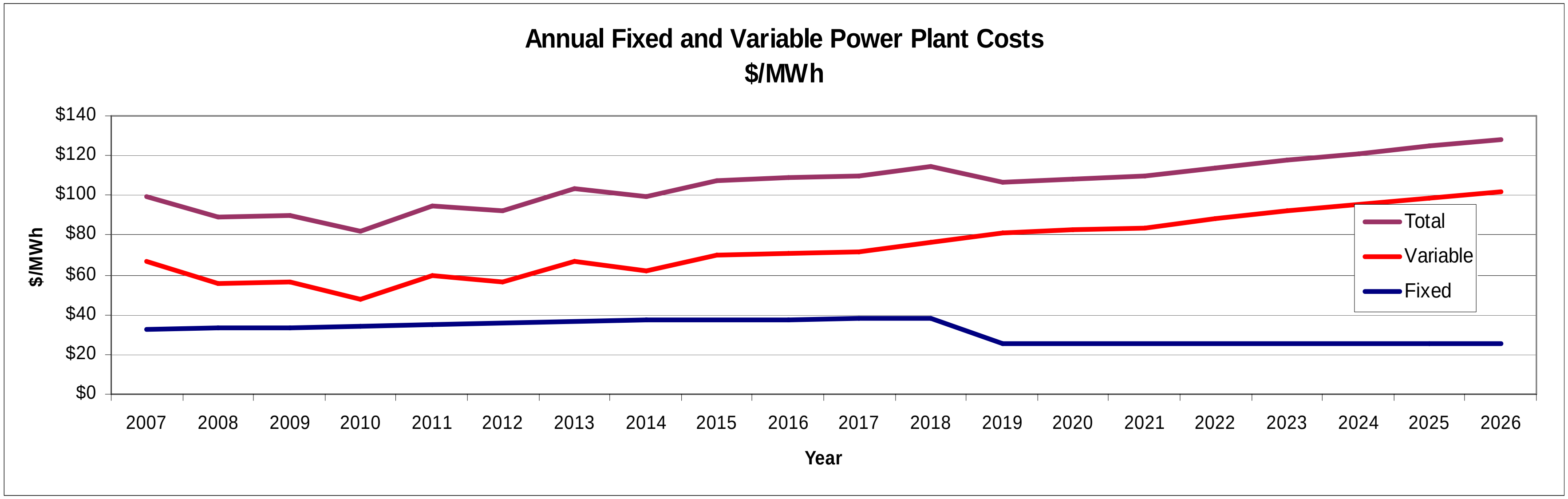
Assumptions Worksheets

Most of the data used in the Model are compiled into these three worksheets. These worksheets store the data for the multitude of technologies and data assumptions that give the Model its flexibility.

Plant Type Assumptions – This worksheet stores all of the power plant-specific data, such as plant size, fuel use, plant performance characteristics, construction costs, operation and maintenance costs, environmental costs, and water usage costs. There are over 200 of these items, but the most important, at least for thermal units, are the fuel costs (fuel price and heat rate) and capital costs. These account for 70 to 90 percent of the cost of a fossil-fueled power plant.

Financial Assumptions - This worksheet stores the capital structure and cost of capital data for the three main categories of ownership: merchant, IOU, and publicly owned. The worksheet provides the relative percentages of equity as opposed to long term debt, as well as the cost of capital for these two basic financing mechanisms. It also provides data on eligibility for tax credits.

Figure 24: Annual Costs – Merchant Combined Cycle Plant



	Levelized	NPV	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Fixed Costs	**$33.35**	**$272**	$32.2	$33.0	$33.8	$34.5	$35.2	$35.9	$36.6	$37.1	$37.4	$37.7	$38.0	$38.3	$25.6	$25.6	$25.7	$25.7	$25.7	$25.7	$25.8	$25.8
Variable Costs	**$66.78**	**$544**	$67.1	$55.8	$56.2	$47.5	$59.4	$56.6	$67.2	$62.0	$70.2	$71.0	$71.7	$76.3	$80.9	$82.4	$83.9	$87.9	$92.1	$95.4	$98.7	$102.2
Total Costs	**$100.13**	**$816**	$99.3	$88.8	$90.0	$82.0	$94.6	$92.5	$103.8	$99.2	$107.6	$108.7	$109.7	$114.6	$106.6	$108.0	$109.6	$113.6	$117.8	$121.1	$124.5	$128.0

Source: Energy Commission

General Assumptions – These are a multitude of assumptions that are common to all power plant types, such as inflation rates, tax rates, tax credits, as well as transmission losses and ancillary service rates.

Based on the user selections in the input-output worksheet, the relevant data in these assumptions worksheets is gathered by a macro and sent to the data worksheets.

Indicates area for data modification
Plant Type Assumptions
Financial Assumptions
General Assumptions

Data Worksheets

This is where the macro stores the data selected from the assumptions worksheets, and basic calculations are made to prepare data for the income statement worksheet. Data 1 and Data 2 worksheets can be envisioned as two parts of the main dataset to be used in the income statement. These are separated solely to keep the worksheets to a reasonable size. Data 1 and 2 also provide the opportunity for the user to modify or replace the data that came from the assumptions worksheets. Care should be taken to modify only those areas that are shaded in color.

Data 1 – This worksheet summarizes key data: plant capacity size and energy data, fuel use (such as heat rate and generation), operational performance data (such as forced outage rate and scheduled outage factor), key financial data (such as inflation rates and capital structure), and tax information (such as tax rates and tax benefits). It also does some calculations in order to calculate certain necessary variables. The following sheet sends data to the Data 1 worksheet.

***Heat Rate Table* –** This worksheet shows the regression that created the heat rate formula as a function of capacity factor in the Data 1 worksheet.

Data 2 – This worksheet calculates construction, operation, maintenance, water use and environmental costs. These calculations depend on data from the following worksheets:

***Plant Site Air and Water Data* –** These are emission and water costs on regional basis that are located outside the Data 2 worksheet.

***Overhaul Calculations* –** These costs are calculated outside the Data 2 worksheet since they are non-periodic overhaul costs that require special treatment to derive the necessary base-year costs needed by the Data 2 worksheet.

Keep in mind that all the data in these worksheets are for base year dollars. These costs are used by the income statement worksheet to calculate the yearly values and account for inflation.

Labor Table – This worksheet calculates the labor costs that are used in the fixed O&M cost calculations in the Data 2 worksheet.

Fuel Price Forecasts – This worksheet provides the fuel prices ($/MMBtu) to the income statement worksheet. For the natural gas price forecast, it provides prices by utility service area, as well as a California average value. It allows storage of different forecasts if needed to conduct various scenario studies. These forecasts should be updated regularly to represent the most recent Energy Commission forecasts. The inflation factors used in this worksheet come from and must absolutely be consistent with the inflation worksheet.

Inflation – This worksheet provides inflation factors used by the income statement worksheet, needed to inflate the various capital and O&M costs. This worksheet calculates two inflation values to simplify the income statement calculations: a historical inflation rate, used for the period from the base year to the start year, and a forward inflation rate, used for the period from the start year to the end of the study.

Income Statement Worksheet

This worksheet takes the data from the above data sources and calculates the fixed and variable cost components of total levelized cost. It develops the yearly values, present values, and levelized costs necessary for the cash-flow and revenue calculations.

Model Improvements Since *2003 IEPR*

The Model has undergone numerous changes since the *2003 IEPR*, both in structure and data inputs.

Improvements in User Interface

One of the major intents was to improve the transparency and usability of this Model because some considered it to be confusing and at times inscrutable. Toward that end, staff made dramatic improvements in the user interface and developed a comprehensive user's guide. The following is a delineation of the most significant improvements in this regard:

- **Combined the Many Workbooks into a Singular Workbook with Drop-Down Menus –** The 2003 version consisted of about 25 separate workbooks, one for each technology and two common workbooks (natural gas prices and financial variables). All of these spreadsheets have been reduced to a singular workbook.

- **Improved Documentation in the Model –** Previously, there was very little documentation, so it was difficult to understand the various components and the source of the data. This new version has over a hundred explanatory comments that pop up in response to the cursor.

- **Created a User's Guide –** Previously, there was no written descriptive material. The staff has completed an extensive user's guide that explains how to use the Model and the Model mechanics. It also provides a definitions section that defines all relevant terminology both in narrative and with formulas.

- **Added the Ability to Do Scenarios –** The Model now has the ability to save scenarios for future use. After a technology has been temporarily modified for a specific case, it can be saved with the "Save as New Scenario" button for future use.

- **Added More Detail to Levelized Cost Output –** The levelized costs are now shown in detail in both $/MWh and $/kW-Yr.

- **Added Graphical Summary Data –** The levelized costs are shown graphically as well as numerically, which makes it easier to see the relevant importance of the various components of the costs.

- **Added Annual Costs Output –** So that the levelized costs can be better interpreted, the annual costs that produced those levelized costs are shown as an output in both numerical and graphical format.

Improvements in Model Mechanics

The Model's mechanics have also been improved to be more complete, more accurate, and more flexible.

- **Added Year-by-Year Inflation Values –** Previously, the Model used one inflation rate, 2 percent, for all years. This is simplistic and not consistent with the inflation factors used for the fuel price forecast. The Model has been modified to accept year-by-year inflation factors that are linked forward to the inflation of fuel prices to ensure consistency.

- **Added Real Escalation Factors –** Previously, the Model had only nominal inflation. The Model now captures both nominal (or general) inflation and real-cost escalation for individual components.

- **Incorporated GADS Definitions –** The Model has been modified to incorporate standard North American Reliability Council (NERC)/Generating Availability Data System (GADS) definitions for the reliability and output factors, most notably for scheduled and forced (unscheduled) outage. This is important within itself to ensure standardization of definitions but can become more important if an attempt to use NERC/GADS data in the future or even attempts to just benchmark Energy Commission values against NERC/GADS data.

- **Modified the Model to Develop Screening Curves –** The Model is limited in its ability to compare one generation against another because it uses a singular assumed capacity factor for each technology. This is a serious limitation. This feature, its importance, and its limitations are described in a separate section below.

- **Corrected the Definitions for Capacity Factor and Availability Factors –** The definitions of capacity and availability factors in the old model were simply wrong and inconsistent with common practices at the Energy Commission. This is important in itself but becomes essential when the Model is used to create screening curves.

- **Improved Heat Rates–** Since fuel cost can be as much as 80 percent of the levelized cost for a combined cycle unit, it is important to have accurate heat rates. The heat rates in the Model have been improved to reflect actual operation rather than manufacturer estimates. Energy Commission staff used actual QFER fuel consumption and electric output data to develop heat rates to reflect actual operation.

- **Miscellaneous Improvements in Calculations –** Improved the calculation of installed cost, weighted average cost of capital (WACC), taxes, depreciation, and ad valorem.

Improvements in Data Inputs

Most of the data in the Model has been updated:

- **Power Plant Data –** All power plant cost data has been revised through data requests to reflect actual as-built data.

- **Natural Gas Prices –** The Model has been updated to reflect the Energy Commission’s most current forecast. It also provides optional forecasts.

- **Inflation Values –** Inflation factors have been updated.

- **Tax Rates, Tax Deductions, and Tax Credits –** These variables were reviewed and updated as necessary.

- **Capital Structure –** Cost of equity and long-term debt were updated along with the debt to equity ratios, discount rate, and weighted average cost of capital.

- **Degradation Factors –** Heat rate degradation factors have been added.

Model Limitations

Models are inherently limited because a number of assumptions must be made for each generation technology. The most important assumptions are:

- Capital costs
- Fuel costs
- Capacity factors
- Heat rates – for thermal plants

Capital Costs

Deriving capital costs is challenging, particularly for alternative technologies since costs tend to drop with increased development over time. Even for well-developed technologies, such as combined cycle and simple cycle plants, it is difficult because of varying location and situational costs. Developers generally keep this information confidential to maintain a competitive edge over other developers.

Fuel Costs

Fuel cost is highly unpredictable and difficult to forecast with a high degree of accuracy. The only safeguard against the unpredictability of fuel cost forecasts is to have alternative forecasts for comparison or to use uncertainty analysis. The Model thereby has the ability to compare the implications of different forecasts.

Capacity Factors

Models are inherently limited because the user must assume a specific capacity factor, which may or may not be applicable to the power plant under consideration. This is a common problem for combined cycle and simple cycle power plants. Combined cycle units are all too commonly modeled as having capacity factors in the vicinity of 90 percent, but the historical information on California power plants, as summarized in **Table 30,** shows that the average is closer to 60 percent or less. The

Model attempts to deal with this problem using the screening curve function, as described below.

Table 30: Actual Historical Capacity Factors

Power Plant	QFER 2004	QFER 2005
Moss Landing Power Plant	55.5%	52.6%
Los Medanos	74.3%	74.7%
Sunrise Power	62.1%	65.7%
Elk Hills Power, LLC	79.9%	72.4%
High Desert Power Project	51.9%	50.3%
Sutter	72.0%	51.3%
Delta Energy Center	72.6%	69.5%
Blythe Energy LLC	26.8%	19.6%
La Paloma Generating	57.2%	46.4%
Von Raesfeld	nd	31.6%
Woodland	nd	51.5%
Average	61.3%	53.2%

Source: Energy Commission

Heat Rates

An actual thermal power plant being considered, such as a combined cycle unit, may operate at an entirely different capacity factor than that selected for the Model. In fact, these plants typically operate at different capacity factors from month to month and even day to day. These varying capacity factors result in differing heat rates. A combined cycle unit has most efficient (lowest) heat rate at full power, or in the case of a duct-fired plant, at near full power since the duct-firing process provides additional power at the cost of lower efficiency. Operation at lower power levels produces less efficient operation (higher heat rates). Two identical power plants with the same capacity factor can have widely different average annual heat rates. For example, both could have 50 percent capacity factors if one operated at full power for half of the year and the other operated at half power for the entire year. Obviously, the latter unit would have a much higher heat rate. The staff's Model attempts to deal with this problem with the screening curve function, as described below.

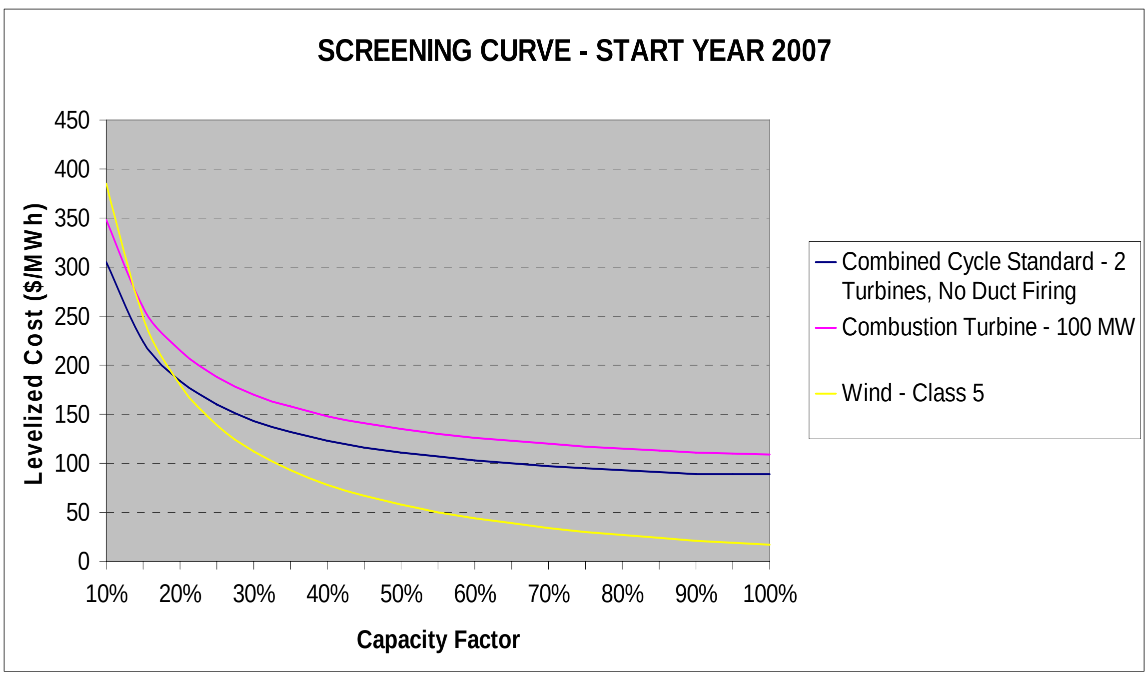
Model's Screening Curve Function

Screening curves allow one to estimate the levelized cost for various capacity factors, rather than the singular capacity factor that is typical of models. This is useful in many ways. The most obvious is that it allows the user to estimate levelized costs for its specific assumption of capacity factor. It also allows the user to assess the cost risk of incorrectly estimating the capacity factor. It allows for the comparison of various technologies as a function of capacity factor – that is, at what capacity factor one technology becomes less costly than another.

The Energy Commission's Model is somewhat unique in that it recognizes the reality that heat rate is a function of capacity factor, and corrects for this in the screening curve. By analyzing historical data from operating power plants in California (Energy Commission's QFER database), it was possible to find a relationship between capacity factor and heat rate that has a high statistical level of confidence – and that formula (through regression) has been embedded in the Model.

The levelized cost can be shown as $/MWh or $/kW-Year. **Figure 25** is an illustrative example of a $/MWh screening curve.

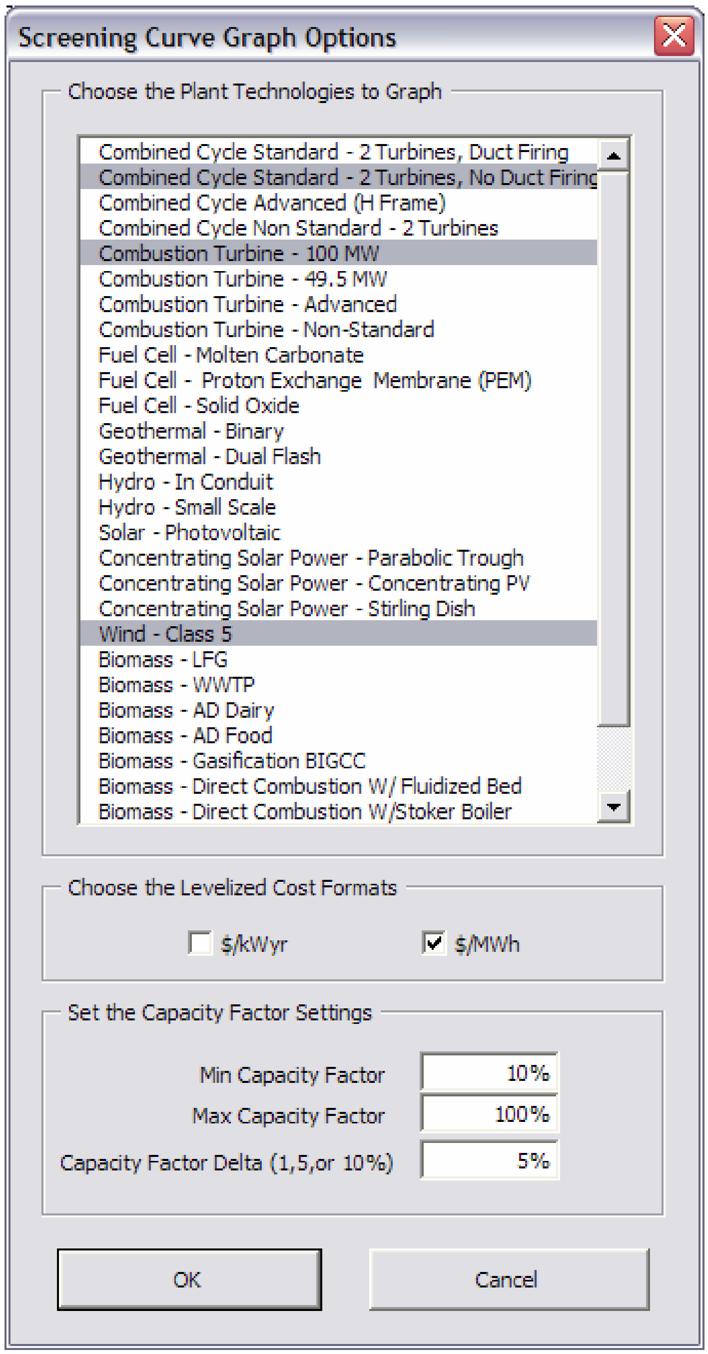
Figure 25: Screening Curve in Terms of Dollars per Megawatt Hour



Source: Energy Commission

Figure 26 shows the corresponding interface window.

Figure 26: Interface Window for Screening Curve



Source: Energy Commission

Misuse of Screening Curves

Care must be taken to not misuse the screening curves. The curves estimate only the relative costs. This is a good starting point, which is why they are called “screening curves.” For those cases where costs are close, additional and more detailed economic analysis is necessary.

It is also essential to use these curves in proper perspective. If the study is to simply compare the costs, the screening curves are useful. If the study is to determine the least cost to the system where the unit will be operating, then the screening curves are of less value and should be very carefully applied.

First of all, the assumed capacity factor is just that, an assumption. The actual capacity factor will depend on its economic viability once it is actually operating in the system. Furthermore, that capacity factor will vary over the seasons of the year and from year to year. In addition, screening curves do not reveal how a unit will affect the system operations. This is where a production cost or market model becomes important since they can capture these kinds of interactions. A production cost or a market model can emulate the system, how the generation unit will operate and how the unit will likely affect the rest of the system. Different generation technologies offer different system attributes and services.

All of this, however, ignores environmental, risk, and diversity factors, which may in the final analysis be the determining factors.

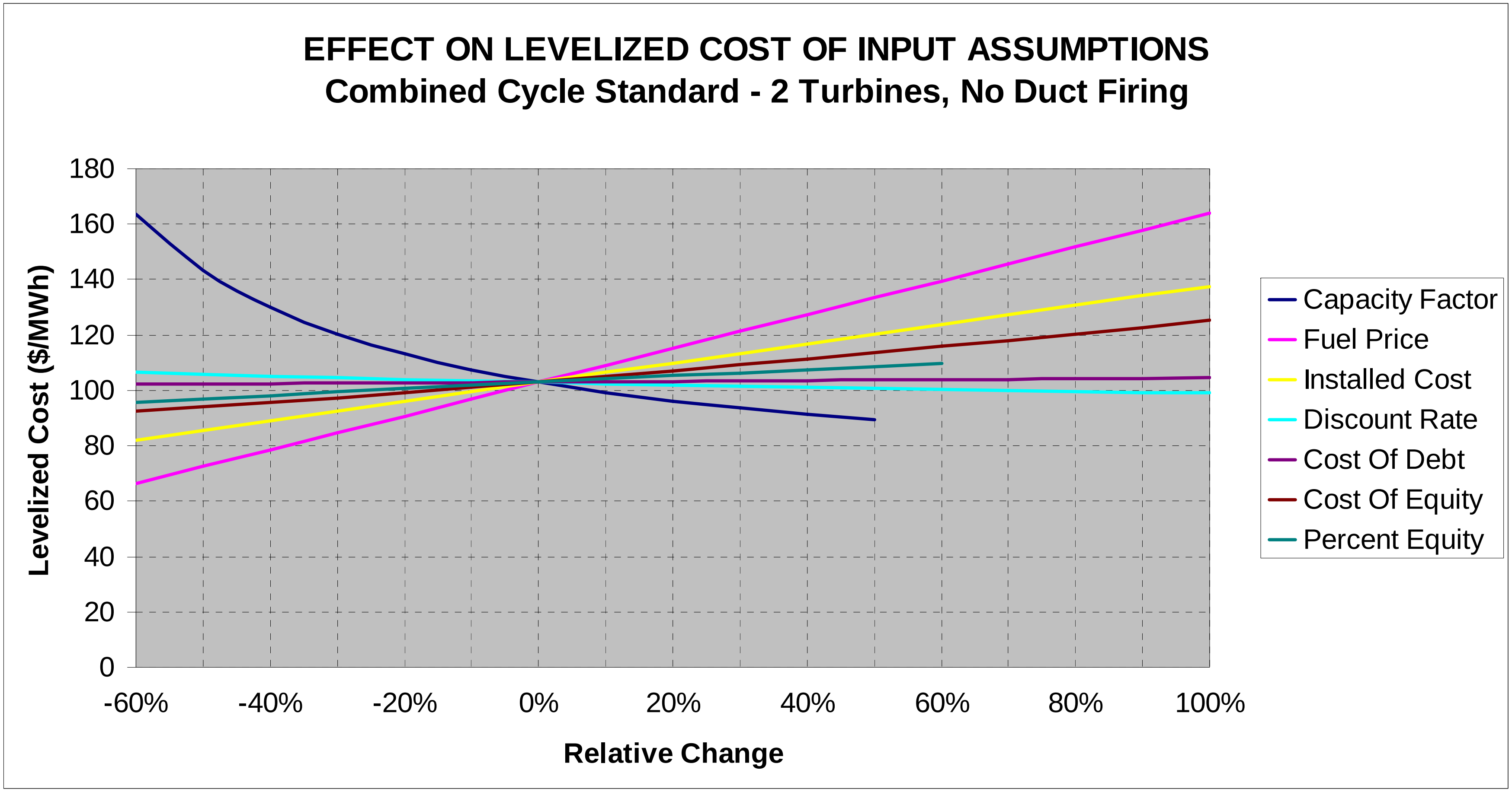
Model’s Sensitivity Curve Function

Although the screening curves can prove useful, they address only one variable to the base case assumptions when estimating levelized costs – the capacity factor. Staff’s new sensitivity curves address a multitude of assumptions: capacity factor, fuel prices, installed cost, discount rate (WACC), percent equity, cost of equity, cost of debt, and any other variable that should be considered. Sensitivity curves show the effect on total levelized cost by varying any of these parameters in three formats:

- Levelized cost ($/MWh or $/kW-Yr)
- Change in levelized cost as a percent
- Change in levelized cost as incremental levelized cost from the base value ($/MWh or $/kW-Yr).

Figure 27 shows an illustrative example of a sensitivity curve.

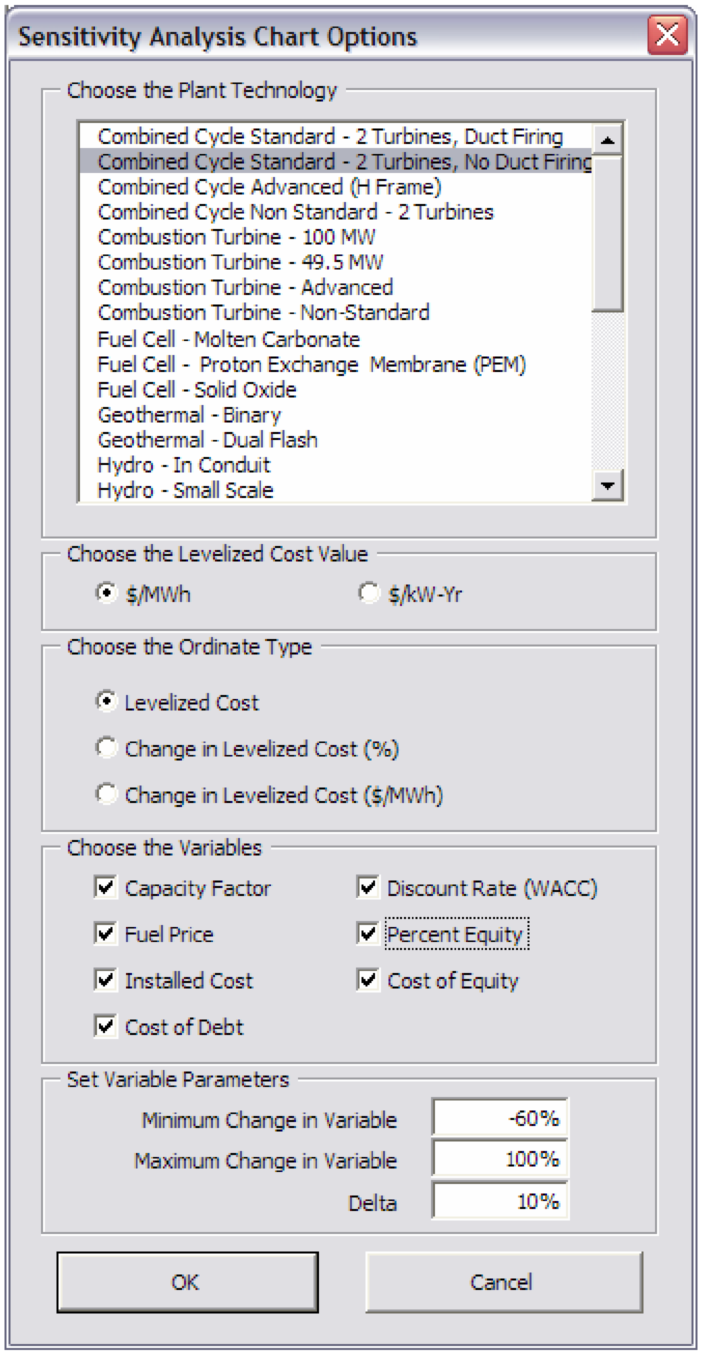
Figure 27: Sample Sensitivity Curve



Source: Energy Commission

Figure 28 shows the interface window for the above sensitivity curve.

Figure 28: Interface Window for Screening Curves



Source: Energy Commission

Model's Wholesale Electricity Price Forecast Function

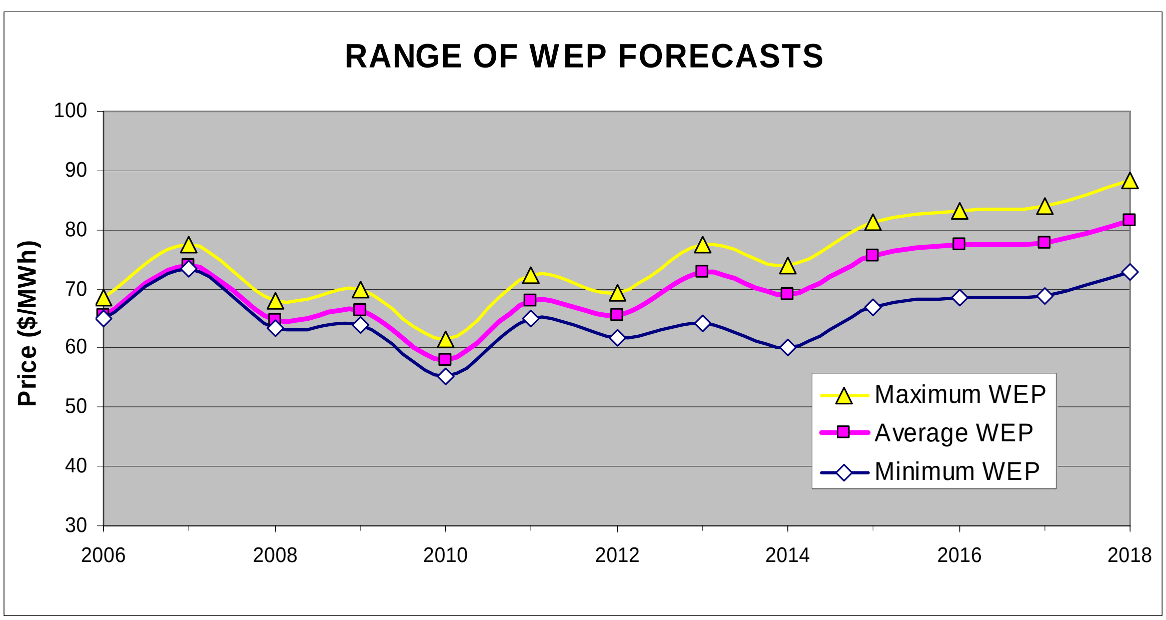
The Model can be used in conjunction with the Marketsym model – or some other production cost model – to forecast wholesale electricity prices. The Model can calculate the fixed cost portion of the wholesale electricity prices (WEP), but not the variable portion. The Marketsym model, on the other hand, can calculate the variable portion of the WEP, but not the fixed portion.

The details of this process are complicated and outside the scope of this report but can briefly be explained as follows. To estimate the fixed portion, the Model must be run to emulate the fixed cost for each of the combined cycles online during the period from 2001 to the end of the forecast period. These annual costs are then analyzed to find the following for each year of the forecast period: the most expensive unit in each year, the least expensive unit in each year and the average cost of all the generating units.

The Marketsym model is run in the cost-based mode for all the years of the forecast using all the above identified resource additions. The fixed costs from the Model are then added to the variable costs from the Marketsym model to get the WEP forecast.

Figure 29 is an illustrative example of the resulting wholesale electricity price forecast. The maximum wholesale electricity price is the most expensive generating unit in each year. The minimum wholesale electricity price is the least expensive generating unit in each year. The average wholesale electricity price is the average of all the generating units operating in that year.

Figure 29: Illustrative Example for Wholesale Electricity Price Forecast



Source: Energy Commission

APPENDIX A: Contact Personnel

The following is a list of the Energy Commission and contractor personnel who participated in the development of the Model, the data gathering process and the computer simulations, along with their phone numbers and e-mail addresses. This list is intended to facilitate information requests related to this report. If you are in doubt as to whom to contact, you can contact the authors, who will direct you to the appropriate source. Copies of this report and the Model are available on the website at:

http://www.energy.ca.gov/2007_energypolicy/documents/index.html#061207

A User's Guide for the Model will be available at this website within the next month.

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Source: Energy Commission

APPENDIX B: Alternative Technology Data

COMPARATIVE COSTS OF CALIFORNIA CENTRAL STATION ELECTRICITY GENERATION TECHNOLOGIES: APPENDIX B RENEWABLE ENERGY COST OF GENERATION INPUTS

CONSULTANT REPORT

Prepared For:
California Energy Commission

Prepared By:
Navigant Consulting Inc.

August 2007
CEC-200-2007-011 APB

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INTRODUCTION

Renewable energy technologies are constantly changing and evolving. Renewables are fairly immature technologies, and there is significant research and development activities taking place. As more investment is made and more is learned, there will be reductions in the capital and operating costs. This research attempts to capture some of these dynamics.

Not as much attention was placed on renewable energy in the 2003 Integrated Energy Policy Report, IEPR, and not as much was being actually put in the field, especially in the United States. But since then, renewable and clean energy is in the paper and on the news almost every day. California is regarded as a leader in this area, and is becoming a more central part of generation strategies. In most cases, costs have continued to decrease and performance has improved for these technologies. But in some cases, some of the costs have actually increased. Just looking at wind and solar, wind capital cost was approximately $1,200 a kilowatt back in 2003, but today it is closer to $2,000. This is because of high demand for turbines, insufficient skilled labor for installation, and increasing steel prices as a result of worldwide demand. All these things contribute to the price increases.

In the solar photovoltaic, PV, area, silicon costs have risen because there has not been an increase in silicon manufacturing capacity. In addition, it takes two to three years to build plants and bring them on-line. These factors have driven up costs on the PV side.

To develop the inputs for renewable energy technology for the Cost of Generation Model, the consultant first reviewed relevant literature. This included studies such as those performed by the Electric Power Research Institute, EPRI, the California Energy Commission, Energy Commission, and other published data. This provided a better understanding of the best published data that was available, as well as insight into the types of facilities that could be built in California.

For example, looking at the potential landfill gas sites in California suggests that there might be more new facilities with a capacity of about one megawatt, rather than larger capacities of existing facilities, which can range up to five or megawatts. Navigant Consulting also reviewed their internal database, comprised of published literature, and consulting work performed for utilities, venture capital firms and others.

The consultant developed “straw man data” that reflected current data appropriate for California. That data was distributed to the people in respective industries that would have a good sense of what the California market is today. The consultant conducted interviews with those industry representatives and asked them if the assumptions were appropriate. This resulted in more refined data that was reviewed with Energy Commission staff. After Energy Commission staff review, the data was reviewed once more by other experts within Navigant, and then the data was submitted for presentation at the June 12, 2007 workshop.

The June 12 workshop provided the public review necessary to validate the data. The entire workshop, including the agenda, distributed materials, audio recording, and transcript is available at the Energy Commission’s website, at:
http://www.energy.ca.gov/2007_energypolicy/documents/index.html#061207

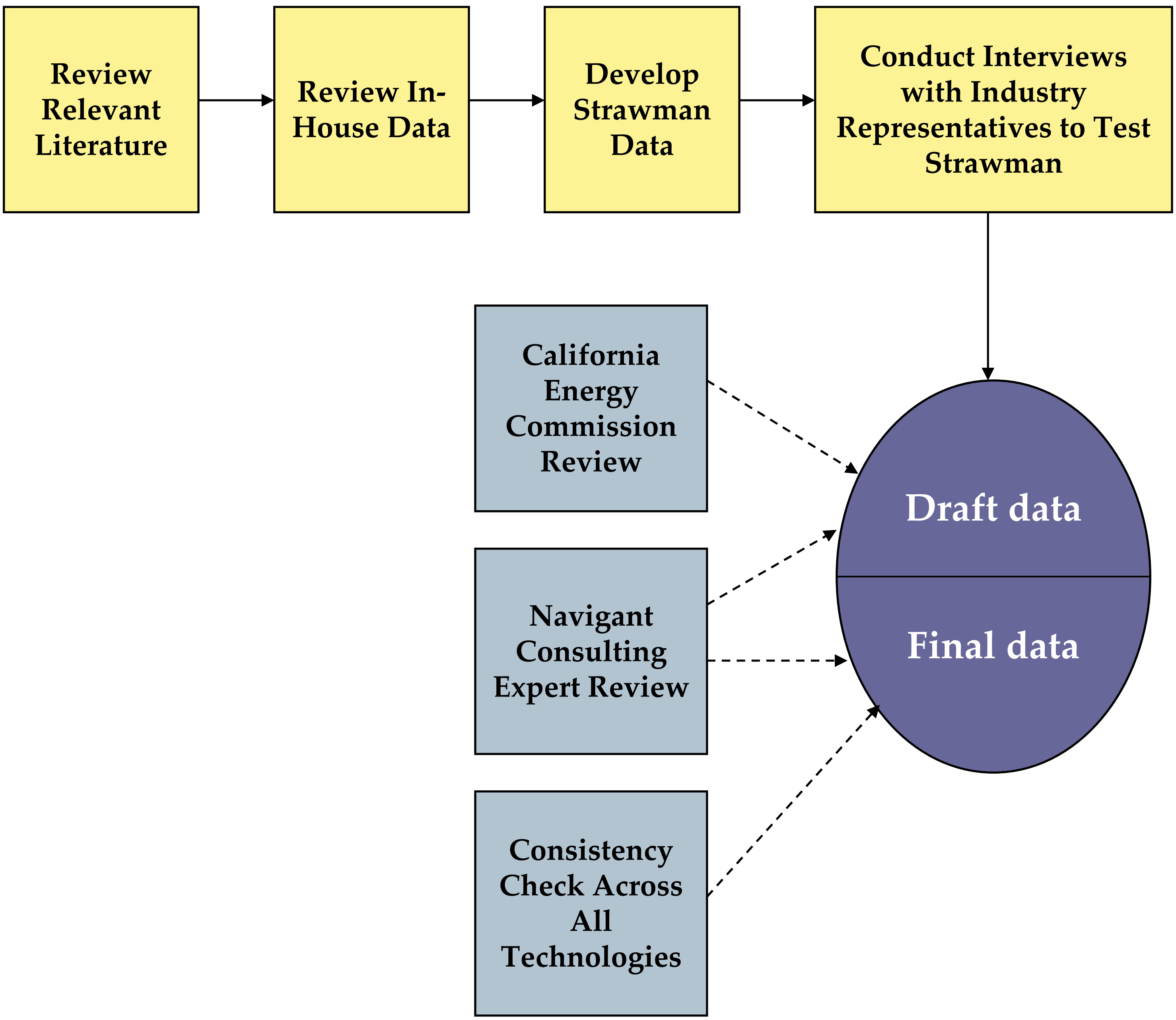
Readers should keep in mind that not all of these technologies are at the same level of maturity. Some technologies, such as utility-scale wind, are well understood. It is a fairly mature technology, even though there is still a significant amount of potential for cost reductions. There are other technologies that are maybe just as, or even more mature, such as landfill gas. But the cost data that is publicly available is sometimes several years old. The data does not always reflect costs that are required based on emission regulations. A higher gas cleanup cost or emission control cost might be necessary.

For technologies that are not as mature, engineering cost estimates or pilot plant costs may be available. These too require review. An engineering cost estimate might be optimistic, or it might not capture some of the difficulties that are often encountered when making a technology commercial and operational. This could be influenced by linear costs or financing costs. Conversely, a pilot plant might suggest higher costs. Some pilot plants can be over-engineered in order to test several functionalities. In reality, when actually built, capital costs could be lower. The Energy Commission process and the modeling approach attempted to insure that this type of data was being taken into consideration.

In the pages that follow, the first page provides the basic description for each technology. There may be several different forms regarding one technology, and this information describes the particular technology under consideration. Following is a page listing the economic assumptions made for the technology. Third is a page presenting performance data for the technology. On each page, the sources of information are listed. The final page provides a brief explanation of key assumptions that were made to finalize the economic and performance estimates.

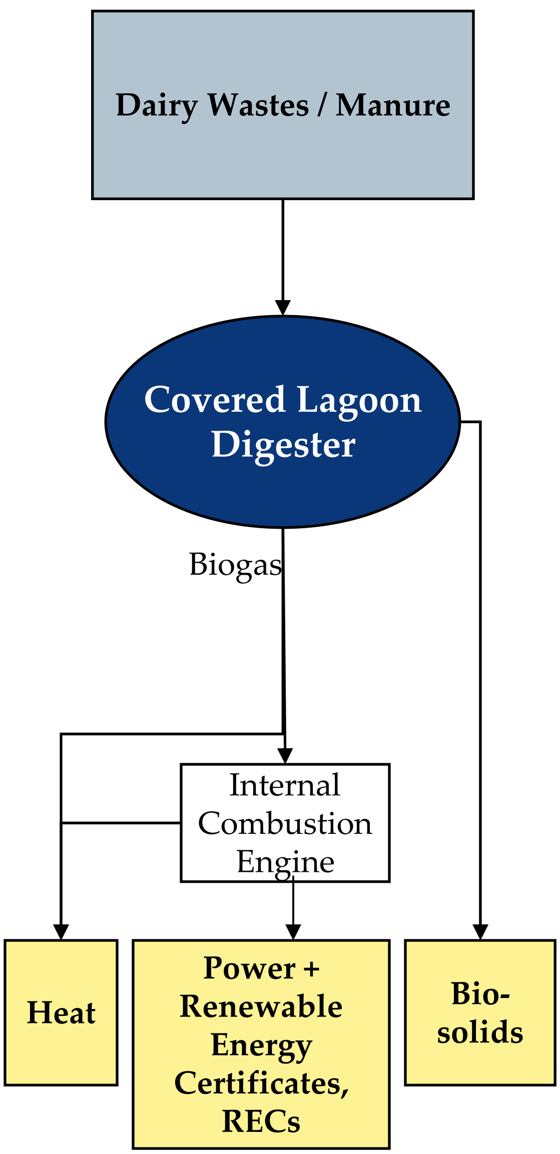
Navigant Consulting Process for Inputs to Integrated Energy Policy Report Model

Navigant Consulting, NCI, reviewed existing literature and in-house data to develop strawman information that was then vetted with industry.



An anaerobic digester treats dairy manure to produce biogas that can be used to produce electricity, heat, and bio-solids.

Schematic of the Technology



Description

- An anaerobic digester, AD, utilizes the natural process of anaerobic decomposition to treat waste (for example dairy cow manure), produce biogas that can be used to power electricity generators, provide heat and produce soil improving material.
- Anaerobic digestion power production with an internal combustion engine is an established technology.
- These cost estimates assume a combined heat and power internal combustion engine.
- Costs can vary depending on the digester being deployed. These cost estimates are for a **covered lagoon**, which is the cheapest and most suitable for warm climates.
- Other conventional digester technologies are Plug-Flow (rectangular flow-through tank, 11% - 13% solids), and Complete Mix (large tanks, 10% solids, most expensive).
- Other more advanced digester technologies use “multi-stage” digesters or “flow” designs with the use of “thermophillic” (high temperature) bacteria.

Economic Assumptions: Anaerobic Digesters – Dairy

	Anaerobic Digesters – Dairy Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity, kilowatts, (kW)	250	A 250 kW system is the expected size of new single-farm, covered lagoon anaerobic digester in California. Sizes may increase over time if other types of organic wastes are added.
Project Life (years)	20	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$5,300	Overnight costs includes development fees, interconnection, but not interest during construction. The cost breakdown between engine/generator, digester and other is an approximation, and is performed differently by each source. The digester component could also be considered installation.
Electrical Facilities ($/kW)	$2,000	From Navigant Consulting sources and estimates.
Digester ($/kW)	$2,600	From Navigant Consulting sources and estimates.
Other ($/kW)	$700	Other includes manure storage, liquids separation, and varies depending on system design.
Fixed operations and maintenance (O&M) ($/kW-yr)	$50	O&M costs are estimated to be near $250/kW-yr in California based on cost estimates at actual facilities. These costs are not typically separated into fixed and variable. NCI estimates that 80% of the costs are variable. These numbers have been confirmed by interviews.
Variable O&M ($/MWh)	$15	

Sources: Navigant Consulting Estimates 2007, Cornell Manure Management Program, California Dairy Power Production Program, Wisconsin Anaerobic Digester Casebook – 2004 Update, NCI Interviews with equipment and digester manufacturers.

Performance Data: Anaerobic Digesters – Dairy

	Anaerobic Digesters – Dairy Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	75%	Capacity factors can vary significantly by dairy and can be dependent on the owner's motivation or amount paid for an O&M service contract.
Fuel Cost ($/MMBtu)	n/a	
Economic benefits from by-products sales (heat, digester solids) ($/kW-yr)	$100	Economic benefits can vary significantly, but based on historical data can amount to $20,000/yr for a 200 kW system.
Higher Heating Value Efficiency, HHV, (%)	20%	HHV efficiency is based on the feedstock to electricity. Feedstock to methane is typically 60% to 70% efficient and the internal combustion engine ~30%.
CO_2 (lb/MWh)	AD – Dairy is assumed to be CO_2 neutral. Senate Bill, SB, 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	1.7	NO_x can vary widely. Figures shown assume 60 parts per million by volume, ppmv, @15% O_2 in exhaust, which complies with the California Air Resources Board, ARB guidelines for best available control technology, BACT.
SO_x (lb/MWh)	0.39	Sulfur content can vary. Figures shown assume SO_2 in exhaust of 10 ppmv @ 15% O_2.

Sources: Navigant Consulting Estimates 2007, Cornell Manure Management Program, California Dairy Power Production Program, Wisconsin Anaerobic Digester Casebook – 2004 Update, NCI Interviews with equipment and digester manufacturers.

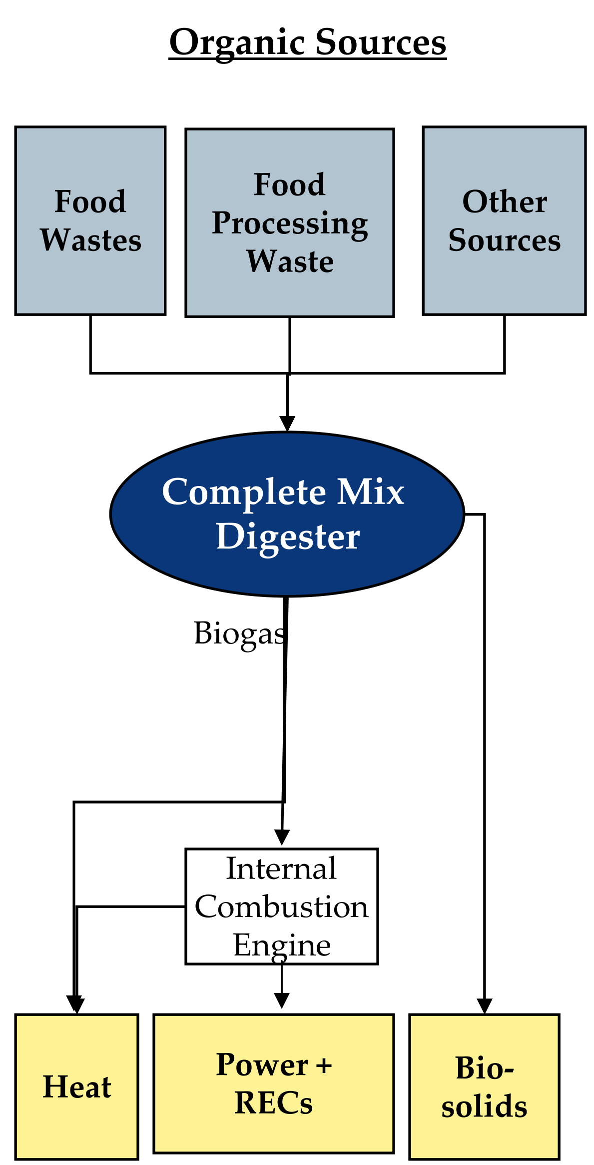
Methodology and Key Assumptions: Anaerobic Digesters – Dairy

Methodology & Key Assumptions

- The costs are for a standard covered lagoon digester. Most systems in California use a covered lagoon. In the future, more and more systems will utilize a complete mix system or other technology that allows multiple feedstocks to be placed in the digester. This technology is described in the "Anaerobic Digester – Food Waste"
- NCI surveyed costs from public– California's Dairy Power Production Program, California's Western United Dairymen, Wisconsin's Agricultural Biogas Casebook, and Cornell University's Manure Management Program. We developed installed cost and O&M based on these sources and confirmed these estimates with interviews with system designers, installers, and equipment providers. Installed costs in California are likely to be higher than the Midwest due to higher labor costs for the construction of the digester and installation of the equipment.
- Actual costs for a covered lagoon digester can vary by 25% depending on foundation and lining requirements for the digester as well as local labor rates.
- Costs for complete mix systems with concrete-lined digesters can cost approximately $700/kW more. These systems are more common on the east coast where manure is scraped into the digesters. In California, it is much more common to wash manure away with water. A covered lagoon system is more adequate for these systems given the moisture content.
- Costs for larger, 1 MW systems can cost 25% less due to economies of scale.
- Future costs are not expected to decrease in real terms as the total cost is driven primarily by installation costs and materials. Future cost declines for both installed costs and O&M are driven by reduced costs for the IC engine.

An anaerobic digester treats food wastes manure to produce biogas that can be used to produce electricity, heat, and bio-solids.

Schematic of the Technology



Description

- An anaerobic digester utilizes the natural process of anaerobic decomposition to treat waste (for example, food wastes), produce biogas that can be used to power electricity generators, provide heat and produce soil improving material.
- These cost estimates assume a combined heat and power internal combustion engine.
- Food wastes could include:
  - Food wastes, from large food retail establishments
  - Fats, oils, and grease, such as Yellow Grease or trap greases
  - Food processing wastes
- Costs can vary depending on the digester being deployed. These cost estimates are for a **Complete Mix,** which deploys large tanks, has 10% solids, and is the most expensive of the conventional digester technologies.

Economic Assumptions: Anaerobic Digesters - Food Waste

	Anaerobic Digesters - Food Waste Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (kW)	2,000	The Plant Capacities will vary widely. There is the potential for capacities to increase in the future as technology advances allow for additional types of feedstocks to be combined and utilized.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$5,300	Total installed costs will vary widely depending on size, number and type of feedstocks, type and use of electricity generating equipment. In many applications, the biogas may be used for process heat or for pipeline quality natural gas.
Electrical Facilities ($/kW)	$1,750	From Navigant Consulting sources and estimates.
Digester ($/kW)	$2,100	
Other ($/kW)	$1,450	
Fixed O&M ($/kW-yr)	$150	Fixed O&M is estimated to be approximately $150/kW-yr. Variable O&M estimated to be $200/MWh, reduced by an economic benefit from a **tipping fee,** or soil amendment credit, estimated to be $3.70/MMBtu. (Assumes $20/ton tipping fee, 70% food waste moisture content). Since no statistical or operating experience, tipping fee is assumed to remain constant.
Variable O&M ($/MWh)	-$60	

Sources: Navigant Consulting Estimates 2007, NCI Estimates for Anaerobic Digester-Dairy, NCI Interview with Dave Konwinski – Onsite Power Systems, NCI interviews with European project developers, owners, and technology providers; *Characterization of Food and Green Waste as Feedstock for Anaerobic Digesters, Interim Report*, 2005, Zhang et. al., California Energy Commission.

Performance Data: Anaerobic Digesters - Food Waste

	Anaerobic Digesters - Food Waste Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	75%	Capacity Factors can vary significantly by plant and are largely dependent on the type of feedstock.
HHV Efficiency (%)	18%	HHV efficiency is based on the feedstock to electricity. Feedstock to methane is typically 60% to 70% efficient and the IC engine ~30%. There is about a 10% loss in energy output to power the digester and mixing equipment.
CO_2 (lb/MWh)	AD – Food Waste is assumed to be CO_2 neutral. SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	1.7	NO_x can vary widely. Figures shown assume 55 ppmv @15% O_2 in exhaust, which complies with the ARB guidelines for BACT.
SO_x (lb/MWh)	0.42	Sulfur content can vary. Figures shown assume SO_2 in exhaust of 10 ppmv @ 15% O_2.

Sources: Navigant Consulting Estimates 2007, NCI Estimates for Anaerobic Digester-Dairy, NCI Interviews with industry players.

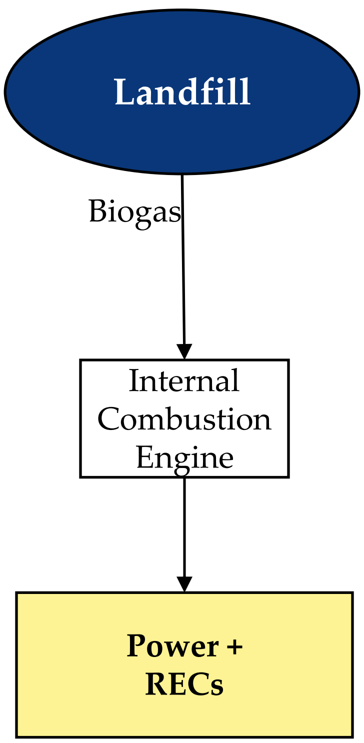
Methodology and Key Assumptions: Anaerobic Digesters - Food Waste

Methodology & Key Assumptions

- The cost estimates are for a complete-mix digester that could utilize a variety of organic wastes. Several different designs and technologies can be used, and the assumption for this technology is that one or two sources of primarily urban wastes are being used, for example food wastes from restaurants, organic waste separated at the landfill, or food processing wastes.
- The added complexity of the system requires additional staff to operate the facility and added capital equipment for preparation of the waste.
- Due to the increased size, the system benefits from economies of scale for the generation equipment and the digesters themselves.
- Future costs are expected to decline as designers and manufacturers of the digesters learn and optimize the design. As designs improve, an increased amount of organic waste may be included, and sizes could increase. These cost estimates assume a constant 2 MW size.
- Actual installed costs for existing facilities are not published in detail. Dave Konwinski from Onsite Power Systems provided guidance on cost data. NCI based its cost estimates on relative costs to a covered lagoon system, published costs for complete-mix systems, historical analysis based on systems in Europe, and input from Dave Konwinski.

A landfill gas fuel to energy, LFGFTE, utilizes the biogas from a landfill to power an electricity generator.

Schematic of the Technology



Description

- A LFGFTE utilizes the biogas produced by decomposing organic waste in landfills to power an electricity generator.
- Since most applications use an internal combustion engine, these cost estimates assume a power-only internal combustion engine (no heat capture/Combined heat and power [CHP]).
- IC Engines are more forgiving of the typically poor fuel quality that comes from a landfill.
- Costs can vary significantly based on the size of the application and the amount of front-end gas clean-up and tail-end emission clean-up. These cost estimates assume both front-end gas clean-up and tail-end emission clean-up due to the increasing stringency of California air emission regulations.

Economic Assumptions: Landfill Gas Fuel to Energy (LFGFTE)

	Landfill Gas to Energy Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (kW)	2,000	The average size of existing facilities in CA is 4 MW. 32 of 51 of existing facilities in 2002 used a reciprocating engine, averaging 3.5 MW. The average size of future facilities using reciprocating engines is 2 MW.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Cost ($/kWpac)	$1,850	Total Installed Costs for landfill gas have increased significantly over the past 5 years. According to Energy Commission reports, historical costs as of 2002 were between $1,100/kW and $1,300/kW. Based on interviews installed costs in 2006 are estimated to be 50% higher, primarily due to the increased cost in permitting costs and increased capital costs for emissions control. Gas collection facilities are required to be in place for municipal solid waste facilities with design capacities over 2.75 million tons. If they need to be added, they typically cost $500/kW.
Non-Fuel Fixed O&M ($/kW-yr)	$20	Historical O&M costs are based on historical costs at existing facilities as obtained from Energy Velocity as well as interviews with industry. The variable O&M includes only the maintenance of the generating equipment and not the maintenance of the landfill collection system, which is estimated to be about $50/kW-yr (10% of the installed cost of the gas collection system each year).
Non-Fuel Variable O&M ($/MWh)	$15	

Sources: Navigant Consulting Estimates 2007. *Landfill Gas-to-Energy Potential in California*, CEC 500-02-041V1; *Economic and Financial Aspects of Landfill Gas to Energy Project Development in California*, Apr 2002, CEC-500-02-020; NCI Interviews; *Energy Velocity*; Gas-fired Distributed Energy Resource Technology Characterizations, DOE/NREL/GTI, October 2003.

Performance Data: Landfill Gas Fuel to Energy (LFGFTE)

	Landfill Gas Fuel to Energy Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Scheduled Outage Factor (%)	6%	Forced outage rates and typical capacity factors are based on historical data at existing plants as reported by Energy Velocity.
Forced Outage Rate (%)	7%	
Typical Net Capacity Factor (%)	85%	
Fuel Cost ($/MMBtu)	-	
HHV Efficiency (%)	29.5%	From Navigant Consulting sources and estimates.
CO_2 (lb/MWh)	LFGFTE is assumed to be CO_2 neutral. SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	1.7	Figures shown assume 65 ppmv @15% O_2 in exhaust, which complies with the ARB guidelines for BACT.
SO_x (lb/MWh)	0.34	Figures shown assume SO_2 in exhaust of 10 ppmv @ 15% O_2.

Sources: Navigant Consulting Estimates 2007. *Landfill Gas-to-Energy Potential in California*, CEC 500-02-041V1; *Economic and Financial Aspects of Landfill Gas to Energy Project Development in California*, Apr 2002, CEC-500-02-020; NCI Interviews; *Energy Velocity*; "Gas-fired Distributed Energy Resource Technology Characterizations", DOE/NREL/GTI, October 2003.

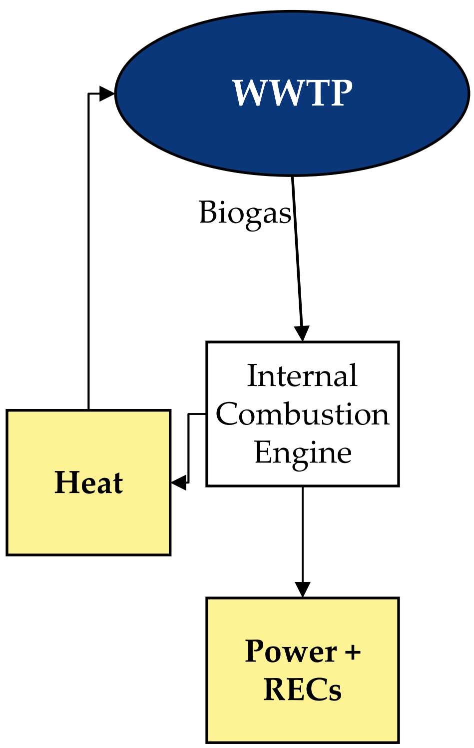
Methodology and Key Assumptions: Landfill Gas Fuel to Energy (LFGFTE)

Methodology & Key Assumptions

- Landfill gas to energy systems come in a wide variety of sizes and use a variety of different generating equipment. For the purpose of this analysis, the costs are based on a 2 MW reciprocating engine, which has been a common common system historically, and many of the planned systems are expected to be similar. Fuel cells and microturbines may become more pervasive as emission requirements become more stringent and the cost of these technologies decreases.
- The costs of landfill gas to energy facilities in California have increased from about $1,200/kW in 2002 to about $1,850/kW in 2006. Actual costs for installed systems varies widely due to the differences in technology, size, accounting, and cost overruns. NCI based its estimates for installed costs on its own historical cost estimates, historical costs published by the Energy Commission, as well as interviews with owners and developers of landfill gas to energy projects.
- The increase in cost has been driven by more stringent permitting requirements that has increased the development costs and increased capital costs for emission control equipment.
- Costs for the electric generating equipment, such as reciprocating engines, are expected to decline by about 1%/yr based on interviews as well as DOE/NREL projections. Development costs and installation costs are expected to remain constant in real terms as these are driven more by labor and permitting.
- The variable O&M includes only the maintenance of the generating equipment and not the maintenance of the landfill collection system, which is estimated to be about $50/kW-yr (10% of the installed cost of the gas collection system annually, or approximately $50/kW-yr).

A waste water treatment fuel to energy (WWTFTE) facility utilizes the biogas produced at a waste water treatment facility to power an electricity generator and produce heat.

Schematic of the Technology



Description

- A waste water treatment fuel to energy (WWTFTE) facility utilizes the biogas produced by decomposing organic waste in a waste water treatment facility to power an electricity generator and produce heat.
- Since most applications use an internal combustion engine, these cost estimates assume a combined heat and power internal combustion engine.
- IC Engines are more forgiving of the typically poor fuel quality that comes from a waste water treatment facility.
- Costs for a WWTFTE facility are typically higher than a LFGTE due to the smaller size of the engine, and the additional costs of the heat capture/CHP. These cost estimates assume both front-end gas clean-up and tail-end emission clean-up due to the increasing stringency of California air emission regulations.

Economic Assumptions: Waste Water Treatment Fuel to Energy (WWTFTE)

	Waste Water Treatment Fuel to Energy Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (kW)	500	From Navigant Consulting sources and estimates.
Project Life (yrs)	20	
Overnight Cost ($/kWpac)	$2,400	Costs for a WWTFTE facility are typically higher than a LFGTE due to the smaller size of the engine, and the additional costs of the heat capture/CHP.
Fixed O&M ($/kW-yr)	$22	Historical O&M costs are based on historical costs at existing facilities as obtained from Energy Velocity as well as interviews with industry. O&M costs are higher for the WWTFTE than the LFGTE due to the decreased scale.
Variable O&M ($/MWh)	$18	

Sources: Navigant Consulting Estimates 2007. NCI cost estimates 2002-2006, NCI Interviews; *Energy Velocity*; Gas-fired Distributed Energy Resource Technology Characterizations, DOE/NREL/GTI, October 2003.

Performance Data: Waste Water Treatment Fuel to Energy (WWTFTE)

	Waste Water Treatment Fuel to Energy Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Scheduled Outage Factor (%)	6%	Forced outage rates and typical capacity factors are based on historical data at existing plants as reported by Energy Velocity.
Forced Outage Rate (%)	7%	
Typical Net Capacity Factor (%)	85%	
Fuel Cost ($/MMBtu)	-	
HHV Efficiency (%)	27.5%	From Navigant Consulting sources and estimates.
CO_2 (lb/MWh)	WWTFTE is assumed to be CO_2 neutral. SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	1.7	Figures shown assume 65 ppmv @15% O_2 in exhaust, which complies with the ARB guidelines for BACT.
SO_x (lb/MWh)	0.39	Sulfur content of waste water treatment plants can vary. Figures shown assume SO_2 in exhaust of 10 ppmv @ 15% O_2. For SO_x this value is consistent with some H_2S removal prior to combustion.

Sources: Navigant Consulting Estimates 2007. Navigant Consulting Estimates 2007. NCI cost estimates 2002-2006, NCI Interviews; *Energy Velocity*; Gas-fired Distributed Energy Resource Technology Characterizations, DOE/NREL/GTI, October 2003.

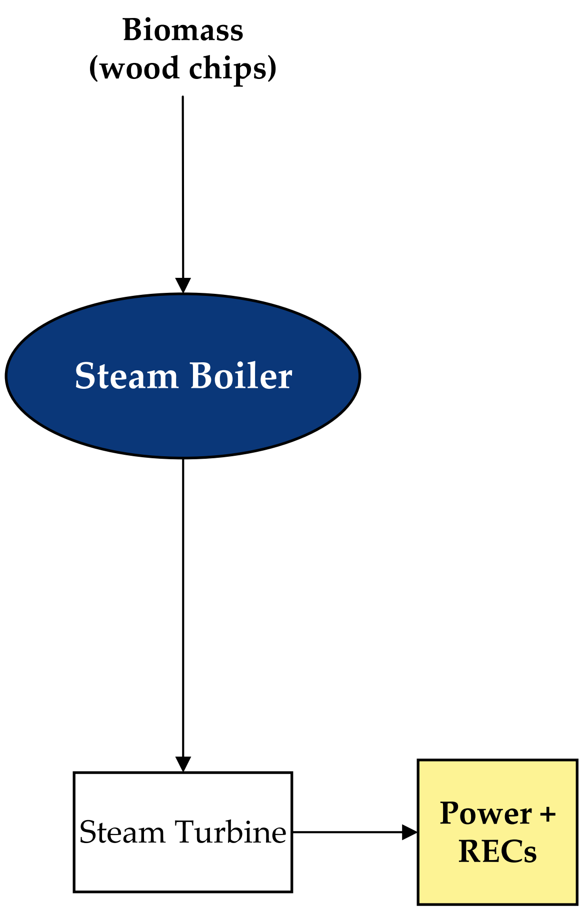
Methodology and Key Assumptions: Waste Water Treatment Fuel to Energy (WWTFTE)

Methodology & Key Assumptions

- The costs of a WWTFTE system will be very similar to that of a LFGFTE system. The configurations are fairly similar, but the WWTFTE system will have higher installed costs because it is a smaller system and it is a CHP application.
- The O&M for a WWTFTE system does not include the O&M for the gas collection system.
- There are limited sources for historical costs of WWTFTE systems. The estimates are based on historical NCI estimates and interviews. The difference in capital costs due to CHP and size were confirmed with DOE/NREL estimates.

Biomass is combusted in a boiler that generates the steam that drives a steam turbine

Schematic of the Technology



Description

- In a *stoker boiler*, biomass is added in a thin layer on a grate near the bottom of the boiler. This provides a more even distribution of feed material.
  - Mature, most commonly used technology. Incremental improvements being made to increase steam temperature and pressure

- In a *fluidized-bed boiler*, combustors burn biomass fuel in a bed of hot granular material. Air is injected at a high-rate underneath the bed to create the appearance of a boiling liquid. This helps to evenly distribute the fuel.
  - Relatively mature technology - fluidized bed combustors are becoming the systems of choice for biomass fuels, due to good fuel flexibility and good emissions characteristics.

Economic Assumptions: Biomass Combustion – Fluidized Bed Boiler

	Biomass Combustion - Fluidized Bed Boiler Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	25	From Navigant Consulting sources and estimates.
Project Life (yrs)	25	
Overnight Cost ($/kW)	$2,750	Overnight costs for 2006 are based on the NREL and Oak Ridge National Lab study. Includes all development costs, such as permitting, inventory capital and start-up costs.
Fixed O&M ($/kW-yr)	$145	Fixed O&M costs for 2006 are based on the NREL and OAK Ridge National Lab study. Includes operating, labor and maintenance costs.
Variable O&M ($/MWh)	$3	Non-Fuel Variable O&M costs for 2006 are based on the NREL and Oak Ridge National Lab study. Includes chemicals, water, ammonia, and ash disposal.
Fuel Cost ($/MMBtu)	$2.5	Fuel costs assume wood chips at $40/dry ton

Source: *Biomass Strategic Value Analysis – In Support of the 2005 Integrated Energy Policy Report* published by the Energy Research and Development Division, California Energy Commission, June 2005; *BioPower Technical Assessment – State of the Industry and the Technology* published by the National Renewable Energy Lab and Oak Ridge National Lab, June 2003; NCI estimates based on DOE/EPRI Technology Characterizations and NCI multi-client study and interviews.

Performance Data: Biomass Combustion – Fluidized Bed Boiler

	Biomass Combustion - Fluidized Bed Boiler Performance Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Scheduled Outage Factor (%)	4%	Scheduled Outage based on approximately 2 weeks/year. This includes a major turbine/generator overhaul every six years lasting one month, 5-7 days of annual for cleaning, tube repairs, etc and 2 days for inspections. 6% forced outage based on interviews.
Forced Outage Rate (%)	6%	
Net Capacity Factor (%)	85%	Based on the California Energy Commission Biomass Strategic Value Analysis, In Support of the 2005 Integrated Energy Policy Report .
HHV Efficiency (%)	22%	NCI estimate based on review of above mentioned studies and interviews.
Annual Output Degradation (%/yr)	0.4%	From Navigant Consulting sources and estimates.
CO_2 (lb/MWh)	Biomass Combustion is assumed to be CO_2 neutral. SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	1.24	Based on NO_X emissions of 0.08 lbs/MMBtu fuel input as indicated by equipment suppliers. This is better than the ARB recommended BACT guidelines of a limit for NO2 in exhaust of 70 ppm at 12% CO_2 (0.128 lbs/MMBtu) for solid biomass fuel firing. See (http://www.arb.ca.gov/drdb/sac/curhtml/r411.pdf) Page 6.
SO_x (lb/MWh)	0.70	Based on sulfur content in the biomass of 0.03%. Only 60% of the sulfur is converted to SO_2 due to the addition of SO_x control minerals in the fluidized bed. This is lower than typical requirements in California for sulfur dioxide emissions from the combustion of solid and solid-derived fuels for power generation. See (http://www.arb.ca.gov/drdb/sd/curhtml/r260-43a.htm)

Source: *Biomass Strategic Value Analysis – In Support of the 2005 Integrated Energy Policy Report* published by the Energy Research and Development Division, California Energy Commission, June 2005; *BioPower Technical Assessment – State of the Industry and the Technology* published by the National Renewable Energy Lab and Oak Ridge National Lab, June 2003; NCI estimates based on DOE/EPRI Technology Characterizations and NCI multi-client study and interviews.

Economic Assumptions: Biomass Combustion – Stoker Boiler

	Biomass Combustion – Stoker Boiler Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	25	From Navigant Consulting sources and estimates.
Project Life (yrs)	25	
Overnight Cost ($/kW)	$2,500	Based on the Energy Commission study, assumed capital costs are marginally lower than for the fluidized bed boiler case.
Fixed O&M ($/kW-yr)	$130	Based on the Energy Commission study, assumed that Fixed O&M costs for a stoker boiler are 10% lower than for a fluidized bed boiler.
Variable O&M ($/MWh)	$3	Non-Fuel Variable O&M are assumed to be the same for a stoker boiler system as for a fluidized bed boiler system
Fuel Cost ($/MMBtu)	$2.5	Fuel costs assume wood chips at $40/dry ton.

Source: *Biomass Strategic Value Analysis – In Support of the 2005 Integrated Energy Policy Report* published by the Energy Research and Development Division, California Energy Commission, June 2005; *BioPower Technical Assessment – State of the Industry and the Technology* published by the National Renewable Energy Laboratory and Oak Ridge National Lab, June 2003; NCI estimates based on DOE/EPRI Technology Characterizations and NCI multi-client study and interviews

Performance Data: Biomass Combustion – Stoker Boiler

	Biomass Combustion – Stoker Boiler Performance Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Scheduled Outage Factor (%)	4%	Scheduled Outage based on approximately 2 weeks/year. This includes a major turbine/generator overhaul every six years lasting one month, 5-7 days of annual for cleaning, tube repairs, etc and 2 days for inspections. 6% forced outage based on interviews.
Forced Outage Rate (%)	6%	
Net Capacity Factor (%)	85%	Based on the Energy Commission Biomass Strategic Value Analysis, In Support of the 2005 Integrated Energy Policy Report .
HHV Efficiency (%)	21.5%	NCI estimate based on review of above mentioned studies and interviews. 0.5% lower than for fluidized bed boiler based on discussions with technology providers.
Annual Output Degradation (%/yr)	0.4%	Based on a total output degradation over the lifetime of the project (25 years) of ~2% (same for fluidized bed boiler). Based on NCI estimates, interviews and review of the following documents: http://www.cpuc.ca.gov/Published/Comment_resolution/54445.htm and http://www.calwea.org/Attached%20Documents/Recd%2004Mar05/CALWEA-CBEA-%20CCC%20comments%20on%20the%20MPR%20Staff%20Report%202-28-05.pdf.
CO_2 (lb/MWh)	Biomass Combustion is assumed to be CO_2 neutral. This is SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	1.24	Based on NO_X emissions of 0.08 lbs/MMBtu fuel input as indicated by equipment suppliers. This is better than the ARB recommended BACT guidelines of a limit for NO_2 in exhaust of 70 ppm at 12% CO_2 (0.128 lbs/MMBtu) for solid biomass fuel firing. See (http://www.arb.ca.gov/drdb/sac/curhtml/r411.pdf) Page 6.
SO_x (lb/MWh)	1.10	Based on sulfur content in the biomass of 0.03%. All the sulfur is converted to SO_2. Also see Slide 21.

Source: *Biomass Strategic Value Analysis – In Support of the 2005 Integrated Energy Policy Report* published by the Energy Research and Development Division, California Energy Commission, June 2005; *BioPower Technical Assessment – State of the Industry and the Technology* published by the National Renewable Energy Laboratory and Oak Ridge National Lab, June 2003; NCI estimates based on DOE/EPRI Technology Characterizations and NCI multi-client study and interviews.

Methodology and Key Assumptions: Biomass Combustion

Methodology & Key Assumptions

- For all years we are profiling a 25 MW_E steam boiler fueled by wood chips and associated steam turbine for power generation.

- Capital Costs:
  - For a fluidized bed boiler system, the NREL and Oak Ridge National Laboratory reports capital costs of $2,426/kW for 2001. NCI adjusted this figure for inflation (inflator of 1.15), that resulted in $2,750/kW for 2006.
  - The California Energy Commission study indicates that capital costs for a stoker boiler system are 15% lower than for a fluidized bed boiler system in 2006. Based on interviews, estimate cost differential to be 10%, or ~$250/kW in 2006.

- Fixed O&M Costs:
  - For a fluidized bed boiler, the NREL and Oak Ridge National Laboratory study reports total yearly costs of $3.1M in 2001, or $125/kW-yr. Applying the above-mentioned inflator to 2006, calculates to $145/kW-yr.
  - Based on the California Energy Commission study, assumed that Fixed O&M costs for a stoker boiler are 10% lower than estimates for a fluidized bed boiler throughout the timeframe.

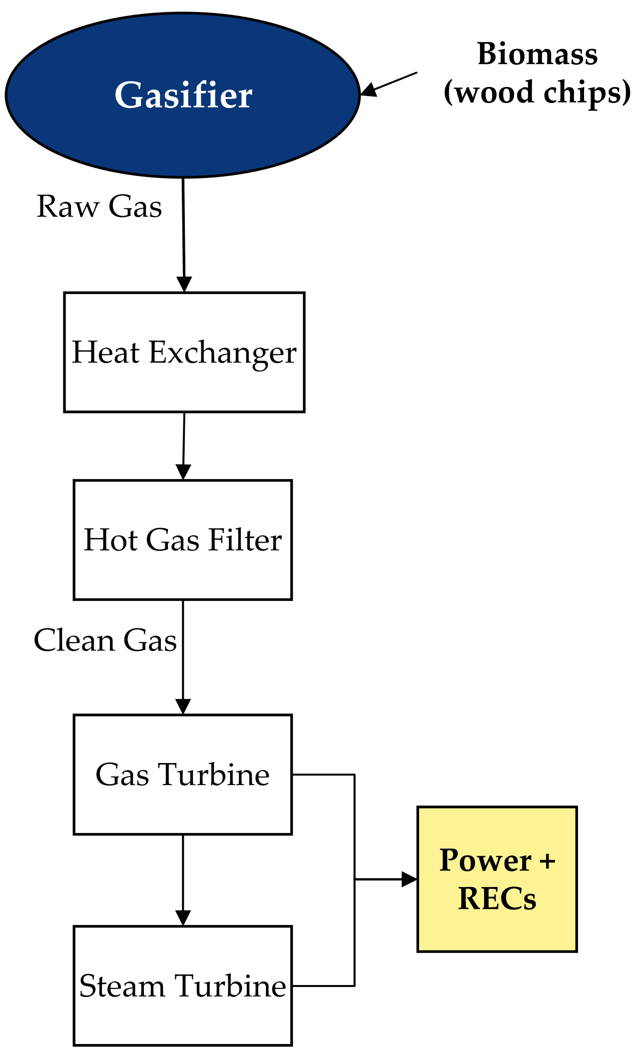
Methodology and Key Assumptions: Biomass Combustion

Methodology & Key Assumptions

- Non-Fuel Variable O&M Costs: The NREL and Oak Ridge National Lab study reports total yearly costs of $560k in 2001, or $3/MWh. Used this same assumption for fluidized bed boilers and stoker boilers alike.
- System HHV Efficiency. NCI estimate. The efficiencies in the California Energy Commission study appear low for the state-of-the-art technologies in the short-term. The NREL and Oak Ridge National Lab study projects higher efficiencies that reflect the use of a biomass drier and steam cycle efficiencies improvements, for example higher pressure, higher temperature and reheat (these make sense only for larger plant sizes). Based on interviews, NCI estimates an efficiency of 22% for a 25 MW_E plant in 2006 that will improve only marginally as the technology is mature. Stoker boilers are assumed to have a slightly lower efficiency due to a lower carbon burnout
- Compared to a stoker boiler system a fluidized-bed boiler:
  - Achieves a higher carbon burn-out.
  - Ensures more fuel flexibility due to the good mixing that occurs on the fluidized bed.
  - The relatively low combustion temperature ensures reduced NO_x emissions, and the CFB process allows for the addition of certain minerals into the bed to control SO_x emissions. We estimate a 40% reduction in SO_x emissions compared to the stoker boiler system.

Biomass is gasified to produce a syngas that fuels a combined cycle power generation facility.

Schematic of the Technology



Description

- This technology gives biomass access to the higher efficiencies of gas fired power generation and combined cycles.
- Key characteristics of the profiled system:
  - Direct (single stage and autothermal), pressurized, fluidized bed gasifier.
  - Heat exchanger to 400C prior to hot gas filter for dust removal (tar removal is not necessary).
  - Cleaned gas is a combusted in a gas turbine, which also supplies the gasifier with pressurized air from the compressor.
  - Residual heat is used in a steam cycle.
- Commercial deployment of the technology has not occurred. One demonstration BIGCC unit has been built in Europe but it is no longer in operation.
  - Information on actual capital and operating costs is limited.

Economic Assumptions: BIGCC

	BIGCC Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	20	From Navigant Consulting sources and estimates.
Project Life (yrs)	25	
Overnight Cost ($/kW)	$2,800	
Fixed O&M ($/kW-yr)	$150	
Non-Fuel Variable O&M ($/MWh)	$3	
Fuel Cost ($/MMBtu)	$2.50	

Sources: *Handbook Biomass Gasification* edited by H. Knoef and published by the Biomass Technology Group, BTG; Biomass *Strategic Value Analysis – In Support of the 2005 Integrated Energy Policy Report*, Energy Research and Development Division, California Energy Commission; *Cost and Performance Analysis of Three Integrated Biomass Gasification Combined Cycle Power Systems* by K. Craig and M. Mann, National Energy Renewable Lab; *Fuels and Electricity from Biomass with and without CO_2 Capture and Storage* by E. Larson, R. Williams, H. Jin; *Integrated Gasification Combined Cycle and Steam Injection Gas Turbine Powered by Biomass Joint-Venture Evaluation* by G. Sterzinger at the Economics, Environment and Regulation; *Biomass-Gasifier/Aeroderivative Gas Turbine Combined Cycles: Part A – Technologies and Performance Modeling* by E.D. Larson and S. Consonni; *Renewable Energy Technology Characterizations* TR-109496 Topical Report. Prepared by Office of Utility Technologies, Energy Efficiency and Renewable Energy, U.S. Department of Energy and EPRI; Interviews with Richard Bain, NREL and Mark Paisley, Taylor Biomass Energy

Performance Data: BIGCC

	BIGCC Performance Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Scheduled Outage Factor (%)	6%	Based on the BTG study, assumed a total downtime of 12%.
Forced Outage Rate (%)	6%	
Net Capacity Factor (%)	85%	From Navigant Consulting sources and estimates.
HHV Efficiency (%)	32%	
Annual Output Degradation (%/yr)	0.4%	
CO_2 (lb/MWh)	BIGCC is assumed to be CO_2 neutral. SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	0.85	See comments on section on biomass combustion technologies (stoker boiler and fluidized bed boiler) for further details.
SO_x (lb/MWh)	0.75	

Sources: *Handbook Biomass Gasification* edited by H. Knoef and published by BTG; *Biomass Strategic Value Analysis – In Support of the 2005 Integrated Energy Policy Report*, Energy Research and Development Division, California Energy Commission; *Cost and Performance Analysis of Three Integrated Biomass Gasification Combined Cycle Power Systems* by K. Craig and M. Mann, National Energy Renewable Lab; *Fuels and Electricity from Biomass with and without CO_2 Capture and Storage* by E. Larson, R. Williams, H. Jin; *Integrated Gasification Combined Cycle and Steam Injection Gas Turbine Powered by Biomass Joint-Venture Evaluation* by G. Sterzinger at the Economics, Environment and Regulation; *Biomass-Gasifier / Aeroderivative Gas Turbine Combined Cycles: Part A – Technologies and Performance Modeling* by E.D. Larson and S. Consonni; *Renewable Energy Technology Characterizations* TR-109496 Topical Report. Prepared by Office of Utility Technologies, Energy Efficiency and Renewable Energy, U.S. Department of Energy and EPRI; Interviews with Richard Bain, NREL and Mark Paisley, Taylor Biomass Energy

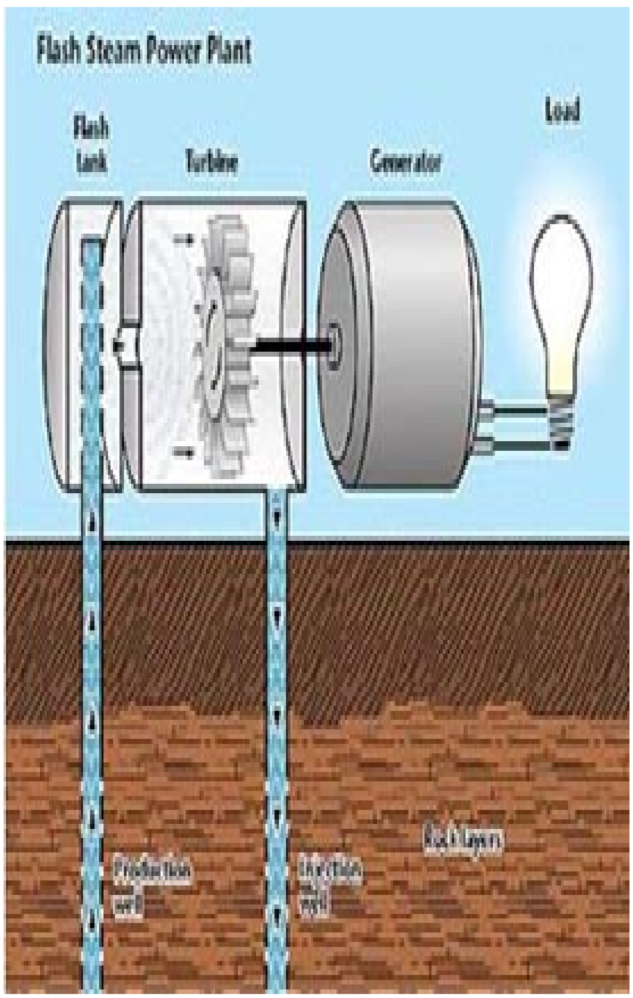
Methodology and Key Assumptions: BIGCC

Methodology & Key Assumptions

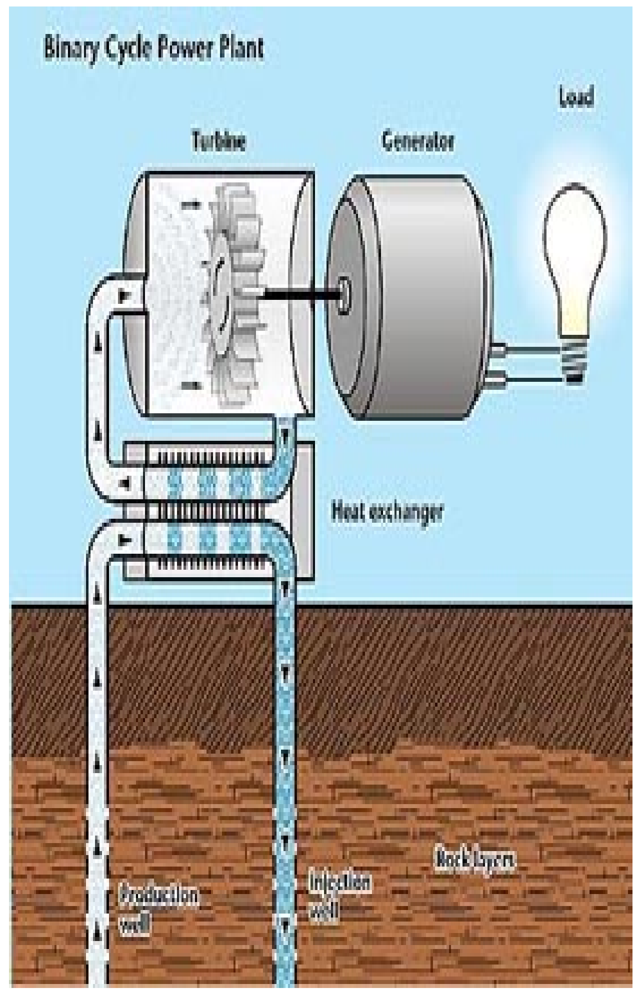
- BIGCC is not a commercial technology. In addition to the direct, pressurized, fluidized bed gasifier, other advanced biomass gasification designs are being studied. Promising options include two-stage (indirect) gasifiers and oxygen-blown gasifiers. It is unclear which variant will prove most cost-competitive in the long-term.
- The reference used for 2006 is a collaborative study conducted by BTG biomass technology group BV, a European firm specializing in bioenergy technologies. Other studies indicate lower capital and operating costs but refer to longer-term economics that incorporate learning curves and other improvements in the technology. The BTG study incorporates the experience of the few operating demonstration units to estimate the current cost for a turnkey BIGCC facility.
  - Unit has 20 MW_E capacity, a capacity factor of 85% and a HHV of 32% (lower than what is assumed in the study based on result of the interviews NCI conducted).
  - Capital costs estimated at $2,800/kW. Major cost items are the gasification island, inclusive of the gasifier, gas cleaning, heat exchangers, etc.. ($1,200/kW) and the gas turbine ($600/kW).
  - Fixed O&M, estimated at $150/kW-yr, include labor (18 people, $50/kW-yr) and maintenance (2% investment, $50/kW-yr).
  - Non-fuel variable O&M, estimated at $3/MWh, include chemicals, water consumption and disposal of residues.
  - Fuel costs of $2.5/MMBtu reflects a cost of $40/ton of wood chips.

Dual Flash systems typically use steam above 400 F and Binary Steam systems use steam below 400 F.

Dual Flash Schematic



Binary Steam Schematic



Source: National Renewable Energy Lab

Economic Assumptions: Geothermal – Dual Flash

	Geothermal – Dual Flash Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	50	Current California installations range from .5 to 90 MW in size. 50 is an average.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Installed Cost ($/kW)	$2,750	
Exploration ($/kW)	$10	
Confirmation Drilling ($/kW)	$290	
Equipment/Installation ($/kW)	$2,345	
Transmission ($/kW)	$105	
Fixed O&M ($/kW-yr)	$80	
Variable O&M ($/MWh)	$5	Water for cooling condensers is the largest component of Variable O&M. Water access issues in California could balance out any gains in water usage efficiency.

Sources: Navigant Consulting Estimates 2007, *Geothermal Strategic Value Analysis,* CEC-500-2005-105-SD June 2005, Potential Improvements to Existing Geothermal Facilities in California, *GRC Transactions*, Vol. 30, 2006, J. Lovekin, S. Sanyal, A, Caner Sener, V. Tiangco, and P. Gutierrez-Santana, Interview with Dan Schochet, Vice President of ORMAT Technologies, January 2007, Jim Lovekin of Geothermex, February 2007 and Vince Signorotti of Cal Energy, March 2007.

Performance Data: Geothermal – Dual Flash

	Geothermal – Dual Flash Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	95%	From Navigant Consulting sources and estimates.
Fuel Cost ($/MMBtu)	n/a	
Heat Rate (HHV)	n/a	
HHV Efficiency (%)	n/a	
Annual Output Degradation (%/yr)	4%	
CO_2 (lb/MWh)	60	CO_2 and SO_x are emitted from the geothermal resource. See page 115 of the Geothermal Resource Council Bulletin May-June '05.
NO_x (lb/MWh)	0	
SO_x (lb/MWh)	0.35	

Sources: Navigant Consulting Estimates 2007, *Geothermal Strategic Value Analysis,* CEC-500-2005-105-SD June 2005; *Potential Improvements to Existing Geothermal Facilities in California*, GRC Transactions, Vol. 30, 2006, J. Lovekin, S. Sanyal, A, Caner Sener, V. Tiangco, and P. Gutierrez-Santana, Interview with Dan Schochet, Vice President of ORMAT Technologies, January 2007. Geothermal Resource Council Bulletin May-June 2005.

Methodology and Key Assumptions: Geothermal – Dual Flash

Methodology & Key Assumptions

- Output and overnight costs can very significantly by site, depending on resource quality. Average values for California are reported.
- NCI surveyed cost and performance data from recent CEC reports on geothermal technology in California. NCI also used internal sources and Energy Velocity. This data was verified by an interview with Vince Signorotti of Cal Energy.
- Future costs are highly uncertain. Costs are assumed to remain constant in real terms as technology advances are balanced by the increased costs of developing relatively less attractive sites.

Economic Assumptions: Geothermal – Binary Steam

	Geothermal – Binary Steam Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	50	Current California installations range from .5 to 90 MW in size. 50 is an average.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Installed Cost ($/kW)	$3,000	From Navigant Consulting sources and estimates.
Exploration ($/kW)	$8	
Confirmation Drilling ($/kW)	$327	
Equipment/Installation ($/kW)	$2,560	
Transmission ($/kW)	$105	
Fixed O&M ($/kW-yr)	$70	
Variable O&M ($/MWh)	$4.5	Water for cooling condensers is the largest component of Variable O&M. Water access issues in California could balance out any gains in water usage efficiency.

Sources: Navigant Consulting Estimates 2007, *Geothermal Strategic Value Analysis* CEC-500-2005-105-SD June 2005, Potential Improvements to Existing Geothermal Facilities in California, GRC Transactions, Vol. 30, 2006, J. Lovekin, S. Sanyal, A, Caner Sener, V. Tiangco, and P. Gutierrez-Santana, Interview with Dan Schochet, Vice President of ORMAT Technologies, January 2007

Performance Data: Geothermal – Binary Steam

	Geothermal – Binary Steam Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	95%	From Navigant Consulting sources and estimates.
Fuel Cost ($/MMBtu)	n/a	
Heat Rate (HHV)	n/a	
HHV Efficiency (%)	n/a	
Annual Output Degradation (%/yr)	4%	From Navigant Consulting sources and estimates.
CO_2 (lb/MWh)	0	Binary steam systems do not emit CO_2, NO_x, or SO_x because the geothermal steam is in a closed loop system and is not vented to the atmosphere.
NO_x (lb/MWh)	0	
SO_x (lb/MWh)	0	

Sources: Navigant Consulting Estimates 2007; *Geothermal Strategic Value Analysis*, CEC-500-2005-105-SD June 2005, *Potential Improvements to Existing Geothermal Facilities in California*, GRC Transactions, Vol. 30, 2006, J. Lovekin, S. Sanyal, A, Caner Sener, V. Tiangco, and P. Gutierrez-Santana, Interview with Dan Schochet, Vice President of ORMAT Technologies, January 2007

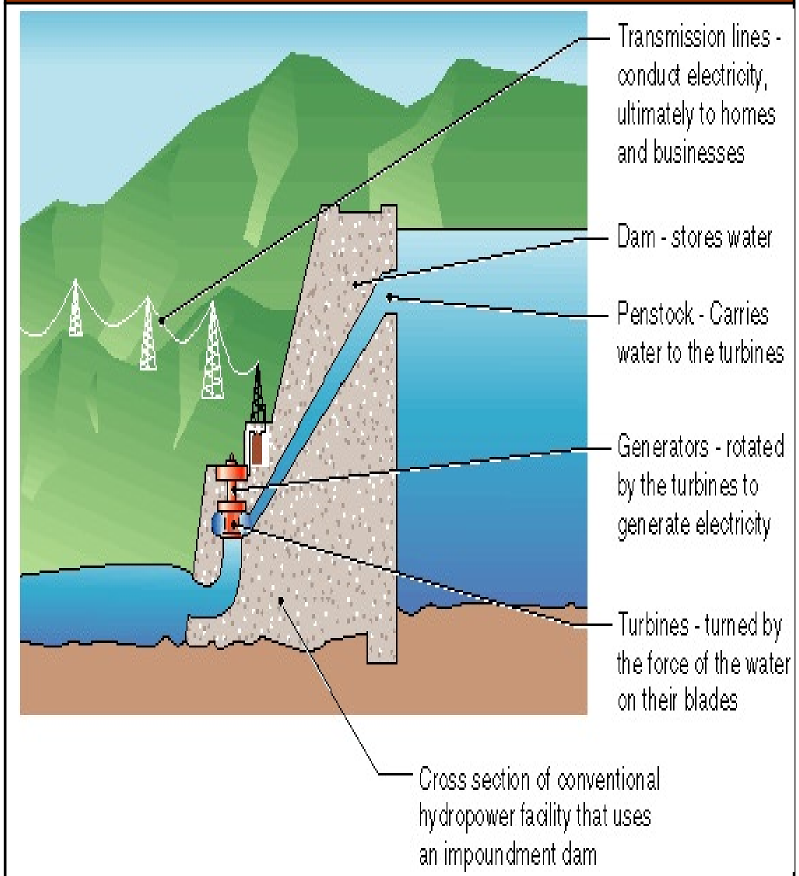
Methodology and Key Assumptions: Geothermal – Binary

Methodology & Key Assumptions

- Output and overnight costs can vary significantly by site, depending on resource quality. Average values for California are reported.
- NCI surveyed cost and performance data from recent CEC reports on geothermal technology in California. NCI also used internal sources and Energy Velocity. This data was verified by an interview with Dan Schochet of ORMAT, Inc. ORMAT is one of the key companies installing plants in California.
- Future costs are highly uncertain. Costs are assumed to remain constant in real terms as technology advances are balanced by the increased costs of developing relatively less attractive sites. Further development in California will require more wells and new drilling techniques to utilize the lower temperature steam.

A small-scale hydropower facility captures the energy of falling water to generate electricity.

Schematic of the Technology



Description

- The most common type of hydroelectric power plant is an impoundment facility. An impoundment facility, typically a large hydropower system, uses a dam to store river water in a reservoir. Water released from the reservoir flows through a turbine, spinning it, which in turn activates a generator to produce electricity. The water may be released either to meet changing electricity needs or to maintain a constant reservoir level.
- Small Scale Hydropower facilities are impoundment facilities that generate between .01 to 30 MW of electricity.

Sources: Idaho National Laboratory,
http://hydropower.inel.gov/hydrofacts/hydropower_facilities.shtml

Economic Assumptions: Small-Scale Hydropower

	Small-Scale Hydropower Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	10	According to Idaho National Engineering and Environmental Laboratory, INEEL, the average MW potential at sites with developed dams without hydropower is 14 MW.
Project Life (yrs)	30	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$4,000	Actual installed costs vary widely based on the amount of civil works and mitigation required. NCI cost estimates are based on Idaho National Laboratory and RETScreen™ estimates for a 10MW facility where the dam is already in place.
Equipment & Construction ($/kW)	$1,800	
Licensing & Mitigation ($/kW)	$2,200	
Non-Fuel Fixed O&M ($/kW-yr)	$13	Median cost for plants 8-11 MWs with Dams and No Power in INEEL Hydropower Resource Economics Database, IHRED, Database is $13/kW-yr.
Non-Fuel Variable O&M ($/MWh)	$3	Median cost for plants 8-11 MWs with Dams and No Power in IHRED Database is $14.5/kW-yr.
Typical Net Capacity Factor (%)	52%	Idaho National Laboratory estimates.
Annual Output Degradation (%/yr)	2%	From Navigant Consulting sources and estimates.

Sources: Navigant Consulting Estimates 2007. Idaho National Laboratory, *Estimation of Economic Parameters of U.S. Hydropower Resources*, June 2003; INEEL Hydropower Resource Economics Database, IHRED; *California Small Hydropower and Ocean Wave Energy Resources*; 2005 IEPR, April 2005; Natural Resources Canada RETScreen™ Energy Model - Small Hydro Project; INL State Resource Assessment.

Methodology and Key Assumptions: Small-Scale Hydropower

Methodology & Key Assumptions

- The costs of a small-scale hydropower facility vary widely depending on the amount of civil works, licensing, and mitigation required.
- The Idaho National Laboratory, INL, as well as the Natural Resources Canada, NRC, both have online tools that help estimate the costs for hydropower.
- The INL has a database of prospective sites that: 1) already have power, 2) are developed with a dam, but do not have power, and 3) are not developed. This analysis focuses on estimating costs for the sites that are developed, but do not have power. The median size of these sites in California is approximately 10 MW.
- Both online tools from the INL and NRC estimate that installed costs in 2002/3 would be approximately $1,500/kW for equipment and construction. INL also estimates costs for mitigation and licensing, which run about $1,750/kW. Based on NCI experience, NCI assumes a 30% increase in costs to arrive at a $4,000/kW installed costs in 2006.
- According to INL, "Estimated costs included in the database including licensing, construction, mitigation, and O&M were not developed by performing individual site analyses. They are general cost estimates based on a collection of historical experience for similar facilities. Therefore, the costs presented in this study should not be interpreted as precise engineering estimates. Actual costs for any specific site could vary significantly from these generalized estimates".

In-Conduit Hydropower facility.

Schematic of the Technology

Description

- In-conduit hydro is that developed within man-made conduits instead of natural streams, rivers, or creeks.
- Key advantages of in-conduit hydropower include no impact on wildlife, reduced O&M due to the cleanliness of the water, more streamlined permitting processes, and often less civil works.
- "Man-made conduits" include pipelines, aqueducts, irrigation ditches, and canals.
- In-conduit hydro can use impoundment, run-of-river, or diversion to generate electricity.

Economic Assumptions: In-Conduit Hydropower

	In-Conduit Hydropower Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	1	According to the June 2006 PIER report, the median size is approximately 1 MW for small hydropower.
Project Life (yrs)	30	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$1,500	Actual installed costs vary widely NCI cost estimates are based on Table 7 of the CEC PIER report *Statewide Small Hydropower Resource Assessment*, and adjusted to $2006.
Non-Fuel Fixed O&M ($/kW-yr)	-	
Non-Fuel Variable O&M ($/MWh)	$13	
Typical Net Capacity Factor (%)	49%	
Annual Output Degradation (%/yr)	1%	From Navigant Consulting sources and estimates.

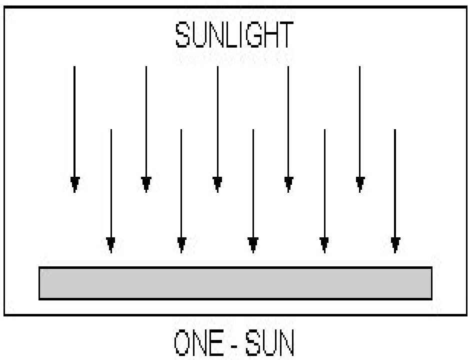
Sources: Navigant Consulting Estimates 2007. *Statewide Small Hydropower Resource Assessment*; California Energy Commission PIER Final Project Report, June 2006.

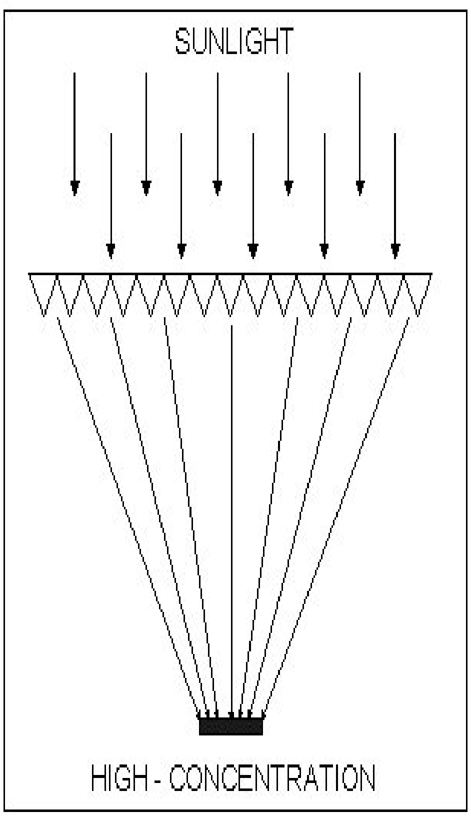
Methodology and Key Assumptions: In-Conduit Hydropower

Methodology & Key Assumptions

- The costs of a In-Conduit Hydropower were estimated by Navigant Consulting in 2006. *Statewide Small Hydropower Resource Assessment*; California Energy Commission, PIER Final Project Report; June 2006; http://www.energy.ca.gov/2006publications/CEC-500-2006-065/CEC-500-2006-065.PDF)
- These estimates are based on that report as well as analysis performed by NCI using the RETScreen™ cost estimator model developed by Natural Resources Canada.

Concentrating photovoltaics, CPV, use lenses or reflective collectors to focus solar energy (typically > 100 suns) on a reduced area of solar cell material that is more efficient.





From www.amonix.com

Arizona Public Service photo: Prescott 35 kW, dual axis tracking system.

Installed system costs for concentrating PV are high due to small production volumes.

	Concentrating PV Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Net Plant Capacity (kW)	15,000	Navigant Consulting, Inc. estimates based on *Arizona Solar Electric Roadmap*, Full Report, Prepared by Navigant Consulting, Inc. for the Arizona Department of Commerce, January 2007 and interview with Vahan Garboushian, President, Amonix, March 7, 2007.
Annual Output Degradation (%/yr)	1%	Interview with Vahan Garboushian, President, Amonix, March 7, 2007. 1% per year up to a maximum of 10% for a system.
Project Life (yrs)	25	Navigant Consulting, Inc. estimates based on *Arizona Solar Electric Roadmap, Full Report*, Prepared by Navigant Consulting, Inc. for the Arizona Department of Commerce, January 2007 and interview with Vahan Garboushian, President, Amonix, March 7, 2007.
Overnight Cost ($/kWp)	$5,000	
Fixed O&M ($/kW-yr)	$45	
Variable O&M ($/MWh)	NA	
Development Time (months)	12	Interview with Vahan Garboushian, President, Amonix, March 7, 2007.

Sources: *Arizona Solar Electric Roadmap, Full Report*, Prepared by Navigant Consulting, Inc, Jan 2007; interview with Vahan Garboushian, President, Amonix, March 7, 2007.

Capacity factors for concentrating PV is estimated around 23% for key areas in Southern California.

	Concentrating PV Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	23%	The systems do not shut down all at once and units are fixed one at a time. Availability is estimated at 98%. Interview with Vahan Garboushian, President, Amonix, March 7, 2007. 1% per year up to a maximum of 10% for a system. Capacity factors based on *Arizona Solar Electric Roadmap, Full Report*, Prepared by Navigant Consulting, Inc. for the Arizona Department of Commerce, January 2007 and interview with Vahan Garboushian, President, Amonix, March 7, 2007. Capacity factor estimate is typical of Imperial Valley area of Southern California.
Fuel Cost ($/MMBtu)	NA	
HHV Efficiency (%)	NA	
CO_2 (lb/MWh)	No Emissions	
NO_x (lb/MWh)		
SO_x (lb/MWh)		

Sources: *Arizona Solar Electric Roadmap, Full Report*, Prepared by Navigant Consulting, Inc, Jan 2007; interview with Vahan Garboushian, President, Amonix, March 7, 2007.

Below are some additional key assumptions and sources used for the Concentrating PV analysis.

Methodology & Key Assumptions

- Companies such as Amonix claim to need 10MW of production volumes to be competitive
  - Arizona Public Service and Amonix have worked together since 1995 and have >600 kW operating in Arizona with 26% efficient cells/250x solar concentration.
- The solar rebates that are applicable to flat plate PV in California are not currently applicable to concentrating PV.

A dish/engine uses a mirrored dish (similar to a large satellite dish) that collects and concentrates the sun's heat onto a receiver, which absorbs the heat and transfers it to fluid within the engine.

The heat causes the fluid to expand against a piston or turbine to produce mechanical power. The mechanical power is then used to run a generator or alternator to produce electricity.

Solar Dish engine economics are still somewhat unknown, and vary widely.

	Dish Engine Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Net Plant Capacity (kW)	15,000	From Navigant Consulting sources and estimates.
Annual Output Degradation (%/yr)	NA	Not Available. No commercial systems have been operational enough to provide an estimate.
Project Life (yrs)	25	From Navigant Consulting sources and estimates.
Overnight Cost ($/kWp)	$6,000	
Fixed O&M ($/kW-yr)	$125 - $200	
Variable O&M ($/MWh)	NA	
Development Time (months)	12	From Navigant Consulting sources and estimates.

Sources: *Arizona Solar Electric Roadmap, Full Report*, Prepared by Navigant Consulting, Inc, Jan 2007; NCI Interviews. National Renewable Energy Laboratory web site, March 2007.

The capacity factors for Dish Engines are expected to be between 23% – 25% in good solar resource areas in California.

	Dish Engine Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	23% - 25%	Systems may have about 10% of the units not being used because they are in repair. There is expected to be limited forced outage in the near term. Assuming installation near Imperial Valley (Southern California). Low end from interview with NREL and high end based on *Arizona Solar Electric Roadmap, Full Report*, Prepared by Navigant Consulting, Inc. for the AZ Department of Commerce, January 2007.
Fuel Cost ($/MMBtu)	NA	
HHV Efficiency (%)	NA	
CO_2 (lb/MWh)	No Emissions	
NO_x (lb/MWh)		
SO_x (lb/MWh)		

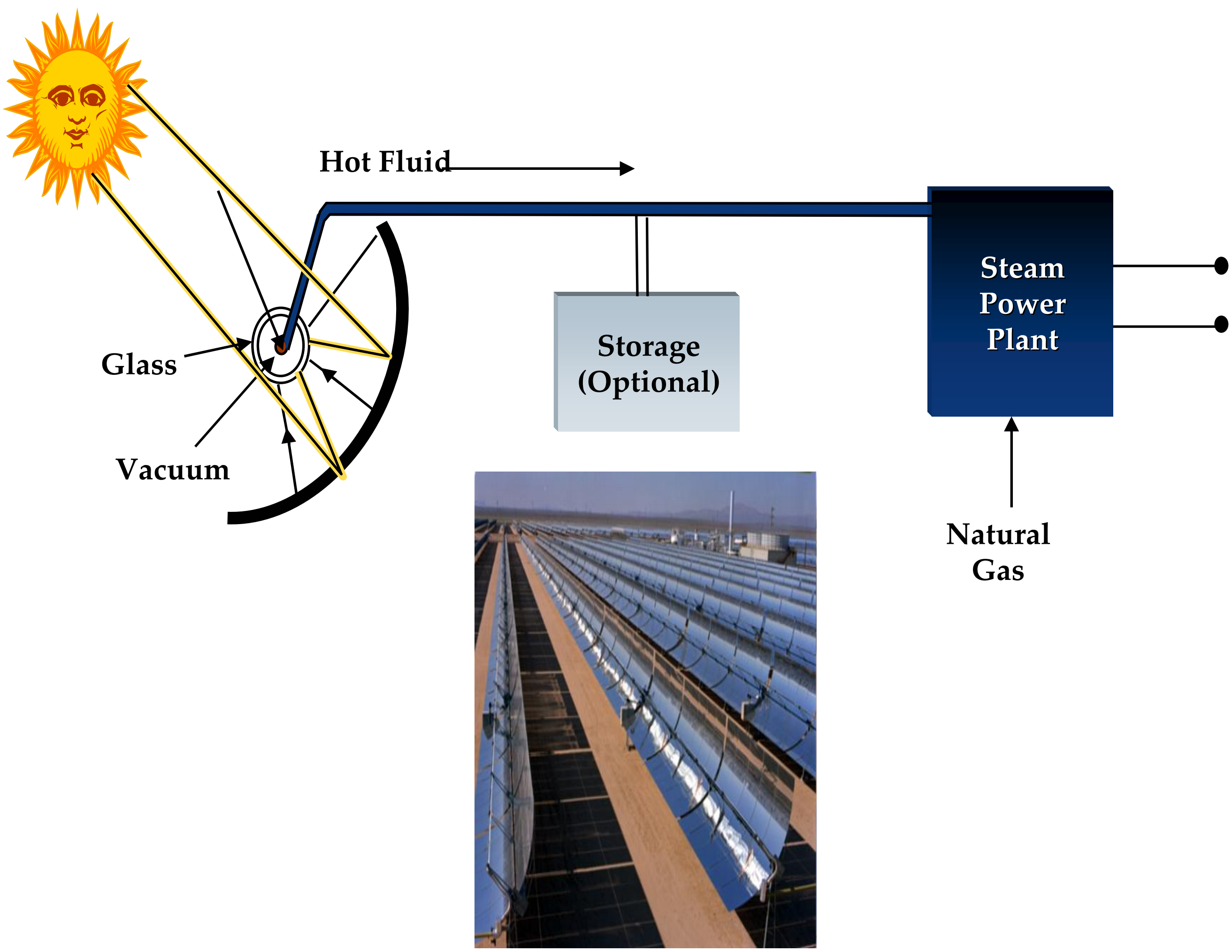
Sources: *Arizona Solar Electric Roadmap, Full Report,* Prepared by Navigant Consulting, Inc, Jan 2007; NCI Interviews.

Methodology and key assumptions and sources used for the Dish Engine analysis:

Methodology & Key Assumptions

- There is limited operational experience for dish Engine technology. Six dishes are in demonstration mode at Sandia and one 25 kW system is operating at the University of NV at Las Vegas.
- SES has a PPA with Southern California Edison for 500 MW with a 350 MW option and a PPA with San Diego Gas & Electric for 300 MWs with a 600 MW option (total potential for 1,750 MW).
- Land use is about 5 acres per MW
- Dish Engines qualify for 5-yr accelerated depreciation and 30% investment tax credit until the end of 2008 when the tax credit amount will reduce to 10%.

Parabolic trough systems use concentrated solar energy to raise the temperature of a heat transfer fluid. Co-firing with natural gas or storage can sometimes be used to ensure dispatch capability.



Parabolic Trough

Parabolic-trough systems concentrate the sun's energy through long rectangular, curved (U-shaped) mirrors. The mirrors are tilted toward the sun, focusing sunlight on a pipe that runs down the center of the trough. This heats the oil flowing through the pipe. The hot oil then is used to boil water in a conventional steam generator to produce electricity. (NREL web site, March 2007.)

Typical system sizes range are expected to increase, and overnight costs are currently too expensive for more widespread adoption.

	Parabolic Trough Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Gross Plant Capacity (kW)	63,500	NCI estimate based on Solargenix report reference in the source listed below, page 52, and discussions with NREL.
Net Plant Capacity (kW)	50,000	
Annual Output Degradation (%/yr)	0.2%	Based on discussions with NREL.
Project Life (yrs)	30	From Navigant Consulting sources and estimates.
Overnight Cost ($/kWp)	$3,900	Assumes 6 hours of molten salt storage starting in 2010. Navigant Consulting estimates are for overnight costs based on Black and Veatch report, and discussions with NREL. Data also from report prepared by NCI, Arizona Solar Electric Roadmap Study. Increasing the plant capacity to 100 MW reduces costs ~10%.
Fixed O&M ($/kW-yr)	$60.0	Solar field O&M assumed to be 35% of total O&M and of that 25% is assumed to be for solar field parts and materials (most of which is receiver replacement. Mirror breakage is only 15% of the total parts cost. NCI estimate based on Interview with NREL, Solargenix report, NCI Solar Electric Roadmap for AZ.
Variable O&M ($/MWh)	NA	
Development Time (months)	20	From Navigant Consulting sources and estimates.
Construction Time (months)	12	

Sources: *Solar Thermal Parabolic Trough Electric Power Plants for Electric Utilities in California*, Solargenix Energy, November 2005, CEC-500-2005-175. NCI Interviews with Hank Price and Mark Mehos, NREL. *Economic, Energy, and Environmental Benefits of Concentrating Solar Power in California*, Black and Veatch for the National Renewable Energy Laboratory, April 2006. NREL/SR-550-39291; *Arizona Solar Electric Roadmap Study*, NCI, Arizona Department of Commerce, January 2007 Interview with Bob Lawrence of Sunray Energy, Inc. March 2007.

The solar field that includes the mirrors and the metal support structure is the most costly part of the trough system.

Year	2010
Plant Size	**100 MW**
Site Work and Infrastructure	1%
Solar Field	45%
Heat Transfer Fluid System	2%
Thermal Energy Storage (6 hrs)	13%
Power Block	8%
Balance of Plant	5%
Contingency	6%
Indirect Costs	20%

Source: Navigant Consulting, Inc. analysis based on Black and Veatch, *Economic, Energy, and Environmental Benefits of Concentrating Solar Power in California*, April 2006.

Trough systems currently do not include storage, but by 2010 storage is expected to be an economic option that will increase capacity factors.

	Parabolic Trough Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Scheduled Outage Factor (%)	NA	Defined as solar output less than 75% of maximum during the top 100 hours of peak demand hours. See pg. 36 of Solargenix report. Outage includes 1 week of scheduled outage every year and a 5 week major overhaul every 5 years. Solar plants have the advantage that they can take outages at night or on cloudy days.
Forced Outage Rate (%)	6%	
Typical Net Capacity Factor (%)	27%	A 50 MW system with 6 hrs of storage is being installed in Spain and should be operational by the end of 2007. Assumes 6 hours of molten salt storage starting in 2010. Capacity factors based on discussion with Hank Price, NREL, February 2007.
Fuel Cost ($/MMBtu)	NA	
HHV Efficiency (%)	NA	
CO_2 (lb/MWh)	No Emissions	
NO_x (lb/MWh)		
SO_x (lb/MWh)		

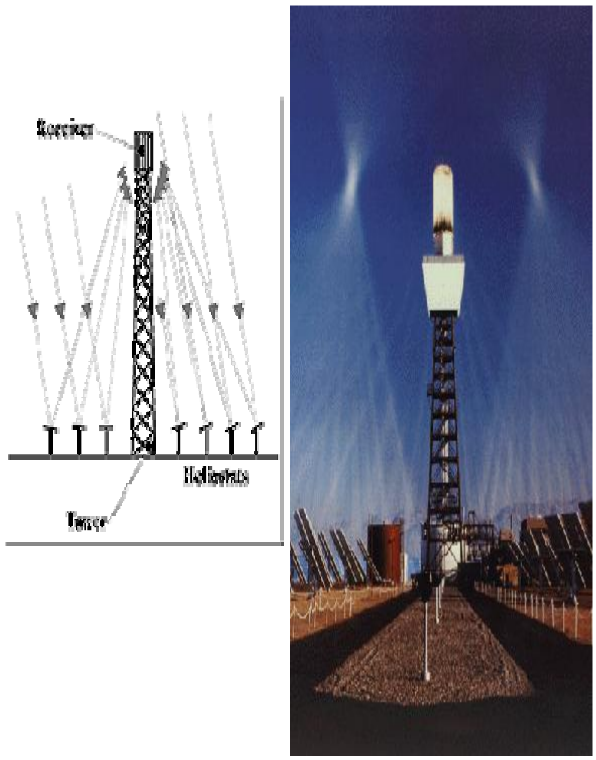
Sources: NCI Estimates 2007. *Solar Thermal Parabolic Trough Electric Power Plants for Electric Utilities in California*, Solargenix Energy, California Energy Commission, November 2005, CEC-500-2005-175. NCI Interviews with Hank Price, NREL.

Methodology, key assumptions, and sources used for the trough analysis:

Methodology & Key Assumptions

- Trough technology is well proven (without storage).
- Requires high direct normal solar (DNI).
- Overnight cost includes cost of heat collection element, mirrors, metal support structure, heat transfer fluid system, thermal energy storage, and thermal energy storage fluid. Currently, heat collection elements produced in Germany and Israel; and mirrors produced in Germany.
- May require water consumption at a rate of 103 million gallons per year. This is for steam cycle, cooling, and washing mirrors. Source: *Solar Thermal Parabolic Trough Electric Power Plants for Electric Utilities in California*, Solargenix Energy, November 2005, CEC-500-2005-175. Page 52.
- 63.5 MW max gross output and 55.5 MW gross output. Net output is 50 MW. Source: *Solar Thermal Parabolic Trough Electric Power Plants for Electric Utilities in California*, Solargenix Energy, November 2005, CEC-500-2005-175. Page 46.
- Construction times at the site are about 1 year. The longest lead time has been the turbine, but from order to on-line for 64 MWe plant is about 20 months. A 100 MW plant will be similar. Component supply can be an issue for large projects, but more receiver and mirror manufacturing facilities are being built. Source: Hank Price, NREL February 26, 2007.

A power tower system uses a large field of mirrors to concentrate sunlight onto the top of a tower, where a receiver sits.



Power Tower

Sunlight heats the molten salt flowing through the receiver. Then, the salt's heat is used to generate electricity through a conventional steam generator. Molten salt retains heat efficiently, so it can be stored for days before being converted into electricity. That means electricity can be produced on cloudy days or even several hours after sunset.

It is unlikely that Power Tower technology can be up and running by 2010, as development time is about 3 – 4 years.

	Power Tower Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Net Plant Capacity (kW)	NA	Based on discussions with NREL March 6,2007. No full scale plants are in operation.
Annual Output Degradation (%/yr)	NA	NCI estimates based on discussions with NREL, 2006; Osuna, et. Al. *PS10, Construction of A 11MW Solar Thermal Tower Plant in Seville, Spain* 2006; Ortega, et. al. *Central Receiver System (CRS) Solar Power Plant Using Molten Salt as Heat Transfer Fluid*, 2006; and Sargent and Lundy, *Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts* 2003; and interview with Mark Mehos, NREL, March 6, 2007.
Project Life (yrs)	NA	
Overnight Cost ($/kWp)	NA	Interview with Mark Mehos, NREL, March 6, 2007.
Fixed O&M ($/kW-yr)	NA	NCI estimates based on discussions with NREL, 2006; Osuna, et. Al. *PS10, Construction of A 11MW Solar Thermal Tower Plant in Seville, Spain 2006*; Ortega, et. al. *Central Receiver System (CRS) Solar Power Plant Using Molten Salt as Heat Transfer Fluid,* 2006; and Sargent and Lundy, *Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts*, 2003; and interview with Mark Mehos, NREL, March 6, 2007.
Variable O&M ($/MWh)	NA	
Development Time (Months)	NA	
Construction Time	NA	

Sources: Osuna, et. Al. PS10, *Construction of A 11MW Solar Thermal Tower Plant in Seville*, Spain 2006; Ortega, et. al. *Central Receiver System (CRS) Solar Power Plant Using Molten Salt as Heat Transfer Fluid*, 2006; and Sargent and Lundy, *Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts*, 2003; NCI Interviews.

Power Tower technology will likely incorporate 15 hours of storage by 2020 to result in capacity factors of 75%.

	Power Tower Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Forced Outage Rate (%)	NA	Interview with Mark Mehos, NREL March 6, 2007.
Typical Net Capacity Factor for Southern CA (%)	NA	The only plant in construction is the PS10 that is being built in Seville, Spain where the capacity factor in 20%. The Solar Tres plant is designed with 15 hours of storage that is likely to result in capacity factors of 64%. NCI estimates based on Osuna, et. al. *PS10, Construction of A 11MW Solar Thermal Tower Plant in Seville, Spain*, 2006; Ortega, et. al. *Central Receiver System (CRS) Solar Power Plant Using Molten Salt as Heat Transfer Fluid*, 2006; and Sargent and Lundy, *Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts*, 2003.
Fuel Cost ($/MMBtu)	NA	
HHV Efficiency (%)	NA	
CO_2 (lb/MWh)	No Emissions	
NO_x (lb/MWh)		
SO_x (lb/MWh)		

Sources: Osuna, et. al. *PS10, Construction of A 11MW Solar Thermal Tower Plant in Seville, Spain*, 2006; Ortega, et. al. *Central Receiver System (CRS) Solar Power Plant Using Molten Salt as Heat Transfer Fluid*, 2006; and Sargent and Lundy, *Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts*, 2003; NCI Interviews.

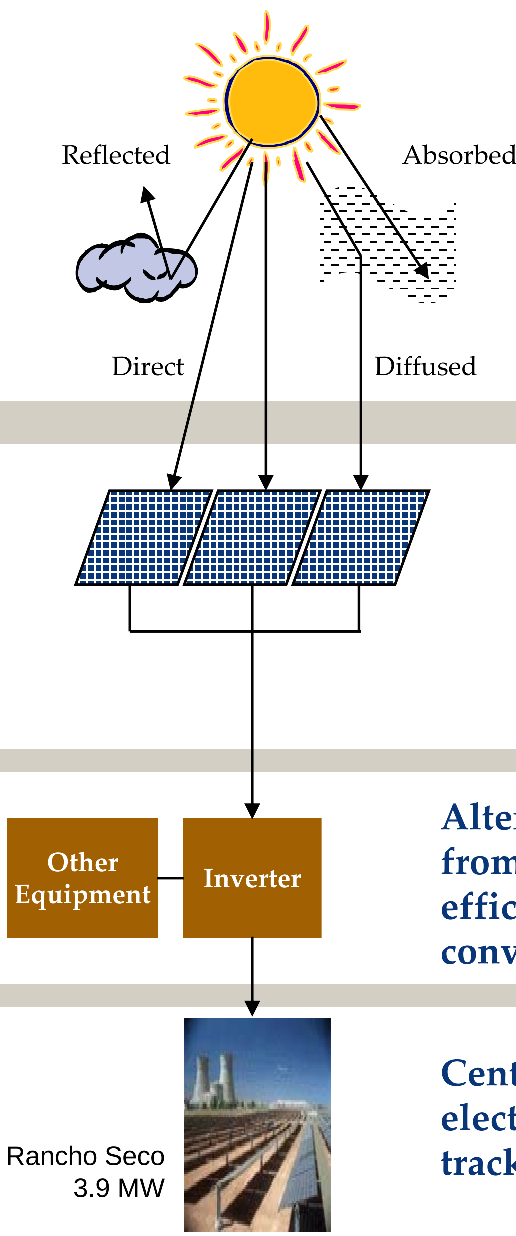
Below are some additional key assumptions and sources used for the power tower analysis.

Methodology & Key Assumptions

- Power Tower technology has limited field performance experience. The 10 MW Solar One plant operated in Barstow, California from 1982 to 1988. It was retrofitted with a molten salt receiver and renamed Solar Two from 1998 to 1999.
- Pacific Gas and Electric, PG&E, announced plans to buy 500 MW from towers build by LUZ II which are scheduled to be on line in 2010, but there is only a memorandum of understanding in place.
- Scales of 50 MW or greater are needed to obtain favorable economics.
- The 30% Investment Tax Credit is applicable until the end of 2008, when it will revert back to 10%.
- The 5-year accelerated depreciation applies to Power Tower technology.
- The degradation is associated with the reflectors and turbines.
- The 11 MW plant in Seville, Spain has only ½ hour of full load storage resulting in about a 25% capacity factor.

PV technology converts solar energy into usable electrical energy.

From Sun to Power Outlet



Solar Resource

Solar energy falling on a PV module can be either direct or diffused.

PV Panel

Direct current, DC, electrical energy output from PV modules is a function of module operating characteristics and external conditions.

Balance of System (BOS)

Alternating current, AC, electrical energy from PV system is a function of system efficiency. An inverter is required to convert DC power to AC.

Load

Central station installations are AC electrical and can be fixed, single axis tracking or dual axis tracking.

NCI has provided business as usual price reductions for central station PV.

	Central Station Single Axis Photovoltaics (PV) Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (kWdc)	1,000	From Navigant Consulting sources and estimates.
Annual Output Degradation (%/yr)	0.4%	
Project Life (yrs)	30	
Overnight Cost ($/kWpac)	$9,320	
Development Costs ($/kW)	NA	
Module ($/kWpac)	$4,370	
Inverter ($/kWpac) includes replacements at years 10 & 20	$603.8	
Installation ($/kWpac)	$1,495	
Other BOS ($/kWpac)	$402.5	
Marketing/Sales/Taxes ($/kWpac)	$230	
Gross Margin ($/kWpac)	$2,219.5	
Non-Fuel Fixed O&M ($/kW-yr)	$24	
Non-Fuel Variable O&M ($/MWh)	NA	

Sources: Annual degradation from Tom Hansen, Tucson Electric, February 10, 2007. Overnight costs: provided by several industry representatives: Barry Cinnamon, Akeena Solar; Les Nelson, California Solar Energy Industries Association, CaLSEIA, and Bill Rever, BP Solar, January 2007. Note: Prices can vary significantly depending on variables such as location, type of owner, and volume of purchase. NCI assumed 80% loss going from DC to AC. Inverter replacement needed every 10 years in out years.

Performance information was based upon an average single axis installation.

	Central Station Single Axis PV Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Scheduled Outage Rate (%)	NA	
Forced Outage Rate (%)	.25%	Inverter is likely to be replaced every 10 years. Source of data is Tom Hansen, Tucson Electric, February 10, 2007. Based on the assumption that the utility will use a sophisticated control systems and therefore forced outages are lower than residential or commercial.
Typical Net Capacity Factor	22.4%	Assumes single axis installation for average insolation levels. Based on output from Clean Power Estimator model.
Fuel Cost ($/MMBtu)	NA	
HHV Efficiency (%)	NA	
CO_2 (lb/MWh)	0.00	
NO_x (lb/MWh)	0.00	
SO_x (lb/MWh)	0.00	

Sources: Annual degradation from Tom Hansen, Tucson Electric, February 10, 2007. Overnight costs: provided by several industry representatives: Barry Cinnamon, Akeena Solar; Les Nelson, CalSEIA, and Bill Rever, BP Solar, January 2007. Note: Prices can vary significantly depending on variables such as location, type of owner, and volume of purchase. NCI assumed 80% loss going from DC to AC. Inverter replacement needed every 10 years in out years.

Below are some additional key assumptions and sources used for the single axis PV analysis.

Methodology & Key Assumptions

- The primary technology installation in 2006 was crystalline silicon technology and therefore some of the early year costs are based on this technology.
- NCI converts all $/Wpdc (direct current) estimates to $/Wpac (alternating current) using a .80 conversion factor to account for module mismatch, inverter efficiency, dust and other losses. This was derived from PVWatts web site and a presentation by Ed Kern, President of Irradiance, *PV Downstream*, presented in January 2007.
- PV system cost reductions are mostly associated with module efficiency improvements, increased manufacturing capacity, and reductions in inverter prices.
- The net capacity factors factor in dust loss and account for expected hours of output. These estimates were pulled from the Clean Power Estimator model.
- Loan period is 20 years.
- There is currently a 30% Investment Tax Credit for commercial installations that will reduce to 10% after 2008. A 5 year MACRs accelerated depreciation should also be applied to all years of analysis as well as a property tax exemption.
- The 30% ITC does not apply to utility owned systems, however, many utility companies negotiate with third parties to own, operate, and lease land for the projects (similar to independent power producers' [IPP] structure).
- Interest during construction is minimal. A 1 MWpdc system could be installed by a crew of eight people in less than eight weeks, based on data from Tucson Electric, February 10, 2007.
- Balance of System other equipment includes mounting structure, switches & fuses, meters, wires & conduits, isolation transformers/ automatic lock-out switches, controls, communication, data acquisition, feeder line connection, and fencing.

Large, utility wind developments convert wind energy into electricity, and can range from 50 MW to 150 MW in size in California.

Schematic of the Technology

GE 1.5 MW Turbines
Source: GE

GE 3.6 MW Turbines
Source: DOE

Gatun, Spain
49.5 MW wind farm
Source: GE

Description

- A 50 MW wind development consisting of multiple wind turbines atop steel towers. Typical facilities today consist of 1.5 to 2.5 MW turbines atop 80m towers.
- In the future, wind farms are likely to see a continued evolution towards larger rotors, turbine sizes, and tower heights.
- Since installed costs and performance vary with turbine size, tower height and site conditions. NCI assumes some typical turbine sizes, tower heights, and site conditions to develop the cost estimates, recognizing that actual wind farm configurations will see a wider range.
- The expected or typical wind regime is uncertain as new wind developments are likely to be in poorer wind regimes, but re-powering at existing good wind sites like Altamont and Tehachapi is also likely.

Economic Assumptions: Utility Wind

	Utility Wind Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	50	Based on current proposed projects in California. Source: AWEA.
Turbine Size (range) (MW)	2.0 (1.5-2.5)	From Navigant Consulting sources and estimates.
Tower Height (range) (meters)	80 (60 – 80)	
Project Life (yrs)	30	
Overnight Cost ($/kW)	$1,900	Overnight Costs can vary widely depending on the several factors. Key assumptions include: turbine prices on a $/kW basis decrease asymptotically by 1.5%/yr to 0.5%/yr due to technological improvements and learning; commodity prices increase ; turbine original equipment manufacturers, OEMs, profit margins decrease due to increased competition; balance of plant cost increases due to interconnection and increased civil works are mitigated by decreased cost per kW due to increased scale (turbine rating per tower).
Turbine ($/kW)	$1,250	
Balance of Plant / Installation ($/kW)	$500	
Permitting / Development ($/kW)	$150	
Fixed O&M ($/kW-yr)	$30	O&M costs are based on historical performance at existing sites as well as interviews with industry. Costs per unit of capacity and energy are expected to decline as machine size and output increase.

Sources: Navigant Consulting Estimates 2007. AWEA, NCI interviews with leading turbine OEMs, project developers, energy maintenance providers, and wind farm owners.

Performance Data: Utility Wind

	Utility Wind Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Scheduled Outage Factor (%)	0.3%	Forced outage rates and typical capacity factors are based on historical data at existing plants.
Forced Outage Rate (%)	1.3%	
Typical Net Capacity Factor – Class 5 (%)	34%	Wind class definition based on wind speed at 50m: Class 5 = 7.5-8 m/s (16.8-17.9 mph). Capacity factors are net of all losses at the plant, such as blade soiling, and aerodynamic losses. Expected capacity factors for a given wind regime are expected to remain relatively constant over time. The improvements in turbine design and increased tower heights (factors that increase the capacity factors) are expected to be partially offset by the use of larger machines, which have lower capacity factors.
Annual Output Degradation (%/yr)	0.25%	From Navigant Consulting sources and estimates.
CO_2 (lb/MWh)	No Air Emissions	
NO_x (lb/MWh)		
SO_x (lb/MWh)		

Sources: Navigant Consulting Estimates 2007, AWEA. NCI estimates validated by NCI interviews with leading turbine OEMs, project developers, energy maintenance providers, and wind farm owners.

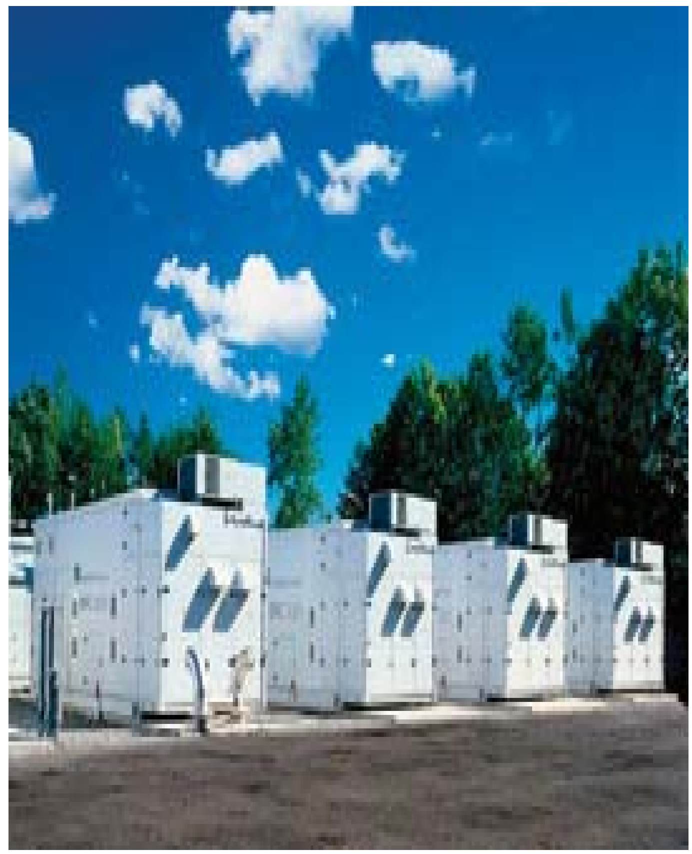
Methodology and Key Assumptions: Utility Wind

Methodology & Key Assumptions

- NCI based its cost estimates on its knowledge of historical installed costs in the U.S. and California as well as its own internal model of wind installed costs.
- Several leading market participants commented on the NCI cost estimates and helped Navigant refine its numbers.
- Installed costs can vary widely depending on the scale of the project, civil works and interconnection requirements, permitting requirements, and buying power of the owner.
- Future costs are based on a defined wind development size, turbine sizes and tower height, but actual system configurations could differ, which would affect costs and performance.
- Key assumptions include:
  - Turbine prices on a $/kW basis decrease asymptotically due to technological improvements and learning.
  - Commodity prices increase by 3%/yr in real terms.
  - Turbine OEM profit margins will decrease due to increased competition.
  - Balance of plant costs remain constant on a $/kW basis as improvements in scale (capacity rating per tower), are balanced by an increase in cost for interconnection, roads, and the absolute cost per tower.
  - Tower heights increase from 80m to 100m.
  - Typical turbine sizes increase from 2 MW to 3.5 MW.
- O&M costs are based on historical performance at existing sites as well as interviews with industry. Costs per unit of capacity and energy are expected to decline as machine size and output increase.

Fuel cells convert hydrogen or a hydrogen-rich gas directly to electricity through a clean, efficient electrochemical reaction.

- The main characteristic that distinguishes fuel cell types is the electrolyte. The four principal types being developed for commercial markets are: proton exchange membrane (PEM), phosphoric acid (PAFC), molten carbonate (MCFC), and solid oxide (SOFC).
- Balance of system components include: fuel processor to convert primary fuel to hydrogen or hydrogen rich gas, air handling, water purification / management, power conditioning (to convert DC electricity to AC), heat recovery equipment (for cogeneration applications or hybrid power cycles), and the enclosure.
- Emissions are negligible because fuels are not combusted. Typically, a small portion of the unconverted fuel is burned, but with very low emissions.
- High efficiency is possible, even at very small scales.



Source: Fuel Cells 2000. representation of the Fuel Cell Energy MCFC Fuel Cells at Sierra Nevada Brewery in California

Broad application of fuel cells is expected to be several years off, but there are some near term opportunities to demonstrate the technology.

- Fuel cells can either use natural gas or carbon-based renewable fuels provided that the gas is properly treated, that is, contaminants are removed, and reformed into a hydrogen-rich gas.
  - Often have more stringent fuel purity requirements than gas turbines or reciprocating engines.
- Renewable fuels include hydrocarbon-based fuels such as landfill gas, biogas from anaerobic digestion, syngas from biomass gasification and liquid fuels such as ethanol and methanol derived from renewable feedstocks. Hydrogen produced from renewable resources can also be used.
- Low-temperature fuel cells (PEM and PAFC) can also use pure hydrogen. High temperature fuel cells (MCFC and SOFC) are less suited to operation on pure hydrogen and typically internally reform natural gas or other hydrocarbon fuels.
- Key advantages over other small prime movers are low emissions and high efficiency. However, the efficiency advantage is largely lost in landfill gas and biogas applications because the fuel cost is low or zero.
- United Technologies, UT Fuel Cells, has successfully operated several PC25 200kW PAFC on landfill gas and biogas from wastewater treatment, and offered a standard package for this type of fuel.
  - However, the cost of the PC25 has remained high (>$4,000/kW) and UT Fuel Cells has decided not to invest further in the technology.
- PEM fuel cells are not receiving much attention for biogas or landfill gas markets.
  - Product sizes are too small for these applications (generally less than 50 kW) and are currently being designed for residential, small commercial and automotive applications.

Technology Description: Molten Carbonate Fuel Cell

- Assumed to be a fuel cell located at a LFGFTE facility. The 2 MW size was chosen so as to be consistent with the LFGFTE technology that uses a reciprocating engine.
- MCFCs are high-temperature fuel cells that use an electrolyte composed of a molten carbonate salt mixture suspended in a porous, chemically inert ceramic matrix of beta-alumina solid electrolyte. Since they operate at extremely high temperatures of 650°C (roughly 1,200°F) and above, non-precious metals can be used as catalysts at the anode and cathode, reducing costs.
- MCFC systems are high temperature technology (operating temperature 650°C). Uses a liquid alkali carbonate mixture to form the electrolyte layer, nickel based catalyst material and stainless steel cell use for other hardware.
- They have the potential to reach higher electrical efficiencies than that of PEMFC or PAFC.
- Unlike alkaline, phosphoric acid, and polymer electrolyte membrane fuel cells, MCFCs don't require an external reformer to convert more energy-dense hydrocarbons to hydrogen. Due to the high temperatures at which MCFCs operate, these fuels are converted to hydrogen within the fuel cell itself by a process called internal reforming, which also reduces cost.
- Molten carbonate fuel cells are not prone to carbon monoxide "poisoning" - making them more attractive for fueling with gases made from coal.
- The primary disadvantage of current MCFC technology is short stack lifetime. The high temperatures at which these cells operate and the corrosive electrolyte used accelerate component breakdown and corrosion, decreasing cell life. Scientists are currently exploring corrosion-resistant materials for components as well as fuel cell designs that increase cell life without decreasing performance.

Economic Assumptions: Molten Carbonate Fuel Cell

	Molten Carbonate Fuel Cell Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (kW)	2,000	Assumes the fuel cell is sized for a landfill gas site and utilizes the methane from the landfill.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$4,350	From Navigant Consulting sources and estimates.
Equipment ($/kW)	$3,600	Based on cost estimates from NREL. Assumes costs decline asymptotically from 3.5% to 1.5%.
Gas Treatment ($/kW)	$300	Similar cost requirements as for a LFGFTE facility using a reciprocating engine.
Balance of Plant & Installation ($/kW)	$450	
O&M ($/kW-yr)	$2.10	Based on cost estimates from NREL. Assumes costs decline asymptotically from 3.5% to 1.5%.
Variable O&M ($/MWh)	$35	
Service Contract ($/MWh)	$6	
Stack Replacement ($/MWh)	$29	

Sources: Navigant Consulting Estimates 2007. *Gas-fired Distributed Energy Resource Technology Characterizations*, DOE/NREL/GTI, October 2003. Fuel Cell Energy 2006 Annual Report. NCI Interviews with fuel cell manufacturers. *Lessons Learned from the World's Largest Digester Gas Fuel Cell. Washington State Recycling Association –Spokane*, May, 2006, Greg Bush -King Co.

Performance Data: Molten Carbonate Fuel Cell

	Molten Carbonate Fuel Cell Economic Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Typical Net Capacity Factor (%)	90%	From Navigant Consulting sources and estimates.
Fuel Cost ($/MMBtu)	n/a	
HHV Efficiency (%)	40%	Based on NREL projections and reported efficiencies at King County 1MW Fuel Cell demonstration project.
CO_2 (lb/MWh)	Assumed to be CO_2 Neutral.	SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.
NO_x (lb/MWh)	0.01	Based on Case Studies cited by Art Soinski, CEC.
SO_x (lb/MWh)	0.003	

Sources: Navigant Consulting Estimates 2007. *Gas-fired Distributed Energy Resource Technology Characterizations*, DOE/NREL/GTI, October 2003. Fuel Cell Energy 2006 Annual Report. NCI Interviews with fuel cell manufacturers. *Lessons Learned from the World's Largest Digester Gas Fuel Cell. Washington State Recycling Association –Spokane*, May, 2006, Greg Bush -King Co.

Methodology and Key Assumptions: Molten Carbonate Fuel Cell

Methodology & Key Assumptions

- The Molten Carbonate Fuel Cell (MCFC) is modeled after a Fuel Cell Energy product placed in operation at a Landfill Gas Fuel To Energy (LFGFTE) facility. Fuel Cell Energy is the largest manufacturer of Molten carbonate fuel cells. The company's Direct Fuel Cell (DFC) products range from 300 kW in size to 2.4 MW.
- Since IEPR assumes a 2MW size for the LFGFTE using a reciprocating engine, a similar size was assumed for the MCFC. The costs for the MCFC equipment would be higher for system sizes <2MW.
- The MCFC would have similar needs for gas treatment and preparation as well as installation, but it would not require emissions treatment.
- Cost and performance estimates are based on prior NCI experience with fuel cell technology as well as cost and performance estimates published in a 2003 DOE/NREL study: *Gas-fired Distributed Energy Resource Technology Characterizations*, DOE/NREL/GTI, October 2003.
- Installed costs for the fuel cell equipment at a landfill are estimated to be higher than one utilizing natural gas due to an approximate 10% de-rating of the output.
- Due to the technological maturity of fuel cells, these cost and performance estimates should be considered within +/- 25% of actual future numbers.

Technology Description: Proton Exchange Membrane Fuel Cell

- Assumed to be a 30kW system at a Wastewater Treatment Fuel to Energy (WWTFTE) facility.
- The proton exchange membrane fuel cell (PEMFC) is also known as the solid polymer or polymer electrolyte fuel cell. A PEMFC contains an electrolyte that is a layer of solid polymer (usually a sulfonic acid polymer, whose commercial name is Nafion™) that allows protons to be transmitted from one face to the other. PEMFCs require hydrogen and oxygen as inputs, though the oxidant may also be ambient air, and these gases must be humidified. PEMFCs operate at a temperature much lower than other fuel cells, because of the limitations imposed by the thermal properties of the membrane itself. The operating temperatures are around 90°C. The PEMFC can be contaminated by CO, reducing the performance and damaging catalytic materials within the cell. A PEMFC requires cooling and management of the exhaust water to function properly.

Economic Assumptions: Proton Exchange Membrane Fuel Cell

	Proton Exchange Membrane Fuel Cell Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (kW)	30	Assumes the fuel cell is sized for a small wastewater treatment site and utilizes the biogas from the digester.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$7,000	
Equipment ($/kW)	$6,000	Based on cost estimates from NREL.
Gas Treatment ($/kW)	$550	High level estimate. Actual costs are difficult to determine as PEMs are not typically considered for such applications.
Balance of Plant & Installation ($/kW)	$450	From Navigant Consulting sources and estimates.
Fixed O&M ($/kW-yr)	$18	Based on cost estimates from NREL.
Variable O&M ($/MWh)	$35	
Service Contract ($/MWh)	$13	
Stack Replacement ($/MWh)	$20	

Sources: Navigant Consulting Estimates 2007. *Gas-fired Distributed Energy Resource Technology Characterizations*, DOE/NREL/GTI, October 2003. NCI Interviews with fuel cell manufacturers.

Performance Data: Proton Exchange Membrane Fuel Cell

	Proton Exchange Membrane Fuel Cell Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	90%	From Navigant Consulting sources and estimates.
Fuel Cost ($/MMBtu)	n/a	
HHV Efficiency (%)	26%	Assumes a reduction in efficiency as a result of the use of wastewater treatment biogas.
CO_2 (lb/MWh)	Assumed to be CO_2 Neutral	SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.
NO_x (lb/MWh)	<0.1	Based on NREL 2003 report.
SO_x (lb/MWh)	negligible	

Sources: Navigant Consulting Estimates 2007. *Gas-fired Distributed Energy Resource Technology Characterizations*, DOE/NREL/GTI, October 2003. NCI Interviews with fuel cell manufacturers.

Methodology and Key Assumptions: Proton Exchange Membrane Fuel Cell

Methodology & Key Assumptions

- Several companies manufacture Proton Exchange Membrane (PEM) fuel cells, including Plug Power, United Technologies, Nuvera, and Hydrogenics. Most products are sized at approximately 10 kW to 50 kW. PEM fuel cells are not typically being developed for stationary commercial or industrial power. Instead, manufacturers are targeting the residential and automotive markets.
- In California, potential markets for a stationary PEM fuel cell is a small wastewater treatment facility or a small animal waste anaerobic digester.
- The cost characteristics here are modeled after a 30 kW PEM fuel cell placed in a WWTFTE facility.
- IEPR assumes a 500 kW size for the WWTFTE facility, but many smaller facilities exist that could be appropriate for a PEM fuel cell. The economics are not as attractive and these markets are not as likely to be targeted by developers, owners, or fuel cell manufacturers.
- Cost and performance estimates are based on prior NCI experience with fuel cell technology as well as cost and performance estimates published in a 2003 DOE/NREL study: *Gas-fired Distributed Energy Resource Technology Characterizations*, DOE/NREL/GTI, October 2003.
- Due to the technological maturity of fuel cells, these cost and performance estimates should be considered within +/- 25% of actual future numbers.

Technology Description: Solid Oxide Fuel Cell, SOFC.

- Assumed to be a 250 kW system at a WWTFTE facility.
- Solid oxide fuel cells are intended mainly for stationary applications with an output from 100 kW to 2 MW. They work at very high temperatures, typically between 700 and 1,000ºC. In these cells, oxygen ions are transferred through a solid oxide electrolyte material at high temperature to react with hydrogen on the anode side. Due to the high operating temperature of SOFC's, they have no need for expensive catalyst, which is the case of proton-exchange fuel cells (platinum). This means that SOFCs do not get poisoned by carbon monoxide and this makes them highly fuel-flexible. Solid oxide fuel cells have so far been operated on methane, propane, butane, fermentation gas, gasified biomass and paint fumes. However, sulfur components present in the fuel must be removed before entering the cell, but this can easily be done by an activated carbon bed or a zinc absorbent.
- Thermal expansion demands a uniform and slow heating process at startup. Typically, 8 hours or more are to be expected. Micro-tubular geometries promise much faster start up times, typically 13 minutes.
- Unlike most other types of fuel cells, SOFCs can have multiple geometries. The planar geometry is the typical sandwich type geometry employed by most types of fuel cells, where the electrolyte is sandwiched in between the electrodes. SOFCs can also be made in tubular geometries where either air or fuel is passed through the inside of the tube and the other gas is passed along the outside of the tube. The tubular design is advantageous because it is much easier to seal and separate the fuel from the air compared to the planar design. The performance of the planar design is currently better than the performance of the tubular design however, because the planar design has a lower resistance compared to the tubular design.

Economic Assumptions: Solid Oxide Fuel Cell

	Solid Oxide Fuel Cell Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (kW)	250	Assumes the fuel cell is sized for a small wastewater treatment site and utilizes the biogas from the digester.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$4,750	Based on cost estimates from NREL.
Equipment ($/kW)	$3,900	
Gas Treatment ($/kW)	$400	High level estimate. Actual costs are difficult to determine as few SOFCs have been designed for such applications.
Balance of Plant & Installation ($/kW)	$450	From Navigant Consulting sources and estimates.
Fixed O&M ($/kW-yr)	$10	Based on cost estimates from NREL.
Variable O&M ($/MWh)	$24	
Service Contract ($/MWh)	$11	
Stack Replacement ($/MWh)	$13	

Sources: Navigant Consulting Estimates 2007. *Gas-fired Distributed Energy Resource Technology Characterizations*, DOE/NREL/GTI, October 2003. NCI Interviews with fuel cell manufacturers.

Performance Data: Solid Oxide Fuel Cell

	Solid Oxide Fuel Cell Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	90%	From Navigant Consulting sources and estimates.
Fuel Cost ($/MMBtu)	n/a	
HHV Efficiency (%)	40%	Assumes a reduction in efficiency as a result of the use of wastewater treatment biogas.
CO_2 (lb/MWh)	Assumed to be CO_2 Neutral[2]	SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.
NO_x (lb/MWh)	<0.05	Based on NREL 2003 report.
SO_x (lb/MWh)	negligible	

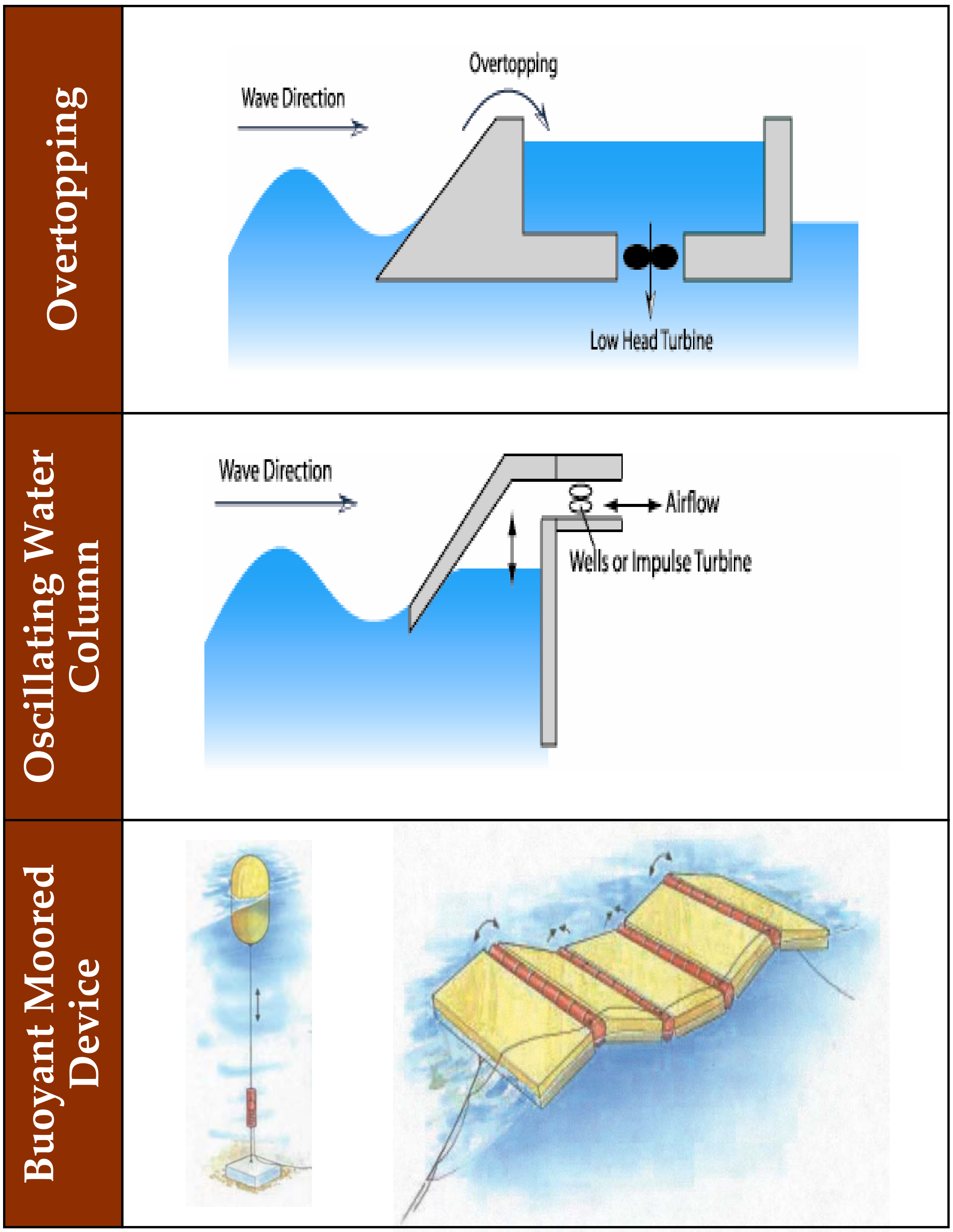
Sources: Navigant Consulting Estimates 2007. *Gas-fired Distributed Energy Resource Technology Characterizations*, DOE/NREL/GTI, October 2003. NCI Interviews with fuel cell manufacturers.

Methodology and Key Assumptions: Solid Oxide Fuel Cell

Methodology & Key Assumptions

- Several companies manufacture SOFCs, including GE Power Systems, Rolls Royce, Mitsubishi, Acumentrics, and Siemens/Westinghouse. Most all products are sized at approximately 250 kW, although many of the test products are under 100 kW.
- In California, potential renewable fuels markets for a stationary SOFC is a small wastewater treatment facility or a small animal waste anaerobic digester.
- The cost characteristics here are modeled after a 250 kW SOFC placed in a WWTFTE facility.
- IEPR assumes a 500 kW size for the WWTFTE facility, but many smaller facilities exist that could be appropriate for a SOFC.
- Cost and performance estimates are based on prior NCI experience with fuel cell technology as well as cost and performance estimates published in a 2003 DOE/NREL study: *Gas-fired Distributed Energy Resource Technology Characterizations*, DOE/NREL/GTI, October 2003

Wave Energy Conversion devices convert wave motion to electricity.



Sources: Electric Power Research Institute

Economic Assumptions: Wave Energy Conversion

	Wave Energy Conversion Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	.75	The 2006 number assumes a small 750 kW pilot plant.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Installed Cost ($/kW)	$6,970	Assumes pilot plant.
Transmission and undersea cables	$1,340	From Navigant Consulting sources and estimates.
Equipment	$4,000	
Facilities	0	
Installation	$990	
Construction Management and Permitting	$640	
Fixed O&M ($/kW-yr)	$30	
Non-Fuel Variable O&M ($/MWh)	$25	

Sources: Navigant Consulting Estimates, 2007

Performance Data: Wave Energy Conversion

	Wave Energy Conversion Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	15%	Capacity factors will vary with site conditions.
Fuel Cost ($/MMBtu)	n/a	
Heat Rate (HHV)	n/a	
HHV Efficiency (%)	n/a	
Annual Output Degradation (%/yr)	1%	From Navigant Consulting sources and estimates.
CO_2 (lb/MWh)	0	Wave energy conversion technologies have no emissions.
NO_x (lb/MWh)	0	
SO_x (lb/MWh)	0	

Sources: Navigant Consulting Estimates, 2007

Methodology and Key Assumptions: Wave Energy Conversion

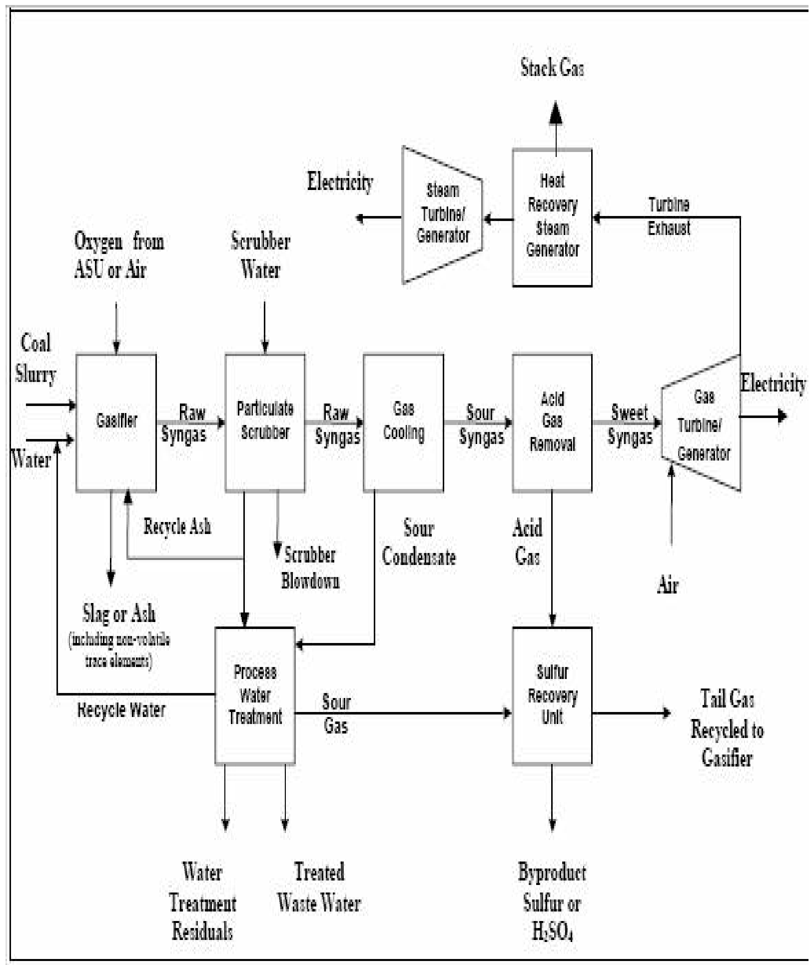
Methodology & Key Assumptions

- No commercial Wave Energy Conversion facilities exist anywhere in the world. NCI analyzed a pilot facility for 2006.
- The 2006 estimates reflect the current technology status and market for wave energy. Assumed that a large scale plant (with greater capacity and lower costs) could not be built at this time.
- System output varies significantly during the year and from year to year. NCI took yearly total outputs and averaged them over the year.
- NCI reviewed data from studies done by EPRI for Wave Energy Conversion facilities built off the Oregon coast. The wave climate closely matches the Northern California locations where PG&E has applied to the FERC for permits.
  - Cost estimates and capacity factors also were reviewed for 2010 and beyond, based primarily on the *System Level Design, Performance and Costs – Oregon State Offshore Wave Power Plant*, EPRI, 2004. These estimates are in agreement with the comments received from Ocean Power Delivery, Wavebob, Community Environmental Council, Mirko Previsic, and Ocean Power Technology. The estimates for 2010, are a plant capacity of 90 MW, a project life of 20 years, an overnight installed cost of $2,700/kW in (2006$), with a 38% capacity factor.
  - The EPRI paper calculated costs for 100 MW worldwide production capability and an 82% progress ratio for learning curves (based upon wind power, PV, and offshore oil and gas).
  - NCI held transmission, facility, and permitting costs constant for a commercial facility over time.

Integrated Gasification Combined Cycle is a power plant using syngas (developed from coal) as a source of clean fuel.

- Integrated Gasification Combined Cycle, or IGCC, is a power plant using synthetic gas (syngas) as a source of clean fuel. Syngas is produced in a gasification unit built for Combined Cycle purposes. Steam generated by waste heat boilers of the gasification process is utilized to help power steam turbines. Heavy petroleum residues, coal, and even biomass are possible feeds for gasification process.
- IGCC is now being considered since it may offer a low-cost long-term option for the reduction of carbon dioxide emissions (through capture and storage).
- The main inhibiting factor for IGCC is high capital cost, but reliability must also be proven before widespread deployment can occur.

Schematic of Generic IGCC Power Plant



Source: *Advanced Fossil Power Systems Comparison Study – Final Report*, National Energy Technologies Laboratory, US Department of Energy.

Economic Assumptions: IGCC

	IGCC Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	500	From Navigant Consulting sources and estimates.
Project Life (yrs)	40	
Overnight Cost ($/kW)	$2,050	The Wisconsin Public Utilities Commission estimate is $1,885/kW for Wisconsin. NCI assumes $2,050, which reflects a cost adjustment for California. Approximately 1%/yr cost improvement is achieved due to learning and technical change.
Fixed O&M ($/kW-yr)	$35	2006 estimates reflect 2006 Wisconsin Public Service Commission IGCC Report estimates, which are more representative of a test facility.
Variable O&M ($/MWh)	$3	

Sources: Navigant Consulting Estimates 2007. EPRI Technical Assessment Guide; Maurstad, O. (2005), *An Overview of Coal-Based Integrated Gasification Combined Cycle (IGCC) Technology*, Laboratory for Energy and the Environment, Massachusetts Institute of Technology; *Annual Energy Outlook 2006, With Projections to 2030*, Energy Information Administration, February 2006; Parsons, E., Shelton, W. Lyons, L. (2002), *Advanced Fossil Power Systems Comparison Study – Final Report*, National Energy Technologies Laboratory, US Department of Energy; *Integrated Gasification Combined-Cycle Technology Draft Report: Benefits, Costs, and Prospects for Future Use in Wisconsin*, June 2006, Wisconsin Department of Natural Resources and the Public Service Commission of Wisconsin; *Avista 2007 Electric Integrated Resource Plan - IRP Modeling Overview: Resource Options and Cost Assumptions*, August 31, 2006, John Lyons.

Performance Data: IGCC

	IGCC Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	80%	Based on Wisconsin Public Service Commission and Department of Natural Resources IGCC Study for IGCC plants using western coal.
Fuel Cost ($/MMBtu)	$1.55	Based upon Energy Commission staff conversations with Global Energy Decisions, Sacramento office, May 2007.
HHV Efficiency (%)	38%	Based on Wisconsin Public Service Commission and Department of Natural Resources IGCC Study for IGCC plants using western coal. Due to its higher moisture content, western coal requires more heat to convert energy into electricity.
CO_2 (lb/MWh)	1,928	Based on Wisconsin Public Service Commission and Department of Natural Resources IGCC Study for IGCC plants using western coal. NCI Emissions Calculator.
NO_x (lb/MWh)	0.53	
SO_x (lb/MWh)	0.30	

Sources: Navigant Consulting Estimates 2007. EPRI Technical Assessment Guide; Maurstad, O. (2005), *An Overview of Coal-Based Integrated Gasification Combined Cycle (IGCC) Technology*, Laboratory for Energy and the Environment, Massachusetts Institute of Technology; *Annual Energy Outlook 2006, With Projections to 2030*, Energy Information Administration, February 2006; Parsons, E., Shelton, W. Lyons, L. (2002), *Advanced Fossil Power Systems Comparison Study – Final Report*, National Energy Technologies Laboratory, US Department of Energy; *Integrated Gasification Combined-Cycle Technology Draft Report: Benefits, Costs, and Prospects for Future Use in Wisconsin*, June, 2006, Wisconsin Department of Natural Resources and the Public Service Commission of Wisconsin; *Avista 2007 Electric Integrated Resource Plan - IRP Modeling Overview: Resource Options and Cost Assumptions*, August,, 2006, John Lyons.

Methodology and Key Assumptions: IGCC

Methodology & Key Assumptions

- The costs of IGCC power plants using coal have been documented in numerous studies, with estimates for installed costs ranging from $1,400/kW to $2,300/kW. Some of the lower estimates were performed over 5 years ago prior to the recent increase in commodity and steel prices.
- NCI used 4 primary sources for its cost estimates:
  - *Integrated Gasification Combined-Cycle Technology Draft Report: Benefits, Costs, and Prospects for Future Use in Wisconsin*, dated June 2006 prepared by the Wisconsin Department of Natural Resources and the Public Service Commission of Wisconsin.
  - *2007 Electric Integrated Resource Plan - IRP Modeling Overview: Resource Options and Cost Assumptions*, Avista, August 31, 2006, John Lyons.
  - *Annual Energy Outlook 2006, With Projections to 2030*, Energy Information Administration, February 2006.
  - *EPRI Technical Assessment Guide*.
- NCI cost estimates for 2006 reflect the higher end of the cost estimates, and are representative of initial test facilities.

Future nuclear power plants in California could be one of several competing designs, and NCI developed cost estimates for a generic advanced nuclear technology.

Generic Description of Nuclear Power Technology

- Nuclear power is the controlled use of nuclear reactions to release energy for the generation of electricity. Nuclear energy is produced when a fissile material, such as uranium-235, 235U, is concentrated such that nuclear fission takes place in a controlled chain reaction and creates heat — which is used to boil water, produce steam, and drive a steam turbine.

Nuclear Power Technology in California

- Currently, there are three different consortia who are leading efforts to build new nuclear power plants in the United States. None of these consortia have any plans to build a new plant in California.
- Several manufacturers are developing advanced nuclear technology designs. The cost estimates for these designs vary widely. IEPR cost estimates are for a generic advanced nuclear technology.

Advanced Nuclear Design Types and Manufacturers

Design	Manufacturer	Size & Type
US APWR	Mitsubishi	1,700 MWe Advanced Pressurized Water Reactor, PWR
US EPR	AREVA	1,600 MWe Evolutionary Power Reactor
ABWR	GE	1,350 MWe Boiling Water Reactor, BWR
ESBWR	GE	1,380 MWe BWR with passive safety features
SWR 1000	Framatome ANP	1,013 MWe BWR
AP600	BNFL – Westinghouse	610 MWe PWR with passive safety features
AP1000	BNFL – Westinghouse	1090 MWe PWR with passive safety features
IRIS	Westinghouse	100-300 MWe PWR
PBMR	ESKOM	110 MWe modular pebble bed gas-cooled reactor
GT-MHR	General Atomics	288 MWe prismatic graphite moderated gas-cooled reactor
ACR 700	AECL	730 MWe heavy water reactor

Economic Assumptions: Advanced Nuclear

	Advanced Nuclear Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	1,000	*Nuclear Power Joint Fact-Finding*, June 2007, The Keystone Center. See page 42, Summary of Construction Cost Estimates, High Case.
Project Life (yrs)	30	
Overnight Cost ($/kW)	$2,865	2007 costs presented in Keystone report adjusted to 2006. See page 34. Assumes some standardization of design and learning from commercial deployment in the U.S.
Fixed O&M ($/kW-yr)	$136	Fixed O&M includes grid integrations costs of $20/kW/yr.
Variable O&M ($/MWh)	$4.86	

Sources: *Nuclear Power Joint Fact-Finding*, June 2007, The Keystone Center; Navigant Consulting Estimates 2007. *The Future of Nuclear Power. An Interdisciplinary MIT Study*, Massachusetts Institute of Technology, 2003; *Annual Energy Outlook 2006, With Projections to 2030*, Energy Information Administration, February 2006; *Avista 2007 Electric Integrated Resource Plan - IRP Modeling Overview: Resource Options and Cost Assumptions*, August, 2006, John Lyons; *EIA Electric Power Annual*, Table 8.2. Average Power Plant Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 1994 through 2005; Press Release for Finnish Utility TVO, December 18, 2003.

Performance Data: Advanced Nuclear

	Advanced Nuclear Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	85%	*Nuclear Power Joint Fact-Finding*, June 2007, The Keystone Center, compromise between low and high case scenarios.
Fuel Cost ($/MMBtu)	$0.54	Based upon Energy Commission staff conversations with Global Energy Decisions, Sacramento office, May 2007.
HHV Efficiency (%)	32.8%	
CO_2 (lb/MWh)	No Emissions	
NO_x (lb/MWh)		
SO_x (lb/MWh)		

Sources: *Nuclear Power Joint Fact-Finding*, June 2007, The Keystone Center; Navigant Consulting Estimates 2007. *The Future of Nuclear Power. An Interdisciplinary MIT Study*, Massachusetts Institute of Technology, 2003; *Annual Energy Outlook 2006, With Projections to 2030*, Energy Information Administration, February 2006; *Avista 2007 Electric Integrated Resource Plan - IRP Modeling Overview: Resource Options and Cost Assumptions*, August, 2006, John Lyons; *EIA Electric Power Annual*, Table 8.2. Average Power Plant Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 1994 through 2005; Press Release for Finnish Utility TVO, December 18, 2003.

Methodology and Key Assumptions: Advanced Nuclear

Methodology & Key Assumptions

- Cost estimates are based on the recent *Nuclear Power Joint Fact-Finding*, June 2007, The Keystone Center. This report reflects the most up to date cost estimates and reflects recent increases in commodity and labor prices.
- Other sources of information include:
  - *The Future of Nuclear Power. An Interdisciplinary MIT Study*, Massachusetts Institute of Technology, 2003;
  - *Annual Energy Outlook 2006, With Projections to 2030*, Energy Information Administration, February 2006;
  - *Avista 2007 Electric Integrated Resource Plan - IRP Modeling Overview: Resource Options and Cost Assumptions*, August 2006, John Lyons;
  - A Press Release for Finnish Utility TVO, December 18, 2003.
- The Keystone and Massachusetts Institute of Technology studies compiled cost statistics from numerous sources, and analyzed the costs of several recent new nuclear power plants in South Korea and Japan.
- Other cost and operational data are very consistent across sources. NCI used the Massachusetts Institute of Technology or Energy Information Administration data except where there definitions were not consistent with the California IEPR approach. For example, the Avista O&M costs fit the IEPR definition more closely.

Glossary

AC	Alternating current
AD	Anaerobic digesters
ARB	California Air Resources Board
BACT	Best available control technology
BOS	Balance of System
BIGCC	Biomass gasification combined cycle
BWR	boiling water reactor
California ISO	California Independent System Operator
CalSEIA	California Solar Energy Industries Association
CHP	Combined heat and power
CO_2	Carbon dioxide
CPUC	California Public Utilities Commission
CPV	concentrating photovoltaic
DC	Direct current
DWR	Department of Water and Power
EAO	Electricity Analysis Office
Energy Commission	California Energy Commission
GW	gigawatt
HHV	Higher heating value
IC	Internal combustion
IEPR	Integrated Energy Policy Report
IGCC	Integrated Gasification Combined Cycle
INEEL	Idaho National Engineering and Environmental Laboratory
kV	kilovolt
LFGFTE	Landfill gas fuel to energy
mmBTU	million British Thermal Units
MCFC	molten carbonate fuel cell

MW	megawatt
NCI	Navigant Consulting
NO_x	oxides of nitrogen
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
PG&E	Pacific Gas and Electric Company
PAFC	phosphoric acid fuel cell
PIER	Public Interest Energy Research
PEM	proton exchange membrane
ppmv	Parts per million by volume
PV	photovoltaic
PWR	pressurized water reactor
RD&D	research, development and demonstration
REC	Renewable Energy Certificates
RPS	Renewable Portfolio Standard
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
SMUD	Sacramento Municipal Utility District
SO_x	oxides of sulfur
SOFC	solid oxide fuel cell
WWTFTE	Waste water treatment fuel to energy

APPENDIX C: Comments on Report

This appendix summarizes all docketed comments on staff's report and Model, as well as staff's responses to these comments.

Pacific Gas & Electric Company (Received 6/22/07)

PG&E Comment 1:
Anaerobic Digesters (AD): The Navigant report shows dairy and food digesters. Similarly priced, but the staff report shows an almost 3-to-1 difference in Tables 2 and 24 while Navigant costs are used in Table 23.

Staff Response to Comment 1:
There is roughly a 2-to-1 difference in levelized cost for AD dairy relative to AD food. However, the dairy and food digesters are similarly priced only in regard to installed cost. Both the variable and fixed O&M costs are quite different for the two technologies. The single biggest factor driving the 2-to-1 difference in levelized cost is the tipping fee of $20/ton for AD food that is not applicable to AD dairy. This tipping fee is captured in the variable O&M which changes the AD food variable O&M levelized cost to become a net savings of $60/MWh compared to the AD dairy which is a net cost of $15.22/MWh. Even though the fixed O&M and corporate taxes of the AD food are higher than the AD dairy, the effect of the tipping fee makes the total levelized cost of AD food significantly lower.

PG&E Comment 2:
Anaerobic Digester Food: Table 24 shows a 94 percent tax credit without derivation, which can explain some of the difference, but this result is inconsistent with Figure 15.

Staff Response to Comment 2:
The 94 percent tax credit derived in Table 24 is using the data in Table 24, but was calculated using a base cost that is confusing to the reader. It was calculated by dividing the difference between the cost without the savings ($97.65) and the cost with the savings ($50.27) by the cost with savings: ($97.65 - $50.27)/$50.27 * 100% = 94.3%. It probably makes more sense to calculate this percentage by dividing the difference by the cost without savings: ($97.65 - $50.27) / $97.65 * 100% = 48.5%. This is corrected in this final report.

PG&E Comment 3:
Biomass Costs: Costs shown in Table 10 for biomass are extremely low and not differentiated between "free" fuel, such as landfill gas, and more expensive fuel, such as wood waste.

Staff Response to Comment 3:
Biomass costs were $40/dry ton for fluidized bed and stoker boiler. “Free” fuels were used for the Biomass landfill gas and waste water treatment plant technologies. Staff believes the costs in the Report are reasonable. Without quantitative data, we cannot make any adjustments.

PG&E Comment 4:
Combined Cycle and Combustion Turbine: Combined cycle costs compared to combustion turbine costs changed from 30 percent higher in the *2003 IEPR* to 15 percent lower in the *2007 IEPR*. In addition, the installed costs of a simple cycle unit almost doubled (see table below). It is unclear why the combined cycle costs are not increased proportionately.

Instant Cost	2003 IEPR ($/kW)	2007 IEPR ($/kW)	% Increase
Combined Cycle Base Load	$ 620	$ 784	126%
Simple Cycle	$ 477	$ 925	194%

These counterintuitive results need to be reviewed. Possible reasons could be that many of the combustion turbines were developed under emergency siting or small power plant exemption (SPPE) cases, which potentially reflects a market premium.

Staff Response to Comment 4:
The differences between the *2003* and *2007 IEPRs* are misleading. The simple cycle cost of *2003 IEPR* was simply too low, making the comparison meaningless. It is important to keep in mind that the 2003 estimates were simply rough estimates. The *2007 IEPR* estimates were developed based on a survey of actual costs. The difference really illustrates the necessity to develop estimates based on actual costs rather than relying on publicly available data as was done in the *2003 IEPR*.

PG&E Comment 5:
Regarding escalation rates, PG&E does not have access to escalation rates used in the analysis but suggests that capital costs be escalated with a construction cost escalation index, as construction materials costs have recently increased significantly faster than inflation.

Staff Response to Comment 5:
Real escalation for fixed and variable costs was assumed to be 0.5 percent per year. Real escalation for capital costs has been assumed to be zero. Nominal escalation is shown in the report in Table 10. Based on the data collected in the survey, staff was unable to discern any long-term pattern in cost escalation beyond nominal inflation. Furthermore, recent history shows costs falling relative to nominal price levels and the more recent construction cost increases only tend to offset the falling trend.

PG&E Comment 6:
Advance Simple Cycle Technology: The advanced simple cycle heat-rate improvement to 7580 BTU/kWh is too optimistic (p. 33) compared to the referenced Energy Information Administration (EIA) heat rate of 8550 BTU/kWh (p. 43). If this 7580 BTU/kWh low heat rate were achieved, the expected capacity factor should be higher than 5 percent.

Staff Response to Comment 6:
Staff agrees with PG&E that the 7580 Btu/kWh estimate is probably unrealistic for actual operation and has decided to use the EIA estimate of 8550 Btu/kWh instead. Staff also concurs that the capacity factor should be greater than 5 percent – even for the EIA estimate – and is changing this value to 15 percent based on Marketsym simulations.

PG&E Comment 7:
Advanced Simple Cycle Technology: The Energy Commission's instant cost of $756/kW for this new technology appears too low. For comparison, the Energy Commission's forecasted cost of a simple cycle unit is $925/kW. PG&E believes the cost of an advanced simple cycle unit will likely be higher.

Staff Response to Comment 7:
The model did assume a small incremental cost increase for advanced turbines using EIA data; however, that cost increase is offset by the fact that the base advanced CT facility is twice the size in MW of the conventional CT facility, thus an economy of scale.

PG&E Comment 8:
Capacity Factors: Use of historical capacity factors during the 2001- 2006 post-energy crises may not be a good estimate for future operation.

Staff Response to Comment 8:
The projected capacity factors are based in part on the Energy Commission's Marketsym modeling and in part on the judgment of the Aspen consultant. At this point, both the 60 percent capacity factor assumed for combined cycle units and the 5 percent capacity factor assumed for simple cycle units may be slightly high, but our best estimates have been rounded up to these approximate values in deference to the uncertainties inherent in this type of estimating.

PG&E Comment 9:
Base Combined Cycle Configuration: Consistent with the *2003 IEPR*, the base case configuration should include costs of dry cooling.

Staff Response to Comment 9: Dry cooling was not used in the base configuration for the *2007 IEPR* as it is relatively uncommon in the existing combined cycle units.

PG&E Comment 10:
Chillers: The effects of chillers on heat rate, capacity degradation, and parasitic load should be considered.

Staff Response to Comment 10:
These effects are considered to an extent by using actual heat rate and generation data from QFER. Chillers are used as peakers during hot periods only. Their overall effect during the year is not enough to significantly affect the COG model results.

PG&E Comment 11:
PG&E recommends that variable costs be excluded in the $kW-yr columns of Table 2: Summary of Levelized Costs, which presents calculated levelized costs that appear to include both fixed and variable costs.

Staff Response to Comment 11:
Staff's intention is to show the total levelized cost in both $/kW-Year and $/MWh as a convenience to future users and sees no purpose in excluding the variable cost portion.

PG&E Comment 12:
Solar Dish Engine: The cost is more than 50 percent higher than solar trough, which is inconsistent with SCE and SDG&E contracts under the MPR.

Staff Response to Comment 12:
The 2006 numbers that were included in the report reflect the current technology status and market for solar dish and solar trough plants from publicly available sources. In the future, larger production volumes are expected to lower overnight costs for solar dish, and storage is expected to be an economic option that will initially increase overnight costs and also increase capacity factors for solar trough. For this project, 2006 costs and capacity factors were used. Staff believes the costs in the report are reasonable. Without quantitative data, we cannot make adjustments.

PG&E Comment 13:
Geothermal: Binary and dual flash technologies appear to be too similarly priced compared to current market prices.

Staff Response to Comment 13:
Staff believes these costs are reasonable. The levelized cost between these two technologies is very close because the capital costs and net capacity factors are very similar. Without quantitative data, we cannot make adjustments.

PG&E Comment 14:
Solid Oxide Fuel Cell: Capital costs appear low, although variable costs for service contract and stack replacement may make up for it.

Staff Response to Comment 14:
Staff believes these costs are reasonable. Without quantitative data, we cannot make any adjustments.

PG&E Comment 15:
Wave: Capital costs are on the high side, and capacity factor appears too low. Integrated Gasification Combined Cycle (IGCC): Costs for this technology should include CO_2 sequestration costs to account for further reductions in greenhouse gas emissions.

Staff Response to Comment 15:
The 2006 numbers included in the report reflect the current technology status and market for wave energy. We did not think it was realistic that a large-scale plant (with considerably greater capacity and lower costs) could have been built at that time, and the analysis reflected this. Cost estimates and capacity factors were estimated for 2010 and beyond based primarily on the *EPRI System Level Design, Performance and Costs – Oregon State Offshore Wave Power Plant* report. These estimates are in agreement with the comments received from Ocean Power Delivery, Wavebob, Community Environmental Council, Mirko Previsic, and Ocean Power Technology. The estimates for 2010 are for a plant capacity of 90 MW, a project life of 20 years, an overnight installed cost of $2,700/kW in (2006$) and with a 38 percent capacity factor. The footnote is correct in this final report. CO_2 sequestration costs are not included as they are beyond the present scope of the model.

PG&E Comment 16:
Advanced Nuclear: Capital costs appear low.

Staff Response to Comment 16:
Staff agrees. New costs have recently become available in the June 2007 Keystone Report, *Nuclear Power Joint Fact Finding*. This is corrected in this final report.

NRDC & UCS (Received 6/27/07)

NRDC Comment 1
The Model will be more valuable to policy makers if it presents the results of sensitivity analysis on cost of greenhouse gas emissions and allows the user to vary the cost of greenhouse gas emissions in the model.

Staff Response to Comment 1:
The requested study is beyond the present scope of the Cost of Generation report. However, staff intends to consider this in subsequent Cost of Generation reports.

NRDC Comment 2
The emission rate for IGCC should be changed from 1,928 pounds of CO_2 per MWh to 1,100 pounds of CO_2 per MWh to conform to the SB 1368 Performance Standard, which has been adopted by the Energy Commission (07-0523-7) and the CPUC (CPUC D.07-01-039, January 25, 2007).

Staff Response to Comment 2:
Navigant agrees that the Energy Commission and CPUC adopted rules and regulations need to be considered. The plant that was profiled would not meet current regulations. Under the current adopted rules and regulations, additional capital investment and operating costs would be needed to meet emission requirements. These changes could also affect plant efficiency.

NRDC Comment 3
The Model should be modified to capture carbon cost of IGCC, as it will increase cost about $14/MWh. Suggests adding $450/kW to capital cost and $3/MWh for variable cost.

Staff Response to Comment 3:
Carbon capture is not sufficiently defined and it implies other things such as carbon tax, which are beyond the present scope of the model.

NRDC Comment 4
Nuclear levelized costs are too low for nuclear power. The Model assumes an installed cost of nuclear of $2,433/kW, whereas the Keystone Center estimates that cost as between $3,600/kW and $4,000/kW.

Staff Response to Comment 4:
Staff agrees. New costs have recently become available in the June 2007 Keystone report *Nuclear Power Joint Fact Finding*. This is corrected in this final report.

NRDC Comment 5
Assuming a forward price for IGCC is inconsistent with the other technologies. Capital costs may be too low. Mesba Unit 1 in northern Minnesota had an instant cost of $3,000/kW ($3600/KW installed).

Staff Response to Comment 5:
The point made by Navigant in the presentation was that many of these technologies will not be built today as there is lead time required for permitting and other approvals. It was assumed that the technologies would be installed in 2006 when creating the estimates. Therefore, Navigant did not assume that one technology was using 2010 technology and the other 2007.

NRDC Comment 6
Wind costs ($99/MWh for Merchant and $67/MWh for IOU) are unreasonably high in that 2006 MPR is set at $84.24 per MWh. Thinks this is due to using cost of equity of 15.19 percent.

Staff Response to Comment 6:
Staff considers the cost of equity to be reasonable but has reconsidered the debt to equity ratio. This is corrected in this final report.

NRDC Comment 7
Solar prices are high due to incomplete or bad assumptions. Does not explain the large difference between Merchant and IOU owned plants – illogical since IOU is not eligible for investment tax credits (ITCs). The Report assumes that the 30 percent ITC will not extend beyond 2008 but Congress is considering an eight-year extension – at a minimum five years should be assumed.

Staff Response to Comment 7:
The difference in merchant and IOU costs comes from the financing mechanisms. Staff considers the cost of equity to be reasonable but has reconsidered the debt to equity ratio. The cost estimates are not impacted by the incentives assumed in future years as the incentives apply based on the time of plant construction. Therefore the assumption of the ITC being extended does not affect the results. Staff agrees that ITC is not applicable to the IOUs and has modified the Model and report accordingly. Navigant did take into consideration the economies of scale that are achieved by combining modular units.

Southern California Edison (Rec'd 6/29/07)

SCE Comment 1:
The Energy Commission report uses a commercial grade LM6000 as the base configuration for the simple cycle combustion turbine. SCE believes that the GE Frame 7x configuration is a more appropriate standard. SCE recommends an additional scenario based on a two-unit or four-unit Frame 7x peaker configuration be incorporated.

Staff Response to Comment 1:
The simple and combined cycle base cases were based on the normal type and number of turbines that have been licensed in the recent past and that are currently undergoing licensing. There are a large number of potential selections for these base cases; however, we believe that the use of siting cases since 2001 provides the most reasonable and typical design. Staff doesn't believe that Frame 7 turbines are a reasonable simple cycle case as staff has seen only two such cases be licensed Tracy (2-7E turbines), and Pastoria expansion project (1-7F turbine with three existing 7F combined cycle turbines); while more than half of the cases were LM6000 turbines. The simple cycle cases under construction or currently under review, not including the LMS100 advanced turbine cases, also are predominately LM6000 turbines and cases outside of Energy Commission jurisdiction would typically have to be LM6000 or smaller turbines (as is the case with the four LM6000 SCE projects in construction in the SCAB and the one LM6000 project proposed in Oxnard). While staff is aware of these five LM6000 cases proposed/being built by SCE, staff is not aware that SCE is proposing any Frame 7 turbines for simple cycle operation.

SCE Comment 2:
The combined cycle scenario as currently described appears to be inefficiently sized by using a 500 MW 2x1 configuration (2 CTs into one steam turbine). SCE believes a scenario similar to the Mountainview plant is more appropriate at approximately 1000 MW, using a 4x2 configuration.

Staff Response to Comment 2:
Four turbine combined cycle projects are not the norm. Of the 15 7F combined cycle projects surveyed (that is, licensed and built since 2001) only three were four turbine projects. The most prevalent, eight cases, were two turbine cases (with one turbine occurring once and three turbines occurring three times). The combined cycle cases under construction or currently under review are predominately two turbine 7F configurations as well.

SCE Comment 3:
Chapter 2. Assumptions, Summary of Assumptions, page 16: The paragraph indicates that Tables 6 and 7 summarize the most common input assumptions and that all costs are for year 2007 nominal dollars. However, Table 6 and 7 presents the same emissions factors for the various technologies, no other assumptions are provided, and no costs are provided. Is the information provided by Tables 6 and 7 the correct information presentation (same data in both tables and no costs)? Please review.

Staff Response to Comment 3:
This was a typographical error. Table 6 should have shown the common input assumptions, not the emission factors. This is corrected in this final report.

SCE Comment 4:
Clean Coal (IGCC) & Nuclear Section, Advanced Nuclear Design Types and Manufacturers Table, page 101: Two (2) major suppliers of advanced nuclear plant designs are not listed in the table but should be considered.

Design	Mfgr.	Size & Type
US APWR	Mitsubishi	1,700 MWe Advanced Pressurized Water Reactor
US EPR	AREV A	1,600 MWe Evolutionary Power Reactor

Staff Response to Comment 4:
These suppliers are added in this final report.

SCE Comment 5:
ADDERS Sheet: It is understood that the Plants Survey Information was used to develop the "Linears" costs indicated in the Model Adjustment Factors tables. Recent Southern California Edison experience indicates that the "Linears" cost used for the simple cycle plant is approximately fifty (50) percent low when compared to actual construction costs for transmission, gas supply, etc.

Staff Response to Comment 5:
Again relying on the data gathered, staff has no evidence to support a higher value. In the absence of specific information, staff can only keep SCE's admonition in mind during future data gathering efforts.

SCE Comment 6:
INPUT-OUTPUT Sheet, INPUT SELECTION Table: For Advanced Nuclear and IGCC Plant Types, selecting a Start (in-service) year other than 2007 produces a "#N/A" indication in the OUTPUT RESULTS Table Fuel Costs columns. It this the intended result for the fuel cost for these Plant Types and Start Year selection? Please review.

Staff Response to Comment 6:
Selecting Advanced Nuclear with a book life of 40 years extends the algorithm beyond its present structure. This is correct in the final version of the Model.

SCE Comment 7:
INPUT-OUTPUT Sheet, INPUT SELECTION Table: After selecting Fuel Cell Plant Types, methane fuel is indicated as the fuel. However, a **"$0"** fuel cost is indicated in the OUTPUT RESULTS Table Fuel Costs columns. It this correct, that no fuel costs are included in the variable costs? If not, how is the fuel cost accounted for. Please review.

Staff Response to Comment 7:
The fuel cost is intentionally set to zero based on the assumption that the fuel cell is sized for a landfill gas site and uses the methane from the landfill.

SCE Comment 8:
INPUT-OUTPUT Sheet, KEY DATA VALUES Table. Fuel Use Summary: The row name "Natural Gas Price ($/MMBtu)" remains the same even when other fuels (coal, nuclear, etc.) are indicated in the INPUT SELECTION Table. However, the selected fuel costs are listed. Is this the intended presentation result for indicating fuel types costs? Please review.

Staff Response to Comment 8:
This is an error in the coding. This is corrected to say Fuel Price, rather than Natural Gas Price in the final version of the Model.

SCE Comment 9:
INPUT-OUTPUT Sheet, KEY DATA VALUES Table. Instant and Installed cost: The Installed Costs generated by the Model are indicated as LESS than the Instant Costs. Is this correct? It would seem that the Installed Costs should be more than the Instant Costs. Please review.

Staff Response to Comment 9:
Staff cannot replicate this concern. The confusion is no doubt generated by the Instant/Installed option in cell C19 on the input-Output worksheet, which allows the user to tell the model whether the cost data in Data 2 worksheet are Instant Costs or Installed Costs. If the Installed option is used, the data in G27 is identical to the cost in G26, which signifies that there is no Instant cost being used. Staff has modified Instructions on the Input-Output worksheet along with a reference adjacent to the cell C19 that should eliminate this confusion.

SCE Comment 10:
FUEL PRICE FORECASTS Sheet: The column header "Natural Gas, $/MMBtu" (left hand side of Sheet) remains the same even when other fuels (coal, nuclear, etc.) are indicated in the INPUT-OUTPUT Sheet, INPUT SELECTION Table. However, the selected fuel costs are listed in the column. Is this the intended header presentation for indicating fuel types costs? Please review.

Staff Response to Comment 10:
This is an error in the coding. It has been corrected to read “Fuel Price,” rather than “Natural Gas Price” in the final version of the Model.

SCE Comment 11:
INPUT-OUTPUT Sheet. KEY DATA VALUES Table. Capacity & Energy Summary, Etc.: For Combined Cycle Advanced (H Frame) Plant Type--when the Turbine Configuration is changed from 2 (default) to 1, there is no change to the power output numbers in the Capacity & Energy Summary, no change in Fuel Use, etc. The Levelized Costs, Instant Costs, Installed Costs, etc. change but the values are questionable since the Capacity does not change. Please review.

Staff Response to Comment 11:
In order for the Model to work correctly, the user must refresh the Plant Type Assumptions, Instruction 10.

Wave Energy (Received 6/20/07)
Ocean Power Delivery (Received 6/22/07)
Community Environmental Council (Received 6/22/07)
Ocean Power Technologies, Inc (Received 6/22/07)
Wavebob (Received 6/29/07)

Summary of these 5 comments:
All of these public entities commented that capital costs were too high and capacity factors were too low, resulting in unrealistically high levelized cost.

Staff response to these 5 comments:
The 2006 numbers that were included in the report reflect the current technology status and market for wave energy. We did not think it was realistic that a large scale plant (with considerably greater capacity and lower costs) could have been built at that time and the analysis reflected this. Cost estimates and capacity factors were estimated for 2010 and beyond based primarily on the EPRI System Level Design, Performance and Costs – Oregon State Offshore Wave Power Plant report. These estimates are in agreement with the comments received from Ocean Power Delivery, Wavebob, Community Environmental Council, Mirko Previsic, and Ocean Power Technologies. The estimates for 2010, are a plant capacity of 90 MW, a project life of 20 years, an overnight instant cost of $2,700/kW in (2006$), with a 38 percent capacity factor. The footnote in the final report will be corrected accordingly.

APPENDIX D: Changes Since Draft Report

This Appendix summarizes the changes since the June 12, 2007 draft report. The significant changes are:

- Advanced simple cycle heat rate and capacity factors changed from 7580 Btu/kWh and 5 percent to 8550 Btu/kWh and 15 percent.
- Nuclear costs were increased to reflect the recently released 2007 Keystone Report. The corresponding changes from the draft report are as follows:
  - Instant cost: From $2509 to $2950 /kW
  - Fixed O&M: From $57 to $140 /kW-Yr
  - Variable O&M: From $1.24 to $5 /MWh
  - Construction period: From five to six years
- The variable cost for Biomass AD-Food's was reduced to reflect a correction in the estimated tipping fee.
- The BETC tax credit for solar concentrating PV was removed for IOU ownership as it is not applicable.
- CSI and SGIP tax credits were removed as not being applicable for central station technologies.
- Debt-to-equity ratio for merchant non-gas fired technologies was changed from 40 percent/60 percent to 60 percent/40percent resulting in reductions in levelized cost between 5 and 18 percent depending on the technology – not accounting for the other updates to the report.
- Tax credits and tax credit accounting revised such that levelized costs decreased for all ownerships and all technologies but most significantly for technologies with tax credits – changes range from 1 percent to 20 percent depending on the technology and ownership.

Table D-1 shows the levelized costs presented in the draft report. **Table D-2** shows the resulting changes in levelized costs due to the above delineated revisions. **Table D-3** shows the resulting change as a percent of draft report's levelized cost.

Table D-1: Draft Report Levelized Costs

In-Service Year =2007 (Nominal 2007$)	Size	Merchant		IOU		POU	
	MW	$/kW-Yr	$/MWh	$/kW-Yr	$/MWh	$/kW-Yr	$/MWh
Conventional Combined Cycle (CC)	500	514.56	101.35	476.31	93.97	443.68	87.79
Conventional CC - Duct Fired	550	521.49	102.72	482.14	95.12	448.59	88.77
Advanced Combined Cycle	800	485.30	95.59	447.16	88.22	413.91	81.90
Conventional Simple Cycle	100	250.81	586.36	196.68	460.01	133.90	313.42
Small Simple Cycle	50	270.85	633.21	213.36	499.02	147.98	346.37
Advanced Simple Cycle	200	205.06	479.40	160.83	376.17	106.18	248.52
Integrated Gasification Combined Cycle (IGCC)	575	678.11	131.66	492.79	95.68	384.74	74.70
Advanced Nuclear	1000	728.50	99.86	538.03	73.75	488.88	67.01
Biomass - AD Dairy	0.25	937.69	145.65	723.65	112.41	636.95	98.94
Biomass - AD Food	2	323.64	50.27	80.72	12.54	-51.00	-7.92
Biomass Combustion - Fluidized Bed Boiler	25	915.59	125.49	793.72	108.78	855.28	117.22
Biomass Combustion - Stoker Boiler	25	854.32	117.09	745.23	102.14	814.95	111.69
Biomass - IGCC	21.25	929.64	127.41	781.13	107.06	771.37	105.72
Biomass - LFG	2	370.07	54.49	294.14	43.66	317.72	47.86
Biomass - WWTP	0.5	458.23	87.35	361.82	70.59	296.38	60.36
Fuel Cell - Molten Carbonate	2	933.83	120.84	774.10	100.17	672.03	86.96
Fuel Cell - Proton Exchange	0.03	1289.91	166.91	1026.94	132.89	858.56	111.10
Fuel Cell - Solid Oxide	0.25	776.26	100.45	615.21	79.61	531.28	68.75
Geothermal - Binary	50	573.15	91.82	400.34	66.10	384.60	67.18
Geothermal - Dual Flash	50	542.03	88.67	383.07	64.58	375.70	67.01
Hydro - In Conduit	1	256.67	63.36	183.90	46.09	185.71	48.01
Hydro - Small Scale	10	700.93	171.03	480.62	119.06	338.23	86.43
Ocean Wave (Pilot)	0.75	1440.72	1201.48	1006.79	846.40	716.79	611.59
Solar - Concentrating PV	15	495.96	271.96	334.48	185.55	204.88	116.23
Solar - Parabolic Trough	63.5	671.03	294.54	497.90	219.23	349.47	154.86
Solar - Photovoltaic (Single Axis)	1	1117.12	608.42	723.14	396.30	461.81	256.29
Solar - Stirling Dish	15	1121.75	544.27	859.49	417.02	643.25	312.10
Wind - Class 5	50	289.10	99.03	195.24	66.88	177.44	60.78

Table D-2: Levelized Cost Changes from Draft to Final Report

In-Service Year =2007 (Nominal 2007$)	Size	Merchant		IOU		POU	
	MW	$/kW-Yr	$/MWh	$/kW-Yr	$/MWh	$/kW-Yr	$/MWh
Conventional Combined Cycle (CC)	500	-8.74	0.84	-9.46	0.50	-15.37	-0.96
Conventional CC - Duct Fired	550	-9.10	0.80	-9.75	0.48	-15.62	-0.98
Advanced Combined Cycle	800	-8.34	0.78	-8.95	0.46	-14.29	-0.88
Conventional Simple Cycle	100	-0.38	13.21	-1.09	8.46	-1.06	4.91
Small Simple Cycle	50	-0.49	14.07	-1.28	8.95	-1.28	5.18
Advanced Simple Cycle	200	90.90	-243.28	92.38	-174.07	94.95	-87.92
Integrated Gasification Combined Cycle (IGCC)	575	-111.54	-5.16	-16.64	10.64	-23.22	6.02
Advanced Nuclear	1000	134.20	18.39	219.74	30.12	175.90	24.11
Biomass - AD Dairy	0.25	-13.17	-2.05	102.92	15.99	163.98	10.83
Biomass - AD Food	2	127.33	19.78	269.57	41.87	269.82	41.91
Biomass Combustion - Fluidized Bed Boiler	25	-49.34	-6.76	0.27	0.04	-15.37	-2.11
Biomass Combustion - Stoker Boiler	25	-43.33	-5.94	0.22	0.03	-15.21	-2.09
Biomass - IGCC	21.25	-80.46	-3.76	-12.55	4.86	-26.55	2.74
Biomass - LFG	2	12.43	1.63	51.80	7.21	35.01	4.50
Biomass - WWTP	0.5	56.42	9.99	104.81	18.25	70.16	11.42
Fuel Cell - Molten Carbonate	2	-47.72	-6.18	136.51	17.66	82.91	10.73
Fuel Cell - Proton Exchange	0.03	119.72	15.49	254.34	32.91	167.11	21.62
Fuel Cell - Solid Oxide	0.25	179.39	23.21	253.40	32.79	164.01	21.22
Geothermal - Binary	50	-95.93	-15.98	-4.03	-2.57	9.64	-1.63
Geothermal - Dual Flash	50	-88.11	-15.00	-3.83	-2.51	8.66	-1.75
Hydro - In Conduit	1	-42.95	-10.52	0.06	-0.41	3.00	-0.23
Hydro - Small Scale	10	-133.22	-32.29	0.44	-0.99	9.73	0.66
Ocean Wave (Pilot)	0.75	-200.80	-170.98	-1.15	-8.76	17.16	5.53
Solar - Concentrating PV	15	124.52	152.88	297.32	248.46	237.22	191.86
Solar - Parabolic Trough	63.5	-173.71	-17.24	6.27	62.14	6.24	44.45
Solar - Photovoltaic (Single Axis)	1	-82.05	96.56	296.34	299.30	219.93	212.58
Solar - Stirling Dish	15	-266.20	-25.38	9.43	109.98	5.51	81.37
Wind - Class 5	50	-43.17	-14.79	0.84	0.29	1.75	0.60

Table D-3: Change as a Percent of Draft Report Levelized Costs

In-Service Year =2007 (Nominal 2007$)	Size	Merchant		IOU		POU	
	MW	$/kW-Yr	$/MWh	$/kW-Yr	$/MWh	$/kW-Yr	$/MWh
Conventional Combined Cycle (CC)	500	-1.7%	0.8%	-2.0%	0.5%	-3.5%	-1.1%
Conventional CC - Duct Fired	550	-1.7%	0.8%	-2.0%	0.5%	-3.5%	-1.1%
Advanced Combined Cycle	800	-1.7%	0.8%	-2.0%	0.5%	-3.5%	-1.1%
Conventional Simple Cycle	100	-0.2%	2.3%	-0.6%	1.8%	-0.8%	1.6%
Small Simple Cycle	50	-0.2%	2.2%	-0.6%	1.8%	-0.9%	1.5%
Advanced Simple Cycle	200	44.3%	-50.7%	57.4%	-46.3%	89.4%	-35.4%
Integrated Gasification Combined Cycle (IGCC)	575	-16.4%	-3.9%	-3.4%	11.1%	-6.0%	8.1%
Advanced Nuclear	1000	18.4%	18.4%	40.8%	40.8%	36.0%	36.0%
Biomass - AD Dairy	0.25	-1.4%	-1.4%	14.2%	14.2%	25.7%	10.9%
Biomass - AD Food	2	39.3%	39.3%	333.9%	333.9%	-529.1%	-529.1%
Biomass Combustion - Fluidized Bed Boiler	25	-5.4%	-5.4%	0.0%	0.0%	-1.8%	-1.8%
Biomass Combustion - Stoker Boiler	25	-5.1%	-5.1%	0.0%	0.0%	-1.9%	-1.9%
Biomass - IGCC	21.25	-8.7%	-2.9%	-1.6%	4.5%	-3.4%	2.6%
Biomass - LFG	2	3.4%	3.0%	17.6%	16.5%	11.0%	9.4%
Biomass - WWTP	0.5	12.3%	11.4%	29.0%	25.9%	23.7%	18.9%
Fuel Cell - Molten Carbonate	2	-5.1%	-5.1%	17.6%	17.6%	12.3%	12.3%
Fuel Cell - Proton Exchange	0.03	9.3%	9.3%	24.8%	24.8%	19.5%	19.5%
Fuel Cell - Solid Oxide	0.25	23.1%	23.1%	41.2%	41.2%	30.9%	30.9%
Geothermal - Binary	50	-16.7%	-17.4%	-1.0%	-3.9%	2.5%	-2.4%
Geothermal - Dual Flash	50	-16.3%	-16.9%	-1.0%	-3.9%	2.3%	-2.6%
Hydro - In Conduit	1	-16.7%	-16.6%	0.0%	-0.9%	1.6%	-0.5%
Hydro - Small Scale	10	-19.0%	-18.9%	0.1%	-0.8%	2.9%	0.8%
Ocean Wave (Pilot)	0.75	-13.9%	-14.2%	-0.1%	-1.0%	2.4%	0.9%
Solar - Concentrating PV	15	25.1%	56.2%	88.9%	133.9%	115.8%	165.1%
Solar - Parabolic Trough	63.5	-25.9%	-5.9%	1.3%	28.3%	1.8%	28.7%
Solar - Photovoltaic (Single Axis)	1	-7.3%	15.9%	41.0%	75.5%	47.6%	82.9%
Solar - Stirling Dish	15	-23.7%	-4.7%	1.1%	26.4%	0.9%	26.1%
Wind - Class 5	50	-14.9%	-14.9%	0.4%	0.4%	1.0%	1.0%

APPENDIX E: Summary of Simple Cycle Cost

This appendix is provided at the request of the California ISO. It summarizes the fixed cost components for simple cycle generating units (combustion turbines) in $/kW-Yr. It is consistent with the summary of levelized costs provided in Tables 2 – 5 of this report.

Table E-1: Simple Cycle Fixed Costs - Merchant

		$/kW-Yr (Nominal 2007$)					
In-Service Year =2007	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**
Conventional Simple Cycle	100	136.59	8.70	6.81	12.74	39.44	**204.28**
Small Simple Cycle	50	145.30	9.25	7.25	20.36	41.85	**224.01**
Advanced Simple Cycle	200	112.21	7.14	5.60	8.25	32.44	**165.64**

Table E-2: Simple Cycle Fixed Costs - IOU

		$/kW-Yr (Nominal 2007$)					
In-Service Year =2007	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**
Conventional Simple Cycle	100	106.14	6.87	3.85	13.00	18.40	**148.26**
Small Simple Cycle	50	112.91	7.30	4.10	20.78	19.47	**164.55**
Advanced Simple Cycle	200	87.19	5.64	3.17	8.42	15.16	**119.58**

Table E-3: Simple Cycle Fixed Costs - POU

		$/kW-Yr (Nominal 2007$)					
In-Service Year =2007	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**
Conventional Simple Cycle	100	60.14	5.04	5.59	13.30	0.00	**84.08**
Small Simple Cycle	50	64.98	5.45	6.04	21.27	0.00	**97.74**
Advanced Simple Cycle	200	46.60	3.91	4.33	8.62	0.00	**63.46**

Levelized costs, including all cost components thereof, can be converted from $/MWh to $/kW-Yr by multiplying the $/MWh value by the load center energy (GWh) and dividing by the gross capacity (MW). Alternatively, the same result can be obtained by using Table 2. Multiply the $/MWh levelized cost by the corresponding $/kW-Yr and divide by the $/MWh. Care must be taken to use the corresponding technology and developer.