Powers Engineering

July 22, 2010

The Honorable Mary Nichols, Chairman
Mr. James Goldstene, Executive Officer
Mr. Dave Mehl
Mr. Gary Collord
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject: Proposed Regulation for California Renewable Energy Standard

Dear Ms. Nichols, Mr. Goldstene, Mr. Mehl, and Mr. Collord:

Powers Engineering has been very involved in California Energy Commission (CEC) renewable energy and natural gas-fired generation siting cases over the last decade, and has actively participated in the Renewable Energy Transmission Initiative (RETI) process on the issue of solar technology cost and performance. Thank you for the opportunity to submit these comments on the proposed regulation for the California Renewable Energy Standard (RES).

A. Summary

The June 2010 California Air Resources Board (CARB) *Proposed Regulation for a California Renewable Electricity Standard - Staff Report: Initial Statement of Reasons* ("Staff Report") overstates the costs of meeting a 33 percent RES.[1] It inflates the current price of solar PV. It overlooks studies predicting that the cost of solar PV will decline by approximately 100 percent and solar thermal by 20 to 30 percent over the next decade. It underestimates the capital and operating costs of existing and new natural gas-fired generation. If accurate costs for natural gas-fired generation are used, a 33 percent RES enjoys a cost *advantage* over increased fossil fuel generation for meeting future electricity needs. Finally, it overstates the amount of renewable energy resources that must be added to reach the 33 percent RES target by incorrectly calculating the renewable energy need and by underestimating the amount of solar PV that California is already committed to building.

B. The current costs of solar PV are lower than those assumed in the Staff Report

The RES report assumes a levelized cost-of-energy (LCOE) for solar photovoltaic (PV) of \$187/MWh. In fact, because the costs of solar PV have been rapidly declining in recent years, this number is too high. Both the RETI Phase 2B Final Report and the U.S. Department of

[1] The terms "Staff Report" and "CARB" are used interchangeably in this comment letter.

Energy's (DOE) May 2010 Solar Vision Study estimate lower costs for solar PV than assumed in the Staff Report.[2,3]

The RETI Phase 2B report states that commercially available distributed thin-film PV has a capital cost range of $3.60 to $4/Wac, and commercially available single-axis tracking polycrystalline silicon PV has a cost range of $4 to $5/Wac.[4,5] These PV costs compare to a capital cost range for solar thermal, assumed to be dry-cooled, of $5.35 to $5.55/Wac. RETI indicates the capacity factor for thin-film PV is essentially the same as for dry-cooled solar thermal (assuming the same location). The capacity factor for single-axis tracking polycrystalline silicon PV is significantly better than that of dry-cooled solar thermal (assuming the same location). Operations and maintenance cost for either fixed thin-film PV or single-axis tracking polycrystalline silicon PV is lower than for dry-cooled solar thermal. This RETI data is summarized in Table 1.

Table 1. RETI capital cost, capacity factor, and O&M cost – dry-cooled solar thermal, fixed thin-film PV, and single-axis tracking polycrystalline silicon PV

Solar Technology	Capital Cost ($/kWac)	Capacity Factor (%)	O&M Cost ($/MWh)
Dry-cooled solar thermal	5,350 – 5,550	20 – 28	30
Fixed thin-film PV	3,600 – 4,000	20 – 27	20 - 27
Single-axis tracking polycrystalline silicon PV	4,000 – 5,000	23 – 31	17 - 25

The effect of the values in Table 1 on the LCOE for dry-cooled solar thermal, fixed thin-film PV, and single-axis tracking polycrystalline silicon PV is shown in Table 2 for ideal sites.[6] The best case 2010 LCOE for PV is $135/MWh. Central Valley and Southern California coastal and near-coastal areas have solar insolation levels within 10 to 15 percent of ideal Mojave Desert sites like Daggett.[7] Presuming the $135/MWh PV LCOE is for ideal Mojave Desert sites, a 10 to 15 percent reduction in solar insolation would increase this LCOE to $148 - $155/MWh. A 2010 mean LCOE for either distributed fixed thin-film PV or single-axis tracking polycrystalline silicon PV of approximately $150/MWh thus would appear reasonable in light of the RETI report PV cost data.

CARB's contractor , Energy, Environment, and Economics, Inc. (E3), previously identified a current solar PV LCOE near $150/MWh in an analysis for the CPUC in June 2009, titled "*33% RPS Implementation Analysis Preliminary Results*."[8] In that analysis, E3 evaluated a high

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[2] RETI, *Phase 2B Final Report*, May 2010.
[3] DOE, *Solar Vision Study – Draft, Chapter 4 – Photovoltaics: Technologies, Cost, and Performance*, May 28, 2010.
[4] RETI, *Phase 2B Final Report*, May 2010, Tables 4-5, 4-7, 4-8, pp. 4-6 and 4-7. RETI defines distributed solar PV as 20 MW arrays at or near distribution substations.
[5] "ac" means alternating current. Solar PV panels produce direct current ("dc") electricity that must be converted to ac electricity via a dc/ac inverter to be compatible with grid power.
[6] RETI, *Phase 2B Final Report*, May 2010, Figure 4-1, p. 4-8.
[7] DOE NREL, *PVWatts calculator, Version 1*: http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/
[8] Energy and Environmental Economics, Inc. (E3), *33% RPS Implementation Analysis Preliminary Results*, prepared for CPUC,June 2009, p. 31.

distributed solar PV ("High DG") alternative to the central station reference case. As a component of the High DG alternative, E3 assessed a low-cost solar PV sensitivity case assuming a future solar PV LCOE of $168/MWh based on a solar PV capital cost of $3,700/kWac.[9]

Likewise, as part of the Renewable Distributed Generation Collaborative (ReDEC),[10] E3 and Black & Veatch evaluated a High DG alternative using $3,700/kWac as the low-cost solar PV sensitivity case.[11] More recently, the RETI Phase 2B report clarified that $3,700/kWac is a commercially available solar PV cost in 2010 and should no longer be considered a sensitivity case.[12] Therefore, at a minimum, CARB should be using a solar PV LCOE of $168/MWh for 2010.[13] This value is significantly lower than the PV LCOE assumption of $187/MWh used in the Staff Report.

Table 2. RETI LCOE comparison at best sites - dry-cooled solar thermal, fixed thin-film PV, and single-axis tracking polycrystalline silicon PV

Solar Technology	Levelized LCOE ($/MWh) – best sites
Dry-cooled solar thermal	$195
Fixed thin-film PV	$135
Single-axis tracking polycrystalline silicon PV	$138

The DOE Solar Vision Study also estimates a much lower cost for solar PV than the cost used by CARB. DOE estimates utility-scale distributed thin-film PV at $2.80/Wdc.[14,15] See Figure 1. RETI identifies the range of dc-to-ac conversion factors of 0.77 to 0.85.[16] Assuming an average dc-to-ac conversion factor of 0.80, $2.80/Wdc converts to $3.36/Wac. This is substantially lower than the $4/Wac used by CARB as the basis for a solar PV LCOE of $187/MWh. It is also substantially lower than the $3.70/Wac that E3 and Black & Veatch use as a basis for a solar PV LCOE of $168/MWh.[17]

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[9] Ibid, p. 31.

[10] See ReDEC homepage: http://www.cpuc.ca.gov/PUC/energy/Renewables/Re-DEC.htm

[11] See December 9, 2009 ReDEC "*Presentation 1A – Existing Analyses*" on ReDEC homepage, p. 5.

[12] RETI, Phase 2B Final Report, May 2010, p. 4-6 (see: http://www.energy.ca.gov/2010publications/RETI-1000-2010-002/RETI-1000-2010-002-F.PDF). "Thin film solar PV was previously treated as a sensitivity study, but due to falling costs and the increased prevalence of thin film, it is now being considered as one of the available commercial technologies in addition to tracking crystalline PV."

[13] E3 and Black & Veatch actually identify the $3,700/kWac capital cost for solar PV as being equivalent to $168/MWh in ReDEC *Presentation 1A – Existing Analyses*, p. 41.

[14] DOE, *DOE Solar Vision Study – Draft*, *Chapter 4*, May 28, 2010, Figure 4-4, p. 7. These capital cost values are provided in Wdc.

[15] Ibid, p. 1. "Distributed utility-scale (also referred to as wholesale distributed generation) PV can be sited near load centers, thus reducing grid congestion and the need for costly transmission and distribution infrastructure."

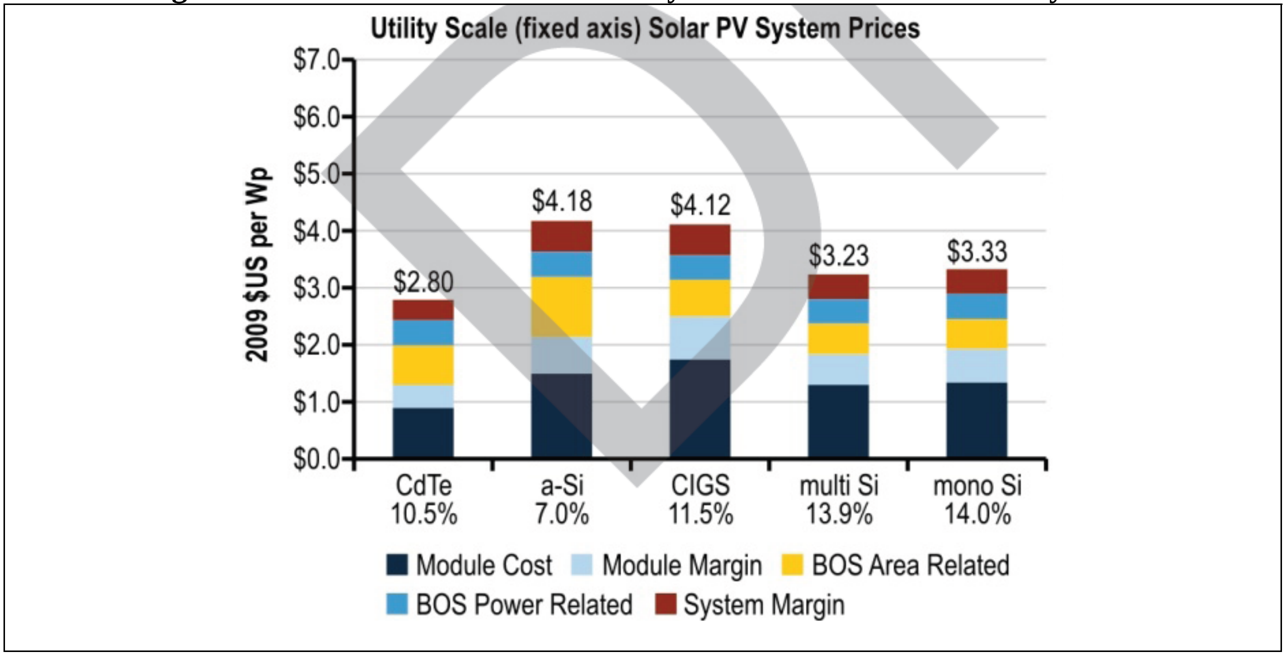
[16] RETI, *Phase 1A Final Report*, August 2008, Appendix B, p. 5-5.

[17] E3 and Black & Veatch (E3/B&V) recently reported substantially higher commercial rooftop PV capital cost, $5/Wdc for a 1 MW rooftop system, in a June 18, 2010 PowerPoint analysis the companies prepared for the CPUC's Long-Term Procurement Proceeding. This E3/B&V estimate for large rooftop PV is not consistent with available data. For example, SCE, in March 2008, estimated a cost of $3.50/Wdc for its 500 MW rooftop PV project. This project will consist of 1 to 2 MW rooftop PV systems. The current DOE cost for thin-film commercial rooftop PV shown in Figure 2 is $3.59/Wdc. First quarter 2010 CSI applications for systems larger than 500 kW are in the range of $3.70/Wdc. A $5/Wdc capital cost translates into $6.25/Wac at a dc-to-ac conversion factor of 0.80. A $6.25/Wac

DOE's projection of current commercial rooftop PV capital cost is provided in Figure 2.[18] As shown in Figure 2, the current capital cost of commercial rooftop polycrystalline silicon PV, identified as "multi Si" and "mono Si", is approximately \$4/Wdc. Using a dc-to-ac conversion factor of 0.80, the capital cost of commercial rooftop polycrystalline silicon PV is approximately \$4/Wdc ÷ 0.80 = \$5/Wac.

The polycrystalline silicon commercial rooftop PV capital cost of \$5/Wac is incrementally less than the \$5.35 to \$5.55/Wac capital cost of dry-cooled solar thermal identified by RETI. The most common form of thin-film PV, CdTe (cadmium-telluride), is lower in cost than polycrystalline silicon PV in commercial rooftop applications at approximately \$3.60/Wdc as shown in Figure 2,. This converts to \$3.60/Wdc ÷ 0.80 = \$4.50/Wac. Thus, the DOE estimates of actual commercial rooftop PV capital costs in 2010 are lower than either CARB or RETI capital cost estimates for solar thermal. The lower cost of commercial rooftop and distributed utility-scale PV suggest that the cost of the proposed 33 percent RES, of which the solar component consists of more than 80 percent solar thermal resources, could be reduced by incorporating a higher percentage of solar PV in the renewable generation mix.

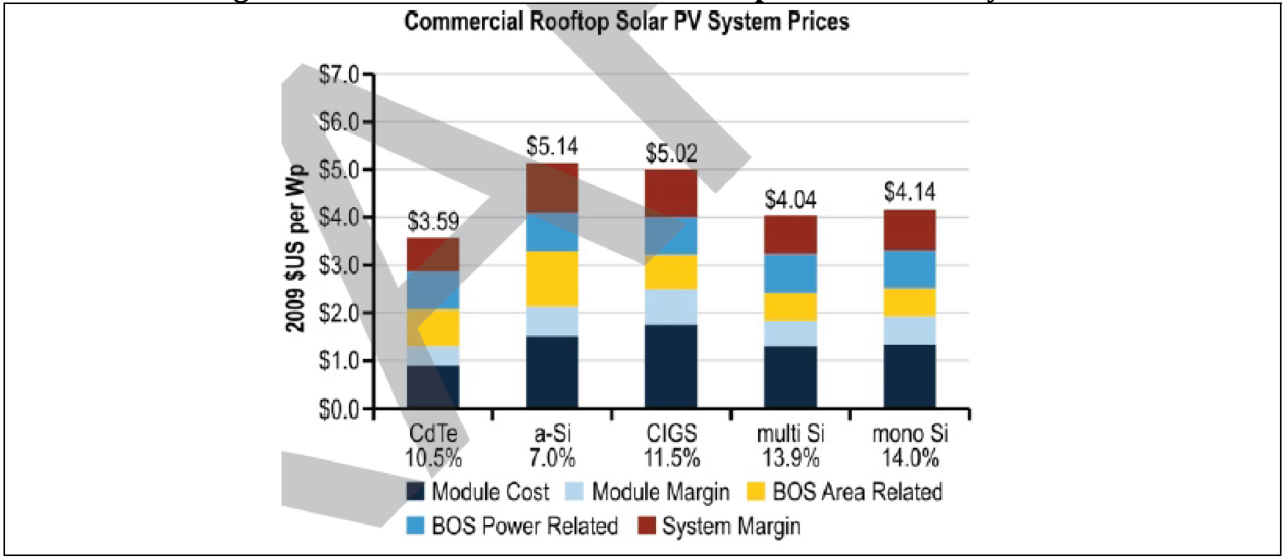
Figure 1. 2010 cost of distributed utility-scale fixed PV identified by DOE



cost is near the average installed cost for large rooftop PV systems installed under the CSI program in SCE and SDG&E territories in 2007, as documented in the March 2008 SCE application for the 500 MW rooftop PV project. SCE reported an average cost of \$6.56/Wac for 1 MW projects in 2007, while average cost for 1 MW projects in SDG&E territory was \$6.47/Wac. It is not credible for E3/B&V to assert that there has been no significant decline in the cost of large commercial rooftop PV since 2007.

[18] DOE, *DOE Solar Vision Study – Draft*, May 28, 2010, Chapter 4, Figure 4-4, p. 7. These capital cost values are provided in Wdc.

Figure 2. 2010 cost of commercial rooftop PV identified by DOE



a-Si: amorphous silicon thin-film PV; CIGS: copper-indium-gallium-selenide thin-film PV.

In sum, CARB should rely on the DOE or RETI data for current commercial rooftop and distributed utility scale PV costs.

C. It is inappropriate to assume no PV price decline from 2010 to 2020, as costs will decline rapidly during this period

Numerous studies have documented the effect of the "learning curve" - that for emerging technologies, the costs of production decrease as the volume of production increases. The DOE Solar Vision study makes this point forcefully. It predicts that across all PV application categories, residential, commercial, and utility, capital costs will decrease by half between 2010 and 2020.[19] See Table 3. The CEC also forecasts that PV costs will drop in half between 2010 and 2020. See Figure 3. The CEC projects that PV, "which has shown dramatic cost change since 2007," will have capital costs equal to wind power by 2024.[20]

The Staff Report assumes that the PV LCOE of $187/MWh (which as discussed above is too high for 2010) remains the constant PV LCOE through 2020.[21] By contrast, the DOE and CEC PV price forecasts would reduce the $187/MWh LCOE to approximately $90/MWh in 2020. If one instead uses $168/MWh, the representative LCOE identified by RETI as a currently available for solar PV,[22] this cost figure would be reduced to approximately $85/MWh in 2020.

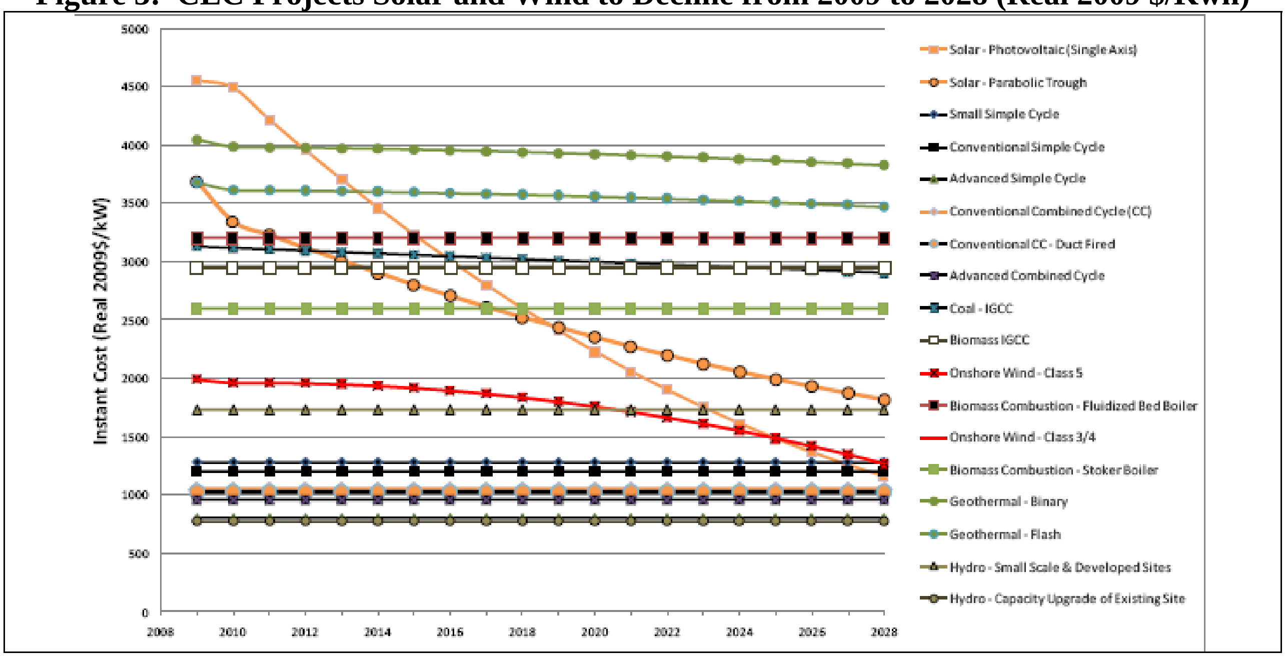
[19] Ibid, Chapter 4, Table 4-2, p. 17.
[20] CEC, *Comparative Costs of Central Station Electricity Generation*, January 2010, p. 17, p. 22.
[21] ARB, *Proposed Regulation for a California Renewable Electricity Standard - Staff Report: Initial Statement of Reasons*, Appendix B - Supporting Documentation for the Technology Assessment, June 2010, p. B-8.
[22] RETI identifies a $3,700/kWac capital cost for fixed PV as commercially available in 2010. See RETI Phase 2B Final Report, May 2010, p. 4-6. [22] E3 and Black & Veatch identify the $3,700/kWac capital cost for solar PV as being equivalent to an LCOE of $168/MWh in ReDEC Presentation 1A – Existing Analyses, p. 41. E3 identifies an

The CEC likewise predicts that solar thermal and wind will likely show significant cost declines over time. See Figure 3. The CEC forecasts a 30 percent decline in the cost of solar thermal from 2010 to 2020, and a 25 percent decline in the cost of wind power over the same period.

Table 3. DOE projects PV costs to decline by half by 2020 (polycystalline silicon PV case)

PV System Component Prices (2009 US$/Wp)	Residential			Commercial			Utility		
	2010	2020	2030	2010	2020	2030	2010	2020	2030
Multicrystalline-Si Module	2.14	1.15	1.03	1.92	1.08	0.98	1.70	1.01	0.92
Inverter	0.51	0.25	0.16	0.40	0.15	0.13	0.36	0.17	0.15
1-axis Tracker	---	---	---	---	---	---	0.48	0.22	0.20
Other Materials	0.51	0.25	0.16	0.73	0.28	0.24	0.31	0.14	0.13
Installation Labor	0.66	0.32	0.20	0.67	0.26	0.22	0.20	0.09	0.08
Permitting & System Design	0.53	0.26	0.16	0.33	0.13	0.11	0.21	0.10	0.09
Installer Overhead & Other	1.60	0.78	0.49	1.05	0.40	0.34	0.80	0.37	0.33
Installed System Cost	**$5.95**	**$3.00**	**$2.20**	**$5.10**	**$2.30**	**$2.00**	**$4.06**	**$2.10**	**$1.90**

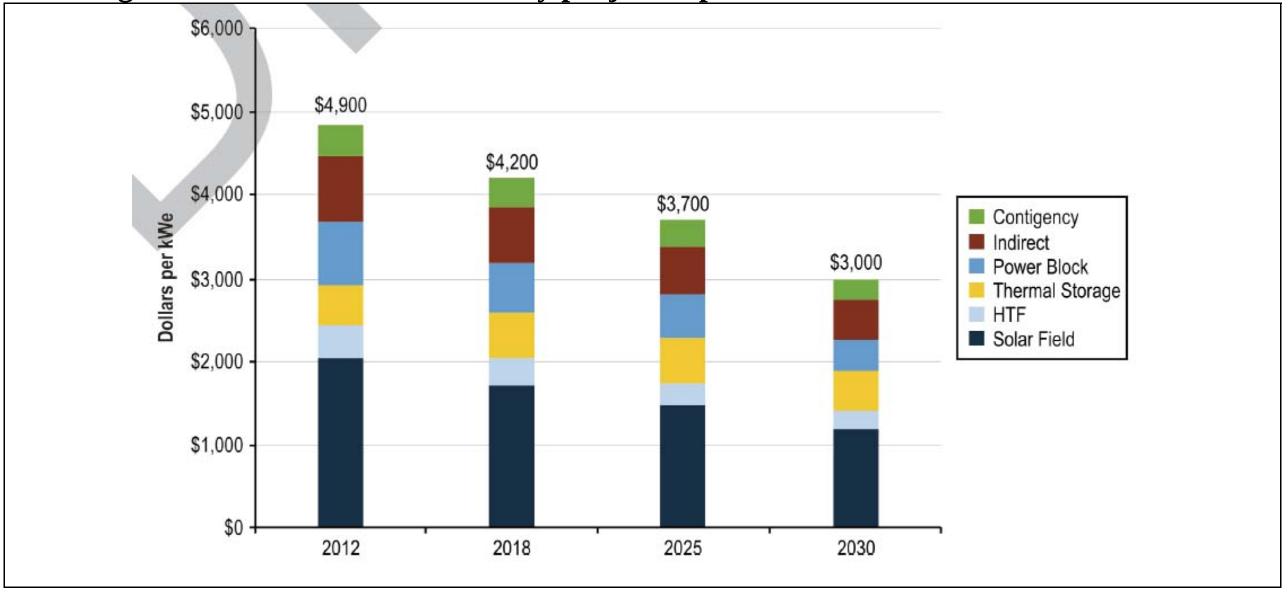
Figure 3: CEC Projects Solar and Wind to Decline from 2009 to 2028 (Real 2009 $/Kwh)



LCOE of $168/MWh based on a capital cost of $3,700/kWac in *33% RPS Implementation Analysis Preliminary Results*, prepared for CPUC, June 2009, p. 31.

The DOE projects that solar thermal will decrease by approximately 20 percent between 2010 and 2020.[23] See Figure 4. DOE is not explicit whether the solar thermal costs shown in Figure 4 are for wet-cooled or dry-cooled solar thermal plants.

Figure 4. DOE Solar Vision Study projected price decline trend for solar thermal



The LCOE identified by RETI for dry-cooled solar thermal in 2010 at best-in-class sites is $195/MWh. Assuming a price decline of 25 percent between 2010 and 2020, the LCOE for dry-cooled solar thermal will be in the range of $150/MWh in 2020.[24,25] The Staff Report does not identify a LCOE for solar thermal. However, Appendix B does list all the cost assumptions for solar thermal.[26] These assumptions are identical to those used in the June 2009 report prepared for the CPUC,[27] which stated a LCOE range for solar thermal of $159 to $228/MWh, or an average of $194/MWh.[28]

D. The Staff Report should have evaluated a "High DG" alternative

As noted, the E3 June 2009 report prepared for the CPUC, which is referenced in the Staff Report,[29] evaluates a High DG alternative to the utility reference case. The High DG alternative

[23] DOE Solar Vision Study – Draft, *Chapter 5 - Concentrating Solar Power: Technologies, Cost, and Performance*, May 2010, Figure 5-9, p. 12. Assume 2010 capital cost of $5,100/kWac and 2020 capital cost of $4,000/kWac. This equals a cost decline of [($5,100/kWac - $4,000/kWac)/$5,100/kWac)] = 22 percent.
[24] The average of the DOE and CEC solar thermal price declines between 2010 and 2020 is [(20 percent + 30 percent)/2] = 25 percent.
[25].$195/MWh (1 – 0.25) = $146/MWh.
[26] Appendix B, Table 7, p. B-27.
[27] E3., *Inputs and Assumptions to 33% Renewables Portfolio Standard Implementation Analysis*, prepared for CPUC, July 2009, Table 7, p. 12.
[28] Ibid, Appendix B, Figure 13, p. 73.
[29] p. ES-13. "The methodology used to estimate this cost in 2020 is consistent with the methodology used in the CPUC's 33 Percent Renewables Portfolio Standard Implementation Analysis Preliminary Results and the Scoping Plan."

substitutes 15,068 MW of distributed PV for 10,000 MW of remote central station solar thermal and PV resources in the 33 percent reference case. Wind resource additions are reduced from 7,573 MW to 4,484 MW.

No similar alternative is evaluated in the Staff Report, even though as noted above recent studies show that distributed PV is more cost-effective than solar thermal. The base case analyzed by CARB relies overwhelmingly on remote solar thermal resources for solar energy production. Solar thermal provides 83 percent of the GWh generated by solar electric resources in the proposed 33 percent RES. Solar PV accounts for only 17 percent.[30] A High DG alternative similar to the one evaluated for the CPUC should be analyzed by CARB. It will show lower estimated compliance costs. In particular, CARB should examine a High DG scenario that maximizes the utilization of distributed PV potential at or near urban/suburban loads centers. Up to 20,000 MW of distributed PV can potentially flow on California's distribution grid without the need to upgrade the the existing distribution system.[31,32]

Moreover, as part of the High DG analysis, CARB should conservatively assume that half of the solar PV is installed before 2015 and half after 2015. Thus the projected 2015 LCOE of solar PV should serve as the solar PV LCOE used in the analysis. Using a 2010 solar PV LCOE of $168/kWh and 2020 solar PV LCOE of $84/MWh gives a mean LCOE, representing the 2015 value, of approximately $130/MWh.[33] If CARB were to use this more accurate figure for solar PV, the 33 percent RES cost would be substantially reduced from the draft estimate.

The High DG alternative would also eliminate the new transmission revenue requirement in the proposed RES. New transmission expense is significant. The proposed RES Low Load Scenario new transmission revenue requirement is $770 million.

A High DG alternative is feasible. Other countries have shown that rapid deployment of distributed solar PV is possible. Germany, approximately the same size as California and with considerably lower solar intensity, added approximately 1,500 MW of distributed PV resources in 2008 and 3,800 MW in 2009.[34,35] Germany had an installed PV capacity of nearly 9,000 MW at the end of 2009 and has set a target PV installation rate of 3,500 MW per year.[36] Spain added

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[30] Table XI-3, p. XI-5, Low Load Scenario. Total in-state and out-of-state solar thermal in 2020, 15,440 GWh. Total in-state and out-of-state solar PV in 2020, 3,192 GWh. Percentage of solar thermal = [15,440 GWh/(15,440 GWh + 3,192 GWh)] = 82.9 percent.

[31] B. Powers, P.E. opening testimony, CEC Docket No. 07-AFC-5, *Ivanpah Solar Electric Generating Station Application for Certification*, December 16, 2009, pp. 7-8.

[32] CARB assigned the same 1.0 percent transmission loss to remote distributed (PV) generation that it assigned to remote central station solar and wind projects (see Appendix B, p. B-26). This is apparently because, for the June 2009 CPUC 33 percent analysis, E3 located the majority of the distributed PV in remote rural locations. E3 retained this assumption in the CARB report. E3 arbitrarily assumed in the June 2009 CPUC analysis that only a third of California's commercial rooftop PV potential could be developed, and therefore to develop 15,000 MW of distributed PV would require locating large amounts of PV near rural substations. This is incorrect. Much more rooftop PV can be developed locally.

[33] The actual mean is $126/MWh, but the $130/MWh figure better reflects the approximate nature of the estimate.

[34] PV Tech, *German market booming: Inverter and module supplies running out at Phoenix Solar,* November 15, 2009.

[35] Worldwatch Institute, *Record Growth in Photovoltaic Capacity and Momentum Builds for Concentrating Solar Power*, June 3, 2010.

[36] Chadbourne & Parke Project Finance Newswire, *Germany Cuts Solar Subsidy*, April 2010.

approximately 2,500 MW of primarily distributed ground-mounted PV resources in 2008.[37] Spain has a smaller economy than California.

Likewise, distributed PV generation in California has been expanding at a brisk pace in recent years. California appears well on its way toward meeting the goals of installing 3,000 MW of rooftop solar by the end of 2016.[38] Larger PV projects also are increasing. The CPUC has already approved RPS-eligible 500 MWdc rooftop/distributed PV projects in SCE and PG&E service territories.[39,40] These two projects will add another 1,000 MWdc, or 800 MWac assuming a dc-to-ac conversion factor of 0.80, by the end of 2014. These investor-owned utility (IOU) PV projects are on the same scale as the largest conventional and renewable energy central station projects.

RETI also identifies additional RPS-eligible PV programs that are likely to achieve full build-out over the next few years, resulting in significant PV generation. These programs include: SMUD's feed in tariff (100 MW limit), SB 32's feed-in tariff for all RPS-eligible renewables up to 3 MW (750 MW limit) and the CPUC's standard contract feed-in tariff for all IOU RPS-eligible renewables up to 10 MW (1,000 MW limit) sum to a total of 1,850 MW of additional PV resources.[41] These projects, including the SCE and PG&E distributed PV programs, represent approximately 2,650 MWac of RPS-eligible distributed PV additions.

Thus, there is very realistic potential to substantially increase distributed PV generation in California over the next decade.

E. CARB substantially underestimates the amount of solar PV that will be built by 2020

The proposed RES Low Load Scenario projects that 3,192 GWh of electricity will be produced by solar PV in 2020.[42] At the assigned solar PV capacity factor of 24 percent, 1,518 MW of solar PV capacity will produce 3,192 GWh of electricity.[43] However, as noted above, the State is already committed to adding approximately 2,650 MWac of RPS-eligible solar PV over the next several years. These reasonably foreseeable RPS-eligible distributed PV additions far exceed the 1,518 MW of solar PV capacity assumed as on-line by 2020 in the Staff Report.

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[37] PV Tech, *Worldwide photovoltaics installations grew 110% in 2008, says Solarbuzz*, March 16, 2009.
[38] California Public Utilities Commission, *Go Solar California, California Solar Initiative Annual Program Assessment*, June 2010.
[39] CPUC June 18, 2009 press release, SCE rooftop PV program: http://docs.cpuc.ca.gov/published/News_release/102580.htm
[40] CPUC April 22, 2010 press release, PG&E solar PV program: http://docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/116816.htm
[41] RETI, *Net Short Calculation – Discussion Draft*, February 22, 2010, p. 20.
[42] Table XI-3, p. XI-5.
[43] Appendix B, Table 7, p. B-27.

As noted, the California Solar Initiative (CSI) program should also add 3,000 MWac of rooftop PV by the end of 2016.[44] CSI solar projects are not currently RPS-eligible, but they may very well be in the future (for example, starting in 2017 after the CSI program ends).

Thus, without any further action, California will add approximately 5,650 MWac of solar PV capacity by 2016 through the PV programs described, and undoubtedly will add more from 2017 to 2020. At a capacity factor of 24 percent assumed in the Staff Report, this 5,650 MWac of solar PV will produce 11,879 GWh of electricity.[45] This is nearly 9,000 GWh more electricity than the 3,192 GWh that is credited to solar PV by CARB in the proposed RES. The proposed RES should be updated to reflect this reality. CARB should also model a scenario in which solar PV installation rate continues to grow in the 2017 to 2020 timeframe. The impact of this will be to lower the expected costs of a 33 percent RES relative to the Staff Report's estimate.

F. CARB's analysis fails to reflect that a 33 percent RES should have a cost *advantage* over increased fossil fuel generation for meeting future electricity needs

As noted above, CARB's analysis inflates the likely costs of renewable generation, failing to factor in significant predicted decreases in the cost of solar PV and solar thermal between now and 2020. At the same time that solar costs decline, natural gas prices and the cost of natural gas-fired generation will increase. CARB's analysis significantly *underestimates* the likely costs of new peaker and baseload natural gas plants over the next decade. CARB should revise its assumed fixed and variable costs for new conventional generation to reflect the most recent costs developed for these generation sources by the CEC.[46] Use of current costs for new conventional generation will show that a 33 percent RES will result in *lower* electricity rates than a business-as-usual scenario relying on increased electric power production from natural gas-fired resources to meet electricity needs.

1. CARB underestimates by a factor of three the costs of new peaker and baseload natural gas units

CARB's estimates of the costs of new peaker and baseload natural gas plants are one-third of the costs calculated by the CEC in its January 2010 cost evaluation. That report assigns a cost of $951/MWh to new state-of-the-art merchant 100 MW peaker gas turbines with a 2018 startup date. The $951/MWh LCOE estimate assumes a 5 percent capacity factor.[47] The Staff Report assumes that a large majority of the new peaker turbine capacity is added between 2016 and 2019.[48] For this reason the use of the forecast LCOE for new peaker turbine capacity with a startup date of 2018 is appropriate.

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[44] California Public Utilities Commission, *Go Solar California, California Solar Initiative Annual Program Assessment*, June 2010.
[45] 5,650 MW x 8,760 hr/yr x 0.24 x (1 GW/1,000 MW) = 11,879 GWh/yr.
[46] CEC, *Comparative Costs Of California Central Station Electricity Generation – Final Staff Report*, January 2010.
[47] Ibid, Table 5 ($/MWh) and Table 11 (average capacity factor).
[48] Appendix B, Table 16 , p. B-34. 4,646 MW of new peaker capacity added between 2009 and 2020. 3,564 MW of the 4,646 MW total is added between 2016 and 2019.

This capacity factor is consistent with the actual capacity factors of the 5,000+ MW of once-through cooled coastal boilers CARB projects will be permanently retired by 2020.[49] The mean retirement date for these once-through cooled units is 2017.[50] The electricity production from new peakers is projected by CARB at 6,900 GWh in 2020 in the proposed RES Low Load Scenario. The annual revenue requirement of this 6,900 GWh of new peaker output would be: 6,900 GWh/yr x 1,000 MWh/GWh x $951/MWh = $6.6 billion/yr.

The CEC assigns a cost of $169/MWh to new state-of-the-art merchant 500 MW combined cycle plant without duct firing with a 2018 startup date. A 75 percent average capacity factor is assumed for combined cycle plants without duct firing.[51] The CEC also evaluates a "low cost" scenario where the average combined cycle plant capacity factor is 90 percent.[52]

The Staff Report assumes the capacity factor of combined cycle plants is 65 percent.[53] CARB projects that new in-state and out-of-state combined cycle plants will generate 27,600 GWh in 2020 in the proposed RES Low Load Scenario. Assuming the CEC average combined cycle case, adjusted to CARB's assumption that combined cycle plants will have a capacity factor of 65 percent (as opposed to the 75 percent assumption used by the CEC), the annual revenue requirement of this 27,600 GWh of new combined cycle plant output would be: 26,700 GWh/yr x 1,000 MWh/GWh x $169/MWh x (0.75/0.65) = $5.2 billion/yr.

When using current CEC cost data, the combined 2020 revenue requirement of new peaker and baseload combined cycle natural gas plants in the proposed RES Low Load Scenario will be $6.6 billion (new peakers) + $5.2 billion (new baseload combined cycle) = $11.8 billion/yr. Yet the revenue requirement identified for this new generation in the proposed RES Low Load Scenario is only about $4.2 billion/yr.[54] This is nearly a 3-to-1 cost discrepancy. Absent a convincing justification otherwise, CARB should use the CEC's most recent cost projections for new peaker and baseload combined cycle plants when calculating the revenue requirements of the new conventional generation component of all scenarios analyzed.

[49] Appendix B, Table 14, p. B-33. Average capacity factor of units to be retired by 2020, adjusted for unit MW capacity, is in the range of 5 and 10 percent. Units included in this average are Alamitos 1-6, Contra Costa, Encina 1-5, Morro Bay, Pittsburg, and South Bay.
[50] Ibid.
[51] CEC, *Comparative Costs Of California Central Station Electricity Generation – Final Staff Report*, January 2010, Table 5 ($/MWh) and Table 11 (average capacity factor).
[52] Ibid, Table 13.
[53] Appendix B, p. B-33.
[54] Table X-1, p. X-5. New conventional fixed costs in 33 percent RES Low Load Scenario = $1.7 billion. Existing and new conventional variable costs in 33 percent Low Load Scenario = $6.2 billion. Existing peaker electric output is 10,350 GWh in 2020 (Table XI-3, p. XI-5). New peaker electric output is 6,900 GWh in 2020. Therefore, new peaker variable costs are approximately 40 percent [6,900 GWh/(10,350 GWh + 6,900 GWh)] of combined peaker variable cost in 2020. Existing baseload combined cycle output is 50,500 GWh in 2020 (Table XI-3, p. XI-5. New baseload combined cycle output is 27,600 GWh in 2020. Therefore, new baseload combined cycle variable costs are approximately 35 percent [27,600 GWh/(50,500 GWh + 27,600 GWh)] of combined baseload combined cycle variable cost in 2020. Therefore, assuming new peaker and baseload combined cycle variable costs are 40 percent of total existing and new conventional variable costs, the 2020 variable cost of the new units is 0.40 x $6.2 billion = $2.5 billion/yr. Adding the $2.5 billion/yr variable cost to the $1.7 billion fixed cost for new conventional generation gives at total revenue requirement for new conventional generation of $4.2 billion/yr.

2. Projected costs for solar in 2020 are below projected costs of natural gas plants

As noted above, current CEC LCOE estimate for new baseload combined cycle units that come online in 2018 is $169/MWh. Adjusting the new baseload combined cycle plant LCOE from the 75 percent capacity assumed by the CEC to the 65 percent capacity factor assumed by CARB increases the combined cycle plant LCOE from $169/MWh to $186/MWh.[55]

In contrast, the projected average cost of distributed PV installed between 2010 and 2020, assuming the estimated LCOE for the mid-point year of 2015 is representative, will be approximately $130/MWh. The projected average cost of solar thermal installed between 2010 and 2020, using the projected 2015 LCOE as representative, will be approximately $170/MWh.[56] Either of these projected LCOE's for solar PV and solar thermal are significantly below the projected LCOE for a new baseload combined cycle plant in 2018. Both solar PV and solar thermal can economically displace the daytime portion of new baseload combined cycle capacity and new peaker capacity during the 2010-2020 time period addressed in the Staff Report.

Thus, using more realistic assumptions about the cost of solar, it likely will be *cheaper* to meet anticipated growth in electricity demand using solar than natural gas. At the minimum, CARB should compare the cost of electricity under a 33 percent RES to the estimated cost of electricity under a business-as- usual scenario. This would show that the incremental cost of implementing a 33 percent RES, as compared to the cost of continuing to obtain new generation from natural gas plants, is much lower than the CARB report suggests.

Notably, CARB's 20 percent RES and 33 percent RES alternatives are both lower-cost than the natural gas base case analyzed in the 33 percent RPS analysis prepared by E3 for the CPUC in June 2009. CARB states a 2020 revenue requirement for the 20 percent RES scenario of $42.6 (low) to $46.1 (high) billion, and a revenue requirement for the 33 percent RES alternative of $45.1 (low) to $49.0 (high) billion.[57] The June 2009 CPUC analysis stated a 2020 revenue requirement for the "all natural gas" scenario of $49.2 billion.[58] This cost differential should be discussed in the Staff Report.

3. Staff Report overestimates the amount of peaker and baseload plants needed to meet the 33 percent RES

CARB has overestimated the amount of new peaker plants and baseload plants needed with a 33 percent RES. As a result, it has inflated the system costs of implementing the 33 percent RES.

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[55] CEC, *Comparative Costs of California Central Station Electricity Generation*, January 2010, Table 5 and Figure A-8.
[56] [$195/MWh + $150/MWh)/2] = $172.50/MWh.
[57] Table XI-6, p. XI-8.
[58] E3,, *33% RPS Implementation Analysis Preliminary Results*, prepared for CPUC, June 2009, p. 8.

a. CARB incorrectly assumes that it is necessary to build nearly 5,000 MW of new peaker gas plants to meet 33 percent RPS

The CARB analysis assumes that nearly 5,000 MW of new peaking gas turbines must be added to keep pace with the projected 1.3 percent per year peak load growth predicted by the CEC for the 2010-2020 period.[59] As alluded to in the Staff Report, California's IOUs are required by the CPUC to maintain peak reserve margins for average 1-in-2 year weather conditions of 15-17 percent.[60]

However, the State already has overcapacity that can help deal with the reserve margin requirement. Reserve margins are at historically high levels. Using PG&E service territory as an example, the California Independent System Operator (CAISO) forecast a 1-in-2 reserve margin for the summer of 2009 of 30.6 percent.[61] This was based on total projected reserves of 27,899 MW, including generation, imports, demand reduction, and interruptible programs.[62] In reality, the actual reserve margin for PG&E in the summer of 2009 did not drop below 44 percent.[63]

CAISO forecasts a 1-in-2 reserve margin for PG&E for the summer of 2010 of 38.5 percent.[64] CAISO projects that 28,555 MW of supply will be available in PG&E territory and that the 1-in-2 peak demand will be 21,154 MW. The forecast 38.5 percent reserve margin in 2010 is a considerably higher reserve margin than the 30.6 percent forecast by CAISO for PG&E in 2009. As noted, the actual reserve margin in 2009 was substantially higher than the CAISO forecast. CARB uses a 1.3 percent per year peak demand 2010-2020 growth rate. This would increase peak demand by 13.7 percent from 2010 to 2020. In PG&E territory, the 1-in-2 peak demand would increase from 21,154 MW in 2010 to 21,154 MW x 1.138 = 24,073 MW. The 1-in-2 reserve margin in 2020 would still be approximately 16 percent in 2020 with no additional supply beyond the 28,555 MW available in PG&E territory in 2010.

CARB assumes that numerous once-through cooled coastal boiler plants will be retired prior to 2020 and that this will reduce available peaking capacity by approximately 5,400 MW.[65] This would reduce the reserve margin calculated above. However, CARB's proposed 33 percent RES includes approximately 19,000 MW of new renewable resources.[66] Approximately 8,500 MW of

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[59] Appendix B, Table 16, p. B-34.

[60] Appendix B, p. B-34.

[61] CAISO identifies PG&E service territory as "north of Path 26," or NP26. For map showing NP26 region, see p. 6, CAISO 2006 summer forecast presentation: http://www.caiso.com/17f4/17f4cf9145150.pdf.

[62] CAISO, *2009 Summer Loads and Resources Operations Preparedness Assessment*, May 7, 2009, Table 1, p. 4.

[63] Pacific Environment Opening Brief, A. 09-09-021, *Application of PG&E for Approval of 2008 Long-Term Request for Offer Results and for Adoption of Cost Recovery and Ratesetting Mechanisms*, April 14, 2010, Table 1, p. 8.

[64] CAISO, *2010 Summer Loads and Resources Operations Preparedness Assessment* May 10, 2010, Table 1, p. 4.

[65] Appendix B, Table 14, p. B-33. 6,617 MW to be retired by 2020. The 1,020 MW Moss Landing and 163 MW Humbolt Bay repower projects listed in Table 14 have occurred and reduce the net lost of capacity to approximately 5,400 MW if these retirements take place as anticipated.

[66] The ~19,000 MW total new renewable energy was calculated by dividing the gigawatt-hour (GWh) contribution of each new renewable technology category in Table XI-3, p. XI-5, by the annual capacity factor for the renewable technology provided in Appendix B, Table 7, p. B-27.

this total will be available at peak summertime demand periods.[67] 8,500 MW of new renewable resources available on-peak far exceeds the worst-case scenario retirement of 5,400 MW of once-through cooled boiler plants.

It also is worthy of note that California's once-through cooling phase-out regulation does not require the retirement of once-through cooled boiler plants.[68] These plants can be retrofit with cooling towers, at one-tenth the cost of building new replacement peaker gas turbine capacity, to comply with the regulation.[69,70,71] CARB should analyze a scenario where the coastal boilers are retrofit to cooling towers to comply with the once-through cooling phase-out regulation to avoid unnecessarily inflating the cost of peaking capacity in 2020.

Energy storage is another alternative that CARB should analyze as a potentially lower-cost alternative to new peaker capacity.[72] At least some forms of energy storage appear to be lower-cost than new peaker turbines.[73] Energy storage is also more compatible with the twin state goals of reducing greenhouse gas emissions and increasing integration of solar and wind resources into the state's electric transmission and distribution system.

b. CARB incorrectly assumes that it is necessary to build almost 28,000 GWh of new baseload combined cycle gas plants to meet the 33 percent RES

CARB assumes that 27,600 GWh of electricity production will be necessary from new baseload combined cycle plants to implement the proposed 33 percent RES.[74] This is based on an assumed

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[67] The ~8,500 MW new renewable energy available on-peak was calculated by dividing the GWh contribution of each new renewable technology category in Table XI-3, p. XI-5, by the availability on-peak capacity factor for the renewable technology provided in Appendix B, Table 7, p. B-27.

[68] See: http://www.waterboards.ca.gov/water_issues/programs/npdes/docs/cwa316may2010/otcpolicy_final050410.pdf

[69] CEC estimates capital cost of new merchant 100 MW peaking gas turbine at $1,250/kW. See

[70] See: http://www.opc.ca.gov/2009/05/california%e2%80%99s-coastal-power-plants-alternative-cooling-system-analysis/. Consultant TetraTech calculated an average cooling tower retrofit capital cost for once-through cooled boiler plants generally in the $90 to $150/kW range.

[71] CEC hearing transcript, Options for Maintaining Electric System Reliability - Preparation of the 2009 Integrated Energy Policy Report, Docket No. 09-IEP-10, May 11, 2009, p. 106, p. 108. "Eric Pendergraft with AES. We own Alamitos, Redondo Beach and Huntington Beach, all in the LA basin about just over 4200 megawatts I think, depending on what statistics you use. . . We have performed high level retrofit studies for closed cycle cooling, both wet and dry cooling. As one might expect there are significant land constraints as well as permitting issues. They're expensive, you know, a rough ballpark for wet cooling at our sites it's approximately $125 or $115 a kilowatt. So for our 4,000 megawatts you're looking at, you know, 500 million dollars, half a billion dollars to retrofit with wet cooling."

[72] CPUC, *Electric Energy Storage: An Assessment Of Potential Barriers And Opportunities - Policy and Planning Division Staff White Paper*, July 9, 2010. See: http://www.cpuc.ca.gov/NR/rdonlyres/71859AF5-2D26-4262-BF52-62DE85C0E942/0/CPUCStorageWhitePaper7910.pdf; CEC, Research Evaluation Of Wind Generation, Solar Generation, And Storage Impact On The California Grid, CEC-500-2010-010 (June, 2010).

[73] California Energy Storage Alliance (CESA), *Energy Storage: A Cheaper and Cleaner Alternative to Natural Gas-Fired Peakers (case study)*, June 2010 (copy attached).

[74] Table XI-3, p. XI-5, Low Load Scenario. California in-state new baseload = 20,900 GWh, out-of-state new baseload = 6,700 GWh. Total in-state and out-of-state = 27,600 GWh.

capacity factor of 65 percent for California's existing fleet of combined cycle plants.[75] The would require the addition of 4,847 MW of new baseload combined cycle capacity.[76]

However, there is approximately 13,000 MW of operational combined cycle capacity in California that on average is operating well below design capacity.[77] The design capacity factor for baseload combined cycle plants is 90 percent.[78] Increasing the capacity factor of 13,000 MW of existing in-state combined cycle capacity from 65 to 90 percent would add nearly 27,000 GWh of electricity production. This is essentially sufficient by itself to meet the 27,600 GWh output from new baseload generation identified by CARB in the proposed 33 percent RES. CARB should examine a scenario where California's existing combined cycle plants are utilized at their design capacity instead of assuming 4,847 MW of new combined cycle plants will be built and operated at a sub-optimal capacity factor.

G. Adding a net present value comparison for the 2011-2030 period would provide critical "cumulative cost over time" comparative information

Comparing the cost of scenarios in only one year, 2020, provides an incomplete picture of the economic impact of each scenario over time. CARB should include a net present value analysis for the complete 2011-2030 period to complement the 2020 point-in-time comparison.

Net present value analysis has been used previously for this purpose. For example, in 2005 a CPUC-contracted study analyzed the cost of moving from a 20 percent RPS in 2010 to a 33 percent by 2020.[79] In the analysis the CPUC compared costs in the year 2020 as well as the net present value of each scenario for the period 2011-2030. The CPUC determined that 33 percent RPS in 2020 would result in small average rate increases through 2021. However, the net present value for the 2011-2030 favored the 33 percent RPS scenario. The point here is that the net present value analysis provided critical comparative cost data that put the 2020 cost data in context.

[75] Ibid, p. B-33.
[76] The 4,847 MW of new combined cycle capacity was calculated by dividing the gigawatt-hour (GWh) contribution of new in-state and out-of-state combined cycle units in Table XI-3, p. XI-5, by the annual capacity factor of 65 percent for the combined cycle units provided in Appendix B, p. B-33. [(27,600 GWh x 1,000 MW/GW)/(8,760 hr x 0.65)] = 4,847 MW.
[77] CEC website, *Power Plants – Status of All Projects*: http://www.energy.ca.gov/sitingcases/all_projects.html. Nineteen (19) operational California combined cycle plants with total capacity of 12,301 MW. There are also two combined-cycle plants in Mexicali, Baja California, the 650 MW Sempra Termoelectrica plant and the 310 MW Intergen plant, that exclusively export to the California market and are under CAISO control. These two plants have no direct connection to the Mexican electricity grid. These two plants add an additional 960 MW to California combined cycle capacity. Total operational California combined cycle capacity is therefore 12,301 MW + 960 MW = 13,261 MW.
[78] CEC, *Comparative Costs Of California Central Station Electricity Generation – Final Staff Report*, January 2010, Table C-6: Recommended Capacity Factors , p. C-12. Combined cycle capacity factor of 90 percent is recommended for use to calculate low cost operation.
[79] CPUC, *Achieving a 33% Renewable Energy Target*, November 2005, p. 2. "The net present value of RPS rate payer impacts for the period 2011 to 2030 is - $175 million (2011$, 9% discount rate), in other words a net savings."

H. The "Net Short" renewable energy range assumed by CARB is too high and inflates the revenue requirement for the proposed RES

The net short estimate relied on by CARB is too high because it fails to take into account revised, lower estimates of growth in demand due to the economic recession and because it fails to fully account for the energy efficiency savings expected to be realized by the state's efficiency programs. The "net short" as the term is used in the CARB draft report is the net amount of renewable energy that must be added by 2020 to meet the 33 percent RES target. CARB identifies a High Load Scenario net short of 66,100 GWh, and a Low Load Scenario net short of 53,500 GWh.

RETI identified the total new renewable energy requirement by 2020, including "net short" new renewable resources that require transmission and those that do not, as 56,118 GWh in February 2010.[80] See Figure 5.

There are two principal differences between the CARB High Load Scenario net short calculation and the RETI net short calculation: 1) CARB includes water agency pumping consumption in its projection of 301,000 GWh eligible "load serving entity" (LSE) retail sales in 2020,[81] and 2) CARB assumes approximately 7,000 GWh less existing renewable energy production than RETI.

CARB's use of 301,000 GWh eligible LSE retail sales in 2020 is incorrect. A fraction of utility supply, 13,556 GWh, is used by water agencies for pumping loads and is not subject to RPS requirements.[82] This 13,556 GWh should have been subtracted from the 301,000 GWh total used by CARB and was not.

RETI assumes approximately 7,000 GWh more existing renewable resources will be available than CARB based on January 2010 input to RETI from the CEC.[83] CARB uses an estimate of 31,270 GWh existing renewable energy resources.[84] There is no discussion regarding the development of this value in Appendix B to the Staff Report, only an apparently unedited discussion of the net short calculations used in the June 2009 33percent RPS analysis E3 prepared for the CPUC. The CARB estimate of 31,270 GWh compares to the CEC's January 2010 estimate of 38,174 GWh used by RETI. See Figure 5. CARB should rely on up-to-date inputs and adopt 56,118 GWh as the new renewable energy requirement in the proposed 33 percent RES High Load Scenario.

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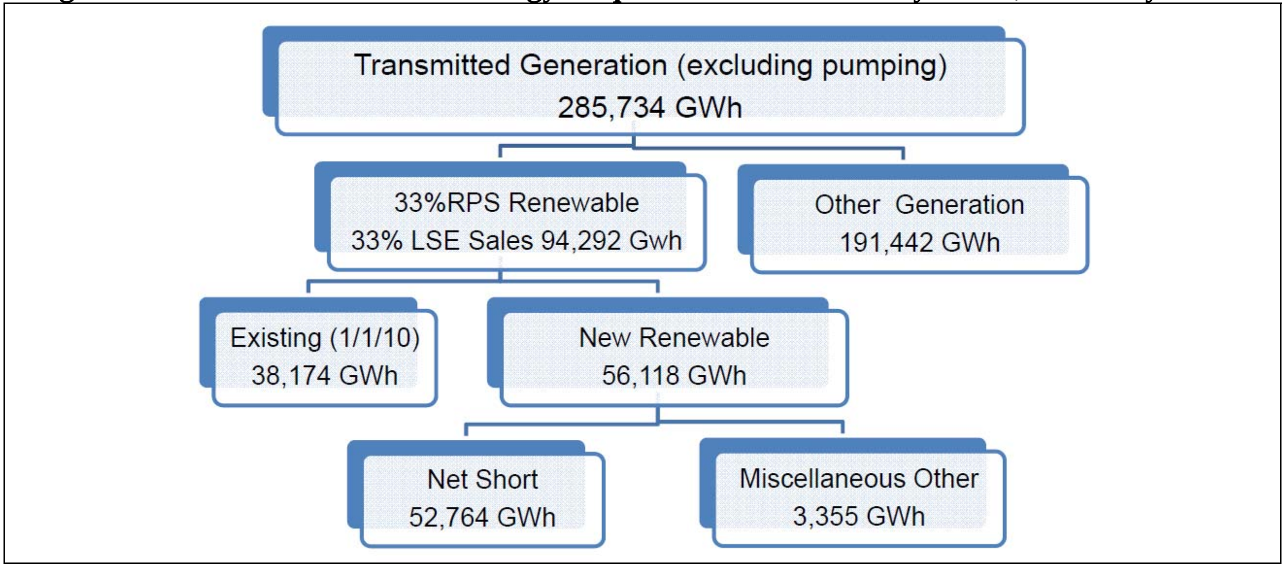
[80] RETI Net Short Update, *Evaluating the Need for Expanded Electric Transmission Capacity for Renewable Energy*, discussion draft, February 22, 2010, p. 7.
[81] Table V-9, p. V-22.
[82] RETI Net Short Update, *Evaluating the Need for Expanded Electric Transmission Capacity for Renewable Energy*, discussion draft, February 22, 2010, p. 6.
[83] Ibid, footnote 19, p. 6. "Private communication from CEC staff. Existing renewables as of 1/1/10 include: 31,272 GWh reported in 2008 Net System Power Report, 2,533 GWh IOU renewable online since 2008 NSP 2,116 GWh short-term out of state on lines since 2008 NSP, 2,253 GWh POU online since 2008 NSP."
[84] Table XI-2, p. XI-4.

Figure 5. 2020 New Renewable Energy Requirement Identified by RETI, February 2010[85]



The proposed RES Low Load Scenario should be 43,578 GWh. CARB states that "modifications to the 2009 [Integrated Energy Policy Report] IEPR forecast that reduces the grid's load demand in 2020 from full implementation of the Scoping Plan measures related to Energy Efficiency, CHP, and Solar DG energy" would reduce eligible LSE retail sales by 38,000 GWh.[86] This results in a net reduction in renewable energy generation of 12,540 GWh in 2020 compared to the High Load Scenario.[87] Therefore the Low Load Scenario analyzed by CARB should be 56,118 GWh - 12,540 GWh = 43,578 GWh.

G. Conclusion

The Staff Report overlooks projections that the cost of solar PV will decline by approximately 100 percent, and solar thermal by 20 to 30 percent, over the next decade. It underestimates the capital and operating costs of existing and new natural gas-fired generation. The proposed 33 percent RES enjoys a cost *advantage* over increased fossil fuel generation for meeting future electricity needs if accurate costs for natural gas-fired generation are used, The Staff Report also overstates the amount of renewable energy resources that must be added to reach the 33 percent RES target by incorrectly calculating the renewable energy need and by underestimating the amount of solar PV that California is already committed to building.

[85] RETI Net Short Update, *Evaluating the Need for Expanded Electric Transmission Capacity for Renewable Energy*, discussion draft, February 22, 2010, p. 7

[86] Table V-9, p. V-22. High Load Scenario assumes 301,000 GWh of LSE retail sales in 2020. Low Load Scenario assumes 263,000 GWh. The difference is 38,000 GWh.

[87] 33percent of 301,000 = 99,330 GWh. 33percent of 263,000 = 86,790 GWh. The reduction in new renewable energy required in 2020 is: 99,330 GWh – 86,790 GWh = 12,540 GWh.

Please feel free to contact me at (619) 295-2072 or bpowers@powersengineering.com if you have any questions about this comment letter.

Sincerely,

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