UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	**Docket No. ER20-1075-000**

ANSWER AND MOTION FOR LEAVE TO ANSWER
OF THE DEPARTMENT OF MARKET MONITORING
OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

The Department of Market Monitoring (DMM), acting in its capacity as the Independent Market Monitor for the California Independent System Operator Corporation (CAISO), submits this answer to the reply comments submitted on April 1, 2020 by the CAISO in the above captioned proceeding.[1]

I. ANSWER

As noted in DMM's initial comments in this proceeding, during the CAISO's 2019 Capacity Procurement Mechanism (CPM) stakeholder process DMM provided the CAISO with a review of the annual fixed O&M costs of gas-fired combined cycle resources based on a wide range of reports and studies.[2] DMM's analysis provides strong evidence that the annual fixed O&M cost estimates from the California Energy

[1] DMM files this answer pursuant to Rules 212 and 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R., §§ 385.212, 385.213. The DMM requests waiver of Rule 213(a)(2), 18 C.F.R. § 385.213(a)(2), to permit it to answer the protests filed in the proceeding. Good cause for this waiver exists here because the answer will aid the Commission in understanding the issues in the proceeding, provide additional information to assist the Commission in the decision-making process, and help to ensure a complete and accurate record in the case. See, e.g., Equitrans, L.P., 134 FERC ¶ 61,250, at P 6 (2011); Cal. Indep. Sys. Operator Corp., 132 FERC ¶ 61,023, at P 16 (2010); Xcel Energy Servs., Inc., 124 FERC ¶ 61,011, at P 20 (2008)

[2] *Motion to Intervene and Comments of the Department of Market Monitoring,* ER20-1075-000, March 17, 2020, pp. 11-13.

Commission (CEC) reports used by the CAISO to set the CPM soft cap significantly overstate the actual fixed annual O&M costs of combined cycle gas units.[3]

When providing this analysis to the CAISO in September 2019, DMM offered to review and discuss this analysis with CAISO staff and provide any more detailed information requested by CAISO staff. However, the CAISO did not address or acknowledge DMM's analysis as part of the public stakeholder process or in the CAISO's February 25, 2020 tariff filing. Instead, the CAISO's final CPM proposal simply stated that its decision not to change the soft cap was based on the fact that the CEC's 2019 report "indicates that the going forward fixed costs for a new combined cycle resource did not materially change over the past five years."[4]

The CAISO commented on the other cost studies provided by DMM for the first time in its April 1, 2020 reply to the Commission, stating that:

> DMM argues that the cap should be lowered because studies elsewhere suggest that fixed O&M costs are lower than the levels the CEC determined in its generation cost study. The studies DMM relies on are not California-specific; several are resource planning studies conducted for individual utilities in other western states, not California. DMM provides no detail regarding any of these studies, but merely lists them.[5]

While the CAISO reply questions the applicability of the cost studies cited by DMM, the CAISO itself has not undertaken any review to assess the accuracy of these studies or the CEC data being utilized to set the CPM soft cap. As indicated in

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3 *Ibid.* Figure 1, p. 13.

4 *Capacity Procurement Mechanism Soft Offer Cap Draft Final Proposal,* California Independent System Operator, January 6, 2020 p. 6 ("2020 Draft Final Proposal"). http://www.caiso.com/InitiativeDocuments/DraftFinalProposal-CapacityProcurementMechanismSoftOfferCap.pdf.

5 *Answer to Comments and Protests of the California Independent System Operator*, ER20-1075-000, April 1, 2020, pp. 9-10.

DMM's comments, the fixed annual O&M estimates used by the CAISO to set the CPM soft cap are about <u>three times higher</u> than the highest estimates of fixed annual O&M found by DMM. Nothing in the CAISO's reply comments explains such a dramatic discrepancy between the CEC cost assumptions and all other studies cited by DMM. Moreover, no generator has provided comments in the CAISO stakeholder process or this proceeding questioning the accuracy of the cost estimates cited by DMM or supporting the cost assumptions in the CEC reports.

In this answer, DMM provides additional details of the annual fixed O&M cost estimates previously submitted by DMM to the CAISO and the Commission. In response to CAISO's argument that the fixed O&M costs for gas units in California are dramatically higher (i.e. 300 percent) than in other states, DMM is also providing information on fixed O&M costs submitted to the CAISO and the Commission in November 2017 for a combined cycle generator in California as part of a proposed Reliability Must-Run contract agreement. The fixed annual costs assumptions from the 2019 CEC report ($58.90/kW-year) used by the CAISO are almost twice (about 183 percent) of the fixed annual costs filed for this 593 MW combined cycle unit ($32.13/kW-year).

Contrary to the CAISO's reply comments, these data provide strong evidence that the CEC data used by the CAISO to set the CPM soft cap significantly overestimates the actual annual going forward fixed costs of gas units.

Review of Other Annual Fixed Cost Studies

Attachment 1 provides additional details of the annual fixed O&M cost estimates for gas-fired combined cycle units shown in Figure 1 of DMM's prior comments submitted to the CAISO and the Commission.[6] Attachment 1 provides detailed information and supporting excerpts for all of the 20 studies and reports summarized in Figure 1 of DMM's prior comments.

Annual Fixed Costs Submitted by Generator within California

Attachment 2 provides information on fixed O&M costs submitted to the CAISO and the Commission in November 2017 for a 593 MW combined cycle gas unit in California as part of a proposed Reliability Must-Run Contract (RMR) contract agreement. Table 1 on the following page provides a summary comparison of the going forward fixed costs filed for this combined cycle unit compared to the cost assumptions from the 2019 CEC report used by the CAISO.

As shown in Table 1, the fixed annual O&M costs from the 2019 CEC report ($41.77/kW-year) equal about 173 percent of the fixed annual O&M cost filed for this RMR unit ($23.51). The CEC cost assumptions for the other two cost categories included in the CAISO's calculation of the soft cap (*ad valorem* and insurance) are also significantly higher than the fixed annual costs filed for this RMR unit for these categories. When combined together, the fixed annual costs from the CEC report

[6] As noted in footnote 17 on page 11 of DMM's initial comments, a list of these studies was provided in DMM's supplemental comments on the CAISO's CPM Soft Offer Cap straw proposal. See *CPM Soft Offer Cap Straw Proposal: Supplemental Comments by Department of Market Monitoring*, September 10, 2019, pp. 5-6: http://www.caiso.com/InitiativeDocuments/DMMSupplementalCommentsCapacityProcurementMechanismSoftOfferCap-StrawProposal.

($58.90/kW-year) are almost twice (about 183 percent) of the fixed annual costs filed for this 593 MW combined cycle unit ($32.13/kW-year).

Table 1. Comparison of RMR Unit Costs with 2019 CEC Report

	2017 RMR filing [1]	2019 CEC report [2]
Unit size (MW)	593 MW	600 MW
Fixed O&M ($/yr)	$13,946,589	$25,062,000
Ad Valorem ($/yr)	$2,081,208	$6,018,000
Insurance ($/yr)	$3,032,016	$4,260,000
GFFC ($/year)	$19,059,813	$35,340,000
Fixed O&M ($/kW-yr)	$23.51	$41.77
Ad Valorem ($/kW-yr)	$3.51	$10.03
Insurance ($/kW-yr)	$5.11	$7.10
GFFC ($/year)	$32.13	$58.90

[1] *Metcalf Energy Center, LLC submits tariff filing per 35.12: Metcalf RMR Agreement Filing to be effective 1/1/2018 under ER18-240.* November 2, 2017. Schedule F, pages 140-142. See also DMM's Attachment 2 provided herein, which includes a detailed description of the data and calculations in Table 1. https://elibrary.ferc.gov/IDMWS/common/OpenNat.asp?fileID=14741407

[2] Neff, Bryan. 2019. Estimated Cost of New Utility-Scale Generation in California: 2018 Update. California Energy Commission. Publication Number: CEC-200-2019-500. Fixed O&M, Ad Valorem and Insurance can be found in Table D-2, page D-2. https://ww2.energy.ca.gov/2019publications/CEC-200-2019-005/CEC-200-2019-005.pdf

These data provide further evidence that the CEC data used by the CAISO to set the CPM soft cap significantly overestimates the actual going forward fixed annual costs of gas units.

III. CONCLUSION

DMM respectfully requests that the Commission afford due consideration to these comments as it evaluates the proposed tariff provisions before it.

Respectfully submitted,

/s/ Eric Hildebrandt

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Independent Market Monitor for the California
Independent System Operator

Dated: April 3, 2020

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon the parties listed on the official service lists in the above-referenced proceedings, in accordance with the requirements of Rule 2010 of the Commission’s Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Folsom, California this 3rd day of April, 2020.

/s/ Candace McCown

Candace McCown

Attachment 1

List of References with Estimates of Annual Fixed O&M Costs

1. APS IRP Brownfield. (2017). *APS Integrated Resource Plan 2017*. Table of generation assumptions in Attachment D-3, pp 309-310. https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/2017IntegratedResourcePlan.ashx

Figure 1-1. Excerpt from APS IRP cited above. Average taken of highlighted numbers (Brownfield gas generators greater than 400 MW). The report was published in 2017, costs were assumed to be in 2017 dollars. DMM then used an online calculator to inflate the costs from 2017 to 2019 dollars.[7]

ATTACHMENT D.3 – GENERATION TECHNOLOGIES

Conventional Generation Technologies Assumptions													
Plant	Location	Annual Capacity (MW)	Summer Capacity (MW)	Winter Capacity (MW)	Capital Costs ($Million)	Capital Costs ($/kW)	Fixed O&M ($/kW-Yr)	Var O&M ($/MWh)	Heat Rate (BTU/kWh)	Lead Time (yrs)	Capacity Factor %	CO_2 Emission (lbs/MWh)	Water Consumption (gal/MWh)
Coal													
Cholla 5 490MW IGCC	Cholla	490	455	518	2,635	5,791	23.51	3.83	10,000	9	86%	2,050	491
Gas Greenfield													
One 7F.05, Evap Inlet	Maricopa	222	216	227	171.9	797	10.08	2.28	9,959	3	10%	1,215	15
Two 7F.05, Evap Inlet	Maricopa	443	431	454	327.2	759	10.08	2.28	9,959	3	10%	1,215	15
Four 7E.03, Evap Inlet	Maricopa	340	320	360	359.0	1,122	8.43	2.83	10,434	3	10%	1,273	22
Six LM6000PC Sprint, Chilled Inlet	Maricopa	282	276	294	415.4	1,505	9.72	2.28	9,723	3	10%	1,186	111
3X0 LMS100PA+ Chilled Inlet, Wet Cooled	Maricopa	319	306	324	451.3	1,475	13.53	2.73	9,125	3	10%	1,113	207
3X0 LMS100PA+ Chilled Inlet, Hybrid Cooled	Maricopa	318	306	324	454.0	1,484	13.53	2.73	9,138	3	10%	1,115	141
3X0 LMS100PA+ Chilled Inlet, Dry Cooled	Maricopa	289	258	312	465.6	1,805	13.53	2.73	9,566	3	10%	1,167	84
5X0 LMS100PA+ Chilled Inlet, Wet Cooled	Maricopa	531	510	540	692.2	1,357	8.51	2.70	9,125	3	10%	1,113	207
5X0 LMS100PA+ Chilled Inlet, Hybrid Cooled	Maricopa	531	510	540	698.1	1,369	8.51	2.70	9,138	3	10%	1,115	141
5X0 LMS100PA+ Chilled Inlet, Dry Cooled	Maricopa	482	430	520	709.4	1,650	8.51	2.70	9,566	3	10%	1,167	84
2X1 CC 7F.05, Evap Inlet, DB on, CT (Wet)	Maricopa	783	729	841	824.9	1,132	6.37	2.21	6,964	4	50%	850	395
2x1 CC 7F.05, Evap Inlet, DB On, ACC	Maricopa	802	710	869	877.3	1,236	6.53	1.82	7,149	4	50%	872	20
Gas Brownfield													
One Redhawk 7F.05, Evap Inlet	Redhawk	222	216	227	160.6	745	10.08	2.28	9,959	3	10%	1,215	15
Two Redhawk 7F.05, Evap Inlet	Redhawk	443	431	454	312.5	725	10.08	2.28	9,959	3	10%	1,215	15
Two Redhawk 7E.03, Evap Inlet	Redhawk	170	160	180	193.8	1,211	16.86	2.83	10,434	3	10%	1,273	22
Two Sundance LM6000PC Sprint, Chilled Inlet	Sundance	94	92	98	168.3	1,830	29.16	2.28	9,723	3	10%	1,186	111
Two Yucca LM6000PC Sprint, Chilled Inlet	Yuma	94	92	98	168.3	1,830	29.16	2.28	9,723	3	10%	1,186	111
5X0 LMS100PA+ Chilled Inlet, Wet Cooled	Maricopa	531	510	540	586.2	1,149	8.51	2.70	9,125	3	10%	1,113	207
5X0 LMS100PA+ Chilled Inlet, Hybrid Cooled	Maricopa	531	510	540	615.9	1,208	8.51	2.70	9,138	3	10%	1,115	141

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2017 INTEGRATED RESOURCE PLAN

[7] All inflation calculations were made using the BLS's CPI Inflation Calculator. https://data.bls.gov/cgi-bin/cpicalc.pl

Figure 1-2. Excerpt from APS IRP cited above (continued).

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ATTACHMENT D.3 – GENERATION TECHNOLOGIES (CONTINUED)

ARIZONA PUBLIC SERVICE COMPANY

Conventional Generation Technologies Assumptions													
Plant	Location	Annual Capacity (MW)	Summer Capacity (MW)	Winter Capacity (MW)	Capital Costs ($Million)	Capital Costs ($/kW)	Fixed O&M ($/kW-Yr)	Var O&M ($/MWh)	Heat Rate (BTU/kWh)	Lead Time (yrs)	Capacity Factor %	CO_2 Emission (lbs/MWh)	Water Consumption (gal/MWh)
Gas Brownfield (continued)													
5X0 LMS100PA+ Chilled Inlet, Dry Cooled	Maricopa	482	430	520	613.5	1,427	8.51	2.70	9,566	3	10%	1,167	84
3X0 LMS100PA+ Chilled Inlet, Hybrid Cooled, Redhawk	Redhawk	312	306	321	432.3	1,413	13.53	2.73	9,138	3	10%	1,115	141
3X0 LMS100PA+ Chilled Inlet, Hybrid Cooled, Sundance	Sundance	312	306	318	441.1	1,442	13.53	2.73	9,138	3	10%	1,115	141
3X0 LMS100PA+ Chilled Inlet, Hybrid Cooled, Cholla	Cholla	312	306	318	500.6	1,636	13.53	2.73	9,138	3	10%	1,115	141
Six Unit Wartsila 18V50	Maricopa	110	110	111	205.6	1,869	24.47	2.85	8,421	3	10%	985	0
2X0 P&W SP60 FT8-3 Mech Chillers	Maricopa	116	92	124	139.9	1,521	29.46	3.05	10,662	3	10%	1,301	140
Inlet Chilling RH (existing 4 GTs) versus Existing Evap Inlet	Redhawk	23	43	0	77.2	1,796	0.00	3.50	6,975	2	10%	851	80
Inlet Chilling WP5 (existing 2 GTs) versus Existing Evap Inlet	Maricopa	16	30	0	43.5	1,451	0.00	3.17	7,290	2	10%	889	40

2. APS IRP Greenfield. (2017). *APS Integrated Resource Plan 2017*. Table of generation assumptions in attachment D3, p 309. https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/2017IntegratedResourcePlan.ashx

Figure 1-3. Excerpt from APS IRP cited above. Average taken of highlighted numbers (Greenfield gas generators greater than 400 MW). The report was published in 2017, costs were assumed to be in 2017 dollars. DMM inflated the costs from 2017 to 2019 dollars.

ATTACHMENT D.3 – GENERATION TECHNOLOGIES

Conventional Generation Technologies Assumptions													
Plant	Location	Annual Capacity (MW)	Summer Capacity (MW)	Winter Capacity (MW)	Capital Costs ($Million)	Capital Costs ($/kW)	Fixed O&M ($/kW-Yr)	Var O&M ($/MWh)	Heat Rate (BTU/kWh)	Lead Time (yrs)	Capacity Factor %	CO_2 Emission (lbs/MWh)	Water Consumption (gal/MWh)
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Cholla 5 490MW IGCC	Cholla	490	455	518	2,635	5,791	23.51	3.83	10,000	9	86%	2,050	491
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Two 7F.05, Evap Inlet	Maricopa	443	431	454	327.2	759	10.08	2.28	9,959	3	10%	1,215	15
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2x1 CC 7F.05, Evap Inlet, DB On, ACC	Maricopa	802	710	869	877.3	1,236	6.53	1.82	7,149	4	50%	872	20

3. Black & Veatch. (2012). *Cost and Performance Data for Power Generation Technologies*. Prepared for the National Renewable Energy Laboratory. Table 4, page 14. Available from Energy Transition Model's online library: https://refman.energytransitionmodel.com/publications/1921/download

Figure 1-4. Excerpt from Black and Veatch report cited above. See highlighted number in the Fixed O&M column. Page 3 of the report notes that all costs are in 2009 dollars. DMM inflated the highlighted cost from 2009 to 2019 dollars.

NATIONAL RENEWABLE ENERGY LABORATORY (NREL) | COST AND PERFORMANCE DATA FOR POWER GENERATION TECHNOLOGIES

Table 4. Cost and Performance Projection for a Combined-Cycle Power Plant (580 MW)

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)	POR (%)	FOR (%)	Min. Load (%)	Spin Ramp Rate (%/min)	Quick Start Ramp Rate (%/min)
2008	1250	–	–	–	–	–	–	–	–	–
2010	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2015	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2020	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2025	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2030	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2035	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2040	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2045	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2050	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50

4. CEC 2007. (2007). Joel Klein and Anitha Rednam, *Comparative Costs of California Central Station Electricity Generation Technologies*, California Energy Commission, Electricity Supply Analysis Division, CEC-200-2007-011. Table 6: Common Assumptions, Page 18. https://ww2.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF

Figure 1-5. Excerpt from CEC report cited above. See highlighted number in the Fixed O&M column. Page 17 of the report notes that all costs are in 2007 dollars. DMM inflated the highlighted cost from 2007 to 2019 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

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5. CEC 2009. (2009). Klein, Joel. 2009. *Comparative Costs of California Central Station Electricity Generation Technologies*, California Energy Commission, CEC-200-2009-017-SD. Table 14: Plant Cost Data – Average Case, Page 54. https://ww2.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF

Figure 1-6. Excerpt from CEC report cited above. See highlighted number in the Fixed O&M column. As stated in the top left of the table all costs are in 2009 dollars. DMM inflated the highlighted cost from 2009 to 2019 dollars.

Table 14: Plant Cost Data—Average Case

Plant Cost Data Start Year = 2009 (2009 Dollars)	Gross Capacity (MW)	Instant Costs ($/kW)			Construction Period (%/Year)						Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)
		Base	Environmental Compliance	Total	Year-0	Year-1	Year-2	Year-3	Year-4	Year-5		
Small Simple Cycle	49.9	1,277	15	1,292	100%	0%	0%	0%	0%	0%	23.94	4.17
Conventional Simple Cycle	100	1,204	27	1,231	100%	0%	0%	0%	0%	0%	17.40	4.17
Advanced Simple Cycle	200	801	26	827	75%	25%	0%	0%	0%	0%	16.33	3.67
Conventional Combined Cycle (CC)	500	1,044	51	1,095	75%	25%	0%	0%	0%	0%	8.62	3.02
Conventional CC - Duct Fired	550	1,021	59	1,080	75%	25%	0%	0%	0%	0%	8.30	3.02
Advanced Combined Cycle	800	957	33	990	75%	25%	0%	0%	0%	0%	7.17	2.69
Coal - IGCC	300	3,128	56	3,184	80%	20%	0%	0%	0%	0%	52.35	9.57
Biomass IGCC	30	2,950	47	2,997	75%	25%	0%	0%	0%	0%	150.00	4.00
Biomass Combustion - Fluidized Bed Boiler	28	3,200	54	3,254	80%	20%	0%	0%	0%	0%	99.50	4.47
Biomass Combustion - Stoker Boiler	38	2,600	58	2,658	80%	20%	0%	0%	0%	0%	160.10	6.98
Geothermal - Binary	15	4,046	0	4,046	40%	40%	20%	0%	0%	0%	47.44	4.55
Geothermal - Flash	30	3,676	42	3,718	40%	40%	20%	0%	0%	0%	58.38	5.06
Hydro - Small Scale & Developed Sites	15	1,730	0	1,730	100%	0%	0%	0%	0%	0%	17.57	3.48
Hydro - Capacity Upgrade of Existing Site	80	771	0	771	100%	0%	0%	0%	0%	0%	12.59	2.39
Solar - Parabolic Trough	250	3,687	0	3,687	100%	0%	0%	0%	0%	0%	68.00	0.00
Solar - Photovoltaic (Single Axis)	25	4,550	0	4,550	100%	0%	0%	0%	0%	0%	68.00	0.00
Onshore Wind - Class 3/4	50	1,990	0	1,990	95%	5%	0%	0%	0%	0%	13.70	5.50
Onshore Wind - Class 5	100	1,990	0	1,990	95%	5%	0%	0%	0%	0%	13.70	5.50

Source: Energy Commission

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6. CEC 2014. (2014). Rhyne, Ivin, Joel Klein. 2014. *Estimated Cost of New Renewable and Fossil Generation in California*. California Energy Commission. CEC-200-2014-003-SD. Table 52: Natural Gas-Fired Technology Operation and Maintenance Costs, Page 139. https://ww2.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SD.pdf

Figure 1-7. Excerpt from page 139 of CEC report cited above. See highlighted number in the Fixed O&M column. As stated in the top left of the table all costs are in 2013 dollars. DMM inflated the highlighted cost from 2013 to 2019 dollars.

Table 52: Natural Gas-Fired Technology Operation and Maintenance Costs

O&M Costs Year = 2013 (Nominal Dollars)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Total O&M ($/kW-yr)
Mid Cost Case			
CT 49.9 MW	$28.39	$0.00	$28.39
CT 100 MW	$27.44	$0.00	$27.44
Advanced CT 200 MW	$25.24	$0.00	$25.24
CC Without Duct-Firing 500 MW	$34.56	$0.61	$37.62
CC - Duct-Firing 550 MW	$34.56	$0.61	$37.62
High Cost Case			
CT 49.9 MW	$75.16	$0.00	$75.16
CT 100 MW	$73.55	$0.00	$73.55
Advanced CT 200 MW	$69.90	$0.00	$69.90
CC Without Duct-Firing 500 MW	$82.42	$1.89	$89.06
CC - Duct-Firing 550 MW	$82.42	$1.89	$89.06
Low Cost Case			
CT 49.9 MW	$9.98	$0.00	$9.98
CT100 MW	$9.66	$0.00	$9.66
Advanced CT 200 MW	$8.93	$0.00	$8.93
CC Without Duct-Firing 500 MW	$13.79	$0.19	$14.97
CC - Duct-Firing 550 MW	$13.79	$0.19	$14.97

Source: Energy Commission.

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7. CEC 2018. (2018). Neff, Bryan. 2019. *Estimated Cost of New Utility-Scale Generation in California: 2018 Update. California Energy Commission*. Publication Number: CEC-200-2019-500. https://ww2.energy.ca.gov/2019publications/CEC-200-2019-005/CEC-200-2019-005.pdf

Figure 1-8. Excerpt from CEC report cited above. See highlighted number in the Fixed O&M row. As stated in the top left of the table all costs are in 2018 dollars. DMM inflated the highlighted cost from 2018 to 2019 dollars.

Table B-23 shows O&M costs for the combined-cycle technology.

Table B-23: O&M Costs for Combined-Cycle Cases

Technology (Nominal 2018 $)	Mid Case	High Case	Low Case
Conventional 640 MW CC Without Duct Firing			
Fixed O&M ($/kW-year)	$41.77	$93.91	$17.00
Variable O&M ($/MWh)	$0.82	$2.37	$0.25
Total O&M ($/MWh)	$9.18	$21.18	$3.66
Conventional 700 MW CC With Duct Firing			
Fixed O&M ($/kW-year)	$41.77	$93.91	$17.00
Variable O&M ($/MWh)	$0.82	$2.37	$0.25
Total O&M ($/MWh)	$9.18	$21.18	$3.66

Source: California Energy Commission

Table B-24 shows O&M costs for combustion turbine technology.

Table B-24: O&M Costs for Combustion Turbine Cases

Technology (Nominal 2018 $)	Mid Case	High Case	Low Case
Conventional 49.9 MW CT			
Fixed O&M ($/kW-year)	$34.42	$85.79	$12.26
Variable O&M ($/MWh)	$0.00	$0.00	$0.00
Total O&M ($/MWh)	$98.22	$244.84	$34.99
Conventional 100 MW CT			
Fixed O&M ($/kW-year)	$33.24	$83.94	$11.86
Variable O&M ($/MWh)	$0.00	$0.00	$0.00
Total O&M ($/MWh)	$94.88	$239.56	$33.85
Advanced 200 MW CT			
Fixed O&M ($/kW-year)	$30.54	$79.70	$10.96
Variable O&M ($/MWh)	$0.00	$0.00	$0.00
Total O&M ($/MWh)	$49.81	$129.97	$17.87

Source: California Energy Commission

Table B-25 summarizes instant, installed, and levelized costs for natural gas-fired technologies in 2018 in nominal (2016) dollars. (Note: The high and low values are based on the 10 percentile and 90 percentile values for the evaluated projects.)

B-25

8. E3. (2017). *Review of Capital Costs for Generation Technologies.* Fixed O&M Recommendations table, page 67. Retrieved form WECC.org: https://www.wecc.org/Reliability/E3_WECC_CapitalCosts_FINAL.pdf

Figure 1-9. Excerpt from E3 report cited above. See highlighted number in the Fixed O&M column. As stated on page 3 of the report all costs are in 2016 dollars. DMM inflated the highlighted cost from 2016 to 2019 dollars.

Fixed O&M Recommendations

Updated

Technology	Subtypes	Fixed O&M ($/kW-yr.)
CHP	Small	$10
	Large	$10
Coal	Steam	$35
	IGCC with CCS	$65
Gas CT	Aeroderivative	$15
	Frame	$9
Gas CCGT	Basic – Wet-Cooled	$10
	Basic – Dry-Cooled	$10
	Advanced – Wet-Cooled	$10
	Advanced – Dry-Cooled	$10
Nuclear		$85
Recip Engine		$18

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9. EIA 2016. (2016). *Capital Cost Estimates for Utility Scale Electricity Generating Plants.* Retrieved from EIA website: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf

Figure 1-10 . Excerpt from EIA report cited above. See highlighted number in the Fixed O&M column. As stated on page 2 of the report all costs are in 2016 dollars. DMM inflated the highlighted cost from 2016 to 2019 dollars.

November 2016

Table 1. Updated estimates of power plant capital and operating costs

	Plant Characteristics		Plant Costs (2016$)			
Technology	Nominal Capacity (MW)	Heat Rate (Btu/kWh)	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	NEMS Input
Coal						
Ultra Supercritical Coal (USC)[10]	650	8,800	3,636	42.1	4.6	N
Ultra Supercritical Coal with CCS (USC/CCS)[11]	650	9,750	5,084	70	7.1	Y
Pulverized Coal Conversion to Natural Gas (CTNG)	300	10,300	226	22	1.3	N
Pulverized Coal Greenfield with 10-15 percent	300	8,960	4,620	50.9	5	N
Pulverized Coal Conversion to 10 percent biomass –	300	10,360	537	50.9	5	Y
Natural Gas						
Natural Gas Combined Cycle (NGCC)	702	6,600	978	11	3.5	Y
Advanced Natural Gas Combined Cycle (ANGCC)[13]	429	6,300	1,104	10	2	Y
Combustion Turbine (CT)	100	10,000	1,101	17.5	3.5	Y
Advanced Combustion Turbine (ACT)	237	9,800	678	6.8	10.7	Y
Reciprocating Internal Combustion Engine (RICE)	85	8,500	1,342	6.9	5.85	N
Uranium						
Advanced Nuclear (AN)	2,234	N/A	5,945	100.28	2.3	Y
Biomass						
Biomass (BBFB)	50	13,500	4,985	110	4.2	N
Wind						
Onshore Wind (WN)	100	N/A	1,877	39.7	0	Y
Solar						
Photovoltaic – Fixed	20	N/A	2,671	23.4	0	N
Photovoltaic – Tracking	20		2,644	23.9	0	N
Photovoltaic – Tracking	150	N/A	2,534	21.8	0	Y
Storage						
Battery Storage (BES)	4	N/A	2,813	40	8	N

10. EIA 2019. (2019). *Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2019.* Table 2, page 5. Retrieved from EIA website:
https://www.eia.gov/outlooks/archive/aeo19/assumptions/pdf/electricity.pdf

Figure 1-11. Excerpt from EIA report cited above. See highlighted number in the Fixed O&M column. As stated in the Fixed O&M column header costs are in 2018 dollars. DMM inflated the highlighted cost from 2018 to 2019 dollars.

February 2019

Table 2. Cost and performance characteristics of new central station electricity generating technologies

Technology	First available year[1]	Size (MW)	Lead time (years)	Base overnight cost (2018 $/kW)	Project contingency factor[2]	Techno-logical optimism factor[3]	Total overnight cost[4,10] (2018 $/kW)	Variable O&M[5] (2018 $/MWh)	Fixed O&M (2018$/ kW/yr)	Heat rate[6] (Btu/ kWh)	Final heat rate (Btu/kWh)
Coal with 30% carbon sequestration (CCS)	2022	650	4	4,713	1.07	1.03	5,169	7.31	72.12	9,750	9,221
Coal with 90% CCS	2022	650	4	5,212	1.07	1.03	5,716	9.89	83.75	11,650	9,257
Conv gas/oil combined cycle (CC)	2021	702	3	952	1.05	1.00	999	3.61	11.33	6,600	6,350
Adv gas/oil CC	2021	1,100	3	736	1.08	1.00	794	2.06	10.30	6,300	6,200
Adv CC with CCS	2021	340	3	1,963	1.08	1.04	2,205	7.34	34.43	7,525	7,493
Internal combustion engine	2020	85	2	1,306	1.05	1.00	1,371	6.03	7.11	8,500	8,160
Conv combustion turbine[7]	2020	100	2	1,072	1.05	1.00	1,126	3.61	18.03	9,840	9,600
Adv combustion turbine	2020	237	2	658	1.05	1.00	691	11.02	7.01	9,800	8,550
Fuel cells	2021	10	3	6,250	1.05	1.10	7,197	46.56	0.00	9,500	6,960
Adv nuclear	2022	2,234	6	5,224	1.10	1.05	6,034	2.37	103.31	10,461	10,461
Distributed generation—base	2021	2	3	1,501	1.05	1.00	1,576	8.40	18.90	8,958	8,900
Distributed generation—peak	2020	1	2	1,804	1.05	1.00	1,894	8.40	18.90	9,948	9,880
Battery storage	2019	30	1	1,857	1.05	1.00	1,950	7.26	36.32	NA	NA
Biomass	2022	50	4	3,642	1.07	1.00	3,900	5.70	114.39	13,500	13,500
Geothermal[8,9]	2022	50	4	2,654	1.05	1.00	2,787	0.00	122.28	NA	NA
MSW—landfill gas	2021	50	3	8,313	1.07	1.00	8,895	9.47	425.38	18,000	18,000
Conventional hydropower[9]	2022	500	4	2,680	1.10	1.00	2,948	1.36	40.85	NA	NA
Wind[10]	2021	100	3	1,518	1.07	1.00	1,624	0.00	48.42	NA	NA
Wind offshore[8]	2022	400	4	4,758	1.10	1.25	6,542	0.00	80.14	NA	NA
Solar thermal[8]	2021	100	3	4,011	1.07	1.00	4,291	0.00	72.84	NA	NA
Solar PV— tracking[8,10,11]	2020	150	2	1,876	1.05	1.00	1,969	0.00	22.46	NA	NA
Solar PV—fixed tilt[8,10,11]	2020	150	2	1,698	1.05	1.00	1,783	0.00	22.46	NA	NA

11. HDR (in PGE IRP). (2018). *Thermal and Pumped Storage Generation Options*. Project prepared for Portland General Electric. Table 3-11-1. NG Plant Fixed and Variable Operating Costs, page 29. Retrieved from https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/sso-thermal-pumped-hydro-hdr-2018.pdf?la=en

Figure 1-12. Excerpt from HDR report cited above. See highlighted number in the Fixed O&M row. As stated in the upper left column header costs are in 2018 dollars. DMM inflated the highlighted cost from 2018 to 2019 dollars.

Table 3.11-1. NG Plant Fixed and Variable Operating Costs

Operating Costs, 2018 $, Degraded		1x0 96 MW Aero SC	1x0 356 MW Frame SC	1x1 517 MW Frame CC	6x0 109 MW RICE (1 Unit)
Summer					
Fixed O&M	$/kW-yr	5.61	2.10	6.57	5.15
Variable O&M	$/MWH	5.20	9.69	3.57	5.42

Additional breakdown of the O&M costs are included in the modeling input tabs in Appendix E.

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12. Lazard. (2017). *Lazard's Levelized Cost of Energy Analysis: Version 11.0*. Table of Key Assumptions, page 20. Retrieved from Lazard website: https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf

Figure 1-13. Excerpt from Lazard report cited above. See highlighted range in the Fixed O&M row. DMM took the mid-point of these numbers at $5.85/kW-yr. The report was published in 2017, DMM is assuming 2017 dollars. DMM inflated the mid-point $5.85/kW-yr cost from 2017 to 2019 dollars.

LAZARD'S LEVELIZED COST OF ENERGY ANALYSIS—VERSION 11.0

Levelized Cost of Energy—Key Assumptions (cont'd)

	Units	Diesel Reciprocating Engine [3]	Natural Gas Reciprocating Engine	Gas Peaking	IGCC [4]	Nuclear [5]	Coal [6]	Gas Combined Cycle
Net Facility Output	MW	1 – 0.25	1 – 0.25	241 – 50	580	2,200	600	550
EPC Cost	$/kW	$500 – $800	$650 – $1,100	$530 – $700	$3,400 – $12,900	$4,900 – $8,900	$2,000 – $6,100	$400 – $1,000
Capital Cost During Construction	$/kW	—	—	—	$800 – $3,250	$1,300 – $2,400	$500 – $1,600	$0 – $100
Other Owner's Costs	$/kW	included	included	$220 – $300	$0 – $0	$292 – $501	$500 – $700	$200 – $200
Total Capital Cost [1]	$/kW	$500 – $800	$650 – $1,100	$750 – $1,000	$4,175 – $16,200	$6,500 – $11,800	$3,000 – $8,400	$700 – $1,300
Fixed O&M	$/kW-yr	$10.00	$15.00 – $20.00	$5.00 – $20.00	$73.00	$135.00	$40.00 – $80.00	$6.20 – $5.50
Variable O&M	$/MWh	$10.00	$10.00 – $15.00	$4.70 – $10.00	$8.50	$0.75	$2.00 – $5.00	$3.50 – $2.00
Heat Rate	Btu/kWh	9,500 – 10,000	8,000 – 10,000	9,804 – 8,000	11,708 – 11,700	10,450	8,750 – 12,000	6,133 – 6,900
Capacity Factor	%	95% – 10%	95% – 30%	10%	75%	90%	93%	80% – 40%
Fuel Price	$/MMBtu	$18.23	$5.50	$3.45	$0.65	$0.85	$1.47	$3.45
Construction Time	Months	3	3	12 – 18	57 – 63	69	60 – 66	24
Facility Life	Years	20	20	20	40	40	40	20
CO_2 Emissions	lb/MMBtu	0 – 117	117	117	169	—	211	117
Levelized Cost of Energy [2]	$/MWh	$197 – $281	$68 – $106	$156 – $210	$96 – $231	$112 – $183	$60 – $143	$42 – $78

Source: Lazard estimates.
(1) Includes capitalized financing costs during construction for generation types with over 24 months construction time.
(2) While prior versions of this study have presented LCOE inclusive of the U.S. Federal Investment Tax Credit and Production Tax Credit, Versions 6.0 – 11.0 present LCOE on an unsubsidized basis.
(3) Low end represents continuous operation. High end represents intermittent operation. Assumes diesel price of ~$2.50 per gallon.
(4) Incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.
(5) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(6) Reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. High end incorporates 90% carbon capture and compression. Does not include cost of storage and transportation.

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13. NETL. (2015). *Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity,* Revision 3. Exhibit 4-16, Page 192. Retrieved from: https://www.netl.doe.gov/projects/files/CostandPerformanceBaselineforFossilEnergyPlantsVolume1aBitCoalPCandNaturalGastoElectRev3_070615.pdf

Figure 1-14. Excerpt from NETL report cited above. In the "Fixed Operating Costs" box the Total is approx. $15.8m and Property Taxes are approx. $8.6m. Subtracting Property Tax from Total, $15.8m - $8.6m = $7.2m for the Fixed O&M portion of the NETL cost estimate. Dividing $7.2m by the 630 MW of the plant equals $11,500/MW-yr. DMM converted this number to $/kW-yr by dividing by 1,000. This equates to Fixed O&M of $11.53/kW-year, which is what DMM has graphed for NETL.

Cost and Performance Baseline for Fossil Energy Plants Volume 1: Revision 3

Exhibit 4-16 Case B31A initial and annual operating and maintenance costs

Case:	B31A – 2x1 CT NGCC w/o CO_2				Cost Base:	Jun 2011
Plant Size (MW,net):	630	Heat Rate-net (Btu/kWh):		6,629	Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		39.70	$/hour	Skilled Operator:		1.0
Operating Labor Burden:		30.00	% of base	Operator:		2.0
Labor O-H Charge Rate:		25.00	% of labor	Foreman:		1.0
				Lab Tech's, etc.:		1.0
				Total:		5.0
Fixed Operating Costs						
					Annual Cost	
					($)	($/kW-net)
Annual Operating Labor:					$2,260,518	$3.591
Maintenance Labor:					$3,551,114	$5.641
Administrative & Support Labor:					$1,452,908	$2.308
Property Taxes and Insurance:					$8,618,615	$13.691
Total:					$15,883,155	$25.230
Variable Operating Costs						
					($)	($/MWh-net)
Maintenance Material:					$5,326,671	$1.13636
Consumables						
	Consumption				Cost ($)	
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (/1000 gallons):	0	1,905	$1.67	$0	$989,284	$0.21105
Makeup and Waste Water Treatment Chemicals (lbs):	0	11,348	$0.27	$0	$943,019	$0.20118
SCR Catalyst (m^3):	w/equip.	0.08	$8,938.80	$0	$229,246	$0.04891
Ammonia (19% NH_3, ton):	0	3.05	$330.00	$0	$311,902	$0.06654
Subtotal:				$0	$2,473,451	$0.52767
Variable Operating Costs Total:				$0	$7,800,123	$1.66404
Fuel Cost						
Natural Gas (MMBtu):	0	100,384	$6.13	$0	$190,912,983	$40.72840
Total:				$0	$190,912,983	$40.72840

14. NREL. (2019). *Annual Technology Baseline: Electricity.* LCOE Summary Table 2017-R&D Only. Retrieved on 4/2/2020 from the NREL website: https://atb.nrel.gov/electricity/2019/summary.html

Figure 1-15. Excerpt from NREL's website as cited above. See the highlight in the Fixed O&M column. As stated in the table title costs are in 2017 dollars. DMM inflated the highlighted cost from 2017 to 2019 dollars.

LCOE Summary Table 2017-R&D Only

		CF Range		CAPEX Range				OPEX	LCOE Range	
	Technology	Min. (%)	Max. (%)	Min. ($/kW)	Max. ($/kW)	Fuel Costs ($/MWh)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Min. ($/MWh)	Max. ($/MWh)
										Dispatchable
Coal	PC	54%	85%	$4.036	$4,036	$ 18	$ 33	$ 5	$ 69	$ 95
	IGCC	54%	85%	$4,409	$4,409	$ 18	$ 54	$ 8	$ 78	$ 108
	CCS-30%	54%	85%	$5,633	$5,633	$ 20	$ 69	$ 7	$ 94	$ 132
	CCS-90%	54%	85%	$6,229	$6,229	$ 24	$ 80	$ 10	$ 108	$ 151
Natural Gas	CT	7%	30%	$ 919	$ 919	$ 33	$ 12	$ 7	$ 64	$ 148
	CC	51%	87%	$927	$927	$ 22	$ 11	$ 3	$ 33	$ 38
	CC-CCS	51%	87%	$2,292	$2,292	$ 25	$ 34	$ 7	$ 54	$ 68
	Nuclear	92%	92%	$6,742	$6,742	$ 7	$ 101	$ 2	$ 67	$ 67
	Biopower	56%	56%	$3,990	$4,184	$ 41	$ 112	$ 6	$ 86	$ 112
	Geothermal	80%	90%	$4,681	$35,813	$ 0	$ 135	$ 0	$ 78	$ 618
	CSP with 10-hr TES	50%	64%	$7,330	$7,330	$ 0	$ 66	$ 4	$ 115	$ 144
										Non-Dispatchable
Wind	Land-based	10%	48%	$1,610	$1,610	$ 0	$ 44	$ 0	$ 30	$ 143
	Offshore	28%	51%	$3,774	$6,323	$ 0	$ 87	$ 0	$ 90	$ 192
Photovoltaic	Utility	15%	27%	$1,308	$2,328	$ 0	$ 20	$ 0	$ 33	$ 59
	Commercial	12%	20%	$1,857	$1,857	$ 0	$ 18	$ 0	$ 66	$ 109
	Residential	13%	21%	$2,770	$2,770	$ 0	$ 23	$ 0	$ 91	$ 150
	Hydropower	60%	64%	$4,022	$7,469	$ 0	$ 43	$ 0	$ 37	$ 72

15. PacifiCorp IRP. (2019). *PacifiCorp Integrated Resource Plan 2019*. Gas-Fueled Supply Side Resource Table Update, Table 7-1 Summary of Natural Gas-Fueled Supply Side Options, page 7-2. https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019-irp/2019-irp-support-and-studies/Gas-Fueled_Supply_Side_Resource_Table_Update_for_the_2019_Integrated_Resource.pdf

Figure 1-16. Excerpt from PacifiCorp table cited above. Average taken of highlighted numbers (combined cycle gas generators). Page 2-1 of the report states all dollars are 2018. DMM then inflated the average of the three highlighted numbers from 2018 to 2019 dollars.

PacifiCorp | GAS-FUELED SUPPLY SIDE RESOURCE TABLE UPDATE

Table 7-1 Summary of Natural Gas-Fueled Supply Side Options

Option	1	2	3	3B	4	5	6	7	8
Greenfield?	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes
CTG/RICE Make	GE	GE	GE	GE	Wartsila	GE	GE	GE	GE
CTG/RICE Model	LM6000PF Sprint	LMS100PA+	7F.05	7F.05	18V50SG	7HA.01	7HA.01	7HA.01	7HA.01
Number of CTG/RICE	3	2	1	1	6	1	1	2	2
Simple Cycle or Combined Cycle (SC or CC)	SC	SC	SC	SC	SC	CC	CC	CC	CC
Duct Firing?	n/a	n/a	n/a	n/a	n/a	No	Yes	No	Yes
Nominal Net Output, MW	142.0	231.3	233.1	233.1	110.6	418.6	469.6	839.9	941.9
Nominal Net Heat Rate, Btu/kWh (HHV)	9,279	8,725	9,811	9,811	8,272	6,450	6,649	6,428	6,620
EPC Capital Cost, $	$145M	$171M	$98M	$95M	$127M	$449M	$469M	$641M	$670M
EPC Capital Cost, $/kW	$1,024	$740	$422	$408	$1,148	$1,073	$999	$763	$711
Fixed O&M, $/kW-yr	$15.0	$9.5	$8.4	$3.0	$15.6	$8.6	$7.7	$5.6	$5.1
Variable Non-fuel O&M, $/MWh	$8.4	$5.3	$12.1	$12.1	$9.3	$1.7	$1.5	$1.6	$1.5

Option	8B	9	10	11	12
Greenfield?	No	Yes	Yes	Yes	Yes
CTG/RICE Make	GE	GE	GE	GE	GE
CTG/RICE Model	7HA.01	7HA.02	7HA.02	7HA.02	7HA.02
Number of CTG/RICE	2	1	1	2	2
Simple or Combined Cycle	CC	CC	CC	CC	CC
Duct Firing?	Yes	No	Yes	No	Yes
Nominal Output, MW	941.9	539.3	602.6	1,082.9	1,208.9
Nominal Heat Rate, Btu/kWh (HHV)	6,620	6,396	6,580	6,370	6,543
EPC Capital Cost, $	$663M	$484M	$505M	$691M	$722M
EPC Capital Cost, $/kW	$704	$898	$838	$638	$597
Fixed O&M, $/kW-yr	$2.9	$6.9	$6.3	$4.6	$4.3
Variable Non-fuel O&M, $/MWh	$1.5	$1.5	$1.4	$1.5	$1.4

BLACK & VEATCH | Summary of Findings 7-2

16. PGE IRP GE. (2015). Portland General Electric. (2015). *Integrated Resource Plan 2016*. Presented at the Public Meeting #2, Portland, OR, USA. Average of GE combined cycle plants in table on page 137. Retrieved from https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2015-07-16-public-meeting.pdf

Figure 1-17. Excerpt from PGE IRP cited above. Average taken of highlighted numbers (GE combined cycle generators). The upper left of the table states the costs are in 2015 dollars. DMM inflated the GE Fixed O&M costs from 2015 to 2019 dollars.

CCCT – Options

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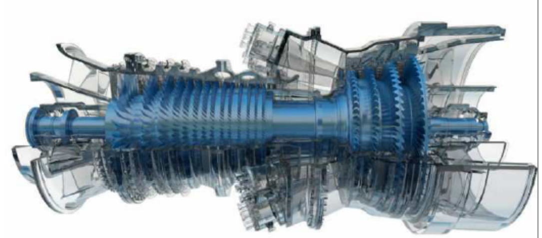
7 CCCT Configurations

(2015$)	Net Capacity MW	Heat Rate Btu/kWh	Overnight Capital $/kW	Fixed O&M $/kW-yr	Non-fuel VOM $/MWh
GE 7F.05	330	6809	$ 981	$ 9.60	$ 2.87
Siemens SGT6-5000F5ee	352	6902	$ 945	$ 9.05	$ 3.16
MPS 501G	365	6926	$ 1,000	$ 8.93	$ 3.00
GE 7HA.01	400	6503	$ 944	$ 8.26	$ 2.60
2x1 GE 7HA.02	810	6485	$ 873	$ 6.02	$ 2.29
Siemens SGT6-8000H	429	6644	$ 927	$ 7.58	$ 2.86
MPS 501J	442	6564	$ 896	$ 7.34	$ 3.02



GE 7HA.01

Portland General Electric

17. PGE IRP Siemens. (2015). Portland General Electric. (2015). *Integrated Resource Plan 2016.* Presented at the Public Meeting #2, Portland, OR, USA. Average of Siemens combined cycle plants in table on page 137. Retrieved from https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2015-07-16-public-meeting.pdf

Figure 1-18. Excerpt from PGE IRP cited above. Average taken of highlighted numbers (Siemens combined cycle generators). The upper left of the table states the costs are in 2015 dollars. DMM inflated the Siemens Fixed O&M costs from 2015 to 2019 dollars.

CCCT – Options

April 2, 2015 Slide 137

7 CCCT Configurations

(2015$)	Net Capacity MW	Heat Rate Btu/kWh	Overnight Capital $/kW	Fixed O&M $/kW-yr	Non-fuel VOM $/MWh
GE 7F.05	330	6809	$ 981	$ 9.60	$ 2.87
Siemens SGT6-5000F5ee	352	6902	$ 945	$ 9.05	$ 3.16
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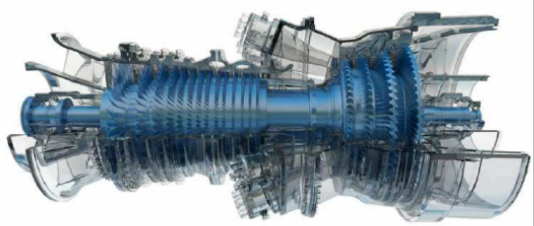

GE 7HA.01

Portland General Electric

18. PSE IRP. (2016). *2017 PSE Integrated Resource Plan*. Page 4-32, Figure 4-18: New Resource Cost Assumptions. Retrieved from: https://www.pse.com/-/media/PDFs/001-Energy-Supply/001-Resource-Planning/8a_2017_PSE_IRP_Chapter_book_compressed_110717.pdf

Figure 1-19. Excerpt from PGE IRP cited above. See highlighted number in the Fixed O&M column. As stated in the upper left column header costs are in 2016 dollars. DMM inflated the highlighted cost from 2016 to 2019 dollars.

Chapter 4: Key Analytical Assumptions

Figure 4-18: New Resource Cost Assumptions

IRP Modeling Assumptions (2016 $)	Name-plate (MW)	First year available	Capacity Factor[1] (%)	Overnight Capital Cost ($/kw)	Fixed O&M [2] ($/kw-yr)	Variable O&M ($/MWh)	Baseload Heatrate[3] (Btu/kWh)
F-Class CCCT 1x1 with DF	413	2022	N/A	$1,267	$8.10	$2.50	6,650
Frame Peaker Duel-Fueled 1x0 with Oil Back-up	239	2021	N/A	$639	$11.23	$0.95	9.823
Frame Peaker NG only 1x0	239	2021	N/A	$571	$6.40	$0.95	9.823
Aero Peaker Duel-Fueled 2x0 with Oil Back-up	227	2021	N/A	$1,070	$10.92	$10.20	8,986
Aero Peaker NG only 2x0	227	2021	N/A	$1,004	$6.50	$10.20	8,986
Recip Peaker Duel-Fueled 12x0 with Oil Back-up	202	2021	N/A	$1,477	$10.70	$7.80	8,527
Recip Peaker NG only 12x0	222	2021	N/A	$1,277	$6.50	$7.80	8,425
Wind Plant - Washington	100	2020	30%	$1,939	$27.12	$3.15	N/A
Wind Plant - Montana	300	2022	46%	$2,065	$33.79	$3.50	N/A
Offshore Wind	100	2022	35%	$7,150	$77.30	$3.15	N/A
Central Station Solar Tracking PV	25	2020	26%	$2,041	$10.00	$0.00	N/A
Biomass	15	2021	85%	$3,950	$113.70	$5.66	N/A
2-hour Lithium Ion Battery	25	2019	N/A	$1,514	$23.68	$0.00	N/A
4-hour Lithium Ion Battery	25	2019	N/A	$2,439	$36.49	$0.00	N/A
4-hour Flow Battery	25	2019	N/A	$2,324	$26.82	$0.00	N/A
6-hour Flow Battery	25	2019	N/A	$3,042	$23.40	$0.00	N/A
Pumped Storage Hydro	25	2030	N/A	$2,400	$15.00	$0.00	N/A

NOTES
1. Expected factor for wind, solar and Biomass; for thermal resources, the capacity factor is dependent on dispatch cost for the scenario.
2. Fixed O&M with oil backup includes the cost for 48 hours worth of oil.
3. Heat rate for CCCT is for the primary unit, the heat rate for the secondary duct firing is expected to be 8,500 Btu/kWh.

4 - 32 PSE 2017 IRP

19. Xcel CO IRP. (2016). *Public Service Company of Colorado 2016 Electric Resource Plan Volume 2*. Table 2.7-10, Fixed O&M for a 700 MW Combined Cycle. Retrieved from Xcel Energy: https://www.xcelenergy.com/staticfiles/xe/PDF/Attachment%20AKJ-2.pdf

Figure 1-20. Excerpt from Xcel's IRP as cited above. DMM calculated Fixed O&M ($/kW-yr) by dividing the Fixed O&M cost (highlighted below) by the Nameplate Capacity (also highlighted). This equals $8.07/kW-yr. As noted in the footnotes for the table "All costs in year 2015 dollars." DMM inflated $8.07/kW-yr from 2015 to 2019 dollars.

Table 2.7-10 Generic Dispatchable Resource Cost and Performance

Dispatchable Resources 1,2	2x1 CC [6,7]	1x1 CC [6,8]	Large CT [9]	LMS CT [10]	Aeroder. CT [11]
Nameplate Capacity (MW)	700	329	205	94	40
Summer Duct Firing Capacity (MW)	101	44	NA	NA	NA
Summer Peak Capacity (MW)	658	289	192	80	31
Fuel Source [3]	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas
Cooling	Dry	Dry	Dry	Dry	Dry
Capital Cost ($/kW) [4]	$843	$1,145	$610	$1,375	$1,988
Book Life	40	40	40	40	40
Fixed O&M Cost ($000/yr) [4]	$5,650	$3,421	$464	$640	$414
Variable O&M Cost ($/MWh)	$0.39	$0.44	$1.28	$1.17	$2.08
Ongoing Capital Expenditures	$3,509	$1,892	$1,692	$192	$110
Heat Rate with Duct Firing	7,839	NA	NA	NA	NA
Heat Rate 100% Loading	6,925	8,492	9,955	9,146	9,635
Heat Rate ~75% Loading	7,011	7,004	11,079	10,145	11,456
Heat Rate ~50% Loading	7,149	7,391	14,661	11,761	14,904
Heat Rate ~30% Loading	8,139	7,732	NA	16,092	23,291
Forced Outage Rate	3%	3%	3%	2%	3%
Maintenance (wks/yr)	3	3	2	2	2
Typical Capacity Factor	37%	37%	9%	10%	10%
CO2 Emissions (lbs/MMBtu)	118	118	118	118	118

Notes:

(1) All Costs in year 2015 dollars

(2) Thermal unit cost and performance characteristics are from Xcel Energy Services and other sources such as CERA, EPRI, and EIA

(3) For all units, a firm fuel charge of $6.16/kW-yr (levelized) has been applied

(4) Estimates of generic capital and fixed O&M costs are based on the midpoint between the costs of a greenfield EPC facility and those of a brownfield facility. Brownfield costs are estimated by removing certain cost items from the greenfield estimate but costs for an actual brownfield facility are very site specific. To estimate the midpoint costs for combined cycle units, greenfield capital and fixed O&M costs have beem reduced by 7.5% and 20% respectively from greenfield costs. To estimate the midpoint costs for combustion turbine units, greenfield capital and fixed O&M costs have been reduced by 12.5% and 20% respectively.

(5) For combined cycle units, modeled heat rates are the average of winter and summer values. For combustion turbine units, modeled heat rates represent the summer values.

(6) For all combined cycle units, a levelized $25/kW-yr charge has been applied to estimate transmission interconnection costs

(7) Based on Siemens 5000F 2x1 CC

(8) Based on GE 7FA 1x1 CC

(9) Based on Siemens 5000F SC

(10) Based on GE LMS 100

(11) Based on GE LMS 6000

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PUBLIC SERVICE COMPANY OF COLORADO — PAGE 2-197

20. SNL Average. (2019). Data downloaded from SNL's online screener tool. S&P Global Market Intelligence. Data reprinted as shown with permission from S&P. https://platform.mi.spglobal.com (subscription required).

Attachment 2

Calpine's 2017 Reliability Must Run Contract Submission

Calpine's unexecuted Reliability Must-Run Service Agreement submitted in November 2017 contained annual financial data for the 593 MW Metcalf Energy Center. [8] Schedule F includes the three components of going forward fixed costs: fixed O&M, *ad valorem* and insurance. As shown in excerpts from Schedule F provided below:

- The unit's Fixed O&M value from line 126 is $13,946,589.
- The unit's annual property taxes (*ad valorem*) on line 30 is $2,081,206.
- Line 21 shows Administrative and General Expenses of $3,032,016. The ISO's tariff defines Administrative and General Expenses[9] as any expenses recorded in FERC's Uniform System of Accounts 920-935. FERC's USA number 924 pertains to Property Insurance.[10] Therefore, DMM assumes that all of the A&G expenses from line 26 represent annual insurance expenses.

Together the Fixed O&M, *ad valorem* and A&G expenses from Calpine's RMR filing total $19,059,813. Divided by the 593 MW capacity of the Metcalf Energy Center, this equates to $32.13/kW-year of going forward fixed costs.

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[8] Metcalf Energy Center, LLC submits tariff filing per 35.12: Metcalf RMR Agreement Filing to be effective 1/1/2018 under ER18-240. November 2, 2017. https://elibrary.ferc.gov/IDMWS/common/OpenNat.asp?fileID=14741407

[9] CAISO Tariff Appendix G, Article II, Section 2, subsection (A), definition (4) Administrative and General (A&G) Expenses.

[10] 18 CFR Part 101 – Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act. Operation and Maintenance Expense Chart of Accounts, Section 8, Account 924 Property Insurance.

Metcalf Energy Center
Schedule F
Contract Year 2018

			Schedule F, Article II Part B: Determination of Annual Revenue Requirement				
			Section 1. Annual Fixed Revenue Requirements and Variable O&M Rate				
1	(A)	(1)	Total Annual Revenue Requirements		**$**	**150,081,155**	
2	(A)	(2)	(less) Total Annual Variable Costs	(-)	$	77,620,453	
3	(A)		Annual Fixed Revenue Requirement	=			$ 72,460,702
4							
5	(B)	(1)	Annual Variable O&M Expenses		$	3,667,172	
6	(B)	(2)	Annual Net Generation (MWh)	(÷)		2,412,041	
7	(B)		Variable O&M Rate ($/MWH)	=			$ 1.52
8							
9	(C)	(1)	Operating Expenses, Section 2		$	110,287,583	
10	(C)	(2)	Return and Income Tax Allowance, Section 3	(+)	$	39,793,572	
11	(C)		Total Annual Revenue Requirement	=			**$ 150,081,155**
12							
13			**Section 2. Operating Expenses**				
14	(A)	(1)	Production O&M Expense				
15	(A)	(1)	(a)Steam Production O&M		$	-	
16	(A)	(1)	(b)Hydro Production O&M		$	-	
17	(A)	(1)	(c)Other Power Generation O&M		$	88,583,891	
18	(A)	(1)	(d)Other Power Supply Expenses		$	-	
19	(A)	(2)	Transmission O&M Expenses		$	-	
20	(A)	(3)	Distribution O&M Expenses		$	-	
21	(A)	(4)	Administrative and General (A&G) Expenses	(+)	$	3,032,016	
22	(A)		Total O&M Expenses	=			$ 91,615,907
23							
24	(B)	(1)	Production Plant Depreciation		$	15,755,767	
25	(B)	(2)	Transmission Plant Depreciation		$	-	
26	(B)	(3)	Distribution Plant Depreciation		$	-	
27	(B)	(4)	General and Intangible Plant Depreciation		$	623,144	
28	(B)		Depreciation Expenses	=			$ 16,378,911
29							
30	(C)	(1)	Property and Property-Related Taxes		$	2,081,208	
31	(C)	(2)	Payroll and Labor-Related Taxes	(+)	$	198,894	
32	(C)	(3)	Other Taxes	(+)	$	12,663	
33	(C)		Taxes Other Than Income Taxes	=			$ 2,292,765
34							
35	(D)		Revenue Credits (show as negative)				$ -
36	(E)		Treatment of Capital Leases				$ -
37							
38	(F)		Total Operating Expenses	(A+B+C+D+E)			$ 110,287,583
39							

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87		**Section 5. Allowable Pre-Tax Rate of Return**				
88	(A)	Base Pre-Tax Rate of Return				**12.25%**
89	(B)	Plus 30% of Increase, if any, in Yield			0%	
90		on 10-Year U.S Treasury Bonds		x	30%	
91						12.25%
92						
93		Allowable Pre-Tax Rate of Return				**12.25%**
94						
95		1 10 Year U.S. Treasury Bond Rates (6 month average)				
96		2 As of Effective Date of Settlement				
97		3	Dec-98		4.65%	
98		4	Jan-99		4.72%	
99		5	Feb-99		5.00%	
100		6	Mar-99		5.23%	
101		7	Apr-99		5.18%	
102		8	May-99		5.54%	
103		9				5.05%
104		10 Latest Available				
105		11	Jul-17		2.34%	
106		12	Jun-17		2.19%	
107		13	May-17		2.30%	
108		14	Apr-17		2.18%	
109		15	Mar-17		2.48%	
110		16	Feb-17		2.42%	
111		17				2.32%
112		18 Increase in 6-month Average, if any:				0.00%
113						
114		**Section 6. Additional Quantities**				
115	(A) (1)	Variable Production O&M Expenses			$ 3,667,172	
116	(A) (2)	Variable A&G Expenses			$ -	
117	(A)	Annual Variable O&M Expenses		=		$ 3,667,172
118						
119	(B) (1)	Total O&M Expenses			$ 91,615,907	
120	(B) (2)	Less the Sum of				
121	(B)	a	Annual Variable O&M Expenses	(-)	$ 3,667,172	
122	(B)	b	Annual Variable Fuel Costs	(-)	$ 61,798,462	
123	(B)	c	Annual Emission Costs	(-)	$ 12,154,819	
124	(B)	d	Annual Non-Fuel Start-Up Costs	(-)	$ 48,865	
125	(B)					
126	(B)	Annual Fixed O&M Expenses		=		$ 13,946,589
127						
128	(C)	Fuel Expenses				
129	(C) (1)	Total Annual Fuel Costs			$ 61,798,462	
130	(C) (2)	Annual Fixed Fuel Costs		(-)	$ -	
131	(C) (3)	Annual Variable Fuel Costs		=		$ 61,798,462
132						
133	(D)	Annual Emission Costs				$ 12,154,819

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