CALIFORNIA
ENERGY
COMMISSION

SCENARIO ANALYSES OF CALIFORNIA'S ELECTRICITY SYSTEM: PRELIMINARY RESULTS FOR THE *2007 INTEGRATED ENERGY POLICY REPORT*

THIRD ADDENDUM

STAFF DRAFT REPORT

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ABSTRACT

This third addendum is a supplement to the original staff report *Scenario Analyses of California's Electricity System* (*Results Report*), issued in June 2007, and is prepared for the September 17, 2007, Integrated Energy Policy Report (IEPR) Committee Workshop. This addendum is intended to provide an overview of the results for three topics:

- Two additional energy efficiency scenarios.
- Carbon adder impact on coal plant dispatch.
- Resource balance and planning reserve margin analysis.

In the *Results Report*, California Energy Commission staff uses a scenario analysis approach to examine the implications of resource plans featuring very high penetrations of energy efficiency measures and renewable energy generation (both rooftop solar photo-voltaic and supply-side generating technologies) in California and the Western Interconnection. This third addendum will be merged with the preliminary results report when the final version of the *Results Report* is prepared later in 2007.

KEYWORDS: resource plans, energy efficiency, renewable generation, solar photo-voltaic, greenhouse gases, power generation, scenario analysis, generation costs, production costs, transmission, Western Interconnection, sensitivity assessment.

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CHAPTER 1: Background

The California Energy Commission (Energy Commission) staff report *Scenario Analyses of California's Electricity System* (*Results Report*), issued in June 2007, documents a wide-ranging set of results, assumptions, and methods used to assess a series of thematic scenarios emphasizing preferred resource strategies to reduce greenhouse gas (GHG) emissions.

The preliminary findings presented in the *Results Report* revealed that, despite creating scenarios to evaluate the consequences of aggressive penetrations of energy efficiency, rooftop photovoltaic, and supply-side renewable generating technologies, no scenario with actions identified for California achieves the 1990 standard of Assembly Bill 32 (Nunez Chapter 488, Statutes of 2005) if the reduction goal were applied to instate generation.[1] As a result of this finding, four additional scenarios with increased impacts from energy efficiency targeted for California were undertaken to evaluate the impact on generation and on carbon emissions. The primary focus is on California and what California can do to reduce GHG emissions. Using the 1990 level for comparison provides a frame of reference for the results of the scenario analyses.

Despite major penetrations of energy efficiency, rooftop photovoltaic (PV), and supply-side renewable generating technologies, the preliminary results showed coal plant generation and emissions across the Western Interconnection virtually unchanged. As a result of this finding, additional analyses were undertaken to evaluate the effect of a carbon adder or carbon tax on the dispatch of coal generation. Several levels of carbon adder were evaluated to determine the level that might affect coal plant dispatch. The study discussed in this report is not a comprehensive assessment of the implications of a carbon adder or tax, but a limited exploration of dispatch consequences leaving the resource mix unchanged.

In addition, the preliminary results raised questions about the resource balance and planning reserve margins across the scenarios and whether higher planning reserve margins could lead to higher costs and potentially impact GHG emissions. As a result of these questions, staff has prepared additional documentation and analysis for the existing nine scenarios presented in the *Results Report* to highlight the resource balance and planning reserve margins for each scenario and the implications of these levels.

[1] The California Air Resources Board (ARB) is developing an implementation plan to achieve the overall AB 32 goals, with the assistance of the Energy Commission and the California Public Utilities Commission for some of the five broad sectors outlined in that legislation. At this time, no decisions have been made as to whether any of the five broad sectors will be required to achieve more or less than its proportional share of the total reductions required.

Lastly, despite a desire to address all planned analyses within the original report, several topics could not be completed in time. Two of three outstanding items were addressed at the August 16 workshop, and one topic remains outstanding, water consumption assessments for power generation in California and the Rest-of-WECC (Western Electricity Coordinating Council). Development of water consumption factors simply proved too difficult with the time and the resources available.

This third addendum to the original draft report, prepared for the September 17, 2007, Integrated Energy Policy Report (IEPR) Committee Workshop, is intended to provide an overview of the results for three topics:

- Two additional energy efficiency scenarios.
- Carbon adder impact on coal plant dispatch.
- Resource balance and planning reserve margin analysis.

Several technical appendices provide the details of these assessments. The water consumption assessments are not yet complete and are not addressed in this report.

CHAPTER 2: Energy Efficiency

The *Results Report* documented in June 2007 described two levels of energy efficiency in California: 1) Case 1B – Current Requirements; and 2) Case 3A – High Energy Efficiency and Variable Demand Response in California Only. Two additional energy efficiency cases were developed to reflect even more aggressive development of energy efficiency in California. This section provides an overview of the assumptions for the higher energy efficiency levels and an assessment of the production cost and other system implications of higher levels of energy efficiency in California only and higher levels of energy efficiency combined with high levels of renewables in California only.

The discussion in this section is an overview drawing upon more detailed assumptions provided in Appendix A to this report. This discussion and the technical appendices will be merged with the preliminary results report when the final version of the *Results Report* is prepared later in 2007.

Overview of Energy Efficiency in the Scenarios Analyses

The following is a list of the nine thematic scenarios that were evaluated in the original scenarios analysis and reported in the *Results Report* and the four new scenarios (two new standalone energy efficiency scenarios and the combination of these higher levels with the original renewables of Scenario 4A) that are evaluated in this analysis, which are denoted in bold.[2]

Case 1 — Current conditions extended into the future.

Case 1B — Compliance with current requirements.

Case 2 — High sustained natural gas and coal prices.

Case 3A — High energy efficiency in California only.

Case 3B — High energy efficiency throughout the West.

Case 3D – Higher energy efficiency in California only.

Case 3E – Highest energy efficiency in California only.

Case 4A — High renewables in California only.

Case 4B — High renewables throughout the West.

Case 5A — High energy efficiency and renewables in California only.

Case 5B — High energy efficiency and renewables throughout the West.

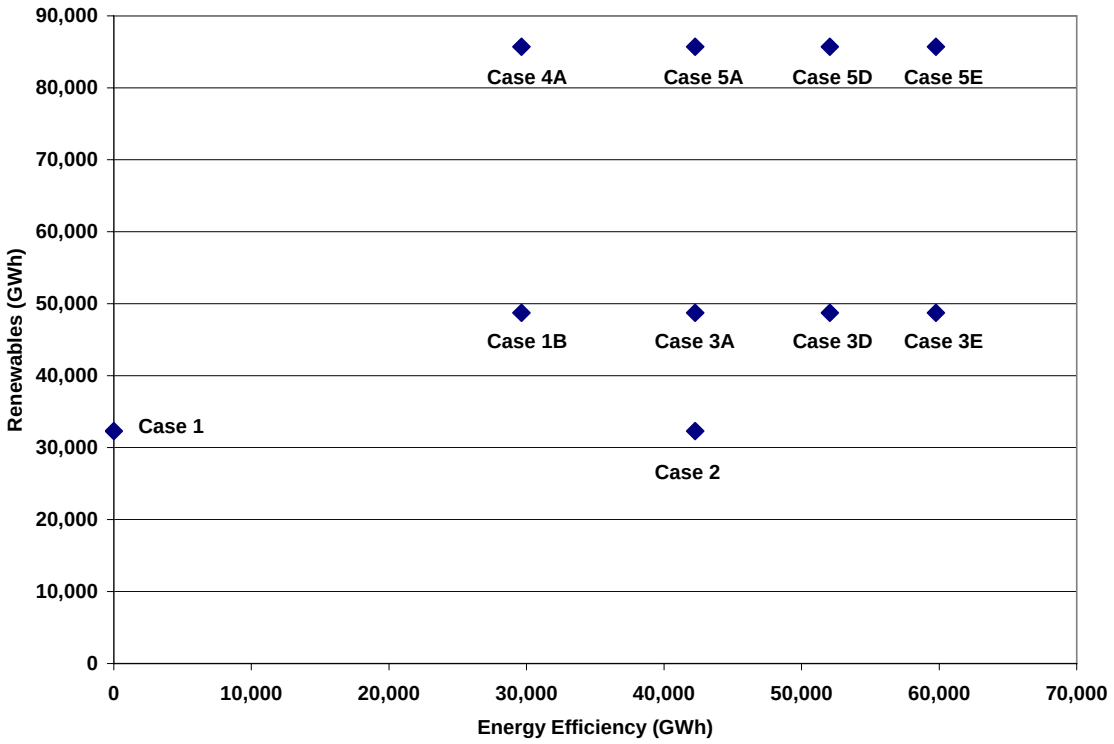
Case 5D – Higher energy efficiency and high renewables in California only.

[2] Case 3C was prepared in an abbreviated manner for use in assessing market price impacts of reduced power generation gas consumption. It was not fully evaluated and is not reported here.

Case 5E – Highest energy efficiency and high renewables in California only.

Figure 2-1 summarizes the relative differences among the thirteen scenarios in terms of their reliance upon energy efficiency and renewables in California. As depicted in the chart, there are four levels of energy efficiency modeled in the scenarios. Case 1 includes the California Public Utility Commission's 2004 to 2008 committed energy efficiency programs and the impacts of existing building and appliance efficiency standards, which are included in the Energy Commission staff's 2006 California load forecast. No additional incremental amounts of energy efficiency or uncommitted energy efficiency are modeled in Case 1. The energy efficiency levels defined in Case 1B are based on current practices. High energy efficiency levels in California are modeled in Case 2, Case 3A, Case 3D, and Case 3E; and these high energy efficiency levels are also combined with high renewables in California in Case 5A, Case 5D, and Case 5E. The high renewables levels in Cases 5A, 5D and 5E are based on the original high renewables levels found in Case 4A as depicted.

Figure 1: Preferred Resource Composition of California Thematic Scenarios in 2020



Source: Energy Commission Staff from Global Energy Results

The four scenarios for energy efficiency can be described as:

Current practices (Case 1B) – For California, the energy efficiency resources reflect the goals summarized in the investor-owned utility (IOU) 2006 procurement plans. For the rest-of-WECC, the current energy efficiency programs were assumed to be embedded in the load forecasts (that is the forecasts reflect sales net of reductions from energy efficiency programs).

Aggressive development (Case 3A) – Reflects aggressive expansion of energy efficiency programs. In California, this is equivalent to the economic potential (minus the portion of the economic potential attributable to emerging technologies) from the *California Energy Efficiency Potential Study. (2006 Itron Study)*

Partial emerging technology deployment (Case 3D) – In addition to the aggressive energy efficiency included in Case 3A, approximately 55 percent of the economic emerging technology potential in California is included.

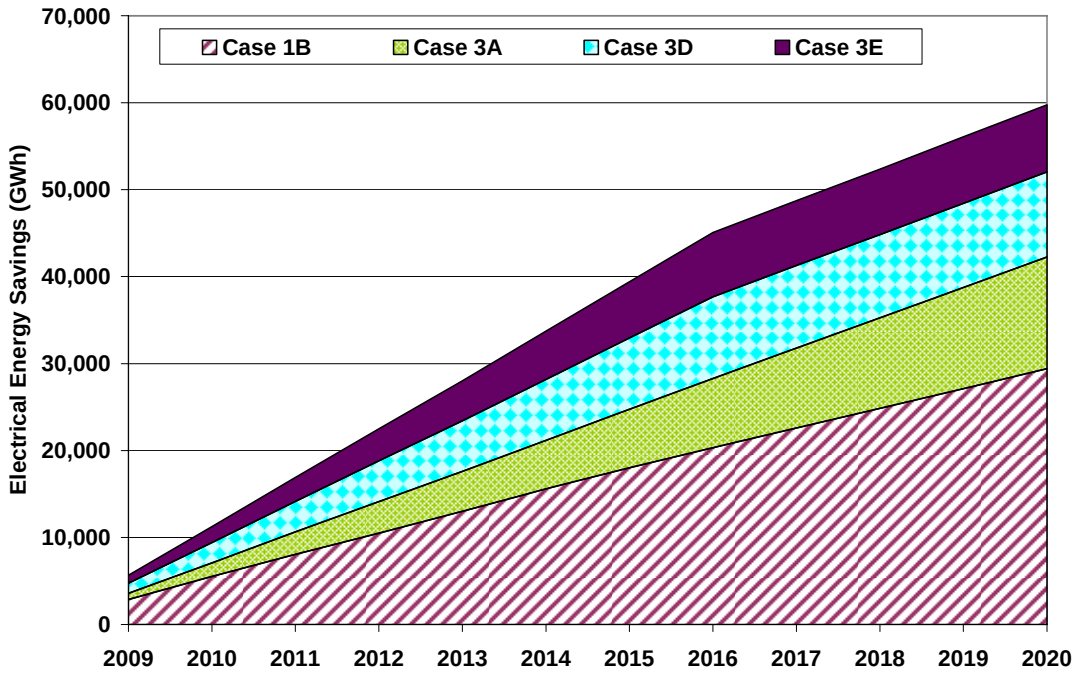
Full emerging technology deployment (Case 3E) – Includes the entire economic emerging technology potential in California.

For California, the energy efficiency scenarios are drawn from the 2006 Itron potential study[3]. Figure 2 depicts the four scenarios of energy efficiency through time graphically, and Table 1 presents the four scenarios numerically. The partial emerging technology deployment and full emerging technology deployment are the new energy efficiency scenarios that are the focus of this analysis. Per the Itron study, "by definition, emerging technologies have little or no market acceptance to date; therefore, estimates of the market potential associated with these technologies are by their very nature somewhat speculative." In the Itron study, emerging technologies were divided into two groups: ones that were commercially available, but uncommon and those that were not immediately commercially available.

Case 3A assumes that 77 percent of the economic potential is achieved. Emerging technology measures represent approximately 23 percent of the economic potential and amounts to approximately 12,481 gigawatt hour (GWh) by 2016. Staff developed two tiers of emerging technology deployment based upon a qualitative rating of the likelihood of success and levelized costs of energy saved. Case 3D includes approximately 55 percent of the emerging technology potential, while Case 3E includes the entire emerging technology potential. The potential in the *2006 Itron Study* developed for the IOUs through 2016 was extended in two ways: (1) to the publicly owned utilities (POUs), and (2) through 2020 for both IOUs and POUs. The potential through 2016 was assumed achieved each year equally between 2009 and 2016, or one-eighth of the potential was assumed achieved each year. After 2016, the potential was grown proportionately to each IOUs forecasted growth in sales (pre-energy efficiency). This assumption resulted in a flat California retail load between 2016 through 2020

[3] Itron, KEMA, RLW, and AEC, May 2006, *California Energy Efficiency Potential Study.*

Figure 2: Energy Efficiency Through Time By Case



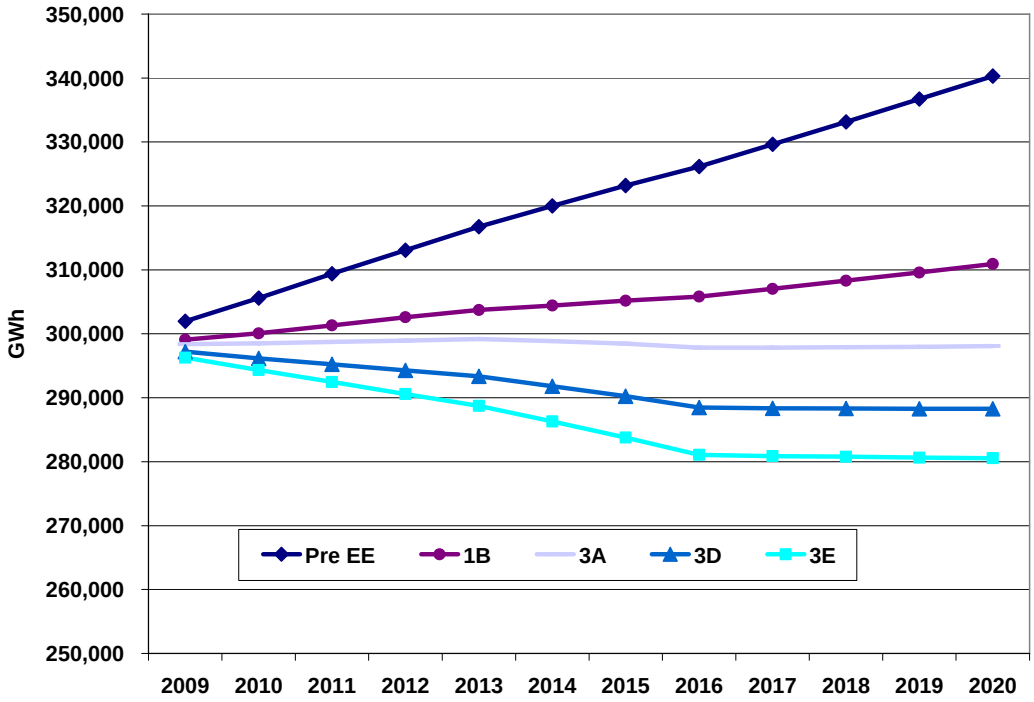
Source: Navigantt Consulting, Inc.

in Cases 3D and 3E after including the impacts of energy efficiency as depicted in Figure 3.

The net effect of these energy efficiency savings is virtually no growth in California retail loads in Case 3A, a decline in retail loads in case 3D, and a further decline in actual loads in Case 3E as depicted in Figure 3. The average annual decline between 2009 and 2020 is -0.3 percent in Case 3D and -0.5 percent in Case 3E.

The detailed assumptions for deriving the energy efficiency scenarios can be found in Appendix A of this report.

Figure 3: Projected Cumulative Impacts on Net Energy for Load



Source: Navigant Consulting, Inc.

Table 1: Cumulative Energy Efficiency Through Time By Case (GWh)

	Case 1B	Case 3A	Case 3D	Case 3E
2009	2,878	3,567	4,739	5,661
2010	5,544	7,086	9,428	11,273
2011	7,966	10,429	13,868	16,577
2012	10,554	14,136	18,813	22,496
2013	13,107	17,584	23,417	28,010
2014	15,719	21,174	28,200	33,734
2015	18,146	24,742	32,950	39,415
2016	20,477	28,293	37,683	45,078
2017	22,768	31,789	41,276	48,747
2018	25,035	35,247	44,824	52,366
2019	27,336	38,756	48,438	56,064
2020	29,638	42,263	52,053	59,763

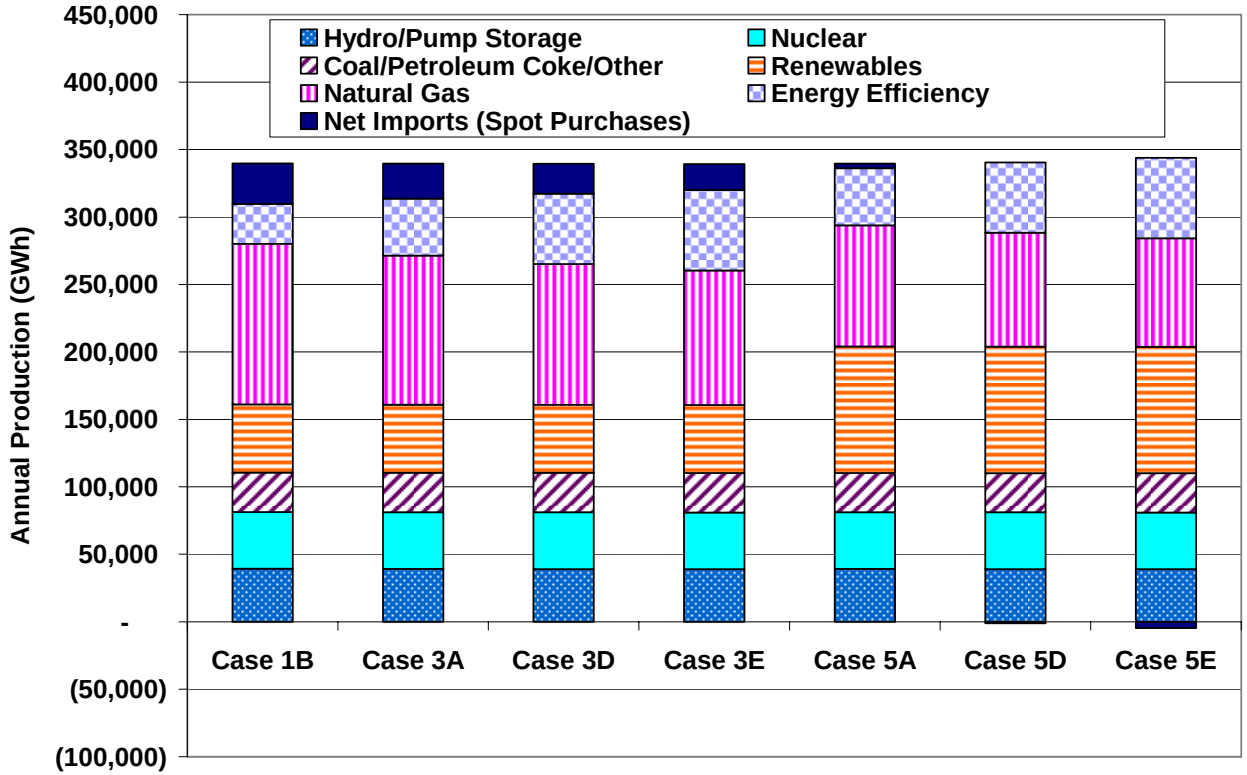
Source: Navigant Consulting, Inc.

Production Cost Model Results

This section provides an overview of the production cost model results and how these compare to the preliminary cases reported in the *Results Report*. The two-zone "scorecards," providing in-depth results comparable to those of the *Results Report* is found in Appendix B.

Figure 4 and Table 2 show the composition of generation to meet California load in 2020. To focus on the new energy efficiency scenarios, the three high energy efficiency cases (Case 3A, Case 3D, and Case 3E) can be compared against one another, and the three high energy efficiency and renewables cases (Case 5A, Case 5D, and Case 5E) can be compared against one another. In general, higher levels of energy efficiency displace natural gas and net imports (spot purchases). In Case 5D and Case 5E with high renewables and higher energy efficiency, California becomes a net exporter as depicted in Figure 5. The combination of high level of renewables in Case 5D and Case 5E is a key driver in this result since California is a net importer in the high energy efficiency cases (Case 3A, Case 3D, and Case 3E) or in the original high renewables case 4A. The "export" result is an artifact of the assumed levels of energy efficiency and renewables constituting cases 5D and 5E. Whether "exports" would really happen on any sustained basis depends upon a host of specific regulatory incentives and requirements that are beyond the scope of this project.

Figure 4: Composition of Generation (GWh) to Meet California Load in 2020[4]



Source: Energy Commission Staff from Global Energy Results

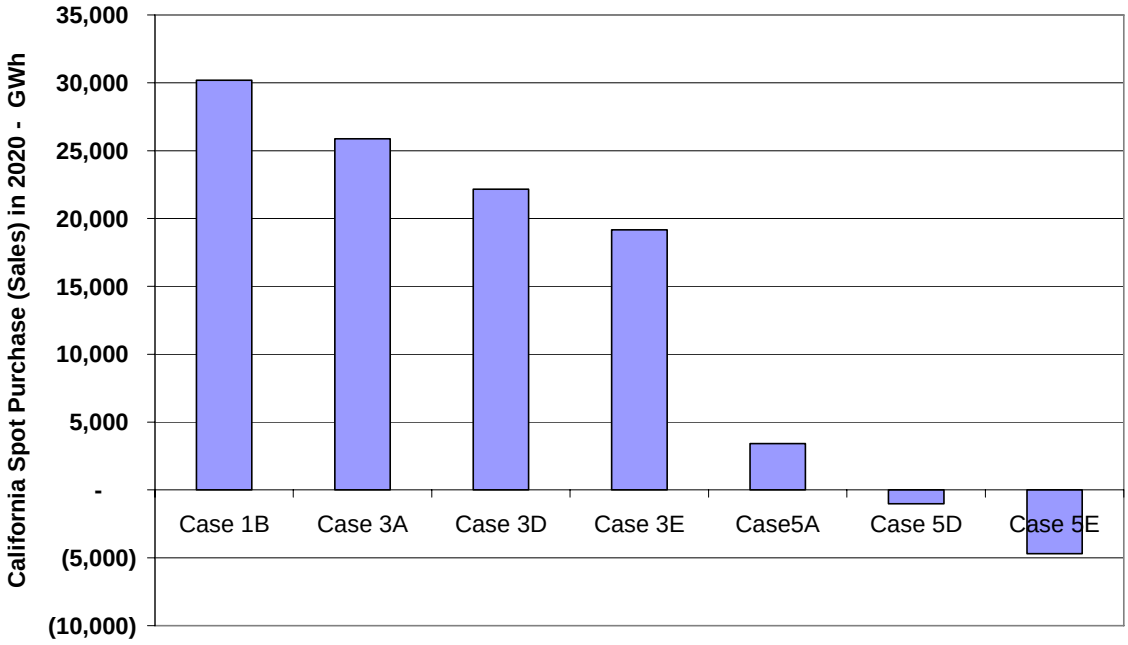
[4] The generation includes remote generation serving California load, and the remote generation was allocated to the appropriate category of generation. Renewables is comprised of geothermal, wind, biomass, concentrating solar power, PV rooftop solar, and other renewables. Fuel oil is included in the Coal/Petroleum Coke/Other category and accounts for less than 0.11 percent of this category.

Table 2: Composition of Generation (GWh) to Meet California Load in 2020

	Case 1B	Case 3A	Case 3D	Case 3E	Case 5A	Case 5D	Case 5E
Coal/Petroleum Coke/Other	29,269	29,232	29,220	29,208	29,088	29,043	29,013
Energy Efficiency	29,638	42,263	52,053	59,763	42,263	52,053	59,763
Hydro/Pump Storage	39,329	39,162	39,066	38,975	39,124	39,026	38,957
Natural Gas	118,926	110,593	104,489	99,753	89,825	84,490	80,453
Net Imports (Spot Purchases)	30,197	25,877	22,165	19,168	3,414	(1,028)	(4,694)
Nuclear	42,101	42,101	42,101	42,101	42,101	42,101	42,101
Renewables	50,371	50,370	50,369	50,368	93,743	93,737	93,731

Source: Energy Commission Staff from Global Energy Results

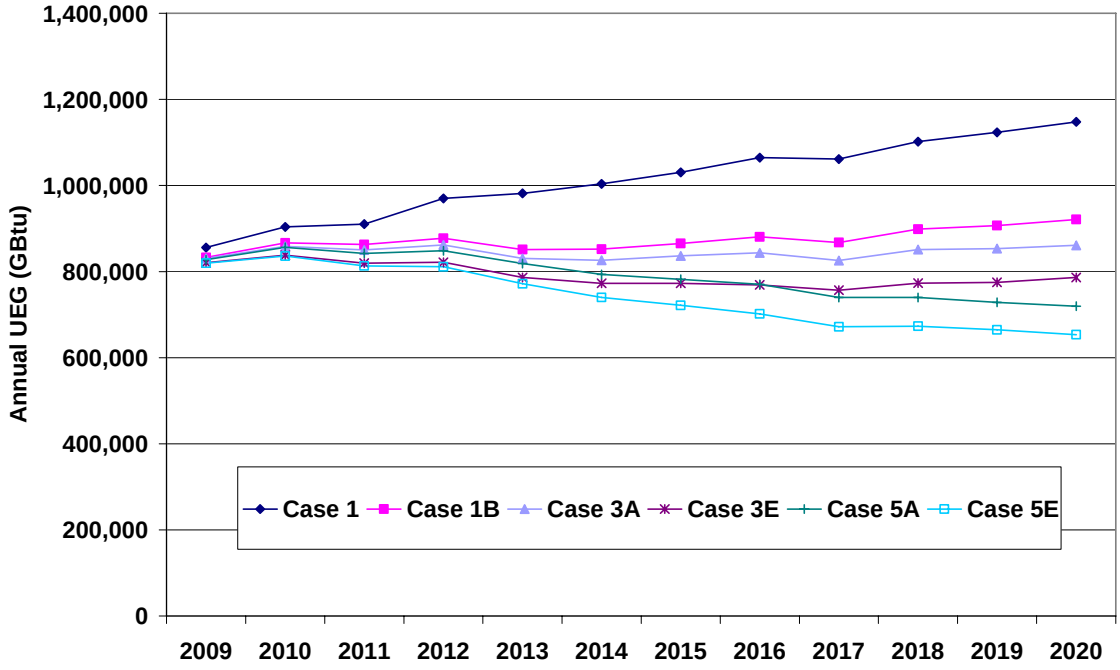
Figure 5: California Spot Purchases (Sales) in GWh in 2020



Source: Energy Commission Staff from Global Energy Results

As natural gas generation in California gets displaced by higher levels of energy efficiency, California gas consumption declines through time. Figure 6 depicts total California gas consumption for power generation through time. The results of the high energy efficiency cases, Case 3D and Case 3E, show that growth in total California gas consumption is flat through time, and the results for high energy efficiency combined with high renewables, Case 5A, Case 5D and Case 5E, show a decline in the California gas consumption for power generation.

Figure 6: Total California Gas Consumption for Power Generation Through Time (GBTu)



Source: Energy Commission Staff from Global Energy Results

The carbon emissions (carbon dioxide only) reported in the *Results Report* were reported in short tons, which is 2,000 pounds per ton. Another common unit for reporting is the metric ton, which is equal to 1,000 kilograms or approximately 2,204 pounds. Since all results in the Scenario Assessment Project are reported in short tons, conversions from metric tons may be necessary to allow comparison of the Scenarios Assessment Project results with values from other projects. Figure 2-7 shows the carbon emissions for California instate generation[5] for all thirteen thematic scenarios through time along with historic carbon emissions inventory and an AB 32 goal of 51.3 million short tons of carbon, an illustrative proportional contribution to the target from electricity generators in California. The California Air Resources Board (ARB) has not stated that it will require each sector to reduce its carbon emissions to 1990 levels, and it could require more or less reductions for the electricity sector. Using the 1990 level for comparison provides a frame of reference for the results of the scenarios analyses. The results show

[5] The Scenario's project use of California instate carbon production should not be considered synonymous with source-based or first-seller, and California carbon responsibility should not be considered synonymous with load-based cap. California Air Resources Board is still working on designing and implementing a process to address AB 32 goals of GHG emission reductions.

that in Case 3D and Case 3E, with higher levels of energy efficiency modeled in California, the AB 32 goal of reducing emissions to 1990 levels is not achieved by 2020. However, the results show that in Case 5E, modeled with the highest level of energy efficiency including full emerging technology potential plus high renewables, the AB 32 goal of a 1990 standard is achieved by 2020, and Case 5D might meet the range of the standard by 2020. Unlike the original group of nine scenarios reported in the results report, this extended set of scenarios does now just barely achieve the implied ARB goal as computed using the Energy Commission inventories for GHG emissions from early 2007. Since the ARB inventories for GHG emissions are changing, only the Energy Commission inventories are presented.

The impact from WECC-wide policies is shown in Cases 3B, 4B, and 5B. In Figure 7, Case 5B has the largest impact on California instate carbon production. If the higher energy efficiency levels were modeled WECC-wide with high renewables, the impact on California instate carbon production would be even greater. However, as previously stated in the Addendum report, California policy makers cannot achieve the implementation of Case 5B without the cooperation of other Western state leaders[6].

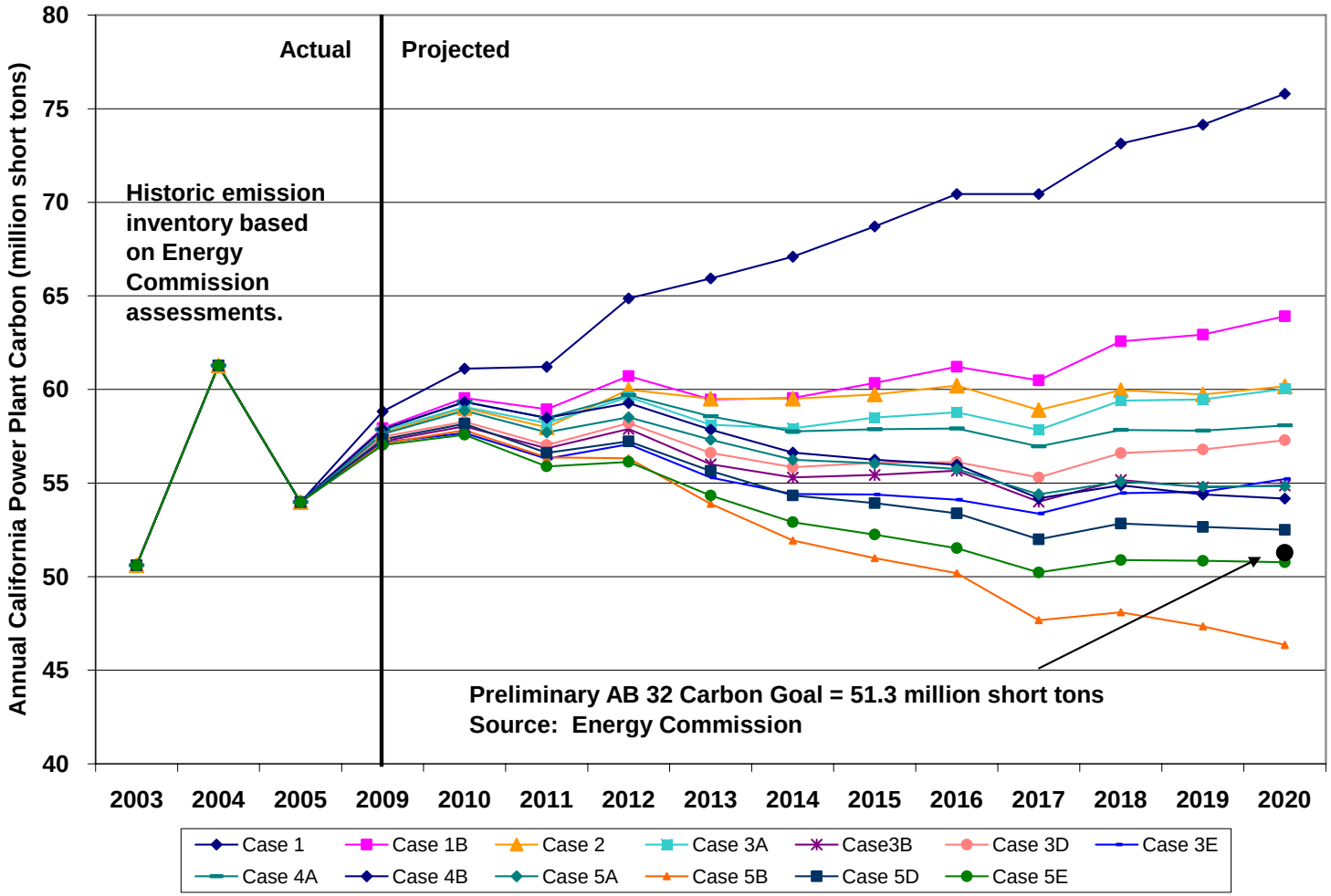
Figure 8 shows the carbon emissions (carbon dioxide) for the sum of power plants located in California, remotely owned generation or under long-term contract to California utilities and short-term market purchase imports (also known as the California carbon responsibility) for all thirteen thematic scenarios through time along with historic carbon emissions inventory, including net imports and an implied AB 32 range for a 1990 level of 99.1 million short tons, if the standard is applied to load-serving entities proportionally. Again, using the 1990 level for comparison purposes provides a frame of reference for the results of the Scenario project but in no way implies that the ARB standard will be applied in this manner. The results show that with more aggressive energy efficiency and partial emerging technology potentials modeled, Case 3D achieves the proportional AB 32 goal by 2020. With the highest level of energy efficiency and full emerging technology potentials modeled, Case 3E exceeds the proportional AB 32 goal by 2020. Furthermore, higher energy efficiency and high renewables combined also show that Case 5D and Case 5E far exceed the AB 32 goal by 2020. The change in California from being a net importer to a net exporter appears to be a key factor in these results. The average carbon emissions per instate generation is lower than the average carbon emissions per net import. In Case 1B, carbon per instate generation is 0.27 tons of CO2 per GWh and carbon per net import is 0.56 tons of CO2 per GWh in 2020, so a change in net imports will have a bigger impact on carbon reductions.

[6] Six Western states and the province of British Columbia have pledged to pursue actions to achieve GHG emission reductions.

Table 3 shows California carbon responsibility through time. As discussed in Section 3.1 of the *Results Report,* imported generation is computed using annual average emissions in the same proportions as the annual average for Rest-of-WECC carbon emissions. For consistency, this same method was applied when California became a net exporter in Case 5D and Case 5E, except using annual average emissions in the same proportions as the annual average for California carbon emissions. Since net imports are shown with a negative sign, the carbon emissions attributed to California based on imports also show a negative sign or a credit to California's carbon responsibility.

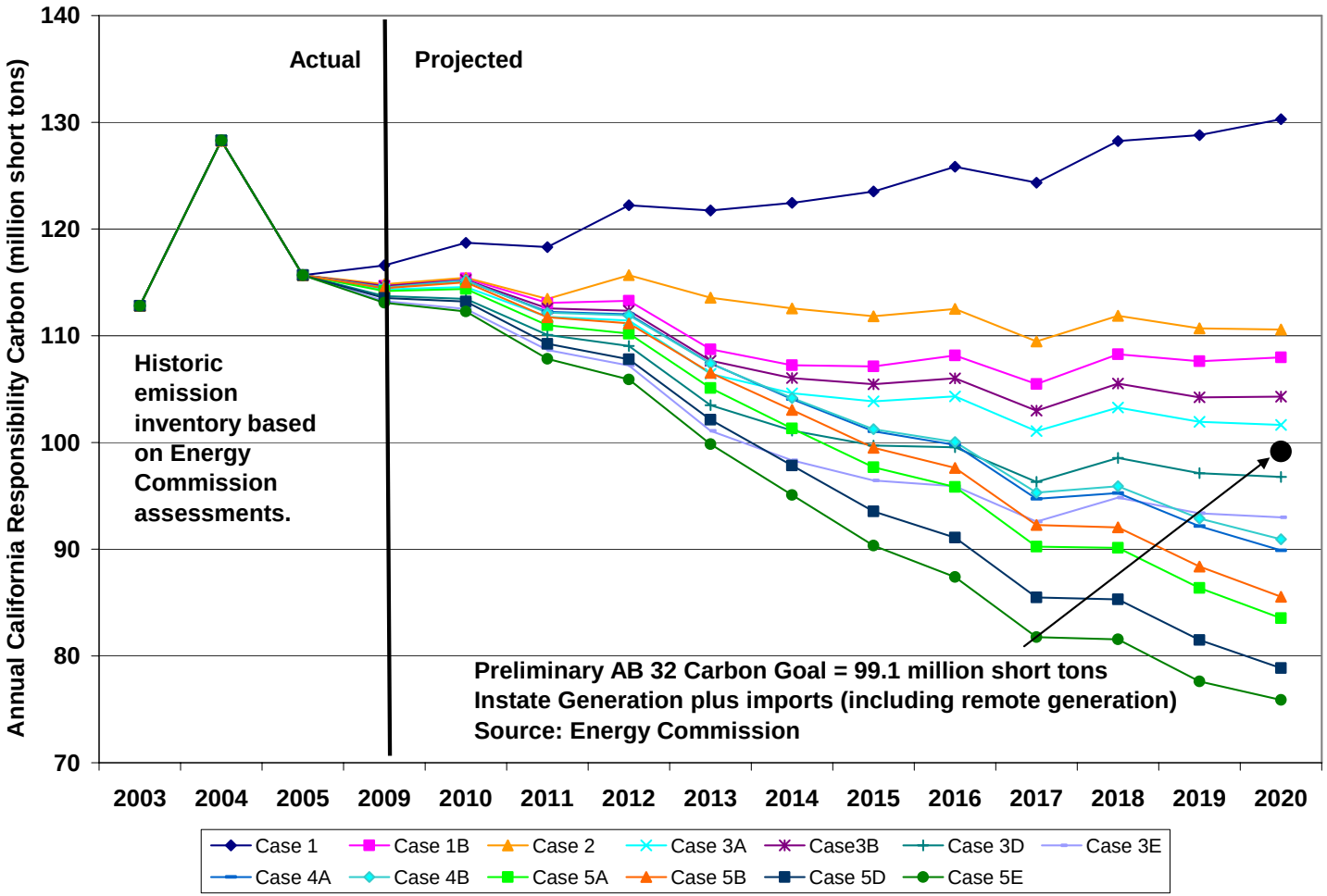
This analysis only evaluated higher energy efficiency levels and higher energy efficiency levels with high renewables (as originally modeled in Case 4A). Higher renewables than that assumed in Case 4A were not considered because of time constraints. Further analysis could be conducted to include higher renewables assumptions, which could extend further into preferred resource options of renewables and energy efficiency in helping California achieve its goal of GHG emission reductions.

Figure 7: California Instate Carbon Production Through Time By Case



Source: Global Energy Decisions, Inc., and California Energy Commission

Figure 8: California Carbon Responsibility (Includes Instate Generation, Remote Generation, and Net Imports) Through Time By Case



Source: Global Energy Decisions, Inc., and California Energy Commission

Table 3: California Carbon Responsibility Through Time By Source (Thousand short tons of carbon dioxide per year)[7]

		2010	2012	2014	2016	2018	2020
Case 1	CA CO2 Production	61,112	64,865	67,096	70,435	73,142	75,803
	CA Remote CO2	26,964	27,065	27,098	27,218	27,232	27,267
	CA Import CO2	30,629	30,299	28,266	28,188	27,859	27,211
	Total CO2	118,705	122,229	122,459	125,842	128,233	130,281
Case 1B	CA CO2 Production	59,543	60,714	59,546	61,203	62,575	63,907
	CA Remote CO2	26,939	26,942	26,938	27,083	27,099	27,087
	CA Import CO2	28,877	25,624	20,760	19,866	18,600	16,982
	Total CO2	115,359	113,280	107,244	108,152	108,273	107,976
Case 2	CA CO2 Production	59,003	59,987	59,508	60,201	59,957	60,164
	CA Remote CO2	26,864	26,815	26,843	26,953	26,984	26,946
	CA Import CO2	29,577	28,885	26,199	25,370	24,938	23,477
	Total CO2	115,443	115,686	112,550	112,524	111,879	110,588
Case 3A	CA CO2 Production	59,066	59,589	57,927	58,781	59,408	60,032
	CA Remote CO2	26,930	26,911	26,914	27,053	27,065	27,048
	CA Import CO2	28,580	24,937	19,780	18,497	16,792	14,572
	Total CO2	114,575	111,436	104,621	104,331	103,266	101,652

[7] The total may not exactly equal the sum of the rows because of rounding.

		2010	2012	2014	2016	2018	2020
Case 3B	CA CO2 Production	58,031	57,892	55,304	55,658	55,162	54,868
	CA Remote CO2	26,892	26,806	26,744	26,828	26,791	26,755
	CA Import CO2	30,312	27,652	23,996	23,528	23,568	22,671
	Total CO2	115,234	112,349	106,044	106,014	105,521	104,294
Case 3D	CA CO2 Production	58,285	58,204	55,855	56,115	56,595	57,283
	CA Remote CO2	26,919	26,877	26,861	27,018	27,033	27,000
	CA Import CO2	28,245	23,960	18,394	16,428	14,923	12,496
	Total CO2	113,450	109,042	101,109	99,561	98,550	96,780
Case 3E	CA CO2 Production	57,666	57,066	54,405	54,109	54,464	55,216
	CA Remote CO2	26,904	26,858	26,816	26,955	26,978	26,950
	CA Import CO2	27,956	23,294	17,109	14,835	13,384	10,816
	Total CO2	112,526	107,219	98,329	95,898	94,827	92,982
Case 4A	CA CO2 Production	59,340	59,695	57,758	57,913	57,839	58,078
	CA Remote CO2	26,935	26,935	26,906	26,988	26,931	26,843
	CA Import CO2	28,890	25,372	19,390	14,870	10,482	4,970
	Total CO2	115,166	112,002	104,054	99,771	95,251	89,891
Case 4B	CA CO2 Production	59,323	59,279	56,623	55,978	54,876	54,172
	CA Remote CO2	26,935	26,914	26,813	26,842	26,619	26,314

		2010	2012	2014	2016	2018	2020
	CA Import CO2	28,921	25,731	20,721	17,222	14,404	10,451
	Total CO2	115,179	111,925	104,157	100,042	95,899	90,938
Case 5A	CA CO2 Production	58,862	58,507	56,251	55,750	55,092	54,836
	CA Remote CO2	26,938	26,896	26,849	26,922	26,862	26,777
	CA Import CO2	28,594	24,808	18,219	13,168	8,175	1,934
	Total CO2	114,394	110,211	101,319	95,840	90,129	83,547
Case 5B	CA CO2 Production	57,829	56,321	51,927	50,181	48,096	46,356
	CA Remote CO2	26,874	26,766	26,513	26,128	25,346	24,257
	CA Import CO2	30,317	28,060	24,618	21,316	18,616	14,932
	Total CO2	115,020	111,147	103,058	97,625	92,058	85,545
Case 5D	CA CO2 Production	58,161	57,227	54,339	53,385	52,830	52,496
	CA Remote CO2	26,907	26,861	26,805	26,871	26,829	26,709
	CA Import CO2	28,144	23,709	16,685	10,828	5,642	(335)
	Total CO2	113,211	107,796	97,829	91,084	85,300	78,871
Case 5E	CA CO2 Production	57,576	56,136	52,911	51,519	50,886	50,767
	CA Remote CO2	26,902	26,839	26,781	26,829	26,759	26,630
	CA Import CO2	27,791	22,934	15,379	9,046	3,911	(1,522)
	Total CO2	112,269	105,909	95,071	87,395	81,556	75,875

Source: Energy Commission Staff from Global Energy Results

To place these elements of California carbon responsibility in context, Table 4 shows California carbon responsibility and the rest-of-WECC carbon responsibility. The remote generation reported for Rest-of-WECC is the portion of the total plant output not assigned by ownership or long term contract to California. As expected, total WECC carbon emissions decline as more energy efficiency is assumed in the scenarios. However, the rest-of-WECC carbon emissions do not change significantly between the sets of cases, one set being the high energy efficiency cases and the other set being high energy efficiency combined with high renewables. All six cases other than Case 1B, while reflecting differing combinations of energy efficiency or renewables in California, have identical loads and generation capacity in Rest-of-WECC. Thus the decline in California imports is synonymous with a decline in Rest-of-WECC exports, which slightly alters the mix of plants used to produce power to serve WECC loads, thus causing the slight increases in GHG emissions in Rest-of-WECC.

Table 4: Predicted GHG Emissions for California and Rest-of-WECC (Thousand tons of carbon dioxide per year) in 2020[8]

Annual CO2 (000 short tons)	Case 1B	Case 3A	Case 3D	Case 3E	Case 5A	Case 5D	Case 5E
California Production	63,907	60,032	57,283	55,216	54,836	52,496	50,767
California Remote Generation	27,087	27,048	27,000	26,950	26,777	26,709	26,630
California Spot Purchase (Sales)	16,982	14,572	12,496	10,816	1,934	(335)	(1,522)
Total California Responsibility	107,976	101,652	96,780	92,982	83,547	78,871	75,875
Rest-of-WECC Production	354,757	355,389	356,037	356,546	358,607	359,308	359,805
Rest-of-WECC Remote Generation	36,294	36,247	36,169	36,101	35,840	35,759	35,645
Total Rest-of-WECC	391,051	391,637	392,206	392,647	394,447	395,067	395,450
Total WECC	499,027	493,289	488,986	485,629	477,994	473,690	470,183

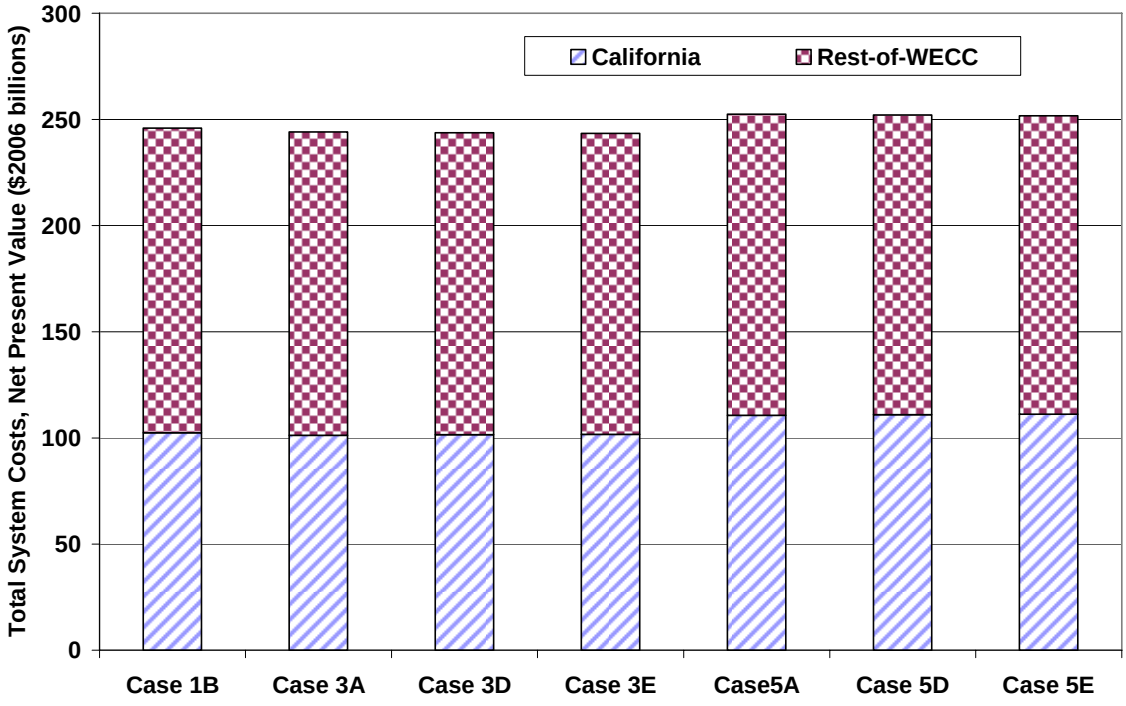
Source: Energy Commission Staff from Global Energy Results

[8] The total may not exactly equal the sum of the rows because of rounding.

Figure 9 and Table 5 report the net present value of total system costs using a discount rate of 8.6 percent. The California system cost savings from the energy efficiency cases are between $0.72 billion and $1.24 billion on a net present value basis over Case 1B. The California system cost from the energy efficiency combined with renewables cases are between $8.17 billion to $8.77 billion more on a net present value basis than Case 1B.

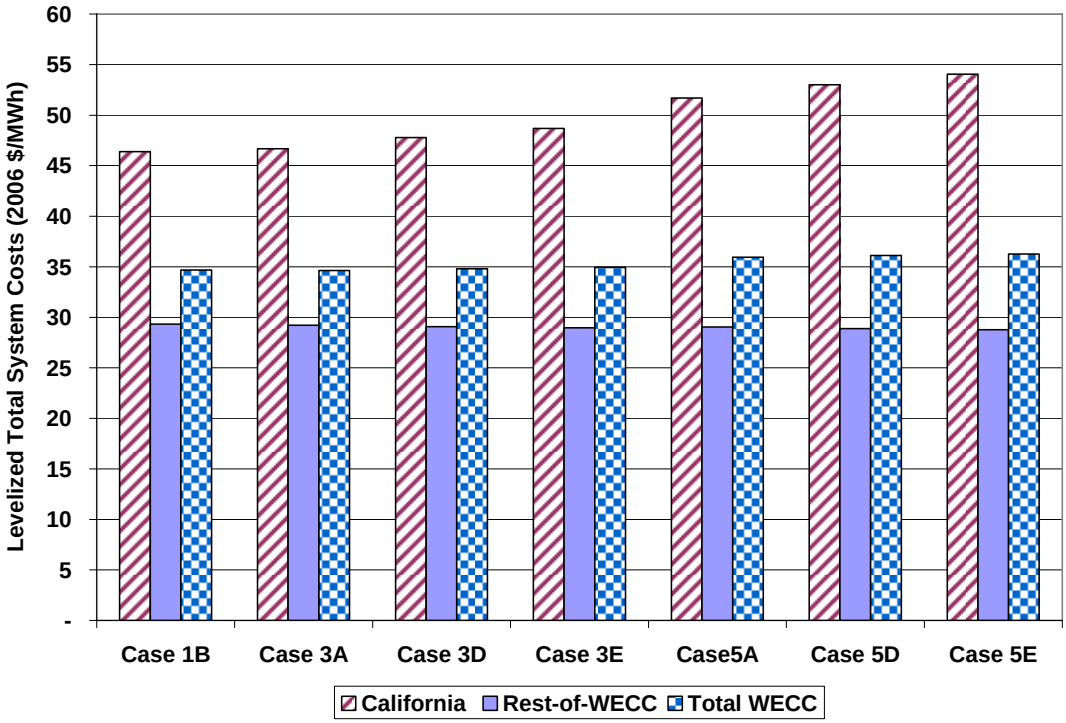
Figure 10 and Table 6 show levelized system costs on a $/MWh basis. To calculate annual system costs in $/MWh, total system costs in dollars are divided by load less demand-side resources of energy efficiency and PV rooftop solar in MWh. The denominator in this calculation changes across the cases as energy efficiency and PV rooftop solar assumptions vary across the cases. The denominator in the energy efficiency cases is smaller than the denominator in the other cases. The annual costs in $/MWh between 2009 through 2020 are levelized to produce a levelized system cost in $/MWh. As a result of this calculation, energy efficiency increases levelized system costs in California on a $/MWh basis, but consumption is lower, resulting in lower total system costs in dollars.

Figure 9: Total System Costs, Net Present Value ($2006 Billion)



Source: Energy Commission Staff from Global Energy Results

Figure 10: Levelized System Costs ($2006/MWh)[9]



Source: Energy Commission Staff from Global Energy Results

Table 5: Total System Costs, Net Present Value ($2006 Billions) [10]

	California	Rest-of-WECC	Total WECC
Case 1B	102.420	143.485	245.905
Case 3A	101.183	142.940	244.123
Case 3D	101.467	142.272	243.739
Case 3E	101.704	141.722	243.426
Case 5A	110.589	141.926	252.515
Case 5D	110.927	141.168	251.776
Case 5E	111.194	140.581	251.776

Source: Energy Commission Staff from Global Energy Results

[9] The annual system costs are levelized between 2009 through 2020 using a discount rate of 8.60 percent.

[10] The total may not exactly equal the sum of the columns because of rounding.

Table 6: Levelized System Costs ($2006/MWh)

	California	Rest-of-WECC	Total WECC
Case 1B	46.38	29.31	34.67
Case 3A	46.67	29.20	34.63
Case 3D	47.78	29.07	34.81
Case 3E	48.69	28.96	34.95
Case5A	51.70	29.02	35.93
Case 5D	52.99	28.87	36.11
Case 5E	54.05	28.76	36.26

Source: Energy Commission Staff from Global Energy Results

Table 7 shows a summary of annual total system costs and carbon in 2020. California total system costs and carbon emissions both decline in the high energy efficiency cases. Though total system costs increase in the high energy efficiency combined with renewables cases, the carbon reductions are the greatest in these scenarios. There is a trade-off between costs and carbon reductions.

Table 7: Summary of Annual System Costs and Carbon in 2020

	California		Rest-of-WECC		Total WECC	
	2020 System Costs ($2006 000)	**2020 GHG Instate Emissions (000 tons)**	**2020 System Costs ($2006 000)**	**2020 GHG Emissions (000 tons)**	**2020 System Costs ($2006 000)**	**2020 GHG Emissions (000 tons)**
Case 1B - Current Requirements	16,354,098	63,907	27,492,976	435,120	43,847,073	499,027
Case 3A - High EE in Calif. Only	15,701,704	60,032	27,282,068	433,257	42,983,772	493,289
Case 3D - Higher EE in Calif. Only	15,181,514	57,283	27,109,006	431,702	42,290,520	488,986
Case 3E - Highest EE in Calif. Only	14,784,143	55,216	26,967,458	430,413	41,751,601	485,629
Case5A - High EE and Renewables in Calif. Only	18,407,604	54,836	26,336,758	423,158	44,744,362	477,994
Case 5D - Higher EE and Renewables in Calif. Only	17,909,019	52,496	26,142,294	421,193	43,496,544	473,690
Case 5E - Highest EE and Renewables in Calif. Only	17,518,242	50,767	25,978,301	419,416	43,496,544	470,183

Source: Energy Commission Staff from Global Energy Results

Implications of the Results

What do these results mean for California or for policy makers interested in energy efficiency, rooftop solar PV, and supply-side renewable generating technologies as strategies to achieve AB 32 goals? Table 8 provides an overview of the new cases in conjunction with the original ones relative to Case 1B. Case 1B reflects staff's expectations of compliance with current requirements or current practice. All of the remaining cases compared to Case 1B reflect the cost and performance differences of these additional emphases on energy efficiency and renewables.

Cases 3A, 3D, and 3E reflect successively increasing levels of GHG reduction by 2020. The cost per unit of GHG reduction from alternative levels of energy efficiency is relatively constant. Most importantly, the cost is negative, for example, society is better off with these higher levels than without them. Energy efficiency is less costly than the generating resources it displaces, so not only does it provide a public good in emission reductions, it provides a collective good to the ratepayers by saving direct expenditures. Case 4A is clearly more costly per unit of GHG reduced than is the energy efficiency, as is Case 5A. Case 5A, however, blends the reduced expenditures for electricity customers with the increased outlays of Case 4A to get both higher total GHG reductions as well as lower increases in aggregate electricity costs than in Case 4A alone. From this perspective, Cases 5D and 5E are also preferred to Case 5A since the increased levels of energy efficiency dilute the out-of-pocket costs to electricity consumers while achieving greater aggregate GHG emissions reductions.

While Cases 3D and 3E are very appealing, their obvious disadvantage compared to Case 3A is that they depend upon emerging technologies that are more speculative than known technologies. The assumptions embodied in the *Itron Study* make these emerging technologies highly attractive, but it is quite possible that they will be more expensive. Case 3A was more conservative, in that it included all of the potential that was cost-effective, except the portion associated with emerging technologies.

The new efficiency cases are also dependent upon program designs that can achieve essentially all of the cost-effective energy efficiency potential identified for the state in the *2006 Itron Study*. Is this actually achievable? Numerous studies have found that achievable energy efficiency savings are less than what economic potential studies have identified. Whether the full potential is achievable is inherently linked to the design of specific programs, which this project has not investigated. Furthermore, are the specific program designs palatable to those who might choose to participate?

Table 8: Measuring Cost Effectiveness of Strategies by Assessing Differences from Case 1B

	2020 System Cost Difference	2020 GHG Instate Emission Difference	2020 Reduction ($/ton)	2020 GHG California Responsibility Emission Difference	2020 Reduction ($/ton)
Case 1B	-	-	NA	-	NA
Case 3A	(652,394)	(3,876)	(168.34)	(6,324)	(103.17)
Case 3D	(1,172,584)	(6,624)	(177.01)	(11,196)	(104.73)
Case 3E	(1,569,955)	(8,691)	(180.63)	(14,994)	(104.71)
Case 4A	2,580,912	(5,829)	442.75	(18,085)	142.71
Case 5A	2,053,506	(9,071)	226.37	(24,429)	84.06
Case 5D	1,554,921	(11,411)	136.26	(29,105)	53.42
Case 5E	1,164,144	(13,140)	88.59	(32,100)	36.27

Source: Energy Commission Staff from Global Energy Results

CHAPTER 3 – Carbon Adder Impact on Dispatch of Coal Plants

Despite major penetrations of energy efficiency, rooftop photovoltaic, and supply-side renewable generating technologies, the preliminary *Results Report* showed coal plant generation and emissions virtually unchanged. Chapter 10 of the *Results Report* suggested that further work would be needed on measures targeted specifically to coal plants, or perhaps carbon emitting plants, to achieve reductions from this portion of the West's resources. The discussion at the workshop held on June 18, 2007, speculated about carbon adder or carbon tax programs and the level of adder that might be required to affect coal plant dispatch. As a result of that discussion, staff initiated an effort to determine what the Scenario project could provide as insights about coal plant emissions within the limits of the waning months of the project.

Staff and Global Energy determined that a modest "dispatch" assessment was within the scope of resources available to the assessment project. A complete assessment of carbon adders, or regulatory schemes to control coal emissions, was far too broad for this project. Instead, the existing scenarios developed into MultiSym datasets could be used to determine how the resource plans embodied therein might react were a carbon adder to be imposed. Consequently, this is an examination of fossil fuel plant dispatch changes as a carbon adder increases the effective dispatch price of each existing plant. It is **not** an examination of how the resource mix might gradually evolve through time if a carbon tax were to be imposed on the electric generating industry. It is **not** an assessment of the tradeoffs between owners of coal facilities paying a carbon tax to reduce CO2 emissions compared to available alternatives in a cap and trade regulatory environment.

Approach

Staff and Global Energy selected two of the nine thematic scenarios as baseline values to use in assessing dispatch changes with levels of carbon adder at $10, $20, $40, and $60/short ton. This adder applied to both natural gas and coal-fired generating facilities, although the impact on coal plants is larger because of the greater carbon dioxide emission factor for coal plants compared to natural gas plants. Table 9 resents generic heat rate and emission factor assumptions for a combined-cycle, gas turbine, and coal plant. The impact of the carbon adder on the dispatch cost of these different types of units at the different levels of carbon adder is included in the lower part of the table. This dispatch adder gets added to the other variable operating costs of the plant to determine its dispatch cost in an economic dispatch.

Table 9
Generic Unit Carbon Dispatch Adder Impact ($/MWh)

	Generic Combined Cycle	Generic Gas Turbine	Generic Coal
Heat Rate (Btu/kWh)	6,500	10,500	9,300
CO2 Emissions Factor (pounds/MMBtu)	119	119	205
Carbon Adder			
$10/short ton	$ 3.87	$ 6.25	$ 9.54
$20/short ton	$ 7.74	$ 12.50	$ 19.08
$40/short ton	$ 15.47	$ 24.99	$ 38.17
$60/short ton	$ 23.21	$ 37.49	$ 57.25

Source: California Energy Commission

Case 1 is the most conventional resource plan and includes the least levels of energy efficiency, rooftop PV, and renewables. It would be expected to have the greater fossil resources, and thus be the most exposed to a carbon adder of any scenario.

Case 5B is the West-wide penetration of high end-user energy efficiency measures, high rooftop PV, and high levels of supply-side renewable generating technologies. It has already been shown in the *Results Report* to have the least proportions of fossil generation of any of the thematic scenarios. It would be expected to be the least exposed to a carbon adder.

Global Energy ran the production cost model for 2009 through 2020 for each of the two selected cases with four levels of carbon adder. This makes a total of eight new runs to be added to the original baseline runs for each of the two cases, which had no carbon adder. Although all of the variables of the "scorecards" are not of direct interest for this partial analysis, processing the ten cases using the standard scorecard allows a complete comparison.

Production Cost Model Results

Table 10 highlights key changes between Case 1 and Case 5B, and then between Case 1 with a high carbon adder and Case 5B with a high carbon adder. Table 10 is organized to show a progression through time for each of the two cases investigated. For Case 1, read the table in the following sequence:

1. The progression from 2009 to 2020 (no adder) shows how fossil-fueled plants grow through time in this most conservative scenario,
2. The progression from 2020 (no adder) to 2020 ($60/ton adder) shows how the generation in 2020 would change if a carbon adder of that level were instituted in that year.

Comparing 2020 (no adder) with 2020 ($60/ton adder) shows a major reduction in Rest-of-WECC coal and a substantial increase in both Rest-of-WECC and California natural gas power plant generation.

Table 10: Generating System Changes in Response to a Carbon Adder (Annual GWh Generated in WECC or Its Sub-regions)

	2009 Generation (No adder)	2020 Generation (No adder)	2020 Generation ($60/short ton)
Case 1			
CA Coal	3,157	3,157	3,037
CA Natural Gas	104,914	145,878	181,066
Rest-of-WECC Coal	222,460	275,537	184,303
Rest-of-WECC Natural Gas	115,902	186,469	260,937
Case 5B			
CA Coal	--	3,120	2,239
CA Natural Gas	--	64,976	105,210
Rest-of-WECC Coal	--	231,618	129,718
Rest-of-WECC Natural Gas	--	66,362	151,389

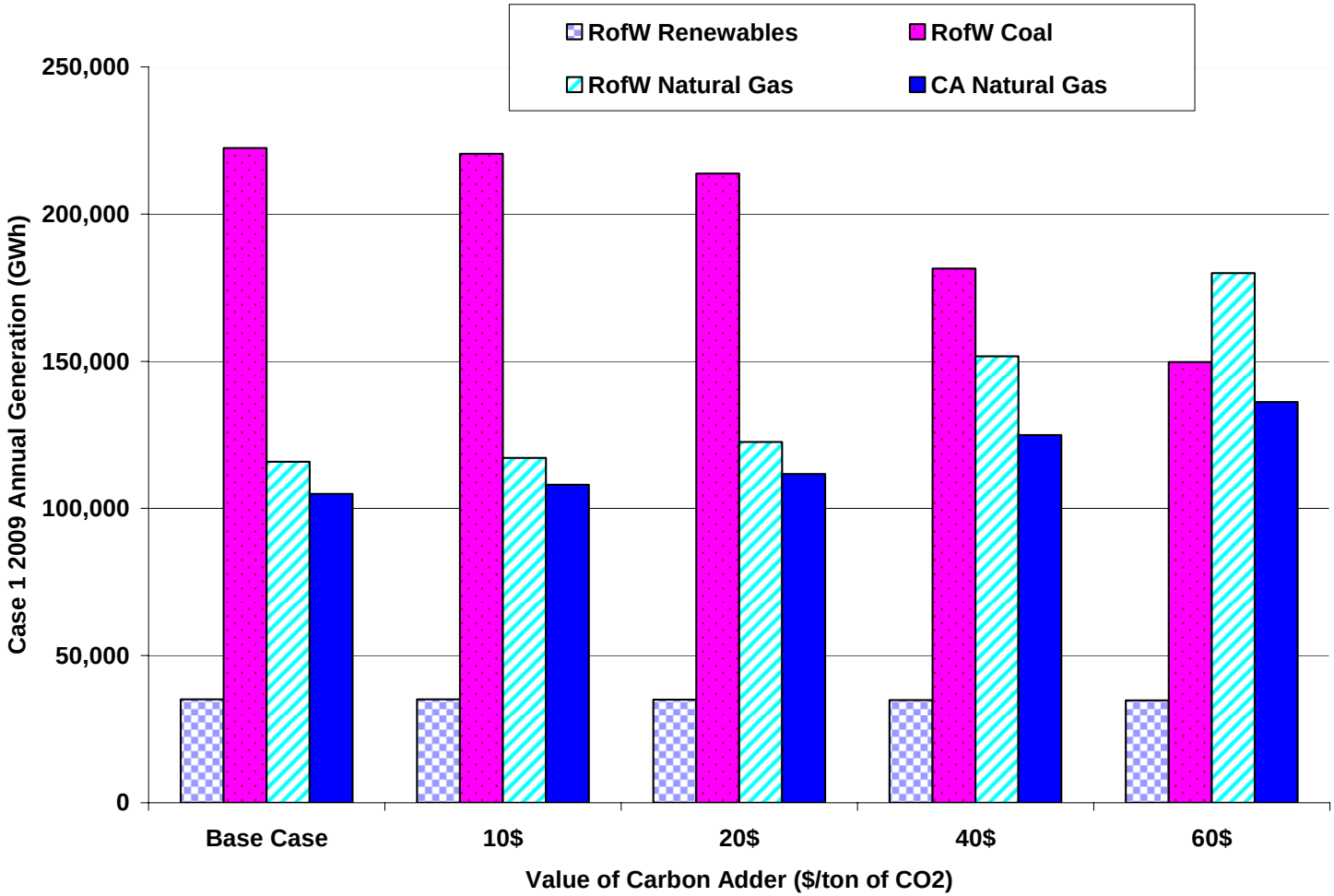
Source: Energy Commission Staff from Global Energy Results

For Case 5B, 2009 values are not shown since the implementation of the Case 5B scenario has had so little time to unfold that there is as yet no meaningful difference from the Case 1B starting point. The Case 5B 2020 (no adder) values can be compared with the Case 1 values directly above in Table 3-2 to see how much the revised resource mix of Case 5B has altered fossil fuel consumption. Large amounts of energy efficiency and renewable generation have been added, displacing fossil-fueled generation for both coal and natural gas. Assuming a carbon adder of $60/ton is then imposed, the dispatch of the coal and natural gas plants is altered to produce the results in the lower right corner of the table.

Figures 11, 12 and 13 provide a summary and interpretation of the results. In general, as the carbon adder increases, coal generation decreases and natural gas generation increases. As shown in Table 9, the carbon adder impacts a generic coal plant two and one-half times more than a generic combined cycle plant. At each increment of carbon adder, coal plant dispatch costs are getting closer to natural gas plant dispatch costs. Put another way, the operating cost differential between coal and natural gas operating costs gets smaller until coal operating costs become more expensive than natural gas. When a coal plant operating cost becomes more expensive than a natural gas plant operating cost, natural gas will displace coal. The results show that a $10/ton adder will have a very small impact, but as the carbon adder increases to $40/ton, a larger impact on coal plant dispatch is seen. At this $40/ton level, many of the coal plants become more expensive than natural gas plants, and at the $60/ton level, further dispatch impacts are seen. This same trend is seen in Case 1 and Case 5B.

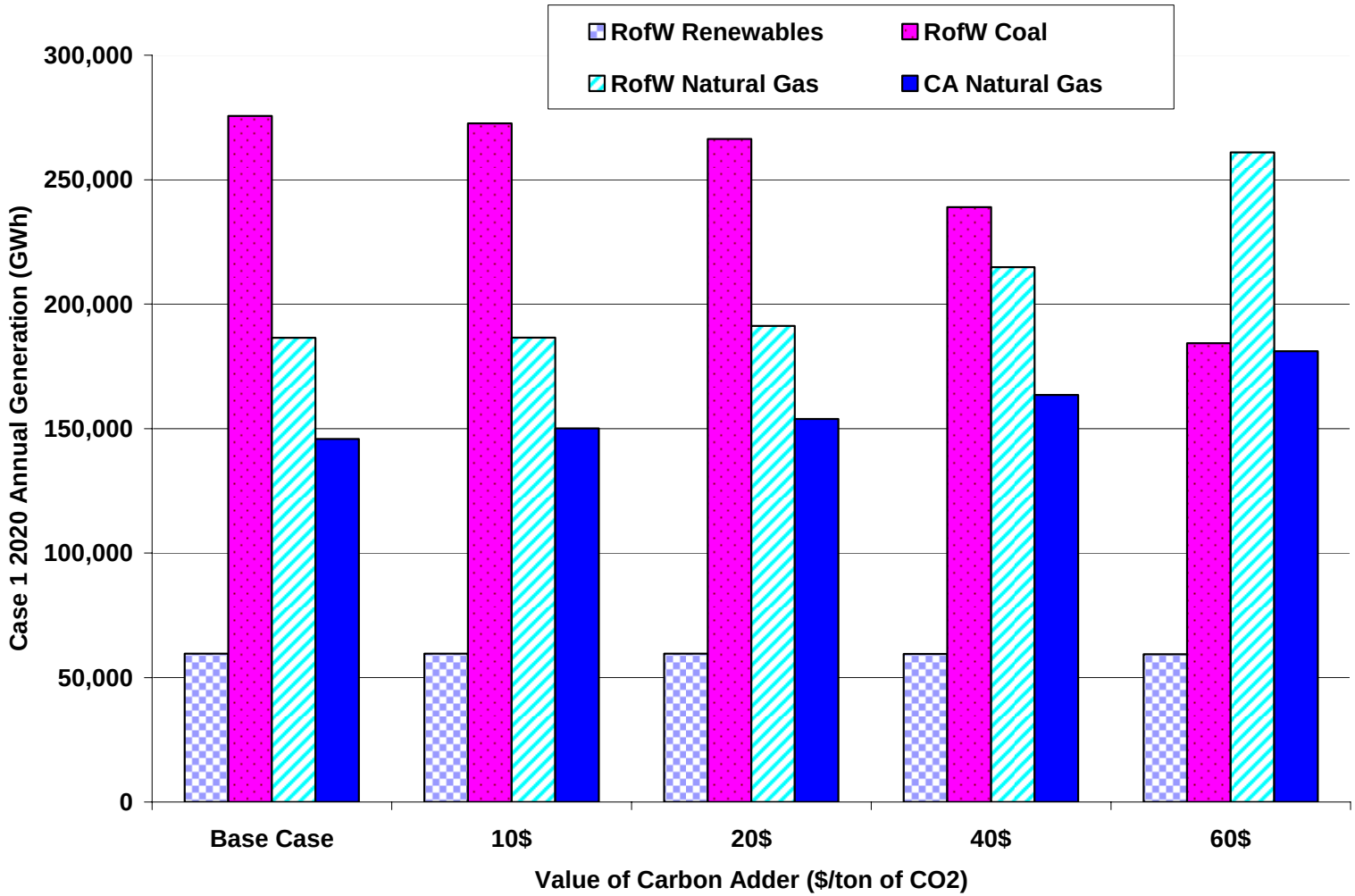
An obvious question is why are there any changes at the level of $10/ton of carbon adder? Under current natural gas and coal prices, the operating cost differential can be quite large. For example, historical operating costs were about $20/MWh for a coal plant with an 11,000 Btu/kWh heat rate and about $60/MWh for a natural gas combined cycle plant with about a 7,000 Btu/kWh heat rate, based on early 2007 data. However, there are some coal plants with higher heat rates and higher coal fuel costs. Figures 14 and 15 provide a "supply curve" from coal- and natural gas-fueled power plants throughout the West. Capacity in megawatts is shown along the X-axis, and the operating costs in $/MWh are shown along the Y-axis. The coal supply curve gets very steep at 40,000 MW with operating costs approaching $37/MWh. The natural gas supply curve shows gas plant operating costs as low as $46/MWh. The operating cost differential is about $9/MWh. Using the data from Table 9, a $10/ton adder would add about $3.87/MWh to a generic combined cycle plant, which is probably representative of the supply at the low end of the supply curve. The coal plants at the steep end of the supply curve probably have a much higher heat rate than the generic coal plant shown in Table 9 and, therefore, would have a larger carbon adder at the $10/ton level. Assuming a 14,500 Btu/kWh heat rate and the same carbon emission factor of 205 pounds/MMBtu, the carbon adder would be about $15/MWh for an inefficient coal plant. The operating costs including the carbon adder at $10/ton would be about $52/MWh and $49.87/MWh for a coal and natural gas plant, respectively. In this simple example, the natural gas plant would displace coal in an economic dispatch. As shown, there are inefficient coal plants operating with high-priced coal that are affected by even a relatively low carbon adder of $10/ton. They are displaced by natural gas–fueled power plants.

Figure 11: Case 1 Annual Generation (GWh) 2009



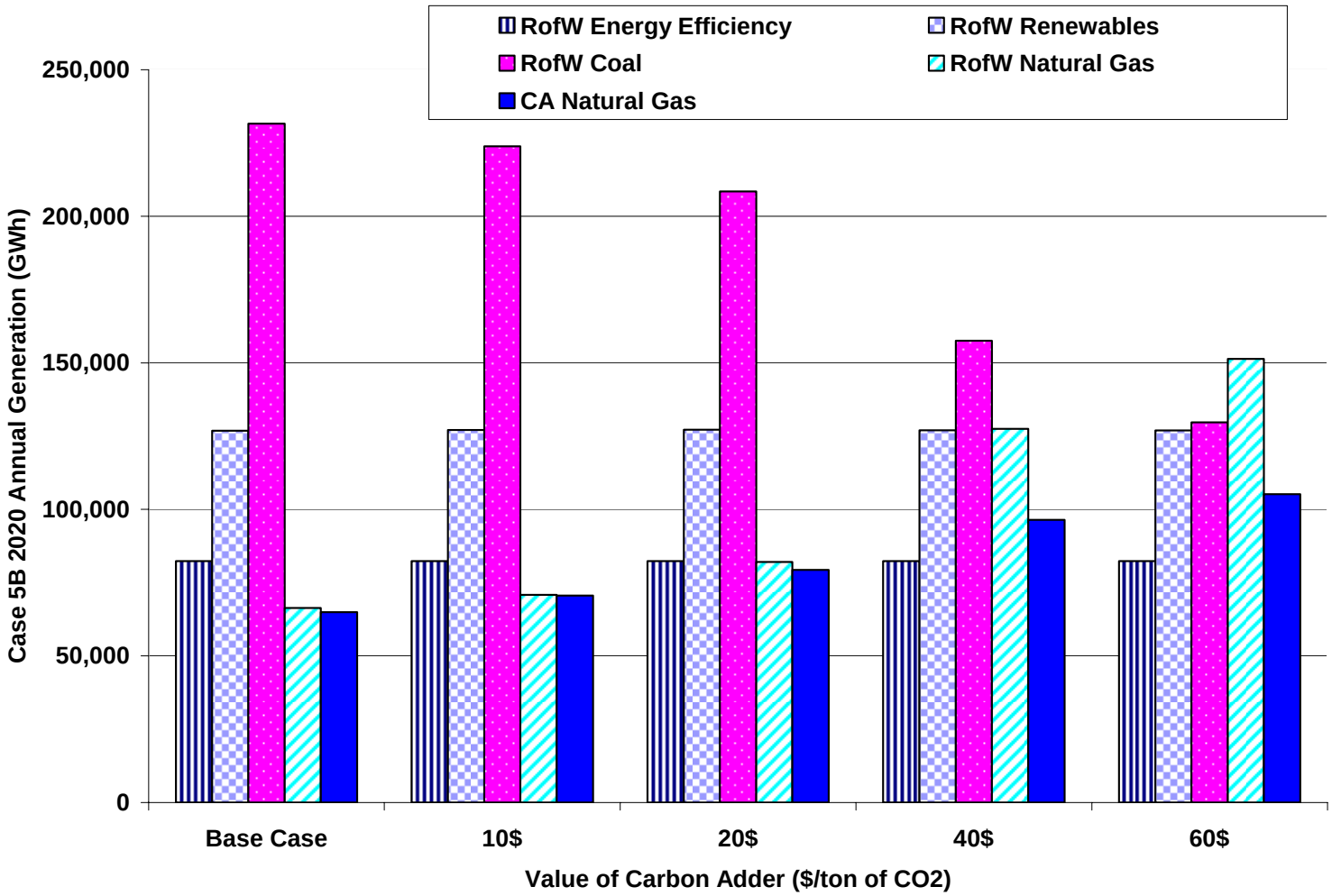
Source: Energy Commission Staff from Global Energy Results

Figure 12: Case 1 Annual Generation (GWh) 2020



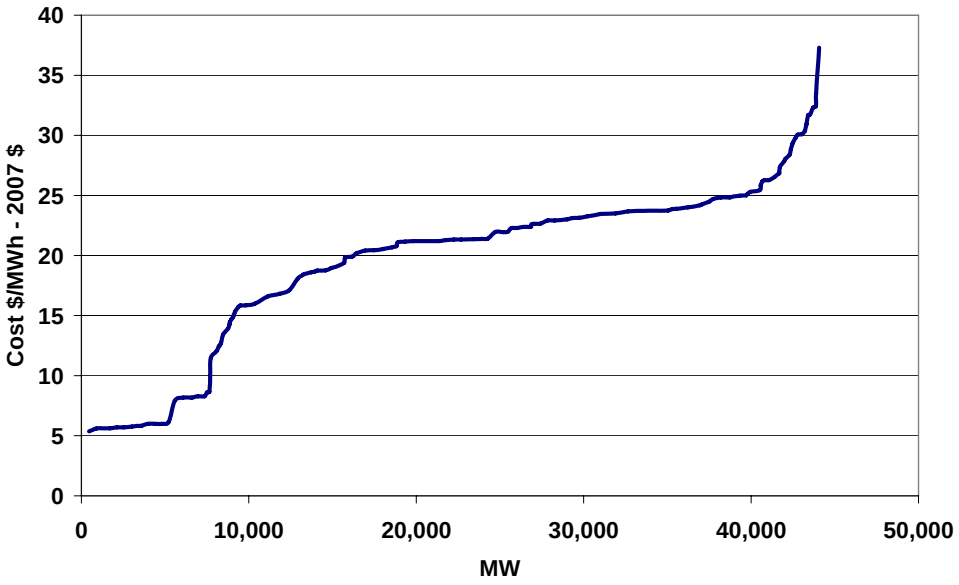
Source: Energy Commission Staff from Global Energy Results

Figure 13: Case 5B Annual Generation (GWh) 2020



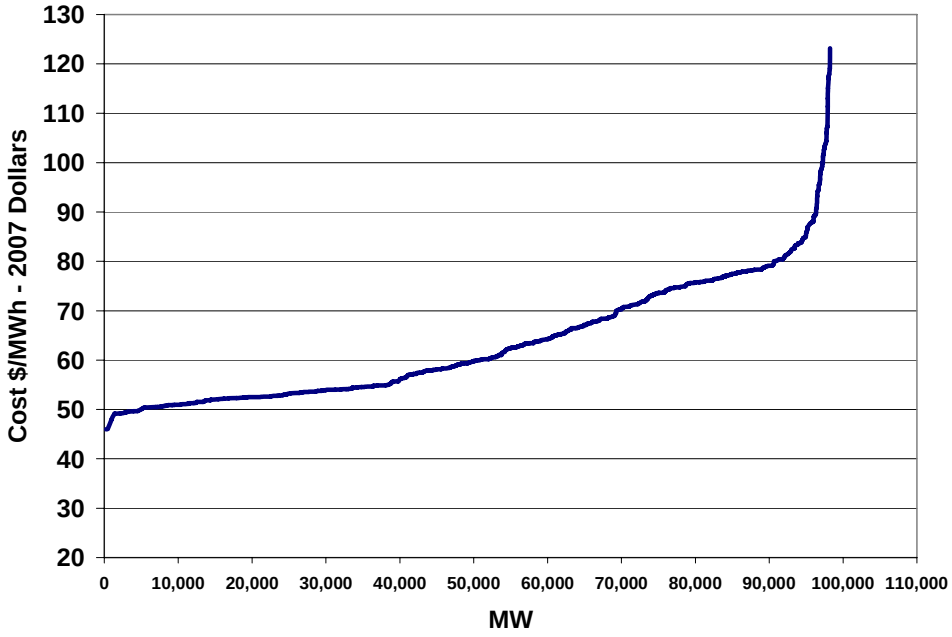
Source: Energy Commission Staff from Global Energy Results

Figure 14: Case 1B WECC Coal Plant Supply Curve 2020



Source: Global Energy Decisions, Inc.

Figure 15: Case 1B WECC Natural Gas Plant Supply Curve 2020 (Henry Hub NG Prices $6.96/MMBtu - $2007)



Source: Global Energy Decisions, Inc.

CHAPTER 4: Resource Balance and Planning Reserve Margins Across the Scenarios

At the June 18, 2007 workshop on the initial staff documentation of the Scenario Assessment Project (*Results Report*), materials describing the capacity composition and reserve level for each scenario were presented in the form of Tables 6-1 through 6-8. The question was asked, "Does the existence of resources in excess of commonly acceptable planning reserve margins mean that the conclusions of the scenario assessment project as it affects the GHG emission projections are erroneous?" The nine scenarios presented in the Results Report showed in general that as preferred resources were added, planning reserve margins increased and GHG emission projections decreased. How do these higher planning reserve margins impact the GHG results and costs presented in the *Results Report*? This brief chapter and associated Appendix D answer this question. Staff believes its method of analysis does not materially affect the conclusions reached about GHG emissions in the *Results Report*.

Overview of Scenario Resource Buildout Process

As noted in Section 5.2 of the *Results Report*, each control area had resources assigned to it in the following manner:

- Must satisfy a 15 percent planning reserve margin based on its control area 1:2 peak demand of the year;
- Resources contributed capacity to satisfy requirements using dependable capacity at its peak month;
- Dependable capacity for wind and solar were calculated using the CPUC method for net qualifying capacity, except only a single year's data contributed to computing the average performance;
- When adjacent control areas' initial imbalances (resources long compared to loads and required reserves, or short compared to loads and required reserves) were magnified by the preferred resources additions, in a few instances these were corrected by increasing transmission transfer capacity to allow supply-side renewable generating technologies in one control area to satisfy a deficit in an adjacent area; and
- Generic natural gas (either peakers or combined cycles) satisfied deficits where preferred resources, with existing and named resources, would not suffice.

As noted in the *Results Report*, generally staff constructed the scenarios by removing generic resources included in Case 1 as preferred resources were added in the scenarios illustrating these strategies. Table 11 identifies the sequence of resource buildout for the various scenarios. Once Case 1B was prepared, it became the starting point for Cases 3A through 4B. Cases 5A and 5B combined the features of Cases 3A and 4A, and Cases 3B and 4B, respectively. At each step as preferred resources were added, generic resources remaining from the original Case 1 were eliminated, if possible.

Table 11: Sequencing of Scenarios in Resource Buildout Process

Scenario	Preceding Scenario	Principal Changes
1 – Current Conditions	Global Fall 2006 Reference Case	CEC load forecasts IBC gas prices Adjust modeling topology
1B – Current Requirements	Case 1	Add expected EE, rooftop PV, and renewables per likely compliance current requirements Delete generics
2 – Sustained High Gas Prices	Case 1	Add EE Tweak a couple out of state additions Delete generics
3A – High EE in California only	Case 1B	Add EE beyond Case 1B for California Delete generics in California
3B – High EE in both California and Rest-of-WECC	Case 3A	Add EE in RofW beyond Case 3A Delete generics
4A- High Renewables in California only	Case 1B	Add rooftop PV and renewables in California Delete generics in California
4B – High Renewables in both California and Rest-of-WECC	Case 4A	Add rooftop PV and renewables in RofW Delete generics in RofW
5A- High EE and Renew in California only	Case 3A and 4A	Merge EE from Case 3A and renewables (rooftop PV and supply-side) from Case 4A in California Delete generics
5B- High EE and Renew in both California and Rest-of-WECC	Case 3B and 5B	Merge EE from Case 3B and renewables (rooftop PV and supply-side) from Case 4B in California Tweak transmission between a couple of transmission areas[11] Delete generics

Source: California Energy Commission

[11] Transfer capacity was increased between New Mexico and Arizona to allow New Mexico wind to satisfy Arizona requirements.

A fundamental topic must be addressed when resources compared to loads are reported for aggregations of trans-areas (or control areas) – diversity in peak hour among subareas within the Western Interconnection. Stated simply, resource needed to satisfy each subarea's peak may seem "excessive" in other hours of the year.[12] The degree to which this phenomenon is important differs from one transmission area (transarea)/control area to another. For example, winter peaking transareas could have thousands of megawatts of difference between their own peaks and their load at the time of WECC coincident peak. If such a transarea had resources exactly at the minimum to satisfy their planning reserve margin target, every megawatt of load difference comparing that transareas's loads at coincident WECC peak to its own peak could be interpreted as "excessive" resources. This phenomenon occurs at some scale for virtually every transarea compared to the WECC coincident peak. Some transareas peak in the winter, so thousands of megawatts of "excess" capacity versus peak contribution exist, while others may peak simply an hour or two differently with minimal difference.

Appendix D provides Global Energy's analysis of this phenomenon for 2020. Load diversity means that approximately 6 percent of resources are "excessive" to those needed at time of system peak for each transarea/control area's own peak.

Overview of Results

Referring back to Table 11, it provides a summary of the sequence and scope of resource case buildout. Case 1 began the process and has the most generic resources required to satisfy planning reserve margin targets. The resource mix of generic combustion turbines, combined cycles, and coal satisfies energy requirements with the majority of the generic resources being comprised of gas turbines. In constructing the cases recognizing policy preferences, staff added preferred resources and eliminated generic resources, if possible.

Table 12 summarizes the level of generic resources by fuel type remaining in the scenarios compared to the capacity of the preferred resources. In 2020, Case 1 has about 44,000 MW of generic natural gas and coal[13], which diminish to about 12,000 MW in Case 5B. Conversely, in 2020 Case 1 has about 14,000 MW of dependable capacity of

[12] A planning reserve margin balances multiple factors: (1) uncertainties of expected loads and performance, (2) correlations among elements creating uncertainties, and (3) evolving mixes of resources. Staff is not aware of any study proposing planning reserve margins to address the reserve requirements of the levels of EE, solar PV, and supply-side renewables encompassed by the preferred scenarios.

[13] The 44,000 MW of generic natural gas and coal is comprised of 675 MW of combined cycle, 6,300 MW of generic coal, and 36,990 generic gas turbines. Of the named capacity additions added by 2020, about 2,100 MW of coal capacity was added in all of the cases. A total of about 8,400 MW of new coal units was added in Case 1.

energy efficiency and renewables, while Case 5B has about 63,000 MW of these. 32,000 MW of generics were removed in Case 5B and replaced with about 49,000 of preferred energy efficiency and renewables.

Figures 16 and 17 provide graphical description of the 2009 and 2020 results, respectively.

Interpreting the Results

Staff does not believe that "excessive" reserves in the preferred cases materially affect GHG results computed for these cases. The following points summarize the reasoning:

- Energy efficiency and renewables are essentially must-take resources that cannot be dispatched. These displace something else.
- Hydro is dispatchable, but it is so cheap that it will not be dispatched outside its normal patterns to support load following and related ancillary services associated with daily load fluctuations.
- Coal and natural gas units are the only resources that are likely to be dispatched differently to accommodate different needs in the high energy efficiency and/or renewable scenarios. Of these, coal units are inherently less dispatchible and are also much less costly than natural gas, so they will continue to be dispatched largely as they are now, which is as baseload units.
- Incremental natural gas units represented by the generic combined cycles and combustion turbines can be dispatched and have relatively short lead times. They also have minimal long lead time unit commitment requirements that might create fuel use related to the number of units rather than fuel use to generate energy from the fleet of natural gas units.[14]
- The consequence of "excess" resources, focused mainly on natural gas plants, is that this category of resource is most likely dispatched at capacity factors below what developers would consider optimal.

Taking these points together, staff does not believe that the GHG results of the scenarios with "excessive" resources create any material differences in the predicted energy generation by fuel type or GHG results. Thus, staff believes that the results reported from comparing one case to another are valid.

Having observed that natural gas generic units might be dispatched less than is considered optimal, does this have significant cost implications that cloud the cost projections of the scenario project? Staff believes that there are minimal implications of "excessive" resources leading to "excessive" costs, but this case is not as strong, or as certain, as the answer to the question concerning the generation results and GHG

[14] Long lead time unit commitment requirements tend to cause units to be committed in advance of their need to allow them time to ramp up to their full operating capacity. The units are operating at a less efficient level during this long lead time which may lead to higher fuel use.

emissions. There are two portions of costs to consider: capital costs and production costs.

Production costs clearly result from the dispatch algorithm determining which power plants to dispatch to meet load under the constraints of the transfer capability between transareas. Dispatch favors the most efficient plants and disfavors the less efficient plants. There is a strong correlation between heat rates of the plants and age, so the generic combined cycles and combustion turbines will be used at higher capacity factors than older units, whether steam turbines, older combined cycles, or combustion turbines. To the extent fewer new units were included, older units with longer lead times in start up operations might have been triggered in unit commitment logic and thus consumed slightly more fuel than calculated in staff's assessment. If this is true, then production costs might be very slightly understated compared to a more in-depth assessment.

As far as capital costs are concerned, in the real world, older units are more likely to be at the end of their useful lives. Thus, even if they are "unneeded," they are more likely than not to have minimal capital in the rate base remaining to be recovered. This means that capital costs might be higher than would be the case if "excessive" resources were not present, but that the magnitude is small. However, the analysis conducted for this project did not address capital costs of existing infrastructure as was noted in the *Results Report*, Chapter 3. Thus, in comparing across scenarios, the only capital costs in the overall system costs are those associated with generic plants that might not be present in all scenarios. As noted in the *Results Report*, when a power plant is present in all cases from Case 1 through Case 5B, its capital cost contribution to the total fixed costs of the electricity system would be identical in each case, thus there is no need to include such a plant's capital costs in the analysis to compute the differences between the cases for use in attributing incremental cost increases or decreases to a preferred resource. Therefore, staff believes that the capital cost element of the overall cost analysis is not appreciably affected by "excessive" reserves, but if it is in error, it is slightly high.

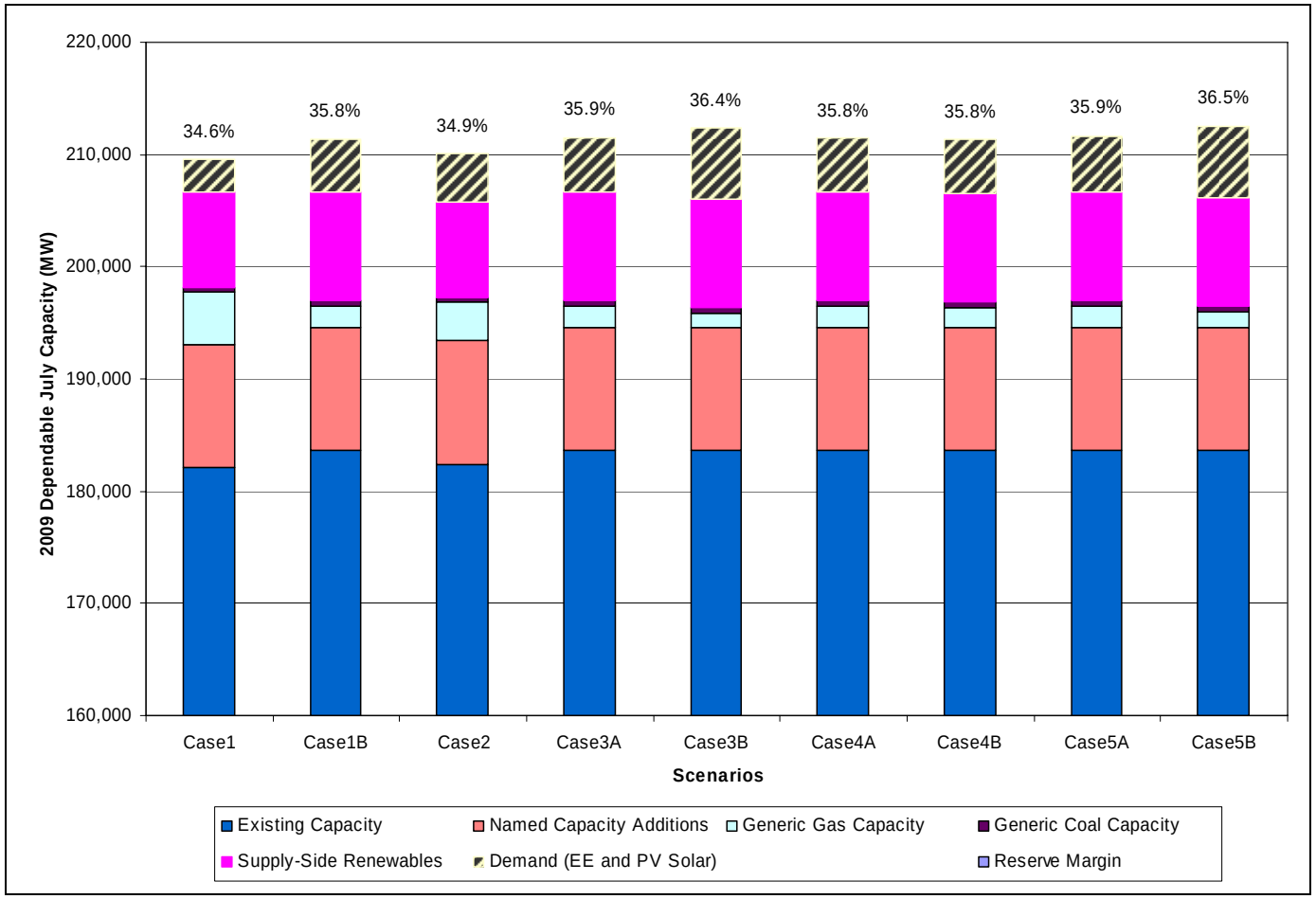
In summary, production costs might be slightly low, and capital costs might be slightly high, perhaps even offsetting one another. Overall costs, therefore, should not be heavily affected by "excessive" reserves. Staff believes that the predicted cost implications for the cases are not materially affected by presence of "excessive" reserves in some cases. The uncertainty of the assumptions about energy efficiency savings, rooftop solar PV installed costs, or supply-side renewable generating technology capital costs are more likely to affect the cost outcomes of the Scenario Assessment Project.

Table 12: Load and Resource Balance Explaining Reserve Margins
(MW of Dependable Capacity)

2009 Dependable									
	Case 1	**Case 1B**	**Case 2**	**Case 3A**	**Case 3B**	**Case 4A**	**Case 4B**	**Case 5A**	**Case 5B**
Load	155,659	155,659	155,659	155,659	155,659	155,659	155,659	155,659	155,659
Resources:									
Demand (EE and PV Solar)	2,812	4,683	4,242	4,840	6,269	4,776	4,779	4,933	6,365
Supply-Side Renewables	8,513	9,686	8,513	9,686	9,686	9,686	9,685	9,688	9,685
Generic Gas Capacity	4,630	1,880	3,390	1,880	1,280	1,880	1,760	1,880	1,340
Generic Coal Capacity	500	500	500	500	500	500	500	500	500
Named Capacity Additions	10,996	10,996	10,996	10,996	10,996	10,996	10,996	10,996	10,996
Existing Capacity	182,070	183,608	182,418	183,608	183,608	183,609	183,609	183,609	183,609
Total Capacity	209,521	211,353	210,059	211,510	212,339	211,447	211,329	211,606	212,495
Reserve Margin	34.6%	35.8%	34.9%	35.9%	36.4%	35.8%	35.8%	35.9%	36.5%
2020 Dependable									
Load	191,372	191,372	191,372	191,372	191,372	191,372	191,372	191,372	191,372
Resources:									
Demand (EE and PV Solar)	2,817	11,447	19,853	15,055	32,249	13,804	14,073	17,413	34,875
Supply-Side Renewables	12,102	15,552	12,347	15,552	15,552	20,702	28,371	20,702	28,371
Generic Gas Capacity	37,665	28,855	23,130	28,315	17,535	25,155	18,515	25,155	8,715
Generic Coal Capacity	6,300	5,800	6,800	5,800	5,000	5,800	5,000	5,800	3,000
Named Capacity Additions	12,910	12,910	12,910	12,910	12,910	12,910	12,910	12,910	12,910
Existing Capacity	174,513	176,051	174,861	176,051	176,051	176,052	176,051	176,052	176,051
Total Capacity	246,307	250,615	249,901	253,683	259,297	254,423	254,920	258,032	263,922
Reserve Margin	28.7%	31.0%	30.6%	32.6%	35.5%	32.9%	33.2%	34.8%	37.9%

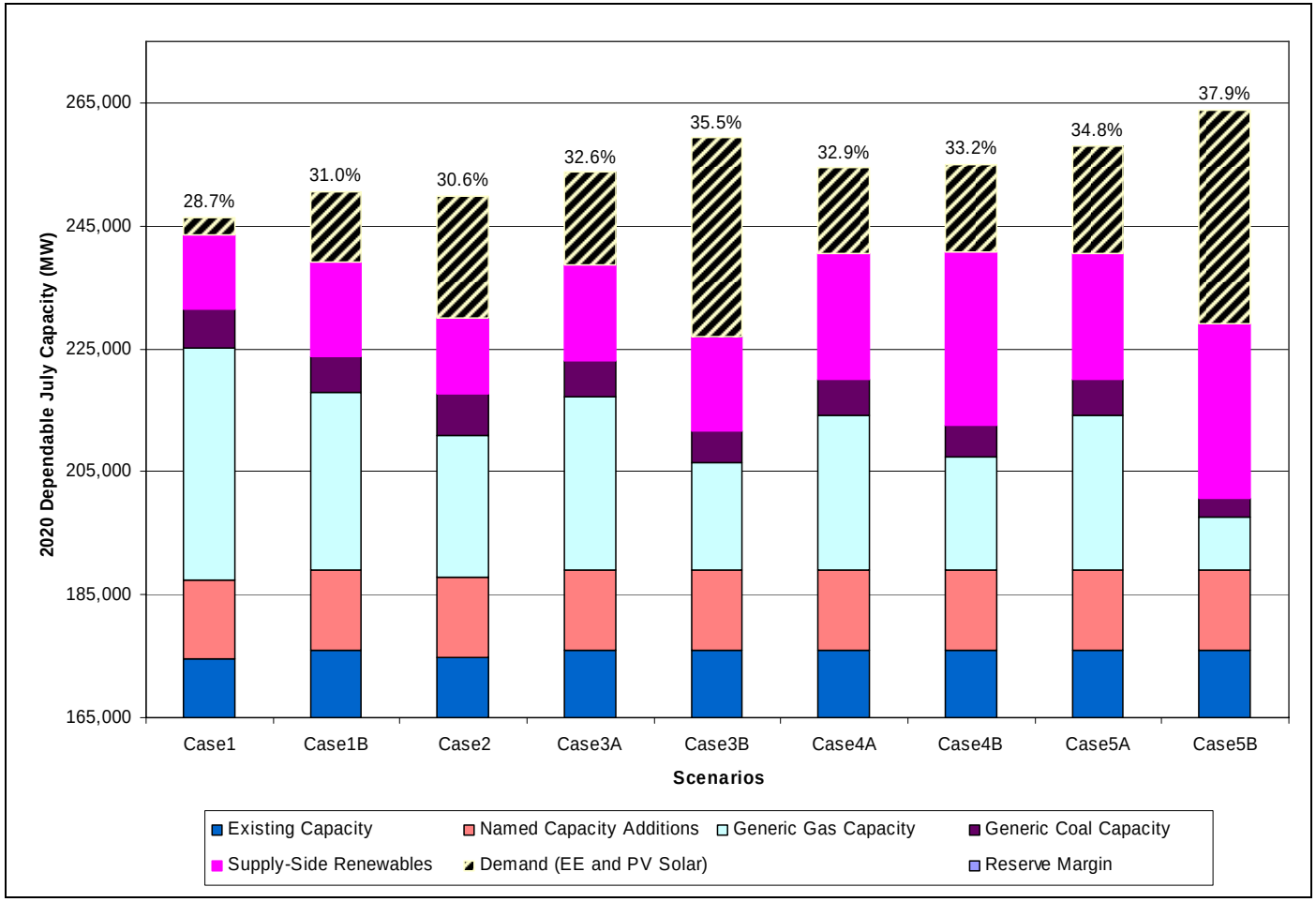
Source: California Energy Commission Staff from Global Energy results (see Appendix D)

Figure 16: 2009 Resources and Reserve Margin by Scenario (Dependable July Capacity, MW)



Source: Energy Commission Staff from Global Energy Results

Figure 17: 2020 Resources and Reserve Margins by Scenario (Dependable July Capacity, MW)



Source: Energy Commission Staff from Global Energy Results

CHAPTER 5: Conclusions

This addendum report completes the initial documentation for virtually all elements of the staff's Scenario Assessment Project.[15] This chapter addresses findings and process conclusions.

Findings

One of the original objectives for this project was to devise and evaluate scenarios featuring large penetrations of energy efficiency, rooftop solar photovoltaic, and supply-side renewable generating technologies. Ascertaining the level of GHG emission reductions that these preferred resource strategies could achieve, along with the traditional measures for evaluating the electricity sector is now complete for 13 scenarios. Clearly, the AB 32 goals for GHG emission reductions (almost entirely carbon dioxide in the electricity sector) served as the target the scenarios sought to achieve. The original scenarios prepared for and documented in the *Results Report and Addendum Report* failed to achieve the levels implied by proportional application of AB 32 goals although Case 5B came close. In presenting the implied AB 32 goal, the prior result reported in the *Addendum Report* was presented in metric tons while the results of the Scenario Analyses were presented in short tons. Staff has corrected this error and converted the implied AB 32 goal into short tons to be consistent with the Scenarios results. As a result of this correction, California instate carbon production for Case 5B meets the implied AB 32 goal.

The two new energy efficiency scenarios evaluated and reported in this addendum reduce prospective emissions enough that the electricity sector now arguably achieves the implied AB 32 goals. Figures 2-7 and 2-8 provide a visual depiction of these GHG emissions for power plants located in California and power plants serving California loads, respectively. This point is arguable because the instate version of GHG emission reductions just barely achieves the implied AB 32 goal in Case 5E, that is, high levels of all three strategies. Alternatively, the California responsibility version (power plants located in California, remotely owned or under long term contract to California utilities, and short-term market purchase imports) can get back to 1990 levels in any number of ways.[16] While the load-based or source-based perspective has been joined from a

[15] Water consumption projections are not yet complete.

[16] Newly issued preliminary California Air Resources Board (ARB) emission inventories, differing somewhat from earlier Energy Commission emission inventories, muddy the water. Instate power plant emissions appear to be only slightly different from earlier Energy Commission values, but inventories for imports are quite different. ARB is responding to feedback from its initial workshop, and no final values will be released for some time. Thus, this report addresses only Energy Commission inventories that have received review and can be more readily compared with the emission projection methods used in this project.

reporting requirements perspective, there are significant ramifications from a projected ease of compliance that have just barely begun to be understood.

Adding preferred resources, of the type and cost-structure explored in this project, does not affect the dispatch of existing coal power plants. Unless something is done to modify the dispatch cost or otherwise revises dispatch protocols of these 40,000 MW plus of capacity, these existing units are by far the cheapest and will continue to operate largely as they have operated, with numerous implications for achieving overall GHG emission reductions.

This project has uncovered strong interactions between the performance of power plants located in California and the Rest-of-WECC as the scenarios explored California-only versus Westwide preferred resource strategies. Imports into California differ strongly among the scenarios as the production cost model seeks to use lowest-cost resources in its unit commitment and dispatch algorithms. California decision makers need to be especially concerned with whether other Western decision-makers implement very high energy efficiency or renewables strategies. If they do, California could see unexpected increases in GHG emissions from a load-based emission responsibility perspective.

Among the three elements of these scenarios – energy efficiency, rooftop solar photovoltaic, and supply-side generating technologies – energy efficiency is by far the cheapest, supply-side renewables are next, and rooftop PV is the most expensive. Table 2-8 reveals a direct comparison of the system costs of the scenarios and their achievement of GHG emission reductions. The uncertainty of the costs of these three elements is considerable, and it is possible that energy efficiency costs would be more likely to increase than decrease, rooftop PV more likely to decrease than increase, and supply-side renewables could move either direction. It seems unlikely, however, that the rank order of these three elements will change.

This project deals primarily with generation costs, but does include some incremental transmission costs. What is shown in the data reported for this study is the increment (or decrement) in certain generation and transmission costs that would be experienced in the different cases. It is not possible to indicate how this increment (or decrement) in costs would be assigned to the various customer classes or to different rate blocks of a retail rate. However, it can be noted that for demand-side resources of energy efficiency and PV rooftop solar, individual ratepayers would likely bear more of the costs, while for supply-side renewables, costs could be spread across all ratepayers.

Staff examined several key sensitivities in this project, finding that GHG emissions are strongly affected by hydro-generation fluctuations, for example, at the level of plus or minus 10 percent from baseline projections in future years. Since this is a factor outside of the control of load-serving entities, and the patterns of hydro-electric generation could actually change as a result of climate change, industry-wide compliance with

GHG emission controls needs to address this important feature of the electricity sector in California and the West.

Process

This project was conducted almost exclusively with an Energy Commission staff and contractor team (Navigant Consulting, Global Energy, and Aspen Environmental Group). The team prepared extensive documentation and conducted several workshops. Stakeholders exhibited relatively little interest, perhaps because those entities inherently interested in these issues are already overwhelmed by participation in the numerous other forums in which these issues are being examined. Because the methods used are detailed and the results extensive and complex, some supplemental means of educating stakeholders about this project and its results should be considered.

Issues of policy-based retirement, refurbishment or repowering of aging power plants, and replacement with dispatchable capacity sufficient to satisfy local capacity requirements were incomplete in the scenarios as originally assessed. A companion study made some progress in linking transmission assessments, production cost modeling, determination of local capacity requirements, and generation resource buildout strategies, but the specifics of the cases examined did not fully mesh with the incredibly complex regulatory issues facing generating facilities. Further work to integrate a wide range of traditional power plant economics with the environmental protection aspirations of multiple agencies is clearly necessary.

There are a number of methodological issues about the assessments that require improvement in analytic methods. Attempts to coordinate traditional production cost examinations of electricity industry impacts with natural gas industry projections and market price interactions achieved limited success. It may also be the case that emissions markets, along with worldwide trade in liquified natural gas, will diminish the autonomy of the Western Interconnection and require that WECC resource assessments be more directly coordinated with those for the rest of North America.

Staff intends to consolidate the June 2007 *Results Report* and the subsequent three addendum reports into a single report with appendices to be issued later in the fall of 2007.

APPENDICES

APPENDIX A: ENERGY EFFICIENCY ASSUMPTIONS

APPENDIX B: CA VS. REST-OF-WECC SCORECARD FOR HIGH ENERGY EFFICIENCY CASES FOR 2020

APPENDIX C: CARBON ADDER DISPATCH SENSITIVITY STUDY

APPENDIX D: RESOURCE BALANCE AND PLANNING RESERVE MARGINS

APPENDIX A
ENERGY EFFICIENCY ASSUMPTIONS

Prepared by Navigant Consulting, Inc.

CALIFORNIA
ENERGY
COMMISSION

ENERGY EFFICIENCY AND DEMAND RESPONSE SCENARIOS FOR CALIFORNIA UTILITIES

CONSULTANT REPORT

September 2007
CEC-200-2007-010-AD3

Arnold Schwarzenegger, *Governor*

Prepared By:

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September 7, 2007

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This work paper summarizes the development of energy efficiency (EE) and demand response (DR) scenarios that were developed to support the California Energy Commission. These scenarios were developed to represent possibilities. They were based on existing studies of potential, but numerous assumptions were required to develop all of the required inputs including EE and DR accomplishments, costs, and load shapes by transmission area (transarea) for the entire WECC.

F-1 Energy Efficiency

Introduction

Energy efficiency (EE) resource estimates (including GWh, costs, and load shapes) were developed by transmission planning area (transarea) for four scenarios:

- **Current practices (Case 1B)** – For California, the EE resources reflect the goals summarized in the investor-owned utility (IOU) 2006 procurement plans. For the rest-of-WECC, the current energy efficiency programs were assumed to be embedded in the load forecasts (that is, the forecasts reflect sales net of reductions resulting from energy efficiency programs).
- **Aggressive development (Case 3A)** – Reflects aggressive expansion of EE programs. In California, this is equivalent to the economic potential (minus the portion of the economic potential attributable to emerging technologies)[1]. For the rest-of-WECC, the aggressive EE development scenario is based on the "Best Practices" scenario from the Western Governors' Association analysis [2](also referred to as CDEAC).
- **Partial emerging technology deployment (Case 3D)** – In addition to the aggressive EE included in aggressive development scenario, approximately 55 percent of the emerging technology potential in California is included.
- **Full emerging technology deployment (Case 3E)** – Includes the entire emerging technology potential in California.

Table F-1, summarizes the California energy and demand savings and the present value of costs (incremental measure costs and program administration and marketing, using a discount rate of 8.4 percent) for these four EE scenarios.

Table F.1: 2020 California Energy and Demand Savings and Present Value of Costs for EE Scenarios

Case	Energy Savings (GWh)	Demand Savings (MW)	PV Costs (Million $)
1B	29,404	6,450	8,286
3A	42,263	7,159	9,334
3D	52,053	8,817	11,780
3E	59,763	10,122	13,706
Discount rate		8.6%	

These EE scenarios were included into the analysis as follows:

	Current Practices	Aggressive Development	Partial Emerging Technology	Full Emerging Technology
California	Cases 1B, 2, 4A, 4B	Cases 3A, 3B, 5A, 5B	3D	3E
Rest-of-WECC	Cases 1, 1B, 3A, 4A, 4B	Cases 3B, 3D, 3E, and 5B		

Source: Navigant Consulting, Inc.

For Case 2, the rest-of-WECC EE was assumed to be equal to 5 percent of the rest-of-WECC sales (approximately half of the aggressive development scenario).

Approach

To evaluate EE as a resource option, annual forecasts of EE, hourly load shapes and costs are required. Annual estimates were developed by transmission planning area (transarea) for each scenario. The primary data sources and analysis that were used to develop each of these forecasts are briefly summarized below.

Annual GWh

The first step in the process was to develop annual forecasts of the EE resource base for each scenario. The major data sources and assumptions underlying the annual forecasted EE are summarized in Table F.2.

Table F.2: Major Data Sources for EE Resource Forecasts

	California	Rest-of-WECC
Current Practices	**IOU Long-Term Procurement Plans**[3]	**Assumed to be embedded in the load forecasts**
Aggressive Development	**The economic potential (excluding the portion due to emerging technologies) from the Itron 2006 Potential Study net of utility accomplishment for 2004-2008.**	**"Best Practices" scenario potential minus the EE savings in the "Current Practices" scenario**[4]
Partial and Full Emerging Technology Deployment	**The emerging technology potential as identified in the Itron 2006 Potential Study extrapolated to POU service areas**	**Not considered**

Source: Navigant Consulting, Inc.

First, a summary of the data sources used for each scenario is provided, followed by a more detailed description of the specific data and results for California and rest-of-WECC.

Current Practices

The California IOU long-term procurement filings include 10-year projections of uncommitted EE. Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) presented alternative plans with projected EE resources less than the CPUC

adopted goals in D.04-09-050. For SCE the “Best Estimate (SCE-Developed Load Scenario)” plan was used. This represents approximately 34 percent less EE than the CPUC goals for 2016[5]. Under this plan, the SCE EE programs would accomplish EE at the levels of SCE’s 2004-2005 programs. For PG&E the “Current World” EE estimates were used. This “Current World” plan represents approximately 35 percent less EE than the CPUC goals for 2016. SDG&E’s plan reflected the CPUC goals but noted that the goals may not be attainable.

Since the procurement plans only included projections through 2016, EE accomplishments for 2017 through 2020 were assumed to grow at the same rate as the loads before EE. Procurement plans were not readily available for POUs, so it was assumed that the POUs could achieve between 50 percent and 100 percent of the IOU EE as a percentage of their loads.

For the rest-of-WECC, Navigant assumed that the load forecasts included the current programs. Several utility integrated resource plans (IRP) were reviewed, and it appeared that the sales forecasts being used for this modeling effort were consistent with sales net of the utility EE programs.

Aggressive Development

For California, the aggressive development scenario is drawn form the 2006 Itron potential study. This study identified the economic potential (that is, all EE that is cost-effective), as well as achievable potential under several different scenarios. The IOU EE in the current practice scenario of 22,169 GWh in addition to the 11,023 GWh that the utilities project to accomplish between 2004 and 2008 (for a total of 33,192 GWh) substantially exceeds the “full incentives achievable potential,” 23,974 GWh. But the aggressive development scenario postulates that a significant portion of the economic potential can be developed by 2020. Emerging technology represents approximately 23 percent of the economic potential. Thus, the aggressive development scenario assumes that 77 percent of the economic potential is achieved. Table F.3 summarizes the adjustments that were made to the Itron economic potential estimates to derive the additional 9,319 GWh of IOU EE for the aggressive development scenario. Since the EE in SDG&E’s procurement plans already exceed the economic potential, SDG&E’s EE resource is the same in both scenarios, and the incremental GWh were assigned to PG&E and SCE.

Table F.3: Derivation of CA IOU Aggressive EE Estimate

	Add/subtract	(GWh)	After Adjusted (GWh)
Economic potential in 2016		**53,150**	
Economic potential growth 2016 -20120	**+**	**1,892**	**54,992**
Emerging technology economic potential	**-**	**12,481**	**42,511**
Utility EE accomplishments 2004-2008	**-**	**11,023**	**31,488**
IOU current practices scenario for 2009	**-**	**22,169**	**9,319**
Aggressive Development Incremental IOU EE			**9,319**

Source: Navigant Consulting, Inc.

Composition of the EE Resource

The EE resources include several hundred measures. The distribution of savings by end-use, sector, and vintage of construction are summarized in table F.4. Compact fluorescent lamps (CFL), in both the residential and commercial sectors, comprise the largest source of savings, amounting to 30 percent of the savings in the current practices scenario and increasing to 34 percent of the savings in the aggressive development scenario. Residential refrigeration is the next largest source of savings. Approximately two-thirds of these refrigerator savings are due to recycling of the second refrigerator.

Table F.4: Distribution of EE Savings by Sector, End-Use, and Vintage of Construction

Sector/End-Use	Current Practices	Aggressive Development
Existing		
Residential		
CFL	27%	30%
Refrigeration	17%	11%
HVAC	7%	3%
Other	2%	4%
Commercial	0%	0%
CFL	3%	4%
Lighting	7%	8%
HVAC	8%	3%
Refrigeration	3%	7%
Other	0%	0%
Minor measures	0%	3%
Industrial	15%	13%
New		
Residential	1%	2%
Commercial	9%	10%
Industrial	1%	1%

Source: Navigant Consulting, Inc.

Emerging Technology Deployment

Two scenarios incorporating increasing amounts of emerging technologies were developed. Two tiers of emerging technology deployment were developed based upon a qualitative rating of the likelihood of success and indicative levelized costs of energy saved. The Itron study identified a number of emerging technologies and provided a qualitative estimate of the likelihood of success, indicative levelized costs of energy saved, and forecast of market adoption, as summarized in Table F.5.

Table F.5: Summary Data and Ratings for Emerging Technologies

NAME	Savings Potential (TCTU)	Percent Saved	CSE $/kWh	Likelihood of Success Rating	Cost Rating	Score
Residential						
1 Watt Standby Power For Home Appliances	60.6	1.05	0.02	4	4	4
Airtight Compact Fluorescent Down Lights	47.9	0.83	-0.01	4	4	4
Aerosol-Based Duct Sealing	38.9	0.93	0.03	3	3	3
Leakproof Duct Fittings19	26.3	1.03	0	4	4	4
High Quality Residential Compact Fluorescent Por	26.4	0.46	0.03	3	3	3
Solid State Refrigeration (Cool Chips TM)	20.9	0.36	0	3	1	2
Residential Heat Pump Water Heaters	19.3	0.33	0.02	3	4	3.5
Residential Cool Color Roofing	4.4	0.3	0.04	3	2	2.5
High Performance Windows (U<0.25)	12.7	0.3	0.03	3	3	3
1 kWh/Day Refrigerator	17.1	0.3	0.04	4	2	3
Advanced HVAC Blower Motors	13.7	0.24	0.04	4	2	3
Robust A/C	8.5	0.59	0.04	3	2	2.5
Advanced A/C Compressors	6	0.42	0.03	3	3	3
Commercial						
Advanced HVAC Controls	12	0	0.03	3	3	3
Leakproof Duct Fittings	48993	1.03	0	4	4	4
Networked Computer Power Management	286	0.6	0.02	3	4	3.5
1-Lamp Fluorescent Fixtures & High Per. Lamps	215	0.45	0.01	3	4	3.5
Commercial LED Lighting	176	0.37	0.03	3	3	3
CO2 Ventilation Control	163	0.34	0.03	4	3	3.5
Low-Wattage Ceramic MH Lamp	130	0.27	0.03	3	3	3
Advanced Packaged AC	81	0.17	0.04	3	2	2.5
Advanced Daylighting Controls	80	0.17	0.02	3	4	3.5

Source: *California Energy Efficiency Potential Study*, Itron, et. Al., 2006, Navigant Consulting, Inc.

The likelihood of success ratings were developed as part of the Itron study. The costs ratings were based on the following assignments:

Cost rating

4	Less then $0.02/kWh Saved
3	$0.03/kWh saved
2	$0.04/kWh saved or more
1	Unknown

The combined scores were developed by assigning equal weights to the cost range and the likelihood of success (that is, the average of the two ratings).

The Itron study also identified several of the emerging technologies in Table F.3 as providing similar savings as ones already included in the economic potential, including the two compact fluorescent lighting measures, the 1 kWh/day refrigerator, and the advanced daylighting controls.

The emerging technology potential by measure type and utility, and their combined scores are summarized in table F.6. The measures with the largest potentials include 1-Watt standby power for residential appliances and network computer management. These two measures represent 38 percent of the emerging technology potential and low estimated cost of energy saved.

Table F.6: Emerging Technology Potential by Utility

	PG&E	SCE	SDG&E	Total	% of Total	Score
Residential						
Electric A/C Combined Measures	532	801	119	1,451	**12%**	3.0
D3. Advanced HVAC Blower Motors	205	119	46	370	**3%**	3.0
A1. 1-Watt Standby Power for Home Appliances	1,234	1,079	312	2,625	**21%**	4.0
R1. Solid State Refrigeration	357	337	92	787	**6%**	2.0
W3. Heat Pump Water Heaters	475	207	72	1,053	**8%**	3.5
Total Residential	2,803	2,544	641	5,988	**48%**	-
Commercial						
Combined Package A/C	382	428	100	910	**7%**	2.8
H11. Leak-Proof Duct Fittings	157	152	41	349	**3%**	4.0
L14. One-Lamp Linear Fluorescent	284	255	72	611	**5%**	3.5
O1. Networked Computer Power Management	1,008	856	248	2,113	**17%**	3.5
L11b. LED Lighting	614	544	155	1,312	**11%**	3.0
H18. CO2 Ventilation Control	107	96	27	231	**2%**	3.5
L6. Low Wattage Ceramic MH Lamp	459	395	115	968	**8%**	3.0
Total Commercial	3,009	2,727	758	6,494	**52%**	
Total	**5,812**	**5,271**	**1,399**	**12,481**		

Source: *California Energy Efficiency Potential Study*, Itron, et. Al., 2006, Navigant Consulting, Inc.

Two scenarios of emerging technology deployment were developed. The first tier included all technologies with a combined score of 3.5 or higher. This tier represents a 2016 potential for the IOUs of 6,982 GWh, as summarized in Table F.7. The second tier includes the remaining emerging technology potential.

Table F.7: Emerging Technology Potential by Combined Score

Score	GWh Potential	Cummulative Percent
4.0	2,974	23%
3.5	6,982	55%
3.0	11,083	87%
2.0	12,780	100%

Source: Navigant Consulting, Inc.

The total resource cost (including program administration and marketing costs) were assumed to be the same as the average cost of the economic potential. This assumption is consistent with the Itron study, where the entire emerging technology

potential was considered to be economic. Given the low estimated cost of the energy saved, as summarized in table F.5, the assumption is reasonable, if not conservative.

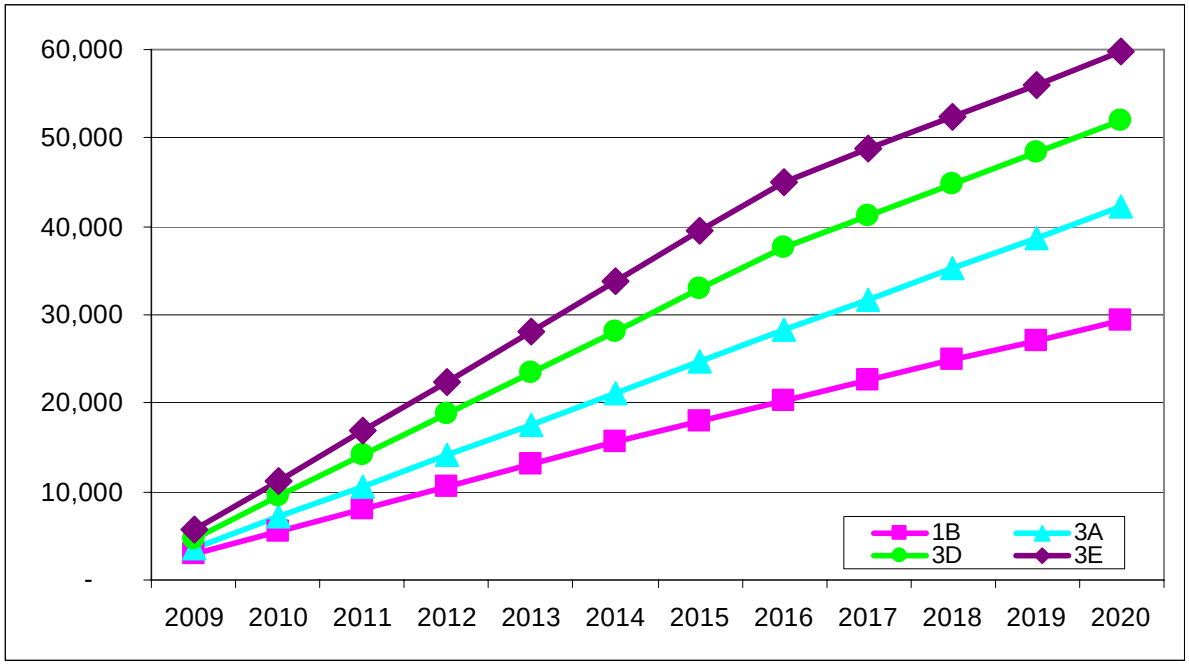
For years 2009 through 2016, one-eighth of the 2016 emerging technology potential is assumed to be attained in each year. After 2016, the additional contribution from emerging technology is assumed to grow at the rate of pre-EE forecasted sales.

Extension to POU and 2020

The potentials in the Itron study were developed for the IOUs through 2016. These were extended to the entire state and 2020. The economic and emerging technology potentials were assumed to increase between 2016 and 2020 at the same rate as the forecasted sales (before energy efficiency). The average annual growth rate for sales before energy efficiency for 2016 through 2020 was 1.14 percent for PG&E, 1.11 percent for SCE, and 1.32 percent for SDG&E.

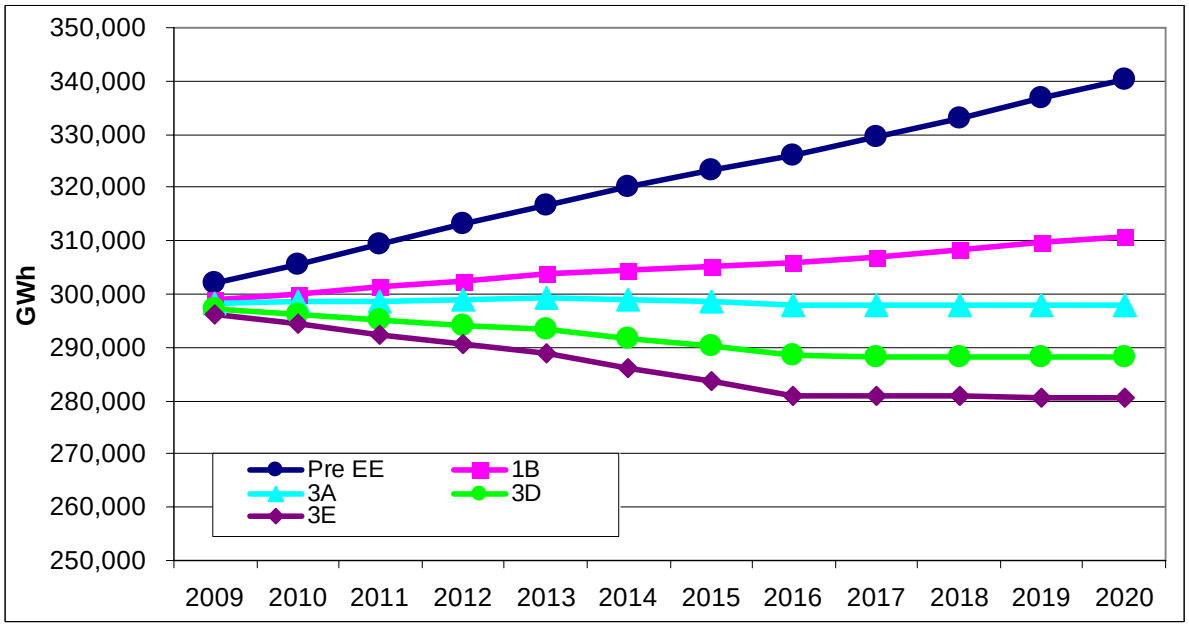
The IOU potentials were extended to the POUs by assuming that the EE savings as a percent of sales for the POUs are the same as a percent of sales as the nearest IOU, with the exceptions of: SMUD is 75 percent of PG&E; Los Angeles Department of Water and Power (LADWP) is 75 percent of SCE; and IID is 50 percent of the average savings percent for the rest of the state. The resulting EE for each scenario is summarized in Figure F.1, and the impact upon forecasted California sales is summarized in Figure F.2. With full deployment of emerging technologies, electricity sales in California would actually decline by approximately 7 percent relative to forecasted 2009 sales prior to additional EE.

Figure F.1: California EE Savings (GWh) Scenarios



Source: Navigant Consulting, Inc.

Figure F.2: Impact of EE Scenarios on Forecasted Sales



Source: Navigant Consulting, Inc.

Rest-of-WECC

The CDEAC analysis is the closest to the Itron study for the WECC. It included estimates of the EE resource for both a "Current Activities" and a "Best Practices" scenario. The report does not provide much detail and the reported numbers include 18 states including California, as well as states that are not in the WECC (for example, Texas, Kansas). The analysis results showed that the Best Practices scenario would reduce energy usage by 20 percent relative to the Reference forecast, with an incremental reduction of 11 percent over and above the "Current Activities" scenario as summarized in Table F.8.

Table F.8: Percentage Savings from Reference Forecast for WGA States by Scenario

Scenario	2010	2015	2020
Current Activities	-4%	-7%	-9%
Best Practices	-7%	-14%	-20%

Source: Navigant Consulting, Inc.

The "Current Activities" scenario includes existing building codes, appliance standards, public sector programs, and utility programs. The utility EE programs represent savings of 2.2 percent of load in 2010 and 5.5 percent by 2020. Based on the modest level of utility DSM programs in the "Current Activities" scenario, the fact that the building codes are already in place, and the apparent consistency between the WECC load forecasts and the utility net of EE programs sales forecasts, it was assumed that the "Current Practices" was already embedded in the rest-of-WECC forecasts. Thus, the difference between the "Best Practices" and "Current Activities" scenarios was used for the aggressive development scenario.

The resulting 82,615 GWh of EE represents approximately 11 percent of rest-of-WECC 2020 loads.

California

For the California cases, the GWh estimates were first developed for each of the IOUs. The EE as a percentage of each IOU's sales was then calculated and applied to each California transarea. Each of the transareas was mapped to a particular IOU for the purposes of determining EE GWh, load shapes, and costs. For some of the transareas dominated by POUs, a discount factor was applied to account that less EE resource may be developed by the POU. Table F.9 summarizes the transareas, the mapped IOU, the discount factor, and the year 2020 EE as a percentage of 2020 sales forecast.

Table F.9: – Transarea Percentage Savings

Transarea	Assigned IOU	Discount Factor	2020 Savings Percent	
			Current Practices	Aggressive Development
North of Path 15	PG&E		10.08%	14.84%
Zone Path 26	PG&E		10.08%	14.84%
SCE Area	SCE		8.93%	13.39%
SDG&E	SDG&E		11.35%	11.35%
SMUD	PG&E	25%	7.56%	11.13%
LADWP	SCE	25%	6.70%	10.04%
IID	SCE	50%	4.67%	6.70%
SF	PG&E		10.08%	14.84%

Source: Navigant Consulting, Inc.

The GWh of EE by IOU and all POUs and year for the current practices and aggressive development scenarios are summarized in Table F.10. The GWh of EE by IOU and POUs for the two emerging technology deployment scenarios are summarized in Table F.11.

Table F.10: California EE Resource Base for Current Practice and Aggressive Development Scenarios (GWh)

	Current Practices					Aggressive Development				
	PG&E	SCE	SDG&E	POU	Total	PG&E	SCE	SDG&E	POU	Total
2009	882	979	288	708	2,857	1,230	1,148	288	901	3,567
2010	1,715	1,889	530	1,369	5,503	2,460	2,296	530	1,800	7,086
2011	2,510	2,745	816	1,987	8,058	3,690	3,444	816	2,688	10,638
2012	3,294	3,555	1,044	2,584	10,477	4,920	4,592	1,044	3,580	14,136
2013	4,126	4,427	1,260	3,199	13,012	6,150	5,740	1,260	4,434	17,584
2014	4,960	5,264	1,500	3,879	15,603	7,380	6,888	1,500	5,406	21,174
2015	5,808	5,964	1,752	4,486	18,010	8,610	8,036	1,752	6,344	24,742
2016	6,652	6,609	1,992	5,069	20,322	9,840	9,184	1,992	7,277	28,293
2017	7,496	7,254	2,232	5,611	22,593	11,070	10,332	2,232	8,155	31,789
2018	8,340	7,899	2,472	6,129	24,840	12,300	11,480	2,472	8,995	35,247
2019	9,184	8,544	2,712	6,682	27,122	13,530	12,628	2,712	9,886	38,756
2020	10,028	9,189	2,952	7,235	29,404	14,760	13,776	2,952	10,775	42,263

Source: Navigant Consulting, Inc.

Table F.11: California EE Resource Base for Partial and Full Emerging Technology Development Scenarios (GWh)

	Partial Emerging Technology Deployment					Full Emerging Technology Deployment				
	PG&E	SCE	SDG&E	POU	Total	PG&E	SCE	SDG&E	POU	Total
2009	1,638	1,478	384	1,237	4,739	1,957	1,807	462	1,435	5,661
2010	3,276	2,957	723	2,472	9,428	3,913	3,614	879	2,866	11,273
2011	4,914	4,436	1,105	3,691	14,147	5,870	5,421	1,340	4,280	16,911
2012	6,553	5,915	1,430	4,916	18,813	7,826	7,228	1,744	5,699	22,496
2013	8,191	7,393	1,743	6,090	23,417	9,783	9,034	2,134	7,059	28,010
2014	9,829	8,872	2,079	7,421	28,200	11,739	10,841	2,549	8,605	33,734
2015	11,467	10,350	2,428	8,705	32,950	13,696	12,648	2,976	10,095	39,415
2016	13,105	11,829	2,764	9,985	37,683	15,652	14,455	3,391	11,580	45,078
2017	14,370	13,325	3,026	10,555	41,276	16,944	15,659	3,646	12,498	48,747
2018	15,600	14,473	3,266	11,485	44,824	18,174	16,807	3,886	13,499	52,366
2019	16,830	15,621	3,506	12,481	48,438	19,404	17,955	4,126	14,578	56,064
2020	18,060	16,769	3,746	13,477	52,053	20,634	19,104	4,366	15,659	59,763

Source: Navigant Consulting, Inc.

Rest-of-WECC

The same percentage savings was applied to each non-California transarea. The resulting EE resource for selected years for each transarea is summarized in Table F.12

Table F.12: Aggressive Development EE (GWh) by Transarea

WECC transarea	2010	2015	2020
AB_S	641	2,228	3,778
ABCN	1,061	3,706	6,286
Arizona	1,816	6,647	11,784
BC	1,452	4,874	8,184
CNP15	2,548	8,964	15,331
CO East	1,141	3,981	6,781
CO West	149	523	896
COB	39	131	216
CSCE	2,653	9,302	15,935
CSDGE	514	1,707	2,875
CZP26	182	642	1,106
ID_SW	356	1,215	2,045
IDE_WYSW	206	695	1,162
IID	45	158	272
La Rosita	143	573	1,086
LADWP	564	1,886	3,084
Montana	265	924	1,571
N Nevada	313	1,143	2,030
NBAJA	143	573	1,086
New Mexico	582	2,110	3,719

WECC transarea	2010	2015	2020
Northwest	3,585	12,154	20,190
S Nevada	744	2,600	4,514
SF	147	515	887
SMUD	433	1,566	2,771
Utah	803	2,952	5,277
WYCE	332	1,163	2,009
Total	**20,855**	**72,934**	**124,877**
California Total	7,086	24,742	42,263
Balance of WECC Total	13,769	48,192	82,615

Source: Navigant Consulting, Inc.

Load Shapes

The load shapes for EE were developed using a three-step process for the California IOUs. These load shapes were applied to all of the other WECC transareas according to the IOU that is climatically the most similar to that transarea.

The first step in the process was to allocate the annual GWh to customer segments (that is, new and existing, industrial, commercial, and residential). Next, the GWh for each customer segment were allocated to end uses to obtain GWh by end use, customer segment, IOU and year. Finally, these annual end-use EE savings were allocated to hours using hourly load shapes (typical day per month). The customer segment and end-use allocation factors were derived from the 2006 Itron potential study. The load shapes were derived form the CEUS[6] and LSUI[7] databases.

Customer Segment Distribution

The annual savings were allocated to customer segments and end uses using the distribution of savings from the full incentives achievable potential for the current practices scenario and the economic potential for the aggressive development scenario. The allocation factors by IOU and year are summarized in Tables F.13 and F.14. The aggressive development allocation factors were also used for the two emerging technology deployment scenarios. These percentages apply to the cumulative EE installed.

Table F.13: Current Practice EE Customer Segment Allocation Factors

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SCE Residential												
Existing	50%	50%	51%	51%	52%	52%	52%	52%	52%	52%	52%	52%
New	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
SCE Commercial												
Existing	25%	24%	24%	23%	23%	22%	22%	22%	22%	22%	22%	22%
New	7%	7%	7%	8%	8%	8%	9%	9%	9%	9%	9%	9%
SCE Industrial												
Existing	17%	17%	16%	16%	16%	16%	15%	15%	15%	15%	15%	15%
New	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
SCE Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
PG&E Residential												
Existing	45%	46%	48%	49%	50%	50%	51%	51%	51%	51%	51%	51%
New	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
PG&E Commercial												
Existing	25%	24%	23%	22%	22%	21%	21%	20%	20%	20%	20%	20%
New	6%	7%	7%	7%	8%	8%	8%	9%	9%	9%	9%	9%
PG&E Industrial												
Existing	21%	20%	19%	19%	18%	18%	17%	17%	17%	17%	17%	17%
New	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
PG&E Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
SDG&E Residential												
Existing	58%	59%	59%	60%	60%	60%	60%	60%	60%	60%	60%	60%
New	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
SDG&E Commercial												
Existing	25%	24%	23%	23%	22%	22%	22%	21%	21%	21%	21%	21%
New	7%	7%	7%	8%	8%	8%	9%	9%	9%	9%	9%	9%
SDG&E Industrial												
Existing	9%	9%	9%	9%	8%	8%	8%	8%	8%	8%	8%	8%
New	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SDG&E Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: Navigant Consulting, Inc.

Table F.14: Aggressive Development and Emerging Technology EE Customer Segment Allocation Factors

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SCE Residential												
Existing	45%	45%	45%	45%	45%	45%	44%	44%	44%	44%	44%	44%
New	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
SCE Commercial												
Existing	32%	31%	31%	31%	30%	30%	30%	30%	30%	30%	30%	30%
New	7%	7%	8%	8%	8%	9%	9%	10%	10%	10%	10%	10%
SCE Industrial												
Existing	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%
New	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
SCE Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
PG&E Residential												
Existing	52%	52%	51%	51%	51%	50%	50%	50%	50%	50%	50%	50%
New	1%	1%	1%	1%	1%	1%	1%	2%	2%	2%	2%	2%
PG&E Commercial												
Existing	26%	26%	26%	26%	25%	25%	25%	25%	25%	25%	25%	25%
New	7%	7%	8%	9%	9%	9%	10%	10%	10%	10%	10%	10%
PG&E Industrial												
Existing	13%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
New	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
PG&E Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
SDG&E Residential												
Existing	55%	54%	54%	53%	54%	53%	53%	53%	53%	53%	53%	53%
New	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
SDG&E Commercial												
Existing	30%	30%	29%	29%	29%	29%	28%	28%	28%	28%	28%	28%
New	7%	8%	8%	9%	9%	10%	10%	11%	11%	11%	11%	11%
SDG&E Industrial												
Existing	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
New	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SDG&E Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: Navigant Consulting, Inc.

End-Use Allocations

The customer segment specific savings were allocated to end uses based upon the savings distribution in the economic potential. For example, if 5 percent of the economic potential GWh for residential existing construction came from air conditioning measures for a particular IOU, then it was assumed that 5 percent of the existing residential savings come from air-conditioning in all years. For existing commercial and industrial facilities, the same end-use allocations were used for all three IOUs. The residential miscellaneous end use in the Itron study was split between whole facility and refrigeration end uses. All new construction EE was assigned to the whole building load shape because most of the new construction results in the Itron analysis were only reported at the total building level, reflecting

the fact that new construction strategies affect multiple end uses. The end-use allocation factors are summarized in Table F.15.

Table F.15: Percentage of Customer Segment Savings Allocated to Each End Use

Customer Segment		Whole Facility	Lighting	HVAC	Refrigeration	Process
Residential Existing	PG&E	16%	64%	5%	15%	
	SCE	16%	61%	8%	15%	
	SDG&E	15%	67%	3%	15%	
Commercial, Existing			51%	36%	12%	1%
Industrial, Existing			25%	3%	2%	54%
New (Res., Com. & Ind.)		100%				

Source: Navigant Consulting, Inc.

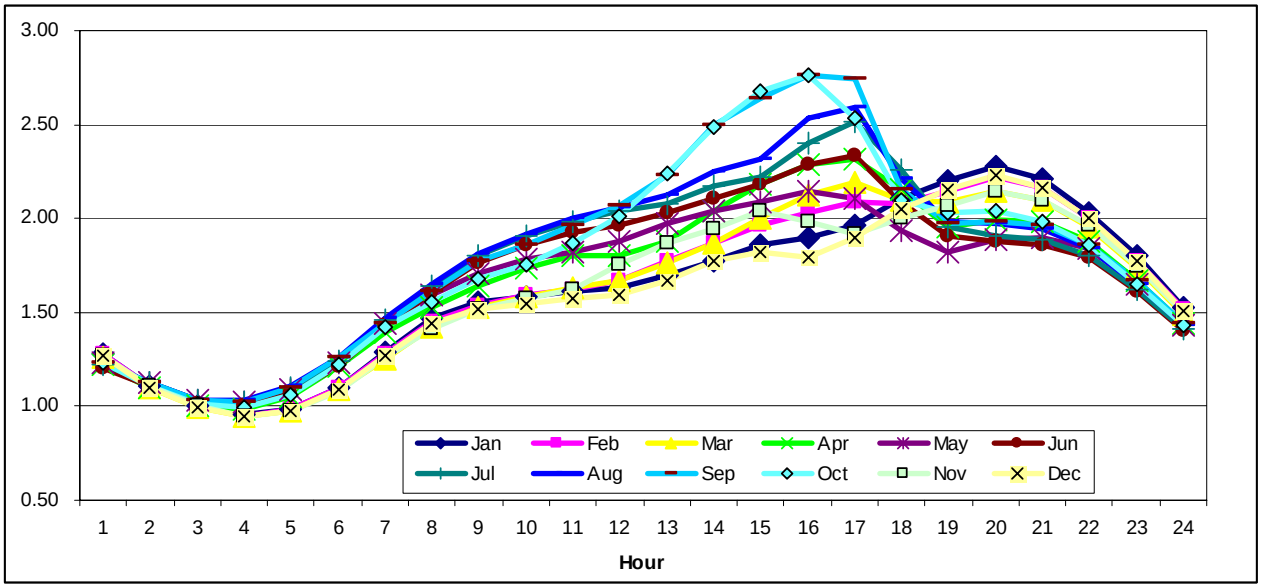
Typical Day Load Shapes

The result of the previous two allocation steps is the GWh of energy saved by year by customer class and end use for each IOU. The last step was to allocate these annual loads to hours using typical day per month load shapes. It was assumed that the savings were proportional to the end-use load. For example, if a measure reduces annual loads by 5 percent, then it is assumed that the end-use load is reduced by 5 percent in all hours. While some measures save less energy on peak than on average, this was not reflected in the load shapes for several reasons:

- Most of the savings in the potential analysis are from measures where it is reasonable to assume that the hourly savings are proportional to annual savings. For example, nearly 80 percent of the savings are from lighting and refrigeration measures where hourly savings would be proportional to annual savings. Of the more 60 percent of savings that come from lighting measures, only a few percent come from lighting controls.
- There are only limited load shape data available for EE measures. Some measure specific load shapes were available, but some of them had anomalies and were not suitable to use for this analysis.

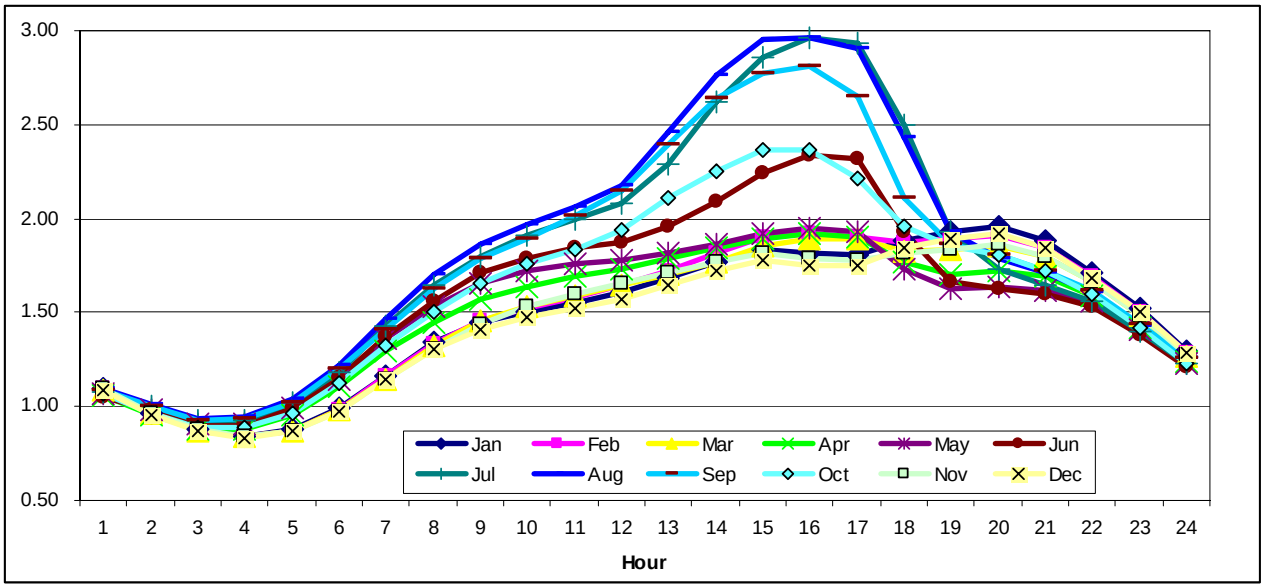
Thus, end-use load shapes were used to allocate the EE to hours. End-use load shapes were extracted from the CEUS database for commercial and industrial segments and from the savings from LSUI database for the residential sector for each IOU. Typical day per month shapes were developed. The shapes were then weighted by the customer segment and end-use allocations factors summarized above to develop aggregate load shapes for each IOU and year. The aggregate load shapes for each IOU for the aggressive development and emerging technology deployment scenarios for 2020 are provided in Figures F.3 through F.5.

Figure F.3: PG&E 2020 Aggressive Development EE Load Shape (1,000 GWh)



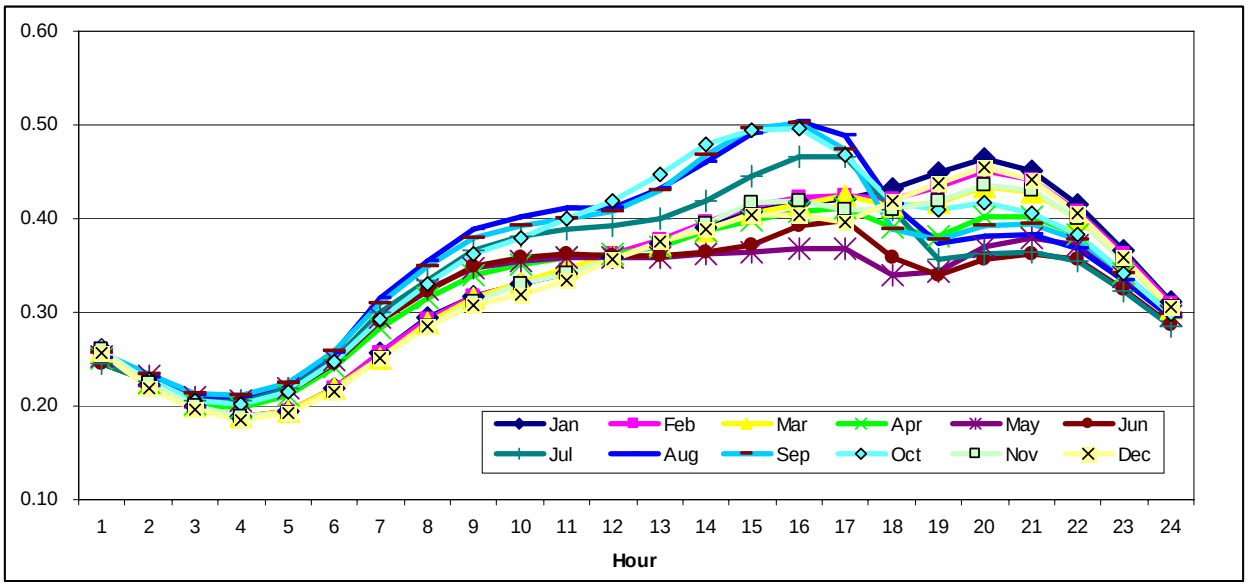
Source: Navigant Consulting, Inc.

Figure F.4: SCE 2020 Aggressive Development EE Load Shape (1,000 GWh)



Source: Navigant Consulting, Inc.

Figure F.4: SDG&E 2020 Aggressive Development EE Load Shape (1,000 GWh)



Source: Navigant Consulting, Inc.

Costs

Costs for developing the EE were estimated from the Itron potential study. Total resource costs, including utility program costs, were used. The measure costs per kW saved were assumed to be the same for the current practices, aggressive development, and emerging technology deployment scenarios. Because the ratio of energy to peak changed between the current practices and the other scenarios, the average cost per GWh are lower in the more aggressive scenarios compared to the current practices scenario. The Itron study indicated lower measure costs for the economic potential than for the achievable potential because there were a few low - cost measures that had very low penetrations in the achievable potential. The EE program administration costs were increased by 20 percent for the aggressive scenarios to reflect that more aggressive marketing will be required. The costs per kW saved are summarized in Table F.16.

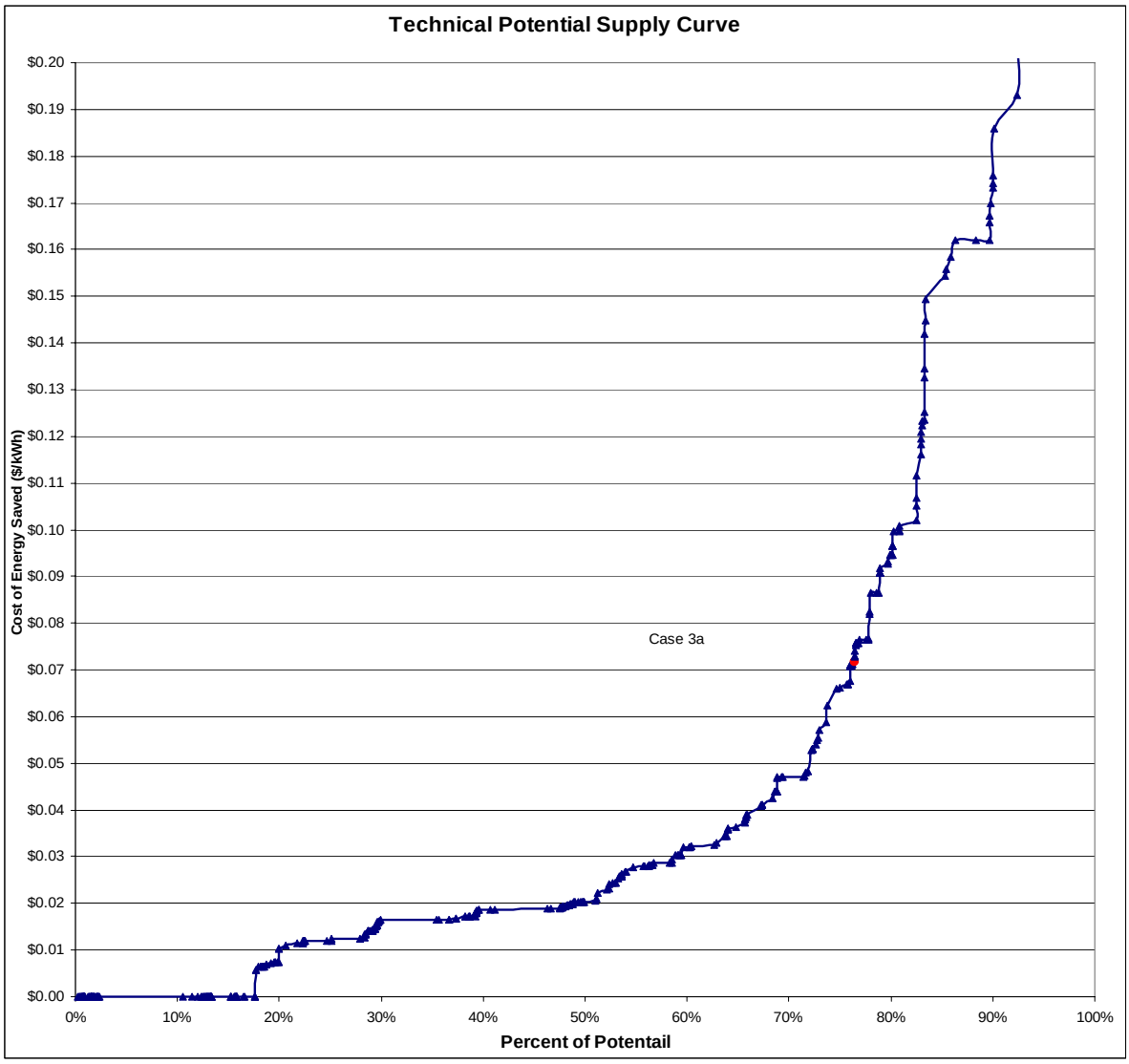
Table F.16: Total Resource Costs Including Program Administration for EE ($/kW reduced)

		Current Practices			Aggressive Development & Emerging Technology		
		SCE	PG&E	SDG&E	SCE	PG&E	SDG&E
Residential	Existing	1,917	2,232	2,137	1,924	2,251	2,160
	New	2,431	2,560	2,830	2,523	2,639	2,897
Commercial	Existing	2,161	2,283	2,525	2,174	2,292	2,540
	New	1,554	1,350	1,188	1,569	1,376	1,199
Industrial	Existing	2,199	2,225	2,024	2,543	2,574	2,337
	New	937	952	1,000	958	990	1,020

Source: Itron Potential Study

The costs of additional measures beyond the economic potential were also examined to determine the extent to which additional EE resources may be available. The percentage of the technical potential available as a function of the levelized costs of energy saved (cents/kWh) was developed for PG&E from the Itron potential and is shown in Figure F.6. The EE supply curve is very steep beyond the resources included in the economic potential. This means that additional EE beyond the economic potential becomes expensive. For example, an additional 1 percent EE would have a cost of energy saved of 7.7 cents/kWh compared to the 7.2 cents/kWh for the most expensive measure in the economic potential.

Figure F.6: Available Energy Efficiency as a Function of Levelized Cost of Energy Saved



Source: Navigant Consulting, Inc., PG&E data from the Itron Potential Study

The costs could be substantially higher. If the costs per kWh from the current practices scenario were used rather than costs, per kW, the costs would be 28 percent higher. These scenarios also assume that the savings are maintained upon the end of the equipment life at no additional cost. The CFLs comprise approximately one-third of the savings and have a measure life of approximately six years. It may be reasonable to assume that by 2015, CFLs will be current costs. Most of the other measures have lives longer than 20 years and would not need to be replaced before 2020. Some costs may be required, however, to re-acquire EE from pre-2009 programs.

Table F.17 compares the costs for the EE assuming the Case 1B costs per first year kWh saved plus a 20 percent higher administration and marketing costs were used for the other EE scenarios. As shown, these costs would be 28 percent higher.

Table F.17: Present Value of Costs using Constant $/kW and Constant $/kWh for each EE Scenario

Case	Energy Savings (GWh)	Demand Savings (MW)	PV Costs (Million $) Constant $/kW	PV Costs (Million $) Constant $/kWh
1B	29,404	6,450	8,286	8,286
3A	42,263	7,159	9,334	11,988
3D	52,053	8,817	11,780	5,093
3E	59,763	10,122	13,706	17,538
Discount rate		8.6%		

Source: Navigant Consulting, Inc.

Assuming an average measure life of 12 years, the levelized cost of energy saved ranges from 4.9 cents/kWh saved (Cases 3A-3E, using the constant $/kW cost calculation) to 6.2 cents per kWh saved for Case 1B, or for all cases if a constant $/kWh cost is used.

F-2 Demand Response

Demand response (DR) estimates were developed from utility submittals to the Energy Commission as part of the 2007 IEPR proceeding. These data are summarized in Table F.18 and compared to 5 percent of forecasted peak loads.

Table F.18: Summary of Utility Reported DR Capability (Committed and Uncommitted) Compared to 5 Percent of Peak Load

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
PG&E	Peak Demand	20,067	20,388	20,714	21,046	21,383	21,725	22,072	22,425	22,784	23,149
	5%	1,003	1,019	1,036	1,052	1,069	1,086	1,104	1,121	1,139	1,157
	Dispatchable	968	1,068	1,068	1,068	1,068	1,068	1,068	1,068	1,068	1,068
	Non-Dispatchable	177	245	270	277	280	284	291	292	294	297
	Subtotal	1,145	1,313	1,338	1,345	1,348	1,352	1,359	1,360	1,362	1,365
	Delta	-	-	-	-	-	-	-	-	-	-
SCE	Peak Demand	23,823	24,180	24,543	24,911	25,285	25,664	26,049	26,440	26,836	27,239
	5%	1,191	1,209	1,227	1,246	1,264	1,283	1,302	1,322	1,342	1,362
	Dispatchable	1,691	1,760	1,820	1,890	1,882	1,951	2,000	2,016	2,019	2,023
	Non-Dispatchable	25	81	142	185	200	203	204	208	211	213
	Subtotal	1,716	1,841	1,962	2,075	2,082	2,154	2,204	2,223	2,230	2,236
	Delta	-	-	-	-	-	-	-	-	-	-
SDG&E	Peak Demand	4,594	4,667	4,742	4,818	4,895	4,973	5,053	5,133	5,216	5,299
	5%	230	233	237	241	245	249	253	257	261	265
	Dispatchable	138	138	138	138	138	138	138	138	138	138
	Non-Dispatchable	126	126	126	126	126	126	126	126	126	126
	Subtotal	264	264	264	264	264	264	264	264	264	264
	Delta	-	-	-	-	-	-	-	-	-	1
SMUD	Peak Demand	3,213	3,297	3,382	3,470	3,560	3,653	3,748	3,845	3,945	4,048
	5%	161	165	169	174	178	183	187	192	197	202
	Dispatchable	115	115	115	115	115	115	115	115	115	115
	Non-Dispatchable	53	53	53	53	53	53	53	53	53	53
	Subtotal	168	168	168	168	168	168	168	168	168	168
	Delta	-	-	1	6	10	15	19	24	29	34
LADWP	Peak Demand	5,839	5,851	5,862	5,874	5,886	5,898	5,909	5,921	5,933	5,945
	5%	292	293	293	294	294	295	295	296	297	297
	Dispatchable	14	14	14	14	14	14	14	14	14	14
	Non-Dispatchable	20	20	30	30	40	40	50	50	50	50
	Subtotal	34	34	44	44	54	54	64	64	64	64
	Delta	258	259	249	250	240	241	231	232	233	233

Demands for IOUs from CEC-400-2006-008-SF, used 2007 demands and average annual growth rates.

Demands for SMUD and LADWP from CEC-400-2005-034-ED2 for 2009 grown at annual average annual growth rates.

DR Program MWs from Form 3-4 (2007), except SDG&E where the goals presented at the March 27, 2007, workshop were used .

Source: Navigant Consulting, Inc.

Based on these data, dispatchable DR capabilities were developed for two cases:

- Cases 1a, 1b, 2, 4a, and 4b: include 3,357 MW of dispatchable DR capability by 2018 as reported by the utilities, reflecting the committed and uncommitted capability from their submittals.
- Case 3a, 3b, 5a, and 5b: increase the dispatchable DR capability by approximately 20 percent to 4,057 MW by 2018, with SCE and PG&E having DR capability of approximately 7.4 percent and 6 percent of their peak demands, exceeding the DR capability as a percentage of load of any region in North America.

The MW by utility and case are summarized in table F.19.

Table F.19: Dispatchable DR Capability by Utility and Case

	Case 1b - Current Practices					Case 3b - Aggressive Development				
	PG&E	SCE	SDG&E	SMUD	LADWP	PG&E	SCE	SDG&E	SMUD	LADWP
2009	968	1,691	138	115	14	968	1,691	138	115	14
2010	1,068	1,760	138	115	14	1,068	1,760	152	125	32
2011	1,068	1,820	138	115	14	1,104	1,820	166	134	51
2012	1,068	1,890	138	115	14	1,139	1,890	180	144	69
2013	1,068	1,882	138	115	14	1,175	1,882	194	154	87
2014	1,068	1,951	138	115	14	1,211	1,951	208	164	105
2015	1,068	2,000	138	115	14	1,246	2,000	222	173	124
2016	1,068	2,016	138	115	14	1,282	2,016	237	183	142
2017	1,068	2,019	138	115	14	1,318	2,019	251	193	160
2018	1,068	2,023	138	115	14	1,389	2,023	265	202	178
2019	1,068	2,023	138	115	14	1,389	2,023	265	202	178
2020	1,068	2,023	138	115	14	1,389	2,023	265	202	178
% of 2018 Peak	4.6%	7.4%	2.6%	2.8%	0.2%	6.0%	7.4%	5.0%	5.0%	3.0%
Case 3a Incremental MW Added Relative to Case 1B						321	-	127	87	164

Source: Navigant Consulting, Inc.

The DR capability for SCE was held the same in the aggressive cases (for example, Case 3A) as in Case 1B because their planned capability already substantially exceeded 5 percent of their peak loads. For the aggressive case DR capability was increased by approximately 20 percent to reflect more aggressive development of DR by increasing DR capability to 6 percent of peak loads for PG&E, 5 percent of peak loads for SDG&E and SMUD, and to 3 percent of peak loads for LADWP.

The costs for the dispatchable DR were assumed to be $100/kW-year, except for SMUD, where costs were assumed to be $360/kW-year. The data provided by the utilities showed tremendous range (SCE - $97/kW-year in 2009 declining to $66/kW-yr in 2018, PG&E - $25/kW-year; LADWP - $10/kW-year, and SMUD - between $348 and $368/kW-year). SCE's 2009 costs of $96/kW-year was rounded to

$100/kW-year and used for all of the utilities except SMUD. For SMUD, $360/kW-year was used as an average cost based on the costs that they provided.

Endnotes

1. Itron, KEMA, RLW, and AEC, May 2006, *California Energy Efficiency Potential Study.*

2. Western Governor's Association, January 2006, *Clean and Diversified Energy Initiative: Energy Efficiency Task Force Report.*

3. Pacific Gas and Electric, San Diego Gas & Electric, Southern California Edison, 2006 Procurement Plan, December 2006, R.06-002-013

4. Western Governor's Association, January 2006, *Clean and Diversified Energy Initiative: Energy Efficiency Task Force Report.*

5. D.04-09-050 established goals through 2013. The 2016 goals are based on the assumption that the goals for 2014-2016 would be approximately the same as the goals for 2013.

6. ITRON, March 2006, *Commercial End-Use Survey*, prepared for the California Energy Commission, CEC-400-2006-005

7. KEMA, JJ Hirsch Associates, November 17, 2006, *Load Shape Update Initiative, Final Report*, prepared for the California Public Utilities Commission

APPENDIX B

CALIFORNIA VERSUS REST-OF-WECC SCORECARD RESULTS FOR HIGH ENERGY EFFICIENCY SCENARIOS

Prepared by Global Energy Decisions, Inc.

Table B-1
Scorecard Line Definitions and Notes

1	Line	Definition
2	**Total WECC System Cost ($000)**	Sum of Lines 4 and 64
3	**California**	
4	**CA System Production Cost ($000)**	Sum of Lines 29, 38, 50, 53, and 59
5	**CA Per Unit Production Cost ($/MWh)**	Line 4 divided by the difference of Line 7 and 23
6	**CA Peak Load (MW)**	California coincident peak load in MW
7	**CA Energy Load (GWh)**	California energy load in GWh (Includes Losses and Pumping Load)
8	**CA "Energy Not Served" (GWh)**	California Loss of load in GWh
9	**CA Generation By Fuel (GWh)**	
10	***Coal***	California Coal-fired Generation (GWh)
11	***Fuel Oil***	California Fuel Oil-fired Generation (GWh)
12	***Geothermal***	California Geothermal Generation (GWh)
13	***Hydro***	California Hydro Generation (GWh)
14	***Natural Gas***	California Natural Gas-fired Generation (GWh)
15	***Nuclear***	California Nuclear Generation (GWh)
16	***Biomass/Other***	California plants including Biomass, Solar, Refuse, Wood, Jet Fuel-fired plants, Petroleum Coke-fired plants, and Variable Demand Reduction (GWh)
17	***Pumped Storage***	California Pumped Storage Generation (GWh)
18	***Wind***	California Wind Generation (GWh)
19	***Total CA Generation (GWh)***	Sum of lines 10 through 18
20	**CA Energy Efficiency and PV Solar (GWh)**	
21	***Energy Efficiency***	California Energy Efficiency Load Reduction (GWh)
22	***PV Solar***	California PV Solar Load Reduction (GWh)
23	***Total CA Energy Efficiency and PV Solar (GWh)***	Sum of Lines 21 and 22
24	**CA O&M Costs**	
25	**CA Fuel Costs ($000)**	California Located Generation Fuel Costs
26	**CA VOM Costs ($000)**	California Located Generation Variable Operations and Maintanence Costs
27	**CA Start Costs ($000)**	California Located Generation Start Costs
28	**CA FOM Costs ($000)**	California Located Generation Fixed Operations and Maintenance Costs
29	***Total CA O&M Costs ($000)***	Sum of Lines 25 through 28
30	**CA Other Costs**	
31	**CA Wheeling Costs ($000)**	California incurred Wheeling Costs
32	**CA Energy Efficiency Costs ($000)**	California Energy Efficiency Program Capital Costs
33	**CA PV Solar Costs ($000)**	California PV Solar Program Capital Costs
34	**CA Variable Demand Response Costs ($000)**	California Variable Demand Response Costs (includes Program Capital Costs and Variable Costs)
35	**CA Transmission Capital Costs ($000)**	California Transmission Capital Costs relative to Line 36
36	**CA Transmission Miles**	California Transmission Miles relative to Line 35
37	**CA Incremental Resource Capital Costs ($000)**	California cost of generic resource additions including the following resource types: Gas Turbines, Combined Cycles, Wind, Geothermal, Concentrated Solar Power, and Biomass
38	***Total CA Other Costs ($000)***	Sum of of Lines 31 through 35, and Line 37
39	**CA Renewable Generation**	
40	**CA Renewable Generation (GWh) - without Hydro**	California renewable generation excluding hydro and pumped storage generation
41	**CA Renewable Energy (%) - without Hydro**	California renewable generation excluding hydro and pumped storage as a percent of California Load (Line 7) net of California EE and PV Solar (Line 23)
42	**CA Renewable Generation (GWh) - with Hydro**	California renewable generation including hydro and pumped storage generation
43	**CA Renewable Energy (%) - with Hydro**	California renewable generation including hydro and pumped storage as a percent of California Load (Line 7) net of California EE and PV Solar (Line 23)
44	**CA Emissions**	
45	**CA CO2 Production (000 tons)**	California CO2 production from generation located within California only
46	**CA GHG 2020/1990 Ratio**	
47	**CA SO2 (000 tons)**	California SO2 production from generation located within California only
48	**CA NOx (000 tons)**	California NOx production from generation located within California only
49	**CA HG (000 tons)**	California HG production from generation located within California only
50	**CA Emission Costs SO2/NOx/HG ($000)**	California Total Emission Costs from generation located within California only
51	**CA Remote Generation**	
52	**CA Remote Generation (GWh)**	California share of generation from remote located plants
53	**CA Remote Generation Cost ($000)**	California share of generation costs from remote located plants including costs associated with Fuel, VOM , Start-up , FOM, and Emissions.
54	**CA Remote CO2 (000 tons)**	California share of CO2 emissions from remote located plants
55	**CA Remote SO2 (000 tons)**	California share of SO2 emissions from remote located plants
56	**CA Remote NOx (000 tons)**	California share of NOx emissions from remote located plants
57	**CA Remote HG (000 tons)**	California share of HG emissions from remote located plants
58	**CA Imports**	
59	**CA Net Import ($000)**	Cost of energy imports from the Rest of WECC priced at California marginal clearing price (SP15)
60	**CA Net Import (GWh)**	Net Energy imports from the Rest of WECC (i.e. the difference in California load and generation)
61	**CA Import CO2 (000 tons)**	CO2 from imported energy from plants in the Rest of WECC into California
62	**CA Gas and Water Consumption**	
63	**CA Gas Consumption (Gbtu)**	Natural gas fuel burn from plants located within California
64	**CA Water Consumption**	Water consumption used in power generation by plants located within California

Continued on next page.

(continued)

1	Line	Definition
65	**Rest of WECC (excludes California results)**	
66	**WECC System Production Cost ($000)**	Sum of Lines 93, 102, 108, and 111
67	**WECC Per Unit Production Cost ($/MWh)**	Line 66 divided by the difference of Line 69 and 87
68	**WECC Peak Load (MW)**	Rest of WECC coincident peak load in MW
69	**WECC Energy Load (GWh)**	Rest of WECC energy load in GWh (Includes Losses and Pumping Load)
70	**WECC "Energy Not Served" (GWh)**	Rest of WECC Loss of load in GWh
71	**Rest of WECC Generation by Fuel (GWh)**	
72	***Coal***	Rest of WECC Coal-fired Generation (GWh)
73	***Fuel Oil***	Rest of WECC Fuel Oil-fired Generation (GWh)
74	***Geothermal***	Rest of WECC Geothermal Generation (GWh)
75	***Hydro***	Rest of WECC Hydro Generation (GWh)
76	***Natural Gas***	Rest of WECC Natural Gas-fired Generation (GWh)
77	***Nuclear***	Rest of WECC Nuclear Generation (GWh)
78	***Biomass/Other***	Rest of WECC plants including Biomass, Solar, Refuse, Wood, Jet Fuel-fired plants, Petroleum Coke-fired plants, and Variable Demand Reduction (GWh)
79	***Pumped Storage***	Rest of WECC Pumped Storage Generation (GWh)
80	***Wind***	Rest of WECC Wind Generation (GWh)
81	***Total Rest of WECC Generation (GWh)***	Sum of Lines 71 through 80
82	***Total Rest ofWECC Exports (GWh)***	Net energy exports from the Rest of WECC into California
83	***Total Rest of WECC Generation Serving WECC Load (GWh)***	The difference of Lines 81 and 82
84	**Rest of WECC Energy Efficiency and PV Solar (GWh)**	
85	***Energy Efficiency***	Rest of WECC Energy Efficiency Load Reduction (GWh)
86	***PV Solar***	Rest of WECC PV Solar Load Reduction (GWh)
87	***Total Rest of WECC Energy Efficiency and PV Solar (GWh)***	Sum of Lines 86 and 87
88	**Rest of WECC O&M Costs**	
89	**WECC Fuel Costs ($000)**	Rest of WECC Located Generation Fuel Costs (excludes cost from WECC/CA shared generation)
90	**WECC VOM Costs ($000)**	Rest of WECC Located Generation Variable Operations and Maintanence Costs(excludes cost from WECC/CA shared generation)
91	**WECC Start Costs ($000)**	Rest of WECC Located Generation Start Costs(excludes cost from WECC/CA shared generation)
92	**WECC FOM Costs ($000)**	Rest of WECC Located Generation Fixed Operations and Maintenance Costs(excludes cost from WECC/CA shared generation)
93	***Total Rest of WECC O&M Costs ($000)***	Sum of Lines 89 through 92
94	**Rest of WECC Other Costs**	
95	**WECC Wheeling Costs ($000)**	Rest of WECC incurred Wheeling Costs
96	**WECC Energy Efficiency Costs ($000)**	Rest of WECC Energy Efficiency Program Capital Costs
97	**WECC PV Solar Costs ($000)**	Rest of WECC PV Solar Program Capital Costs
98	**WECC Variable Demand Response Costs ($000)**	Rest of WECC Variable Demand Response Costs (includes Program Capital Costs and Variable Costs)
99	**WECC Transmission Capital Costs ($000)**	Rest of WECC Transmission Capital Costs relative to Line 100
100	**WECC Transmission Miles**	Rest of WECC Transmission Miles relative to Line 99
101	**WECC Incremental Resource Capital Costs ($000)**	Rest of WECC cost of generic resource additions including the following resource types: Gas Turbines, Combined Cycles, Wind, Geothermal, Concentrated Solar Power, and Biomass
102	***Total Rest of WECC Other Costs ($000)***	Sum of of Lines 95 through 99, and Line 101
103	**Rest of WECC Emissions**	
104	**WECC CO2 Production (000 tons)**	Rest of WECC CO2 production from generation (excludes CO2 from WECC/CA shared generators) also excludes CO2 accounting to CA exports
105	**WECC SO2 (000 tons)**	Rest of WECC SO2 production from generation (excludes SO2 from WECC/CA shared generators)
106	**WECC NOx (000 tons)**	Rest of WECC NOx production from generation (excludes NOx from WECC/CA shared generators)
107	**WECC HG (000 tons)**	Rest of WECC HG production from generation (excludes HG from WECC/CA shared generators)
108	**WECC Emission Costs SO2/NOx/HG ($000)**	Rest of WECC Total Emission Costs (exlcludes emission costs from WECC/CA shared generators)
109	**Rest of WECC Remote Generation**	
110	**WECC Remote Generation (GWh)**	WECC share of generation from WECC/CA shared plants
111	**WECC Remote Generation Cost ($000)**	WECC share of generation costs from WECC/CA shared plants including costs associated with Fuel, VOM , Start-up , FOM, and Emissions.
112	**WECC Remote CO2 (000 tons)**	WECC share of CO2 emissions from WECC/CA shared plants
113	**WECC Remote SO2 (000 tons)**	WECC share of SO2 emissions from WECC/CA shared plants
114	**WECC Remote NOx (000 tons)**	WECC share of NOx emissions from WECC/CA shared plants
115	**WECC Remote HG (000 tons)**	WECC share of HG emissions from WECC/CA shared plants
116	**Rest of WECC Gas Consumption**	
117	**WECC Gas Consumption (Gbtu)**	Natural gas fuel burn from plants located in the Rest of WECC

Table B-2
CA vs Rest-of-WECC Scorecard for Energy Efficiency Scenarios

	California Energy Commission IEPR - Draft Score Card	Case 3a			Case 5a		
		Base	Case 3d	Case 3e	Base	Case 5d	Case 5e
	2020 2020	2020			2020		
1	**Comparative Ranking**						
2	**Total WECC System Cost ($000)**	42,983,772	42,290,520	41,751,601	44,744,362	44,051,312	43,496,544
3	**California**						
4	**CA System Cost ($000)**	15,701,704	15,181,514	14,784,143	18,407,604	17,909,019	17,518,242
5	**CA Per Unit System Cost ($/MWh)**	53	53	53	64	64	65
6	**CA Peak Load (MW)**	66,903	66,903	66,903	66,903	66,903	66,903
7	**CA Energy Load (GWh)** *Includes Losses and Pumping Load*	339,597	339,463	339,336	339,558	339,420	339,324
8	**CA "Energy Not Served" (GWh)**	0	0	0	0	0	0
9	**CA (Excludes Remote*) Generation By Fuel (GWh)**						
10	***Coal***	3,158	3,158	3,158	3,157	3,155	3,153
11	***Fuel Oil***	4	7	6	6	0	20
12	***Geothermal***	20,022	20,022	20,022	33,178	33,178	33,178
13	***Hydro***	33,910	33,910	33,910	33,910	33,910	33,910
14	***Natural Gas***	108,511	102,500	97,864	88,108	82,864	78,918
15	***Nuclear***	33,694	33,694	33,694	33,694	33,694	33,694
16	***Other***	13,285	13,279	13,273	22,650	22,632	22,614
17	***Pumped Storage Output***	2,204	2,107	2,017	2,165	2,067	1,999
18	***Wind***	16,813	16,813	16,813	31,220	31,220	31,220
19	***Total CA Generation***	231,600	225,489	220,755	248,088	242,719	238,705
20	**CA Distributed Generation (GWh)**						
21	***Energy Efficiency***	42,263	52,053	59,763	42,263	52,053	59,763
22	***PV Solar***	1,629	1,629	1,629	8,036	8,036	8,036
23	***Total Distributed Generation***	43,892	53,682	61,392	50,299	60,089	67,799
24	**CA (Excludes Remote*) O&M Costs**						
25	**CA Fuel Costs ($000)**	6,955,756	6,633,081	6,389,482	6,246,597	5,972,883	5,768,078
26	**CA VOM Costs ($000)**	441,083	428,682	419,068	492,168	481,702	473,759
27	**CA Start Costs ($000)**	59,217	52,274	48,567	51,870	42,718	38,021
28	**CA FOM Costs ($000)**	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892
29	***Total CA Ot&M Costs***	8,609,947	8,267,929	8,011,009	7,944,527	7,651,196	7,433,751
30	**CA Other Costs**						
31	**CA Wheeling Costs ($000)**	32,134	31,545	31,318	29,951	29,643	29,591
32	**CA Energy Efficiency Costs ($000)**	1,271,481	1,310,733	1,341,649	1,271,481	1,310,733	1,341,649
33	**CA PV Solar Costs ($000)**	633,822	633,822	633,822	2,987,984	2,987,984	2,987,984
34	**CA Variable Demand Response Costs ($000)**	230,009	229,985	229,985	230,059	229,994	229,985
35	**CA Transmission Capital Costs ($000)**	315,567	315,567	315,567	365,982	365,982	365,982
36	**CA Transmission Miles**	258	258	258	618	618	618
37	**CA Incremental Resource Capital Costs ($000)**	2,182,693	2,182,693	2,182,693	4,428,736	4,428,736	4,428,736
38	***Total CA Other Costs***	4,665,706	4,704,345	4,735,034	9,314,194	9,353,073	9,383,928
39	**CA Renewable Generation**						
40	**CA Renewable Generation (GWh)**	48,740	48,740	48,739	85,707	85,701	85,695
41	**CA Renewable Energy (%)**	16%	17%	18%	30%	31%	32%
42	**CA Renewable Generation (GWh) - with Hydro**	87,902	87,806	87,714	124,830	124,727	124,652
43	**CA Renewable Energy (%) - with Hydro**	30%	31%	32%	43%	45%	46%
44	**CA (Excludes Remote*) Emissions**						
45	**CA CO2 Production (000 tons)**	60,032	57,283	55,216	54,836	52,496	50,767
46	**CA GHG 2020/1990 Ratio**	0	0	0	0	0	0
47	**CA SO2 (000 tons)**	68	68	68	67	66	66
48	**CA NOx (000 tons)**	237	236	235	242	242	241
49	**CA HG (000 tons)**	13	13	13	13	13	13
50	**CA Emission Costs SO2/NOx/HG ($000)**	97,017	96,216	95,552	105,313	104,151	103,209
51	**CA Remote* Generation**						
52	**CA Remote* Generation (GWh)**	38,228	38,127	38,021	37,757	37,641	37,514
53	**CA Remote* Generation Cost ($000)**	947,054	942,171	936,540	926,531	920,944	915,102
54	**CA Remote* CO2 (000 tons)**	27,048	27,000	26,950	26,777	26,709	26,630
55	**CA Remote* SO2 (000 tons)**	14	14	14	14	14	14
56	**CA Remote* NOx (000 tons)**	46	46	46	46	46	46
57	**CA Remote* HG (000 tons)**	222	222	222	221	221	221
58	**CA Net Purchases and Sales**						
59	**CA Net Purchase +/Sale - ($000)**	1,381,980	1,170,852	1,006,008	117,039	-120,345	-317,747
60	**CA Net Purchase +/ Sale - (GWh)**	25,877	22,165	19,168	3,414	-1,028	-4,694
61	**CA Net Purchase +/Sale - CO2 (000 tons)**	14,572	12,496	10,816	1,934	-335	-1,522
62	**CA Gas and Water Consumption**						
63	**CA Gas Consumption (Gbtu)**	861,060	818,295	786,429	719,623	681,124	653,321

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	California Energy Commission IEPR - Draft Score Card	Case 3a			Case 5a		
		Base	Case 3d	Case 3e	Base	Case 5d	Case 5e
	2020 2020	2020			2020		
65	**Rest of WECC (excluding California results)**						
66	**Rest of WECC System Cost ($000)**	27,282,068	27,109,006	26,967,458	26,336,758	26,142,294	25,978,301
67	**Rest of WECC Per Unit System Cost ($/MWh)**	36	36	36	35	35	34
68	**Rest of WECC Peak Load (MW)**	125,514	125,514	125,514	125,514	125,514	125,514
69	**Rest of WECC Energy Load (GWh)** *Includes Losses and Pumping Loa*	757,750	757,750	757,750	757,749	757,749	757,749
70	**Rest of WECC "Energy Not Served" (GWh)**	0	0	0	0	0	0
71	**Rest of WECC (Excludes Remote*) Generation by Fuel (GWh)**						
72	***Coal***	271,510	271,411	271,322	270,370	270,098	269,760
73	***Fuel Oil***	127	106	131	102	113	126
74	***Geothermal***	16,407	16,407	16,407	16,407	16,407	16,407
75	***Hydro***	207,385	207,385	207,385	207,385	207,385	207,385
76	***Natural Gas***	162,303	158,906	156,138	141,907	137,904	134,782
77	***Nuclear***	9,251	9,251	9,251	9,251	9,251	9,251
78	***Other***	19,309	19,301	19,289	19,261	19,254	19,241
79	***Pumped Storage Output***	452	452	452	452	452	452
80	***Wind***	34,609	34,609	34,609	34,609	34,609	34,609
81	***Total Rest of WECC Generation***	721,353	717,827	714,984	699,742	695,472	692,012
82	***Total Rest of WECC Exports***	25,877	22,165	19,168	3,414	-1,028	-4,694
83	***Total Excluding Remote* Generation and Exports***	695,476	695,662	695,816	696,329	696,500	696,706
84	**Rest of WECC Distributed Generation (GWh)**						
85	***Energy Efficiency***	0	0	0	0	0	0
86	***PV Solar***	527	527	527	527	527	527
87	***Total Distributed Generation***	527	527	527	527	527	527
88	**Rest of WECC (Excludes Remote*) O&M Costs**						
89	**Rest of WECC Fuel Costs ($000)**	14,882,260	14,723,623	14,594,005	13,900,091	13,719,975	13,569,043
90	**Rest of WECC VOM Costs ($000)**	1,095,073	1,088,773	1,083,027	1,052,572	1,044,617	1,037,902
91	**Rest of WECC Start Costs ($000)**	70,967	72,270	74,007	93,852	94,467	97,287
92	**Rest of WECC FOM Costs ($000)**	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561
93	***Total Rest of WECC O&M Costs***	17,760,862	17,597,227	17,463,600	16,759,076	16,571,620	16,416,793
94	**Rest of WECC Other Costs**						
95	**Rest of WECC Wheeling Costs ($000)**	212,746	212,689	212,851	214,389	215,331	216,766
96	**Rest of WECC Energy Efficiency Costs ($000)**	0	0	0	0	0	0
97	**Rest of WECC PV Solar Costs ($000)**	208,108	208,108	208,108	208,108	208,108	208,108
98	**Rest of WECC Variable Demand Response Costs ($000)**	0	0	0	0	0	0
99	**Rest of WECC Transmission Capital Costs ($000)**	1,187,588	1,187,588	1,187,588	1,308,908	1,308,908	1,308,908
100	**Rest of WECC Transmission Miles**	4,535	4,535	4,535	4,535	4,535	4,535
101	**Rest of WECC Incremental Resource Capital Costs ($000)**	6,063,888	6,063,888	6,063,888	6,037,957	6,037,957	6,037,957
102	***Total Rest of WECC Other Costs***	7,672,330	7,672,273	7,672,434	7,769,362	7,770,304	7,771,739
103	**Rest of WECC (Excludes Remote*) Emissions**						
104	**Rest of WECC CO2 Production (000 tons)**	355,389	356,037	356,546	358,607	359,060	358,663
105	**Rest of WECC SO2 (000 tons)**	401	401	401	399	399	399
106	**Rest of WECC NOx (000 tons)**	461	461	461	458	457	456
107	**Rest of WECC HG (000 tons)**	2,723	2,723	2,722	2,714	2,712	2,709
108	**Rest of WECC Emission Costs SO2/NOx/HG ($000)**	231,333	231,158	231,039	229,785	229,496	229,094
109	**Rest of WECC Remote* Generation**						
110	**Rest of WECC Remote* Generation (GWh)**	61,747	61,561	61,407	60,893	60,722	60,516
111	**Rest of WECC Remote* Generation Cost ($000)**	1,617,543	1,608,348	1,600,385	1,578,536	1,570,874	1,560,676
112	**Rest of WECC Remote* CO2 (000 tons)**	36,247	36,169	36,101	35,840	35,759	35,645
113	**Rest of WECC Remote* SO2 (000 tons)**	27	27	27	27	27	27
114	**Rest of WECC Remote* NOx (000 tons)**	61	61	61	61	60	60
115	**Rest of WECC Remote* HG (000 tons)**	343	343	343	342	342	342
116	**Rest of WECC Gas Consumption**						
117	**Rest of WECC Gas Consumption (Gbtu)**	1,276,222	1,249,967	1,227,433	1,126,281	1,099,738	1,076,133

APPENDIX C

CARBON DIOXIDE DISPATCH ADDER SENSITIVITY STUDY

Prepared by Global Energy Decisions, Inc.

CALIFORNIA
ENERGY
COMMISSION

CARBON DIOXIDE DISPATCH ADDER SENSITIVITY STUDY

CONSULTANT REPORT

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Overview of the Carbon Dioxide Dispatch Adder Sensitivity Study

As a supplemental study to the June 2007 Integrated Energy Policy Report (IEPR) – Scenario Analysis Project, the California Energy Commission (Energy Commission) Staff requested Global Energy Decisions, Inc., (GED) to measure the impact of a carbon dioxide dispatch adder on the production simulation results of the June 2007 Scenario Analysis Project. This request stems from discussion at the June 18, 2007 Integrated Energy Policy Report (IEPR) workshop at which the preliminary results of the project were first reviewed with stakeholders and the public. Among the comments were questions and recommendations about how to understand the relatively unchanged level of coal generation across all of the scenarios.

As a part of the Scenario Analysis Project, Global Energy had already developed input datasets and run production simulation models for nine thematic scenarios and a variety of alternative sensitivity cases, none of which consider a carbon tax. In this new work, Global Energy was asked to perform additional economic dispatch analysis using various levels of carbon dioxide dispatch adders.

The bookend Cases 1 and 5B were used as a basis for review in this analysis. Starting with these two cases, additional production simulations were conducted using a range of carbon dioxide dispatch adders. This analysis is **not** an examination of how the resource mix might gradually evolve through time if a carbon tax were to be imposed on the electric generating industry. In addition, this analysis is **not** an assessment of the tradeoffs between owners of coal facilities paying a carbon tax to reduce carbon dioxide emissions compared to available alternatives in a cap and trade regulatory environment. This analysis is intended to show the impact of a carbon dioxide dispatch adder on power plant dispatch, assuming all other input assumptions are held constant. The following pages explore the input assumptions and results of this analysis.

Study Input Assumptions

To perform this analysis, Global Energy was asked to resimulate Case 1 and Case 5B at varying carbon dioxide dispatch adder levels: $10/ton, $20/ton, $40/ton, and $60/ton. The original cases did not include a carbon dioxide dispatch adder. The carbon dioxide dispatch adder is applied to any generator in the simulation model in the Western Electric Coordinating Council (WECC) that emits carbon dioxide (CO2) and is included in the dispatch price of the generator so that dispatch decisions are made accordingly. There was no attempt made at predicting what market dynamics may change in response to a carbon tax. Thus, all input assumptions (including resource mix and fuel prices) made in the initial Scenario Project work for Cases 1 and 5B remain constant across each of the carbon cases evaluated in this study. Thus, the results should not be interpreted as an evaluation of carbon tax policies, but on the much more limited analysis of how the particular fleet of power plants might respond to the imposition of a carbon adder affecting dispatch.

The rerun of these scenarios resulted in different dispatch costs due to the carbon dioxide dispatch adders and the associated reshuffling of the supply stack. The results of these carbon dioxide adder cases have been recorded and arranged in the same scorecard arrangement as the original Scenario Analysis Project work and can be found in Attachment A of this Appendix. The following section reports the key findings of this analysis.

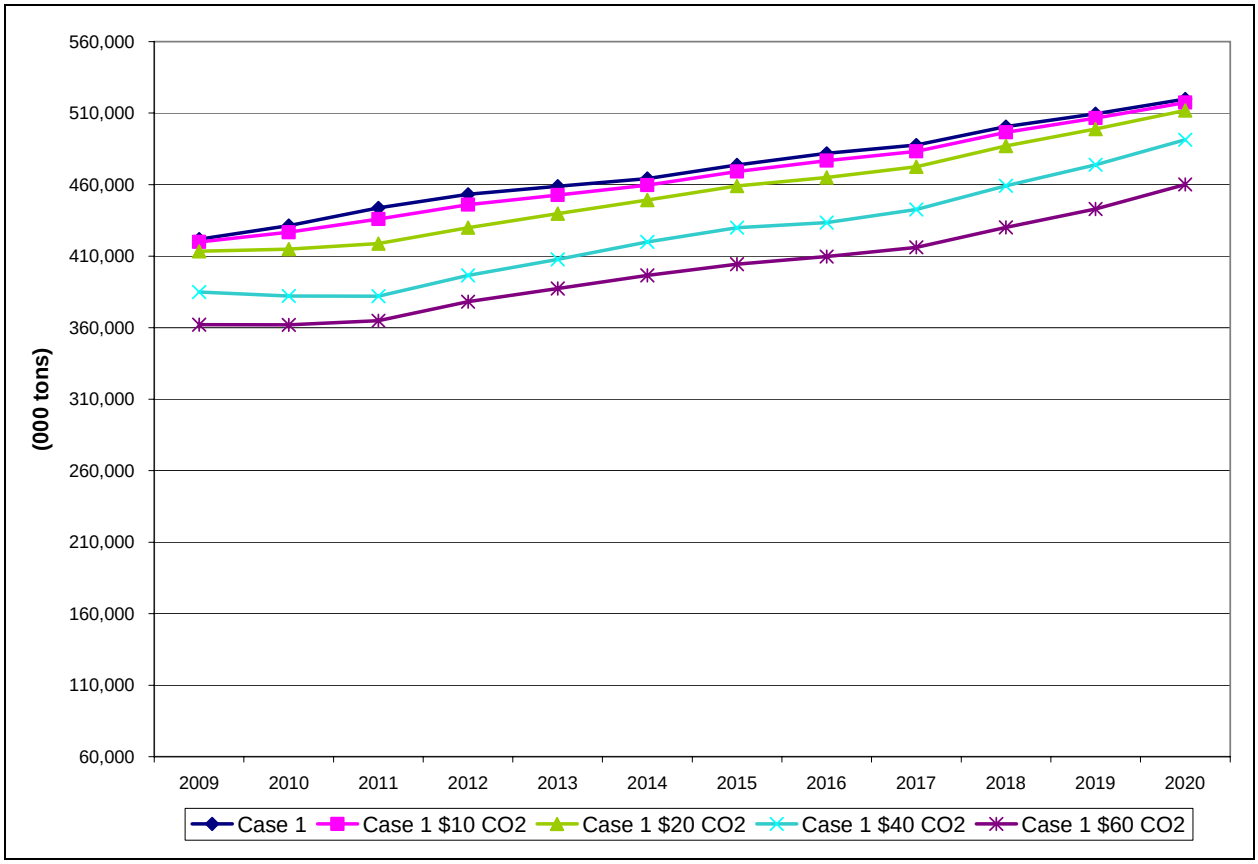
Carbon Dispatch Adder Results

The results of the re-simulation of Cases 1 and 5B under the four carbon dioxide dispatch adder variations described earlier are reported in this section. Generally, the carbon dioxide dispatch cases increase production costs, decrease coal-fired generation, increase gas-fired generation, and decrease carbon dioxide emissions compared to the original cases. The carbon dioxide dispatch adder increases costs across the board for carbon emitting generators and penalizes higher carbon emitting generators more than generators with lower emission rates. Because of the varying levels of carbon dioxide emission rates, heat rates, and variable costs of the generators in the simulation model, the carbon dioxide dispatch adders studied in this analysis affect the dispatch order at different magnitudes. The changes in the reshuffling of the dispatch order across each case are evident in the results presented below.

Changes in Carbon Dioxide Emissions

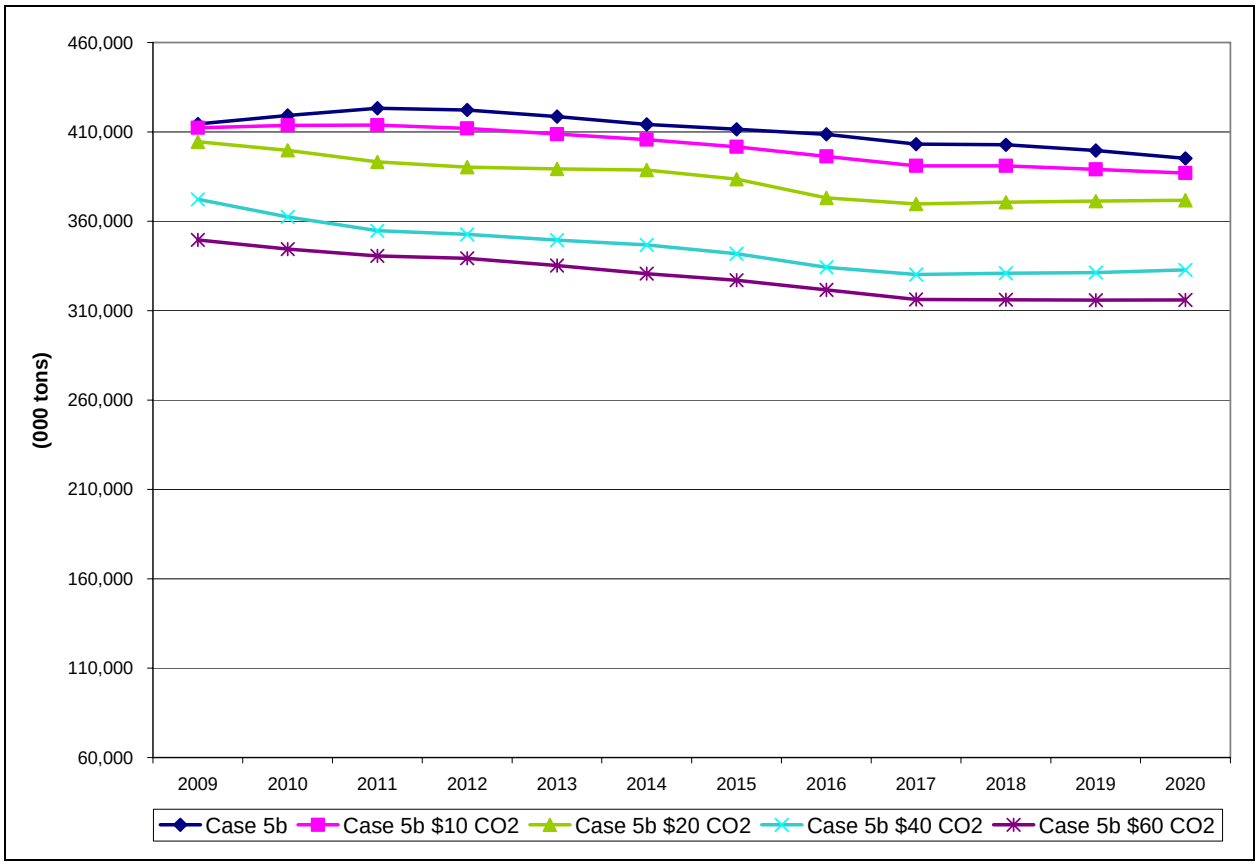
Figures 1 and 2 illustrate the differences in carbon dioxide emissions in the WECC across each of the scenarios in Cases 1 and 5B, respectively. As observed in the charts, WECC-wide carbon dioxide emissions decrease incrementally starting at the $10/ton carbon dispatch adder case and ending at $60/ton carbon dioxide dispatch adder case. In Case 1, carbon dioxide emissions decrease on average by 1, 3, 10, and 15 percent in the $10/ton, $20/ton, $40/ton, and $60/ton of carbon dioxide cases, respectively. In Case 5B, carbon dioxide emissions decrease on average by 2, 7, 16, and 20 percent in the $10/ton, $20/ton, $40/ton, and $60/ton of carbon dioxide cases, respectively.

Figure 1
Case 1 – WECC Carbon Dioxide Emissions in Power Generation



Source: Global Energy Decisions, Inc.

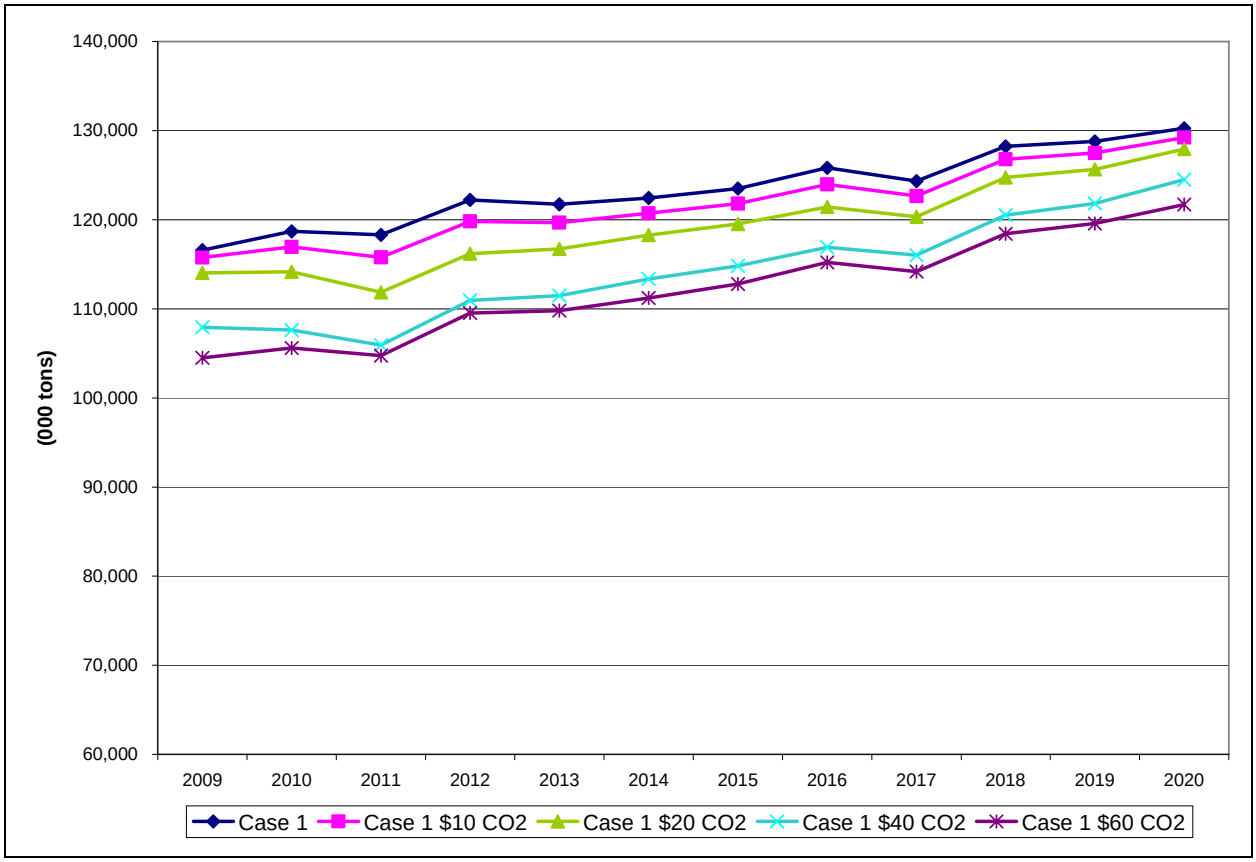
Figure 2
Case 5B – WECC Carbon Dioxide Emissions in Power Generation



Source: Global Energy Decisions, Inc.

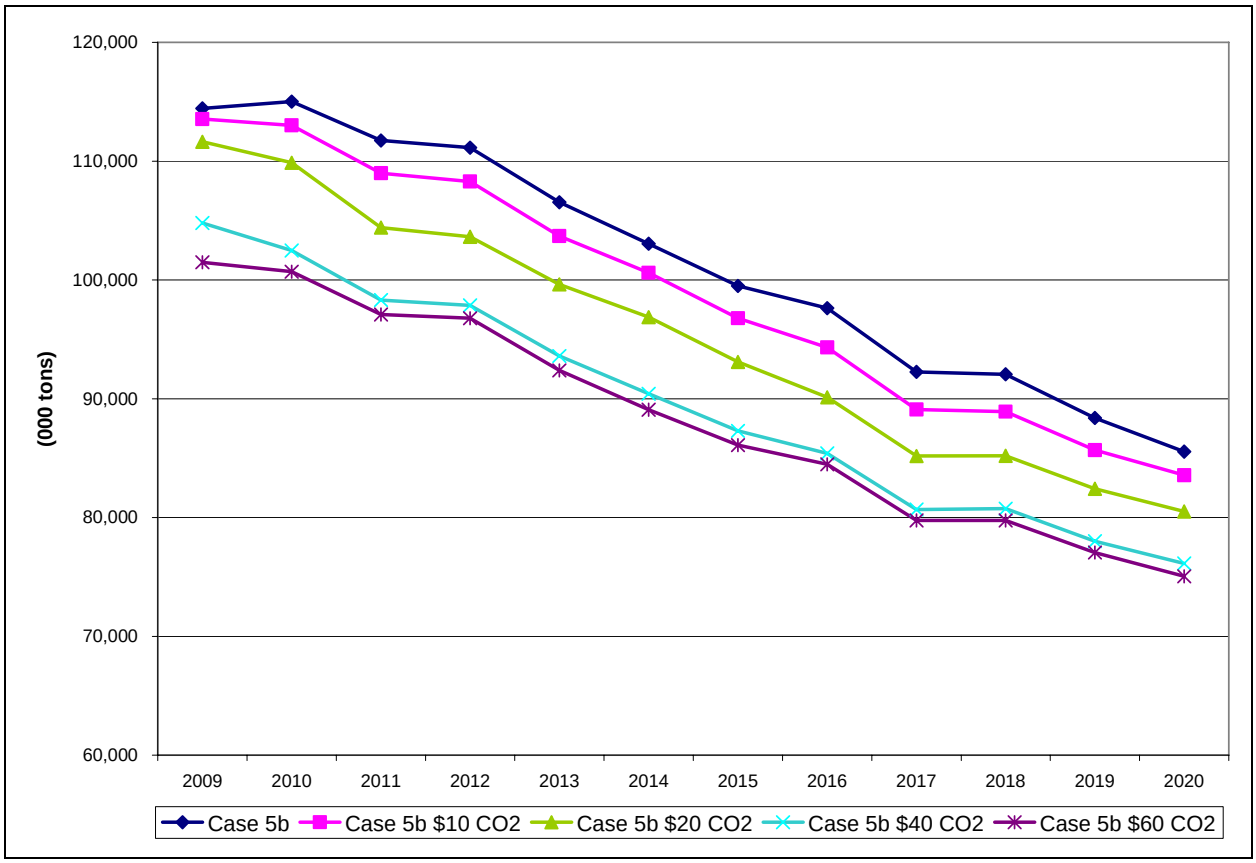
Figures 3 and 4 illustrate the differences in carbon dioxide emissions in California across each of the scenarios in Cases 1 and 5B, respectively. The figures include carbon dioxide emissions from generators physically located in California, remotely located generators, and emissions assigned to import energy. In Case 1, California carbon dioxide emissions decrease on average by 1, 3, 7, and 9 percent in the $10/ton, $20/ton, $40/ton, and $60/ton carbon cases, respectively. In Case 5B, California carbon emissions decrease on average by 3, 6, 12, and 13 percent in the $10/ton, $20/ton, $40/ton, and $60/ton carbon cases, respectively.

Figure 3
Case 1 – California Carbon Dioxide Emissions in Power Generation



Source: Global Energy Decisions, Inc.

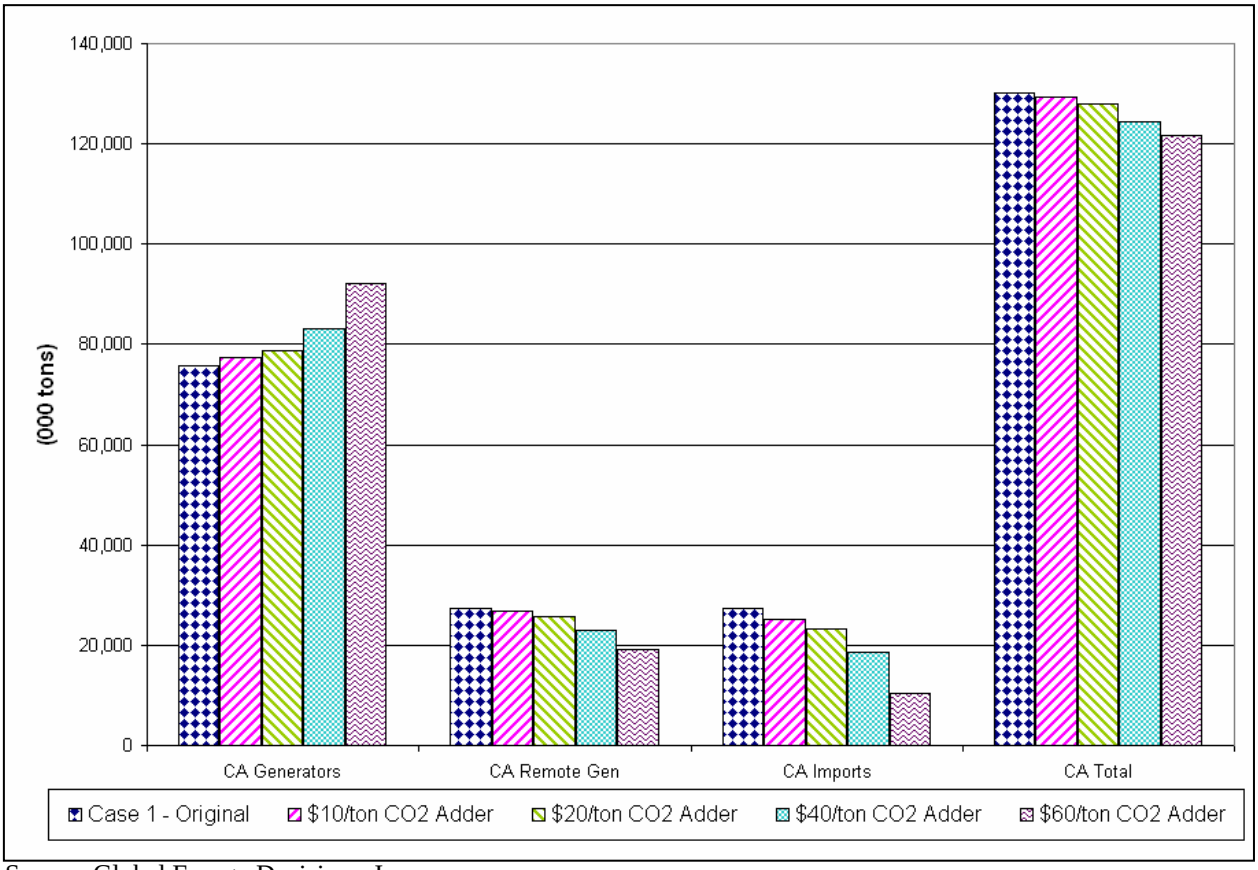
Figure 4
Case 5B – California Carbon Dioxide Emissions in Power Generation



Source: Global Energy Decisions, Inc.

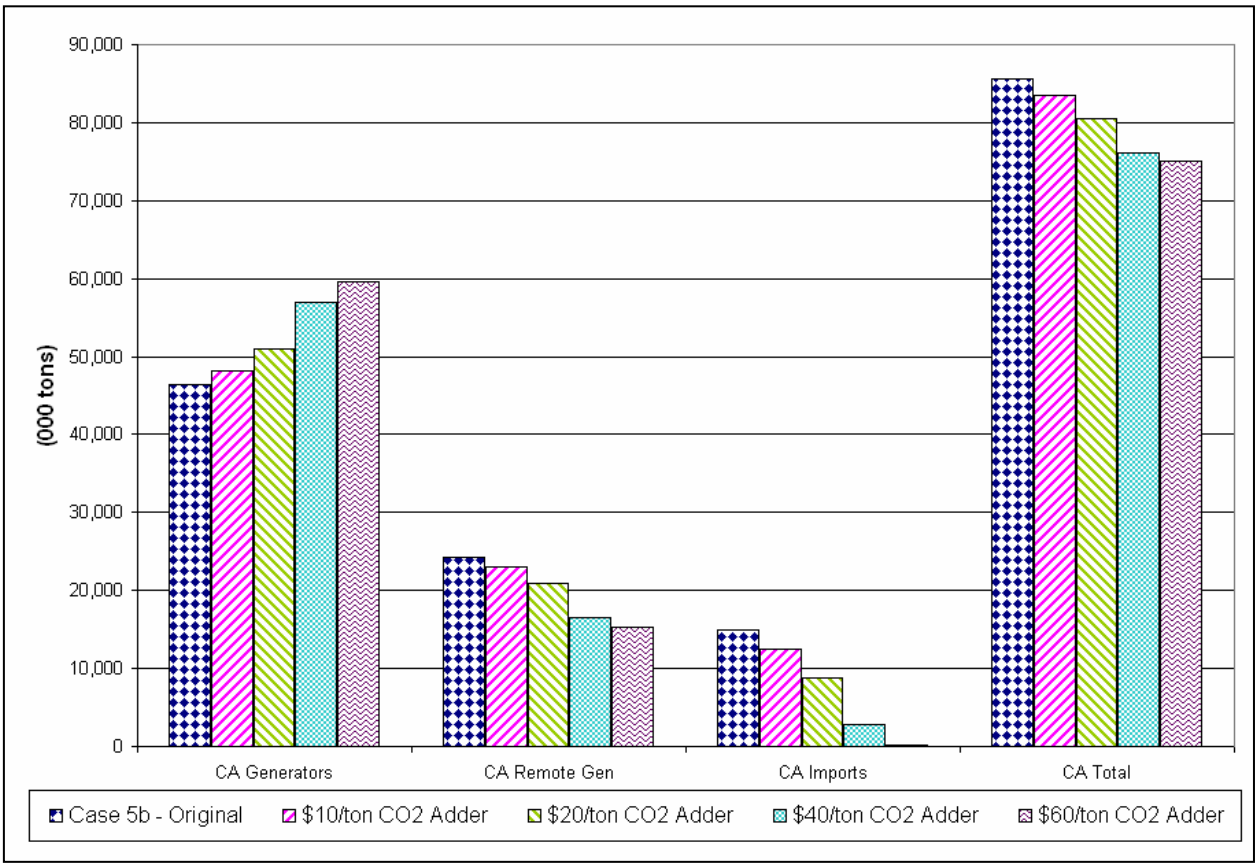
Figure 5 and 6 report the individual components that make up the carbon dioxide emission total in California for 2020 in Cases 1 and 5B, respectively. In Case 1 across all carbon cases, California carbon dioxide emissions from local generation increase, while carbon dioxide from remote generators attributed to California and carbon dioxide emissions from California imports decrease. The sum of these California carbon dioxide sources equates to a decrease in carbon dioxide emissions attributed to California across all carbon adder cases, although in varying amounts. Similar observations can be made about Case 5B in Figure 6.

Figure 5
Case 1 – Year 2020 California Carbon Dioxide Emissions in Power Generation by Source



Source: Global Energy Decisions, Inc.

Figure 6
Case 5B – Year 2020 California Carbon Dioxide Emissions in Power Generation by Source



Source: Global Energy Decisions, Inc.

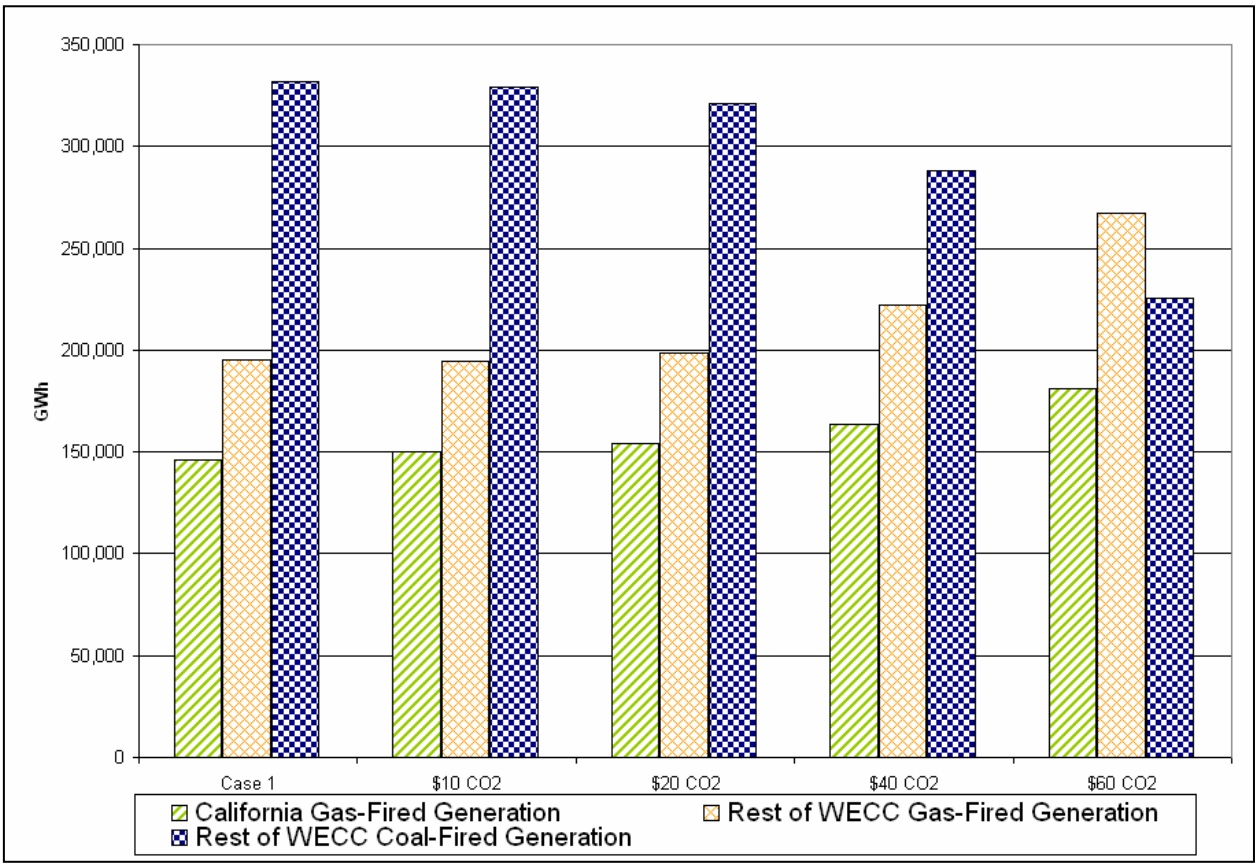
The results reported so far do not, of course, address the principal source of carbon dioxide emissions in the West, e.g., coal generation in the Rest-of-WECC. The following section reports changes in generation by fuel type.

Changes in Generation by Fuel Type

As observed in Figures 5 and 6, generation from California-located generators increased in each of the carbon adder cases. This can be explained by the displacement of coal-fired generation located outside California by California-located gas-fired generation. In addition, starting in the $40/ton carbon case, an increase in gas-fired generation in the Rest-of-WECC is noted, which contributes to the displacement of even more coal-fired generation. Aside from changes in gas- and coal-fired generation, little change is observed in generation associated with other fuel types since the majority of remaining generation is from renewable sources or from nuclear power. In the modeling for the Scenario Analysis Project both of these generation categories are essentially must take, and so there is no remaining under utilized capacity that can be dispatched to make up displaced coal generation.

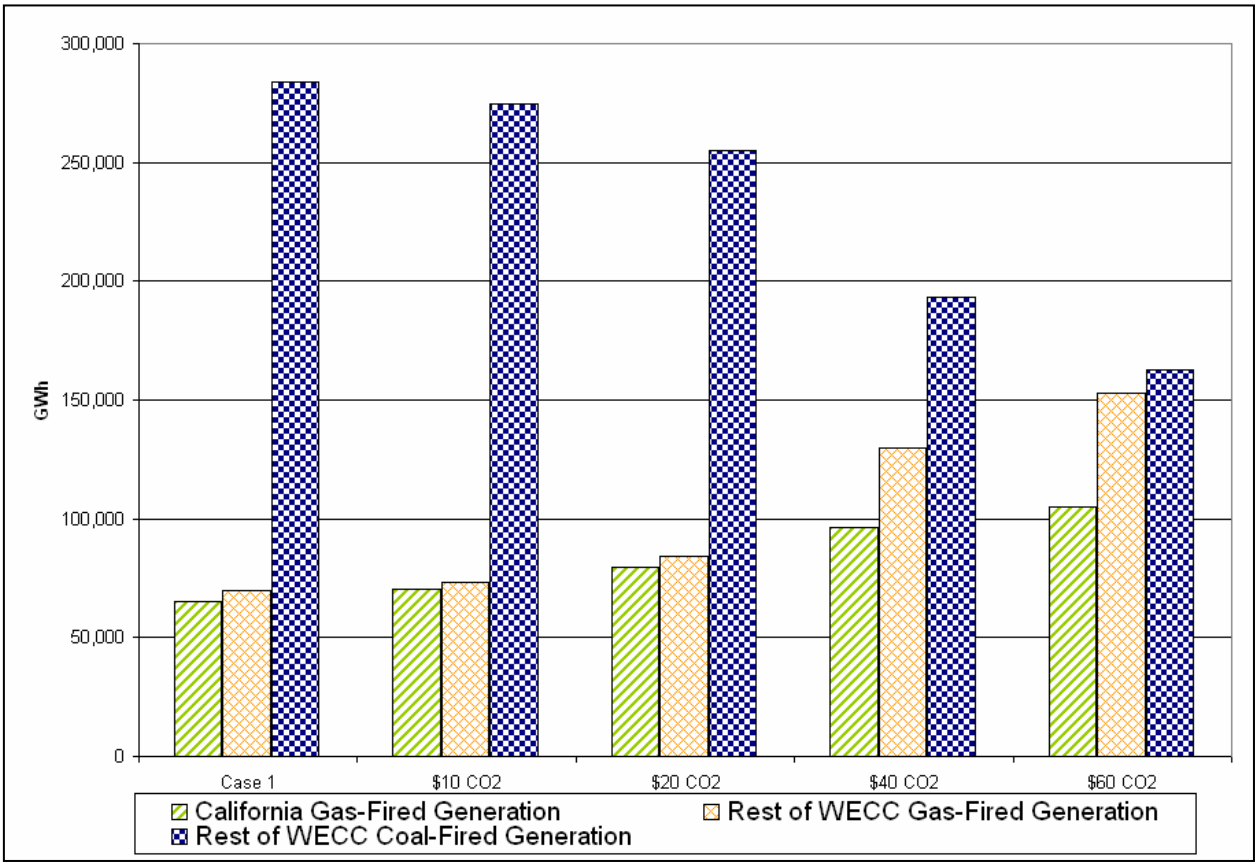
Figures 7 and 8 illustrate the changes in California and Rest-of-WECC gas-fired generation and Rest-of-WECC coal-fired generation across each of the carbon cases in 2020 for Cases 1 and 5B, respectively.

Figure 7
Case 1 – Year 2020 Changes in Gas and Coal Generation



Source: Global Energy Decisions, Inc.

Figure 8
Case 5B – Year 2020 Changes in Gas and Coal Generation



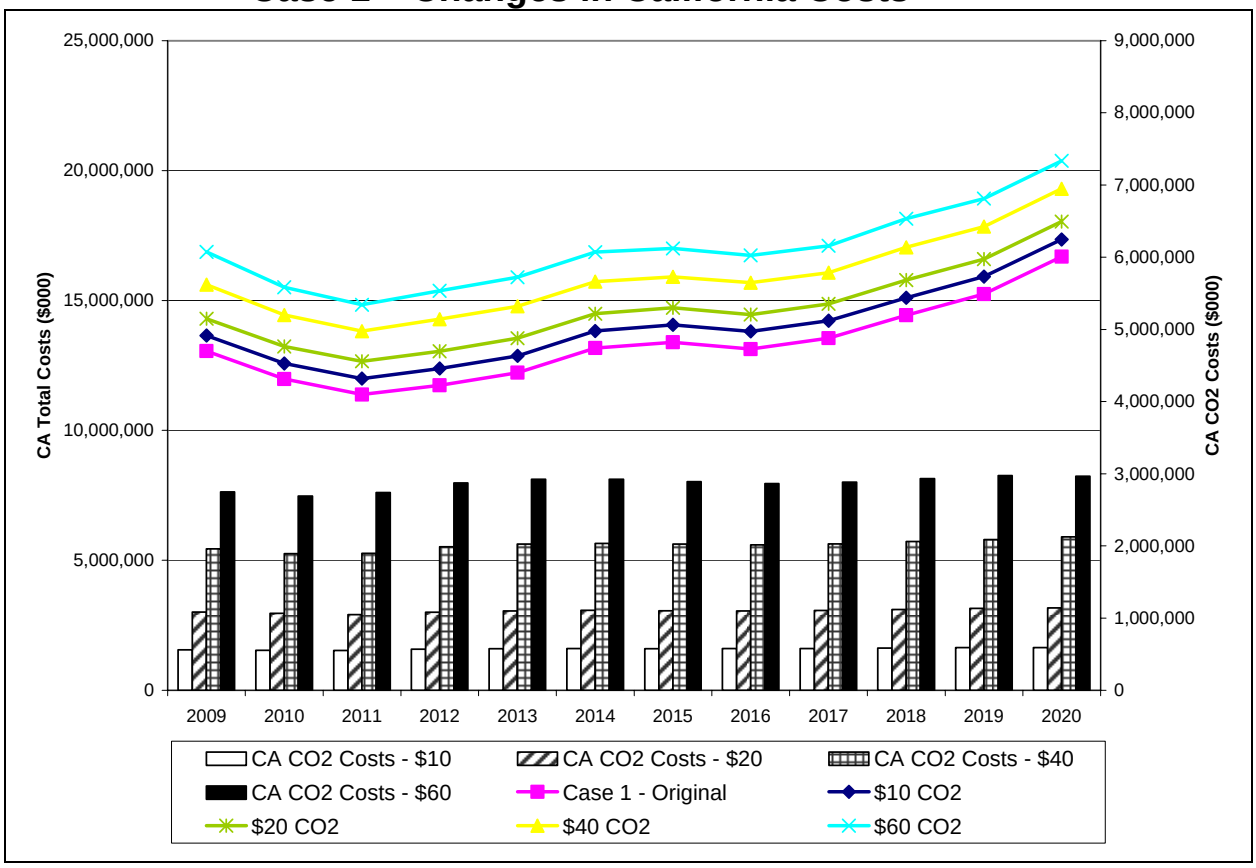
Source: Global Energy Decisions, Inc.

Changes in Total System Costs

Including the carbon dioxide dispatch adders into the production simulation increases production costs because of the redispatch of resources and the actual dispatch adder assumed. Figures 9 and 10 illustrate the changes in total system costs for California (on the primary Y-axis) and the carbon adder costs for California (on the secondary Y-axis) for Cases 1 and 5B across all variations. Total system costs for California reported here are inclusive of generation costs, wheeling costs, incremental resource capital costs, incremental transmission costs, emissions costs, import energy costs, and costs associated with remote generators that serve California load. The carbon adder costs reported are from generators physically located in California as well as remote generators that are assigned to meet California load. Additional detail on these individual costs can be found in Attachment A.

As can be expected, total system costs in California increase chronologically in each of the cases. On average, Case 1 California total system costs increased by $2/MWh, $4/MWh, $8/MWh, and $11/MWh in the carbon cases of $10/ton, $20/ton, $40/ton, and $60/ton, respectively. This increase is primarily driven by the addition of the carbon dioxide adder into the simulation model. The secondary Y-axis illustrates the carbon dispatch adder costs for California across each of the cases.

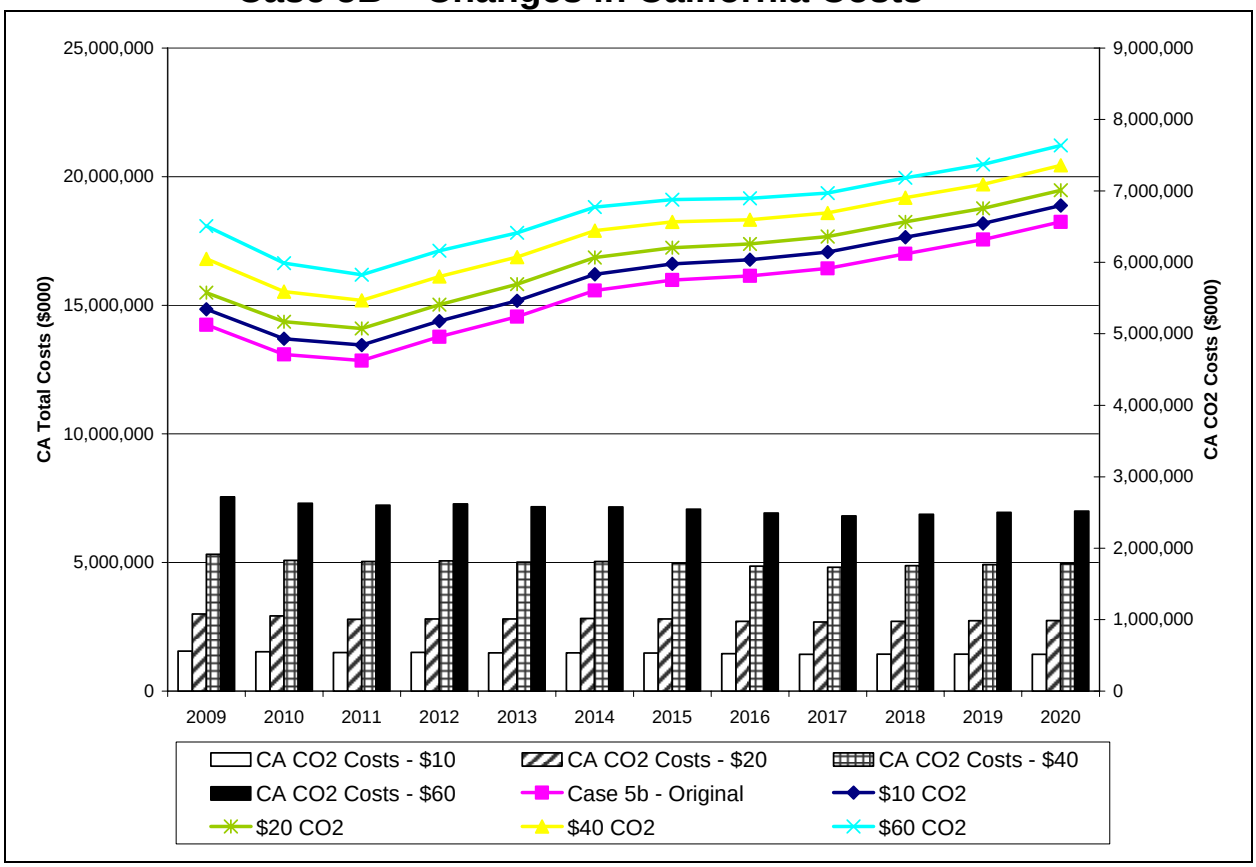
Figure 9
Case 1 – Changes in California Costs



Source: Global Energy Decisions, Inc.

In Case 5B, on average, California total system costs increased by $2/MWh, $4/MWh, $8/MWh, and $11/MWh in the carbon cases of $10/ton, $20/ton, $40/ton, and $60/ton, respectively. This increase is primarily driven by the addition of the carbon adder into the simulation model. The secondary Y-axis illustrates the carbon dispatch adder costs for California across each of the cases using the resource mix of scenario 5B.

Figure 10
Case 5B – Changes in California Costs

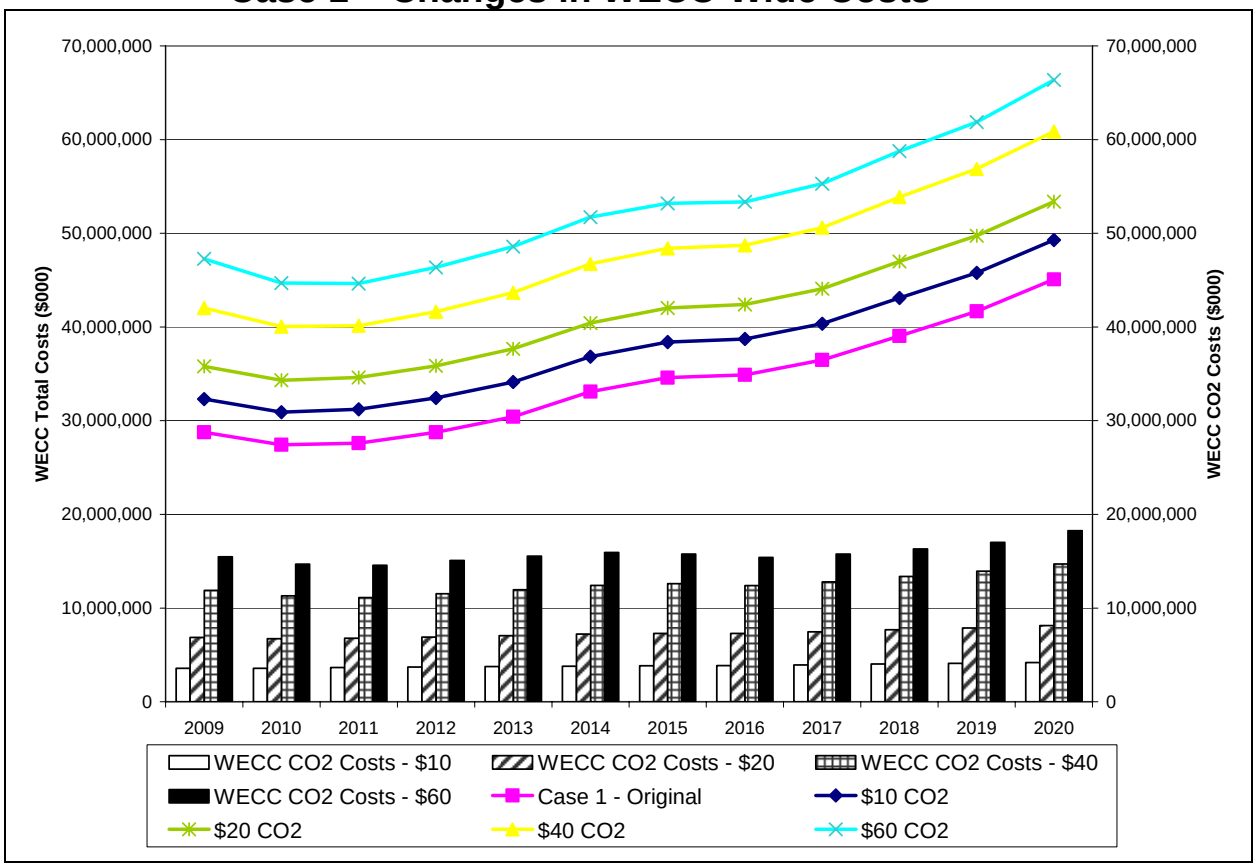


Source: Global Energy Decisions, Inc.

Figures 11 and 12 illustrate the changes in total WECC system costs (on the primary Y-axis) and carbon adder costs (on the secondary Y-axis) for Cases 1 and 5B across all variations. Total WECC system costs reported here are inclusive of generation costs, wheeling costs, incremental resource capital costs, incremental transmission costs, and emissions costs. Additional detail of these individual costs can be found in Attachment A.

In Case 1, on average, WECC-wide total system costs increased by $4/MWh, $7/MWh, $14/MWh, and $19/MWh in the carbon dioxide adder cases of $10/ton, $20/ton, $40/ton, and $60/ton, respectively. This increase is primarily driven by the addition of the carbon dioxide adder into the simulation model. The secondary Y-axis illustrates the total WECC carbon dioxide dispatch adder costs across each of the cases.

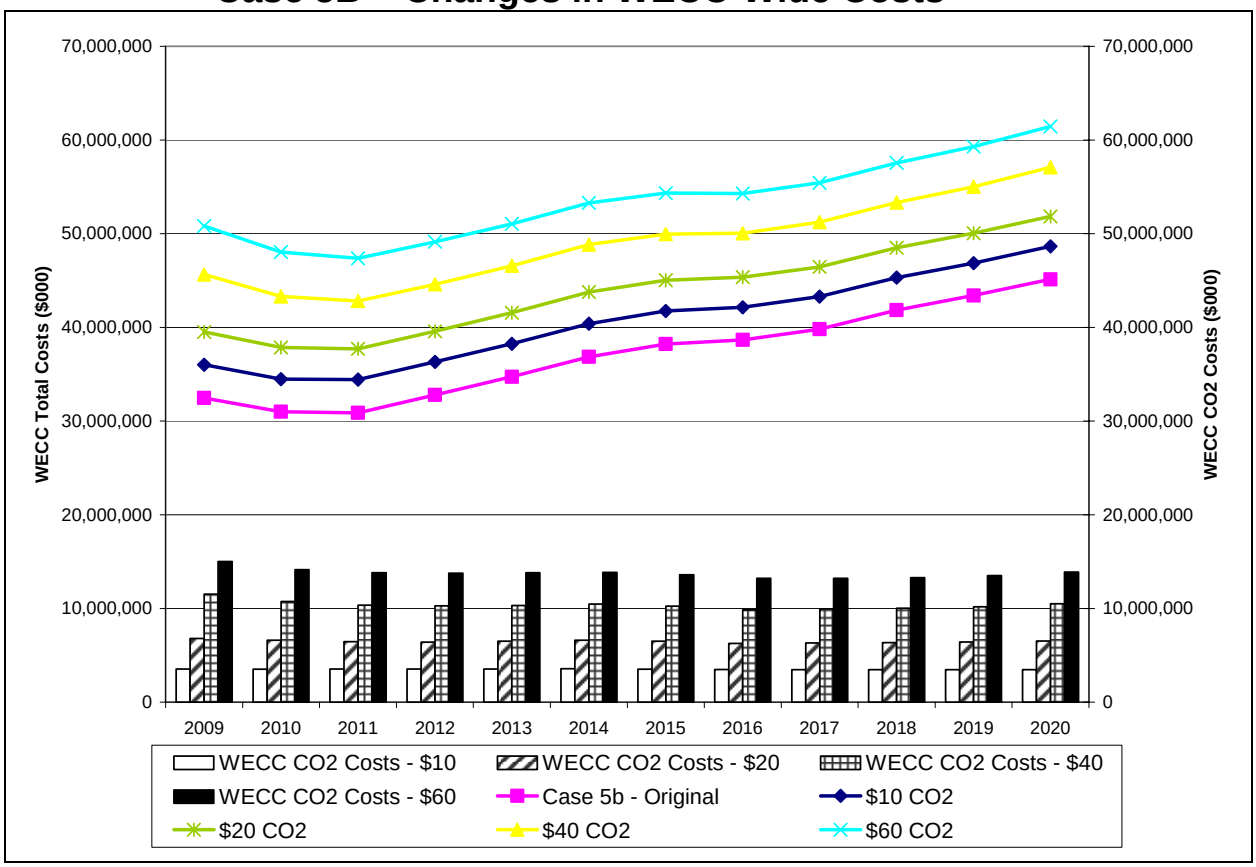
Figure 11
Case 1 – Changes in WECC-Wide Costs



Source: Global Energy Decisions, Inc.

In Case 5B, on average, WECC-wide total system costs increased by $4/MWh, $7/MWh, $13/MWh, and $18/MWh in the carbon dioxide adder cases of $10/ton, $20/ton, $40/ton, and $60/ton, respectively. This increase is primarily driven by the addition of the carbon dioxide adder into the simulation model. The secondary Y-axis illustrates the total WECC carbon dioxide dispatch adder costs across each of the cases.

Figure 12
Case 5B – Changes in WECC-Wide Costs



Source: Global Energy Decisions, Inc.

Detailed Scorecard Results

Attachment A consists of the California versus Rest-of-WECC scorecard for the sample year of 2020 for the original cases and carbon cases included in this study. This scorecard is in the same format as reported in the June 2007 *Results Report* which allow a direct comparison of geographic aggregations and variables as defined in Appendix C-1 of the June 2007 report. The results include load, generation, production costs, capital costs, import energy, export energy, emissions data, and fuel data.

A separate Excel spreadsheet includes the complete California versus Rest-of-WECC and transarea scorecards in the same format as reported in the June 2007 *Results Report* for the cases discussed in this analysis.

Attachment A

CA vs. Rest-of-WECC scorecard for 2020 for Cases 1 and 5B under the various carbon dispatch adder sensitivities

Table A-1
Scorecard Line Definitions and Notes

	Line	Definition
1	**Line**	**Definition**
2	**Total WECC System Cost ($000)**	Sum of Lines 4 and 64
3	**California**	
4	**CA System Production Cost ($000)**	Sum of Lines 29, 38, 50, 53, and 59
5	**CA Per Unit Production Cost ($/MWh)**	Line 4 divided by the difference of Line 7 and 23
6	**CA Peak Load (MW)**	California coincident peak load in MW
7	**CA Energy Load (GWh)**	California energy load in GWh (Includes Losses and Pumping Load)
8	**CA "Energy Not Served" (GWh)**	California Loss of load in GWh
9	**CA Generation By Fuel (GWh)**	
10	***Coal***	California Coal-fired Generation (GWh)
11	***Fuel Oil***	California Fuel Oil-fired Generation (GWh)
12	***Geothermal***	California Geothermal Generation (GWh)
13	***Hydro***	California Hydro Generation (GWh)
14	***Natural Gas***	California Natural Gas-fired Generation (GWh)
15	***Nuclear***	California Nuclear Generation (GWh)
16	***Biomass/Other***	California plants including Biomass, Solar, Refuse, Wood, Jet Fuel-fired plants, Petroleum Coke-fired plants, and Variable Demand Reduction (GWh)
17	***Pumped Storage***	California Pumped Storage Generation (GWh)
18	***Wind***	California Wind Generation (GWh)
19	***Total CA Generation (GWh)***	Sum of lines 10 through 18
20	**CA Energy Efficiency and PV Solar (GWh)**	
21	***Energy Efficiency***	California Energy Efficiency Load Reduction (GWh)
22	***PV Solar***	California PV Solar Load Reduction (GWh)
23	***Total CA Energy Efficiency and PV Solar (GWh)***	Sum of Lines 21 and 22
24	**CA O&M Costs**	
25	**CA Fuel Costs ($000)**	California Located Generation Fuel Costs
26	**CA VOM Costs ($000)**	California Located Generation Variable Operations and Maintanence Costs
27	**CA Start Costs ($000)**	California Located Generation Start Costs
28	**CA FOM Costs ($000)**	California Located Generation Fixed Operations and Maintenance Costs
29	***Total CA O&M Costs ($000)***	Sum of Lines 25 through 28
30	**CA Other Costs**	
31	**CA Wheeling Costs ($000)**	California incurred Wheeling Costs
32	**CA Energy Efficiency Costs ($000)**	California Energy Efficiency Program Capital Costs
33	**CA PV Solar Costs ($000)**	California PV Solar Program Capital Costs
34	**CA Variable Demand Response Costs ($000)**	California Variable Demand Response Costs (includes Program Capital Costs and Variable Costs)
35	**CA Transmission Capital Costs ($000)**	California Transmission Capital Costs relative to Line 36
36	**CA Transmission Miles**	California Transmission Miles relative to Line 35
37	**CA Incremental Resource Capital Costs ($000)**	California cost of generic resource additions including the following resource types: Gas Turbines, Combined Cycles, Wind, Geothermal, Concentrated Solar Power, and Biomass
38	***Total CA Other Costs ($000)***	Sum of of Lines 31 through 35, and Line 37
39	**CA Renewable Generation**	
40	**CA Renewable Generation (GWh) - without Hydro**	California renewable generation excluding hydro and pumped storage generation
41	**CA Renewable Energy (%) - without Hydro**	California renewable generation excluding hydro and pumped storage as a percent of California Load (Line 7) net of California EE and PV Solar (Line 23)
42	**CA Renewable Generation (GWh) - with Hydro**	California renewable generation including hydro and pumped storage generation
43	**CA Renewable Energy (%) - with Hydro**	California renewable generation including hydro and pumped storage as a percent of California Load (Line 7) net of California EE and PV Solar (Line 23)
44	**CA Emissions**	
45	**CA CO2 Production (000 tons)**	California CO2 production from generation located within California only
46	**CA GHG 2020/1990 Ratio**	
47	**CA SO2 (000 tons)**	California SO2 production from generation located within California only
48	**CA NOx (000 tons)**	California NOx production from generation located within California only
49	**CA HG (000 tons)**	California HG production from generation located within California only
50	**CA Emission Costs SO2/NOx/HG ($000)**	California Total Emission Costs from generation located within California only
51	**CA Remote Generation**	
52	**CA Remote Generation (GWh)**	California share of generation from remote located plants
53	**CA Remote Generation Cost ($000)**	California share of generation costs from remote located plants including costs associated with Fuel, VOM , Start-up , FOM, and Emissions.
54	**CA Remote CO2 (000 tons)**	California share of CO2 emissions from remote located plants
55	**CA Remote SO2 (000 tons)**	California share of SO2 emissions from remote located plants
56	**CA Remote NOx (000 tons)**	California share of NOx emissions from remote located plants
57	**CA Remote HG (000 tons)**	California share of HG emissions from remote located plants
58	**CA Imports**	
59	**CA Net Import ($000)**	Cost of energy imports from the Rest of WECC priced at California marginal clearing price (SP15)
60	**CA Net Import (GWh)**	Net Energy imports from the Rest of WECC (i.e. the difference in California load and generation)
61	**CA Import CO2 (000 tons)**	CO2 from imported energy from plants in the Rest of WECC into California
62	**CA Gas and Water Consumption**	
63	**CA Gas Consumption (Gbtu)**	Natural gas fuel burn from plants located within California
64	**CA Water Consumption**	Water consumption used in power generation by plants located within California

Continued on next page.

(continued)

1	Line	Definition
65	**Rest of WECC (excludes California results)**	
66	**WECC System Production Cost ($000)**	Sum of Lines 93, 102, 108, and 111
67	**WECC Per Unit Production Cost ($/MWh)**	Line 66 divided by the difference of Line 69 and 87
68	**WECC Peak Load (MW)**	Rest of WECC coincident peak load in MW
69	**WECC Energy Load (GWh)**	Rest of WECC energy load in GWh (Includes Losses and Pumping Load)
70	**WECC "Energy Not Served" (GWh)**	Rest of WECC Loss of load in GWh
71	**Rest of WECC Generation by Fuel (GWh)**	
72	***Coal***	Rest of WECC Coal-fired Generation (GWh)
73	***Fuel Oil***	Rest of WECC Fuel Oil-fired Generation (GWh)
74	***Geothermal***	Rest of WECC Geothermal Generation (GWh)
75	***Hydro***	Rest of WECC Hydro Generation (GWh)
76	***Natural Gas***	Rest of WECC Natural Gas-fired Generation (GWh)
77	***Nuclear***	Rest of WECC Nuclear Generation (GWh)
78	***Biomass/Other***	Rest of WECC plants including Biomass, Solar, Refuse, Wood, Jet Fuel-fired plants, Petroleum Coke-fired plants, and Variable Demand Reduction (GWh)
79	***Pumped Storage***	Rest of WECC Pumped Storage Generation (GWh)
80	***Wind***	Rest of WECC Wind Generation (GWh)
81	***Total Rest of WECC Generation (GWh)***	Sum of Lines 71 through 80
82	***Total Rest ofWECC Exports (GWh)***	Net energy exports from the Rest of WECC into California
83	***Total Rest of WECC Generation Serving WECC Load (GWh)***	The difference of Lines 81 and 82
84	**Rest of WECC Energy Efficiency and PV Solar (GWh)**	
85	***Energy Efficiency***	Rest of WECC Energy Efficiency Load Reduction (GWh)
86	***PV Solar***	Rest of WECC PV Solar Load Reduction (GWh)
87	***Total Rest of WECC Energy Efficiency and PV Solar (GWh)***	Sum of Lines 86 and 87
88	**Rest of WECC O&M Costs**	
89	**WECC Fuel Costs ($000)**	Rest of WECC Located Generation Fuel Costs (excludes cost from WECC/CA shared generation)
90	**WECC VOM Costs ($000)**	Rest of WECC Located Generation Variable Operations and Maintanence Costs(excludes cost from WECC/CA shared generation)
91	**WECC Start Costs ($000)**	Rest of WECC Located Generation Start Costs(excludes cost from WECC/CA shared generation)
92	**WECC FOM Costs ($000)**	Rest of WECC Located Generation Fixed Operations and Maintenance Costs(excludes cost from WECC/CA shared generation)
93	***Total Rest of WECC O&M Costs ($000)***	Sum of Lines 89 through 92
94	**Rest of WECC Other Costs**	
95	**WECC Wheeling Costs ($000)**	Rest of WECC incurred Wheeling Costs
96	**WECC Energy Efficiency Costs ($000)**	Rest of WECC Energy Efficiency Program Capital Costs
97	**WECC PV Solar Costs ($000)**	Rest of WECC PV Solar Program Capital Costs
98	**WECC Variable Demand Response Costs ($000)**	Rest of WECC Variable Demand Response Costs (includes Program Capital Costs and Variable Costs)
99	**WECC Transmission Capital Costs ($000)**	Rest of WECC Transmission Capital Costs relative to Line 100
100	**WECC Transmission Miles**	Rest of WECC Transmission Miles relative to Line 99
101	**WECC Incremental Resource Capital Costs ($000)**	Rest of WECC cost of generic resource additions including the following resource types: Gas Turbines, Combined Cycles, Wind, Geothermal, Concentrated Solar Power, and Biomass
102	***Total Rest of WECC Other Costs ($000)***	Sum of of Lines 95 through 99, and Line 101
103	**Rest of WECC Emissions**	
104	**WECC CO2 Production (000 tons)**	Rest of WECC CO2 production from generation (excludes CO2 from WECC/CA shared generators) also excludes CO2 accounting to CA exports
105	**WECC SO2 (000 tons)**	Rest of WECC SO2 production from generation (excludes SO2 from WECC/CA shared generators)
106	**WECC NOx (000 tons)**	Rest of WECC NOx production from generation (excludes NOx from WECC/CA shared generators)
107	**WECC HG (000 tons)**	Rest of WECC HG production from generation (excludes HG from WECC/CA shared generators)
108	**WECC Emission Costs SO2/NOx/HG ($000)**	Rest of WECC Total Emission Costs (exlcludes emission costs from WECC/CA shared generators)
109	**Rest of WECC Remote Generation**	
110	**WECC Remote Generation (GWh)**	WECC share of generation from WECC/CA shared plants
111	**WECC Remote Generation Cost ($000)**	WECC share of generation costs from WECC/CA shared plants including costs associated with Fuel, VOM , Start-up , FOM, and Emissions.
112	**WECC Remote CO2 (000 tons)**	WECC share of CO2 emissions from WECC/CA shared plants
113	**WECC Remote SO2 (000 tons)**	WECC share of SO2 emissions from WECC/CA shared plants
114	**WECC Remote NOx (000 tons)**	WECC share of NOx emissions from WECC/CA shared plants
115	**WECC Remote HG (000 tons)**	WECC share of HG emissions from WECC/CA shared plants
116	**Rest of WECC Gas Consumption**	
117	**WECC Gas Consumption (Gbtu)**	Natural gas fuel burn from plants located in the Rest of WECC

Table A-2
CA vs Rest-of-WECC Scorecard

		CEC IEPR - CA vs Rest of WECC Scorecard	Case1					Case 5b				
			Base Case	10$	20$	40$	60$	Base Case	10$	20$	40$	60$
YEAR		2020 2020	2020		2020			2020		2020		
			Case 1					Case 5b				
	1											
2020	2	Total WECC System Cost ($000)	45,074,700	49,271,223	53,383,516	60,870,680	66,362,664	45,136,436	48,647,886	51,843,634	57,095,520	61,445,392
	3	California										
	4	CA System Cost ($000)	16,684,128	17,350,123	18,036,115	19,297,360	20,375,652	18,238,302	18,879,616	19,472,165	20,439,234	21,208,563
	5	CA Per Unit System Cost ($/MWh)	49	51	53	57	60	63	65	67	71	73
	6	CA Peak Load (MW)	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903
	7	CA Energy Load (GWh) Includes Losses and Pumping Load	340,458	340,458	340,458	340,458	340,458	339,535	339,535	339,535	339,535	339,535
	8	CA "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0	0
	9	CA (Excludes Remote*) Generation By Fuel (GWh)										
	10	*Coal*	3,158	3,158	3,158	3,124	3,037	3,120	3,130	3,097	2,827	2,239
	11	*Fuel Oil*	11	23	37	44	9	40	11	19	9	0
	12	*Geothermal*	15,632	15,632	15,632	15,632	15,632	33,178	33,178	33,178	33,178	33,178
	13	*Hydro*	33,910	33,910	33,910	33,910	33,910	33,910	33,910	33,910	33,910	33,910
	14	*Natural Gas*	145,878	150,098	153,876	163,471	181,066	64,976	70,647	79,393	96,430	105,210
	15	*Nuclear*	33,694	33,694	33,694	33,694	33,694	33,688	33,694	33,694	33,694	33,694
	16	*Other*	7,729	7,709	7,693	7,632	7,537	22,217	22,345	22,328	21,806	21,177
2020	17	*Pumped Storage Output*	2,805	2,805	2,805	2,805	2,805	2,158	2,158	2,158	2,158	2,158
	18	*Wind*	10,360	10,360	10,360	10,360	10,360	31,220	31,220	31,220	31,220	31,220
	19	*Total CA Generation*	253,176	257,387	261,163	270,673	288,049	224,506	230,292	238,996	255,232	262,785
	20	CA Distributed Generation (GWh)										
	21	*Energy Efficiency*	0	0	0	0	0	42,263	42,263	42,263	42,263	42,263
	22	*PV Solar*	0	0	0	0	0	8,036	8,036	8,036	8,036	8,036
	23	*Total Distributed Generation*	0	0	0	0	0	50,299	50,299	50,299	50,299	50,299
	24	CA (Excludes Remote*) O&M Costs										
	25	CA Fuel Costs ($000)	9,140,077	9,336,550	9,525,474	10,040,933	11,155,340	5,238,327	5,445,343	5,777,972	6,594,486	7,024,034
	26	CA VOM Costs ($000)	488,000	498,086	507,300	528,616	584,330	447,965	458,879	475,970	508,182	523,968
	27	CA Start Costs ($000)	64,897	50,571	46,190	35,429	32,300	56,414	63,855	64,019	33,016	23,686
	28	CA FOM Costs ($000)	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892
	29	*Total CA Ot&M Costs*	10,846,866	11,039,099	11,232,855	11,758,871	12,925,862	6,896,598	7,121,969	7,471,853	8,289,576	8,725,580
	30	CA Other Costs										
2020	31	CA Wheeling Costs ($000)	36,007	35,108	34,498	34,123	34,982	36,830	33,517	32,184	35,234	35,689
	32	CA Energy Efficiency Costs ($000)	0	0	0	0	0	1,271,481	1,271,481	1,271,481	1,271,481	1,271,481
	33	CA PV Solar Costs ($000)	0	0	0	0	0	2,987,984	2,987,984	2,987,984	2,987,984	2,987,984
	34	CA Variable Demand Response Costs ($000)	2,506	2,864	3,182	3,744	4,080	230,035	230,043	230,095	230,328	230,554
	35	CA Transmission Capital Costs ($000)	0	0	0	0	0	365,982	365,982	365,982	365,982	365,982
	36	CA Transmission Miles	0	0	0	0	0	618	618	618	618	618
	37	CA Incremental Resource Capital Costs ($000)	1,929,457	1,929,457	1,929,457	1,929,457	1,929,457	4,428,736	4,428,736	4,428,736	4,428,736	4,428,736
	38	*Total CA Other Costs*	1,967,970	1,967,428	1,967,137	1,967,324	1,968,519	9,321,048	9,317,743	9,316,462	9,319,745	9,320,427
	39	CA Renewable Generation										
	40	CA Renewable Generation (GWh)	32,299	32,299	32,299	32,285	32,253	85,519	85,638	85,649	85,377	84,895
	41	CA Renewable Energy (%)	9%	9%	9%	9%	9%	30%	30%	30%	30%	29%
	42	CA Renewable Generation (GWh) - with Hydro	72,062	72,062	72,062	72,048	72,016	124,635	124,755	124,765	124,493	124,012
	43	CA Renewable Energy (%) - with Hydro	21%	21%	21%	21%	21%	43%	43%	43%	43%	43%
	44	CA (Excludes Remote*) Emissions										
	45	CA CO2 Production (000 tons)	75,803	77,321	78,872	83,043	92,208	46,356	48,195	50,912	56,883	59,597
2020	46	CA GHG 2020/1990 Ratio	0	0	0	0	0	0	0	0	0	0
	47	CA SO2 (000 tons)	69	68	68	65	62	57	57	56	45	37
	48	CA NOx (000 tons)	238	238	239	240	243	239	239	239	233	207
	49	CA HG (000 tons)	13	13	13	12	12	12	12	12	10	8
	50	CA Emission Costs CO2/SO2/NOx/HG ($000)	98,867	421,778	724,542	1,306,680	1,920,447	93,797	378,252	666,037	1,208,664	1,680,402
	51	CA Remote* Generation										
	52	CA Remote* Generation (GWh)	38,717	38,135	37,057	34,400	30,775	34,968	33,647	31,576	27,329	26,013
	53	CA Remote* Generation Cost ($000)	971,493	1,216,163	1,430,522	1,765,322	1,906,751	839,046	1,025,536	1,155,953	1,309,372	1,538,319
	54	CA Remote* CO2 (000 tons)	27,267	26,853	25,816	22,937	19,140	24,257	22,961	20,856	16,520	15,297
	55	CA Remote* SO2 (000 tons)	14	14	14	13	11	13	13	12	10	9
	56	CA Remote* NOx (000 tons)	47	46	45	40	33	42	41	37	29	27
	57	CA Remote* HG (000 tons)	222	221	217	205	187	214	209	200	159	140
	58	CA Imports										
	59	CA Net Import ($000)	2,798,933	2,705,655	2,681,059	2,499,163	1,654,075	1,087,812	1,036,116	861,859	311,877	-56,165
	60	CA Net Import (GWh)	48,566	44,937	42,237	35,386	21,634	29,762	25,298	18,665	6,676	439
	61	CA Import CO2 (000 tons)	27,211	25,061	23,258	18,536	10,379	14,932	12,405	8,749	2,731	168
	62	CA Gas and Water Consumption										
2020	63	CA Gas Consumption (Gbtu)	1,147,817	1,157,007	1,182,795	1,254,427	1,416,068	566,556	595,882	647,451	764,095	824,399
	64	CA Water Consumption										

Continued on next page.

(continued)

		CEC IEPR - CA vs Rest of WECC Scorecard	Case1					Case 5b				
			Base Case	10$	20$	40$	60$	Base Case	10$	20$	40$	60$
YEAR		2020 2020	2020		2020			2020		2020		
			Case 1					Case 5b				
2020	65	Rest of WECC (excluding California results)										
	66	Rest of WECC System Cost ($000)	28,390,572	31,921,100	35,347,401	41,573,320	45,987,012	26,898,134	29,768,270	32,371,469	36,656,285	40,236,829
	67	Rest of WECC Per Unit System Cost ($/MWh)	37	42	47	55	61	40	44	48	54	60
	68	Rest of WECC Peak Load (MW)	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514
	69	Rest of WECC Energy Load (GWh) Includes Losses and Pumping Load	757,759	757,759	757,759	757,759	757,759	757,824	757,824	757,824	757,824	757,824
	70	Rest of WECC "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0	0
	71	Rest of WECC (Excludes Remote*) Generation by Fuel (GWh)										
	72	*Coal*	275,537	272,616	266,335	239,006	184,303	231,618	223,888	208,471	157,543	129,718
	73	*Fuel Oil*	55	59	66	71	86	154	167	162	169	145
	74	*Geothermal*	9,337	9,337	9,337	9,337	9,337	27,822	27,822	27,822	27,822	27,822
	75	*Hydro*	207,385	207,385	207,385	207,385	207,385	207,385	207,385	207,385	207,385	207,385
	76	*Natural Gas*	186,469	186,550	191,267	214,841	260,937	66,362	70,825	82,059	127,479	151,389
	77	*Nuclear*	9,251	9,251	9,251	9,251	9,251	9,246	9,251	9,251	9,251	9,251
	78	*Other*	11,863	11,838	11,810	11,763	11,731	24,113	24,498	24,606	24,350	24,339
	79	*Pumped Storage Output*	459	459	459	459	459	502	502	502	502	502
	80	*Wind*	43,538	43,538	43,538	43,538	43,538	79,670	79,670	79,670	79,670	79,670
	81	*Total Rest of WECC Generation*	743,893	741,033	739,448	735,651	727,026	646,871	644,007	639,927	634,169	630,220
	82	*Total Rest of WECC Exports*	48,566	44,937	42,237	35,386	21,634	29,762	25,298	18,665	6,676	439
	83	*Total Excluding Remote* Generation and Exports*	695,327	696,096	697,211	700,265	705,392	617,109	618,709	621,262	627,493	629,782
2020	84	Rest of WECC Distributed Generation (GWh)										
	85	*Energy Efficiency*	0	0	0	0	0	82,408	82,408	82,408	82,408	82,408
	86	*PV Solar*	0	0	0	0	0	1,317	1,317	1,317	1,317	1,317
	87	*Total Distributed Generation*	0	0	0	0	0	83,725	83,725	83,725	83,725	83,725
	88	Rest of WECC (Excludes Remote*) O&M Costs										
	89	Rest of WECC Fuel Costs ($000)	15,971,375	15,934,954	16,029,560	16,763,888	18,627,088	9,707,213	9,707,591	9,829,977	11,138,518	12,145,167
	90	Rest of WECC VOM Costs ($000)	1,097,990	1,094,438	1,094,408	1,106,602	1,123,169	859,866	861,589	863,303	854,546	830,334
	91	Rest of WECC Start Costs ($000)	57,520	56,517	55,923	48,983	59,058	119,380	108,078	107,468	80,042	89,864
	92	Rest of WECC FOM Costs ($000)	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561
	93	*Total Rest of WECC O&M Costs*	18,839,446	18,798,470	18,892,453	19,632,035	21,521,876	12,399,020	12,389,820	12,513,310	13,785,668	14,777,926
	94	Rest of WECC Other Costs										
	95	Rest of WECC Wheeling Costs ($000)	221,769	220,414	217,614	213,190	215,300	281,847	269,583	259,831	261,367	278,373
	96	Rest of WECC Energy Efficiency Costs ($000)	0	0	0	0	0	2,531,869	2,531,869	2,531,869	2,531,869	2,531,869
	97	Rest of WECC PV Solar Costs ($000)	0	0	0	0	0	451,623	451,623	451,623	451,623	451,623
	98	Rest of WECC Variable Demand Response Costs ($000)	0	0	0	0	0	0	0	0	0	0
	99	Rest of WECC Transmission Capital Costs ($000)	0	0	0	0	0	2,452,282	2,452,282	2,452,282	2,452,282	2,452,282
	100	Rest of WECC Transmission Miles	0	0	0	0	0	8,536	8,536	8,536	8,536	8,536
	101	Rest of WECC Incremental Resource Capital Costs ($000)	7,445,604	7,445,604	7,445,604	7,445,604	7,445,604	7,142,004	7,142,004	7,142,004	7,142,004	7,142,004
	102	*Total Rest of WECC Other Costs*	7,667,374	7,666,018	7,663,218	7,658,794	7,660,905	12,859,624	12,847,361	12,837,609	12,839,145	12,856,151
	103	Rest of WECC (Excludes Remote*) Emissions										
	104	Rest of WECC CO2 Production (000 tons)	353,053	352,094	348,811	334,989	311,592	276,607	271,750	262,169	233,977	220,247
	105	Rest of WECC SO2 (000 tons)	402	396	385	343	287	366	352	328	263	218
	106	Rest of WECC NOx (000 tons)	457	452	440	397	340	415	399	371	298	262
	107	Rest of WECC HG (000 tons)	2,766	2,745	2,687	2,428	1,836	2,333	2,266	2,108	1,561	1,269
	108	Rest of WECC Emission Costs CO2/SO2/NOx/HG ($000)	232,657	3,479,922	6,510,818	11,503,741	13,825,753	201,408	2,843,966	5,140,122	7,953,366	10,251,052
	109	Rest of WECC Remote* Generation										
	110	Rest of WECC Remote* Generation (GWh)	62,433	61,664	60,549	57,495	52,368	56,990	55,391	52,837	46,606	44,317
	111	Rest of WECC Remote* Generation Cost ($000)	1,651,096	1,976,689	2,280,912	2,778,749	2,978,478	1,438,082	1,687,123	1,880,428	2,078,106	2,351,701
	112	Rest of WECC Remote* CO2 (000 tons)	36,533	36,115	35,111	31,833	26,823	32,996	31,641	29,052	22,708	20,744
	113	Rest of WECC Remote* SO2 (000 tons)	27	27	26	25	22	25	25	24	18	17
	114	Rest of WECC Remote* NOx (000 tons)	61	61	59	54	45	57	55	51	39	36
	115	Rest of WECC Remote* HG (000 tons)	343	342	337	313	276	328	322	304	238	213
2020	116	Rest of WECC Gas Consumption										
	117	Rest of WECC Gas Consumption (Gbtu)	1,463,538	1,480,065	1,512,652	1,707,528	2,117,771	595,856	611,602	666,472	983,580	1,173,454

APPENDIX D

RESOURCE BALANCE AND PLANNING RESERVE MARGIN ANALYSIS

Prepared by Global Energy Decisions, Inc.

CALIFORNIA
ENERGY
COMMISSION

APPROACH TO RESOURCE BUILD-OUT USED IN THE CALIFORNIA ENERGY COMMISSION SCENARIOS PROJECT

CONSULTANT REPORT

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Resource Build-out Approach used in the California Energy Commission Scenarios Project

I. Base Case Resource Build-out – Proposed and Generic Unit Additions

When preparing a forecast of power markets in the Western Electricity Coordinating Council (WECC) through 2020, one needs to start with a forecast of loads over the time period. Next, the existing fleet of supplies (generators) needs to be inventoried. Assumptions need to be made about possible retirements of these plants.

In addition to the existing fleet, there are also power plants that have been proposed by utilities and independent power producers for construction in the WECC. The list of plants proposed to be constructed in WECC is very large. As of this writing, there are approximately 84,000 megawatts (MW)[1] of new plants proposed, but not currently under construction, in the WECC. Of these proposed plants, approximately 60,000 MW would be fueled by either coal or natural gas. It does not make sense to assume that all 84,000 MW of the proposed plants will be built. Experience shows us that many proposed plants are eventually cancelled. Further, it is clear that the WECC does not need this much power. Further, proposed plants may not be of a technology with which load serving entities will want to contract.

For this study, the only proposed plants that Global Energy has added to the existing fleet are those proposed plants that have procured a power purchasing agreement (PPA) with a credit worthy load-serving entity and 750 MW (nameplate) per year of generic wind plants, which Global Energy believes will be built in response to various states' Renewable Portfolio Standard goals.

The forecast load can next be compared with the sum of (a) the existing fleet of supplies (adjusted for assumed retirements) and (b) the proposed plants that have a PPA and the generic wind.

Global Energy assigns all loads and resources in WECC to one of 12 modeled control areas. Although in reality there are more control areas in the WECC than Global Energy models, the 12 regions modeled represent an aggregation of control areas with similar operating requirements (such as similar operating reserve targets). Transmission areas (transareas) that represent geographic areas within a control area are mapped to the

[1] Global Energy Decisions tracks power plant developments throughout North America in its analytical data warehouse software Energy Velocity. The 84,000 MW of newly proposed plants consist of those that are considered to be in various phases of development including plants that are in the permitting and feasibility study process, simply announced in a news source, and projects that are currently placed on hold. The plant data is gathered from various publicly available reports and news articles.

appropriate control area. For the Energy Commission Scenario project, we made an assumption that each of the control areas in WECC will need to line up resources sufficient to cover its peak load (1-in-2) plus 15 percent planning reserve margin (after derating the wind) for each year of the forecast period. The resources included in a control area are those resources that are identified in the database as being associated with that control area (no matter where the plant is located) and that will contribute towards that control area's operating reserves. Further, to the extent Global Energy has knowledge about contracts to buy and sell power between control areas, Global Energy also reflect the contract obligations and rights in the calculation of control area planning reserve margin. Global Energy obtains contract information from NERC reports or sub-regional agencies, all of which are publicly available. Where contract end dates are not available, Global Energy makes assumptions on the term of the contract depending on the transarea/control area involved. The peak-load hour is different for each control area, often in different seasons, but certainly in different hours of the year.

In completing the resource build-out for purposes of the base case forecast of power markets in the WECC, Global Energy checks to see if a control area is falling below its 15 percent planning reserve margin requirement in any year. If so, we add resources in the control area footprint to bring it back to at least its 15 percent planning reserve margin. Global Energy used the list of proposed plants to determine what technology might be built in that geographic area when adding the generic plants necessary to meet control area planning reserve margins.

Table 1 below shows the planning reserve margin for 2020 for the Base Case for each of the 12 modeled control areas. The table indicates the control area peak load and the generation needed to meet the peak load plus a 15 percent planning reserve margin. This table also shows the load in each control area on the hour when the coincident peak load in WECC occurs. The loads on the coincident peak hour are less than the load on the control area peak hour. This table also shows the WECC-wide coincident peak reserve margin, which reserve margin is necessarily higher than any single Control Area reserve margin because of the diversity in peak hour among control areas.

Table 1 – Base Case - 2020 Control Area and WECC wide Planning Reserve Margin

Control Area	Control Area Peak Load Month	Control Area Peak Load	Control Area Resources at Peak Load*	Control Area Planning Reserve Margin	Control Area Load at Coincident WECC Peak (excludes Sales)	Control Area Resources at Coincident WECC Peak (excludes Purchase)*
AESO	December	13,069	17,667	35%	11,880	17,623
Arizona	July	26,335	30,346	15%	23,876	29,829
BCHA	January	13,461	16,042	19%	9,217	15,757
CFEW	August	3,572	4,408	23%	3,466	4,508
CAISO	July	59,569	70,110	18%	58,903	63,713
CO-WY	July	16,315	18,879	16%	15,672	18,968
IID	July	1,451	1,784	23%	1,014	1,711
LADWP	July	8,261	9,516	15%	5,941	9,296
New Mexico	July	5,769	6,657	15%	5,519	6,170
Northwest	January	48,537	66,467	37%	43,142	64,641
Southern Nevada	July	11,744	13,543	15%	9,607	11,503
Sierra Pacific Power	July	3,210	3,701	15%	3,135	2,589
WECC Total - Non-Coincident		211,293	259,121	**WECC Total - Coincident**	**191,372**	**246,308**
					WECC Planning Reserve Margin	**29%**

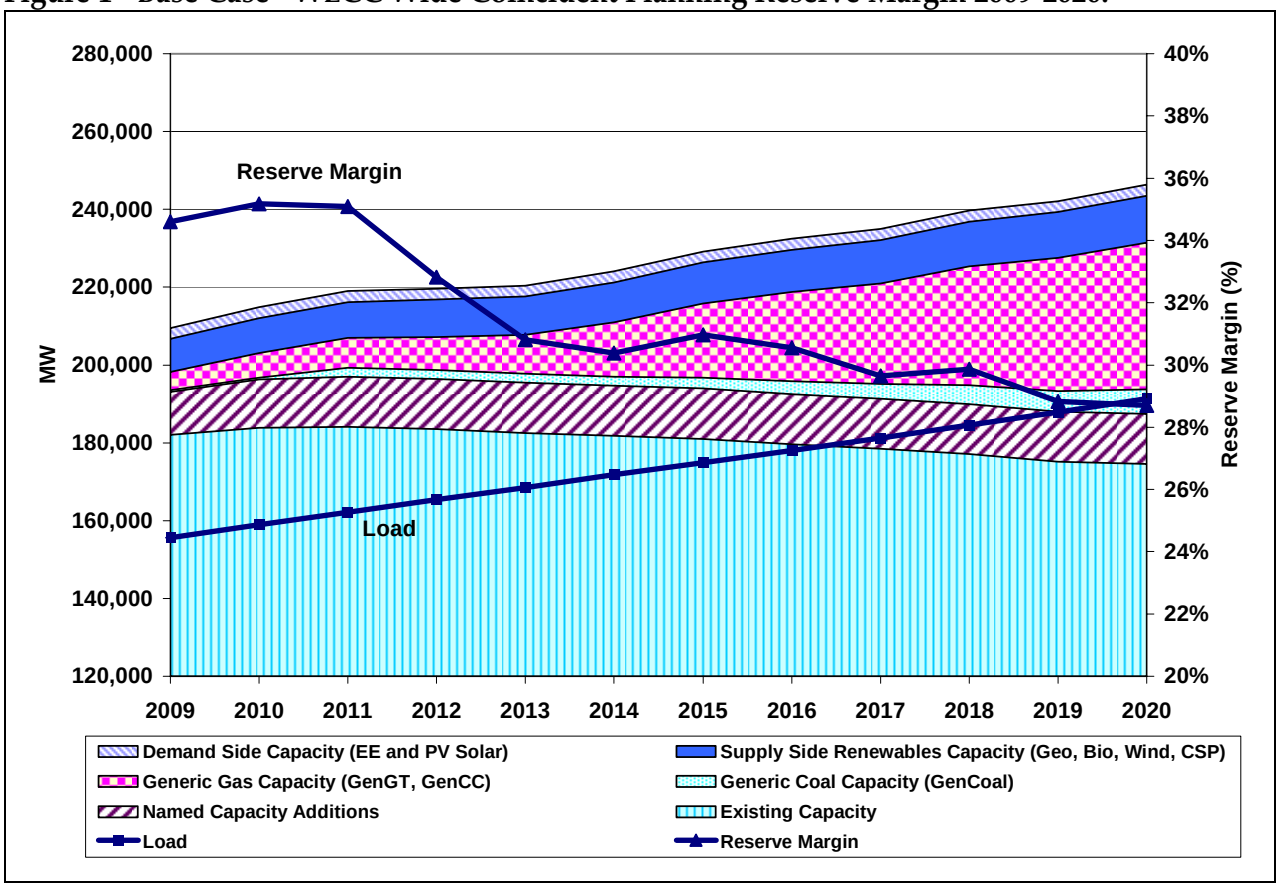
*Resource totals reflect dependable capacity.
**All values in MW except for Planning Reserve Margin Calculation

Source: Global Energy Decisions.

As observed in Table 1, some control areas exhibit a planning reserve margin greater than 15 percent. In the instances of Northwest and BC Hydro control areas, which are energy constrained areas, looking at the peak reserve levels (rather than focusing on total energy) results in a higher planning reserve margin. In other control areas that exhibit a planning reserve margin greater than 15 percent, such as Imperial Irrigation District (IID) and Mexico (CFEW), the size of the areas on a peak load basis is relatively small and the lumpiness of the resources being added can contribute to a higher planning reserve margin. Though lumpiness of resource additions could account for part higher reserve margin in the Alberta (AESO) control area, it appears that too much generic resources may have been added to the build-out in the base case.

The base case WECC coincident peak planning reserve margin can be calculated for every year of the forecast period 2009-2020. For the base case, such planning reserve margin is shown in Figure 1 below. As can be observed in this chart, the WECC-wide coincident reserve margin is quite high in the early years because of an existing overbuild of supply in WECC. Despite a series of factors in recent years that have led to higher levels of resources and a resulting reserve margin normally considered more than necessary, this study did not assume that these causative forces will continue. Reserve margins were allowed to diminish down towards the level considered sufficient in most integrated resource plans and other assessments. Thus, the overbuild ramps down in future years as load growth and resource retirements eat into the overbuilt supply.

Figure 1 - Base Case - WECC Wide Coincident Planning Reserve Margin 2009-2020.



Source: Global Energy Decisions.

II. Modifying Generic Resource Build-out for "Preferred" Resource Types

Under those scenarios where the base case assumptions are modified to reflect more penetration of preferred resource types, the first step is determining how much additional capacity (over the base case assumption) of the preferred resource type will be built. Next, it is necessary to calculate the resource adequacy contribution of the preferred resource types due to the fact that some of the preferred resource types have variable availability such as wind and solar generation. As such, a fossil fuel-fired generator whose resource adequacy contribution at the time of peak is likely in the range of 90-100 percent is worth more in terms of resource adequacy compared to the contribution that wind generation has at the time of peak which may be in the 0-20 percent range. Therefore, calculating resource adequacy for the preferred resources that have variable availability is necessary so that reserve margin calculations are accurate and reflect the dependable capacity available at the time of peak. For example, a 100 MW wind plant may have a resource adequacy contribution of 20 MW. A summary of derate factors by resource type and transarea used in calculating resource adequacy values can be found in Appendix E of the June 2007 Scenarios report.

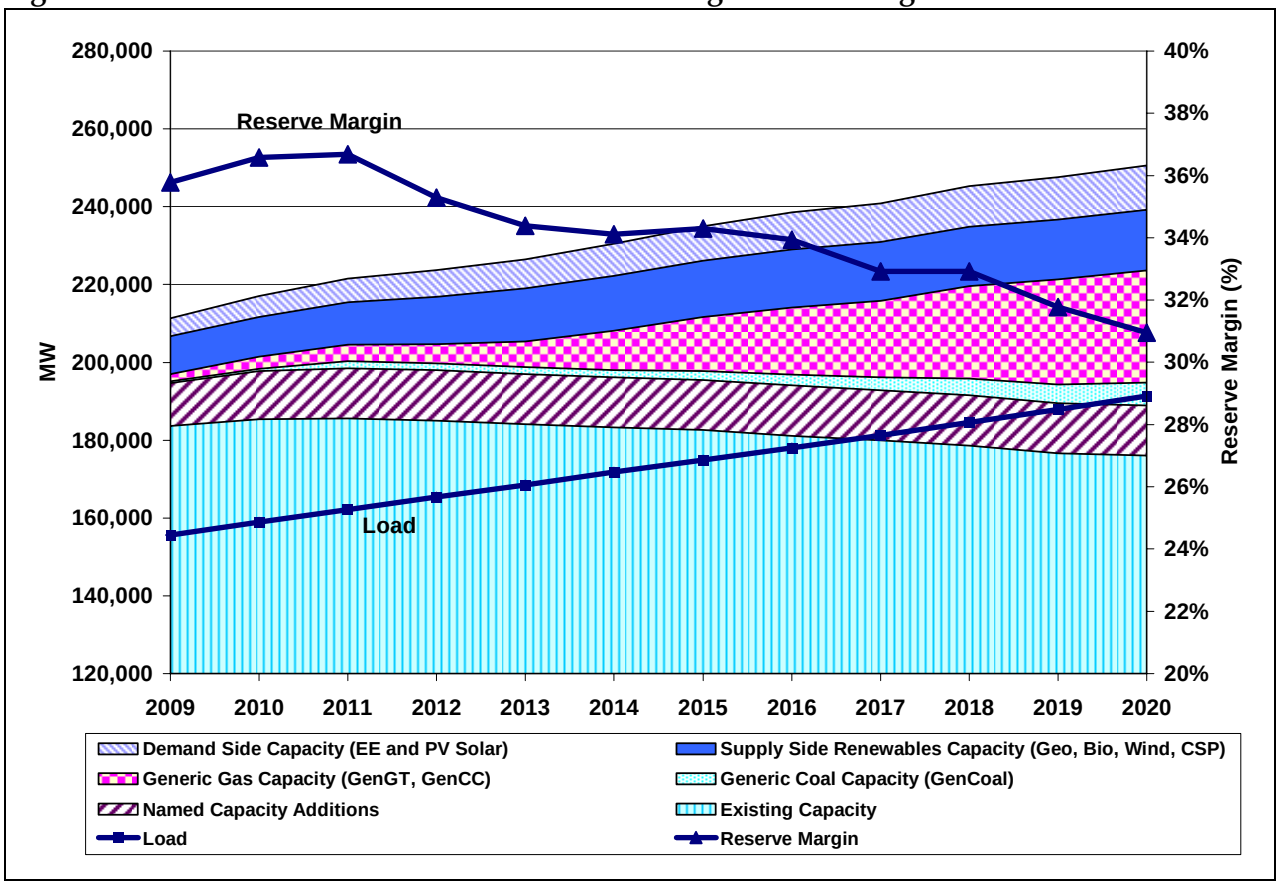
When these preferred resources were added to a transarea, gas or coal-fired generic additions that had been added in that transarea in the base case were removed. While the lumpiness of the generic fossil resources hindered the ability to displace these resources for the preferred resources on a dependable megawatt for megawatt basis, an attempt was made at such a result. Since some of the preferred resource types produce considerably less energy (i.e. wind and solar for example) megawatt for megawatt compared to a gas or coal generator, generic gas turbines were removed initially followed by the removal of generic combined cycle and coal steam turbines. In the early years of the forecast, Global Energy had added little generic coal or gas in many of the transareas (because they were already "long"), so adding the additional preferred resource simply acted to increase planning reserve margins. However, the cumulative increase in preferred resources would cause us to remove the first generic resource that was built in that zone.

In some of the scenarios with extremely high levels of assumed new preferred resources and significant amounts of energy efficiency and rooftop solar, many zones had no more generic coal and gas that could be removed. That left these zones "long" on power. In the Scenario project, Global Energy did assume some new transmission would be built to allow preferred resources in one zone to cancel the need for some gas plants in another zone. The two circumstances where this adjustment was made due to the substantial amounts of preferred resources being added, was in Case 5b between Arizona and New Mexico, and Utah and Wyoming. As an example, one transarea (New Mexico) had no generic coal or gas generation to displace as preferred resources were added, and a neighboring transarea (Arizona) had generic resources to displace. To

allow one transarea (Arizona) to account for this increase in preferred resources of another transarea (New Mexico), transmission upgrades were assumed to allow the preferred resource generation to flow through to the neighboring transarea. However, in this work Global Energy did not attempt to optimize a plan for transmission and renewables offsetting gas-fired generation.

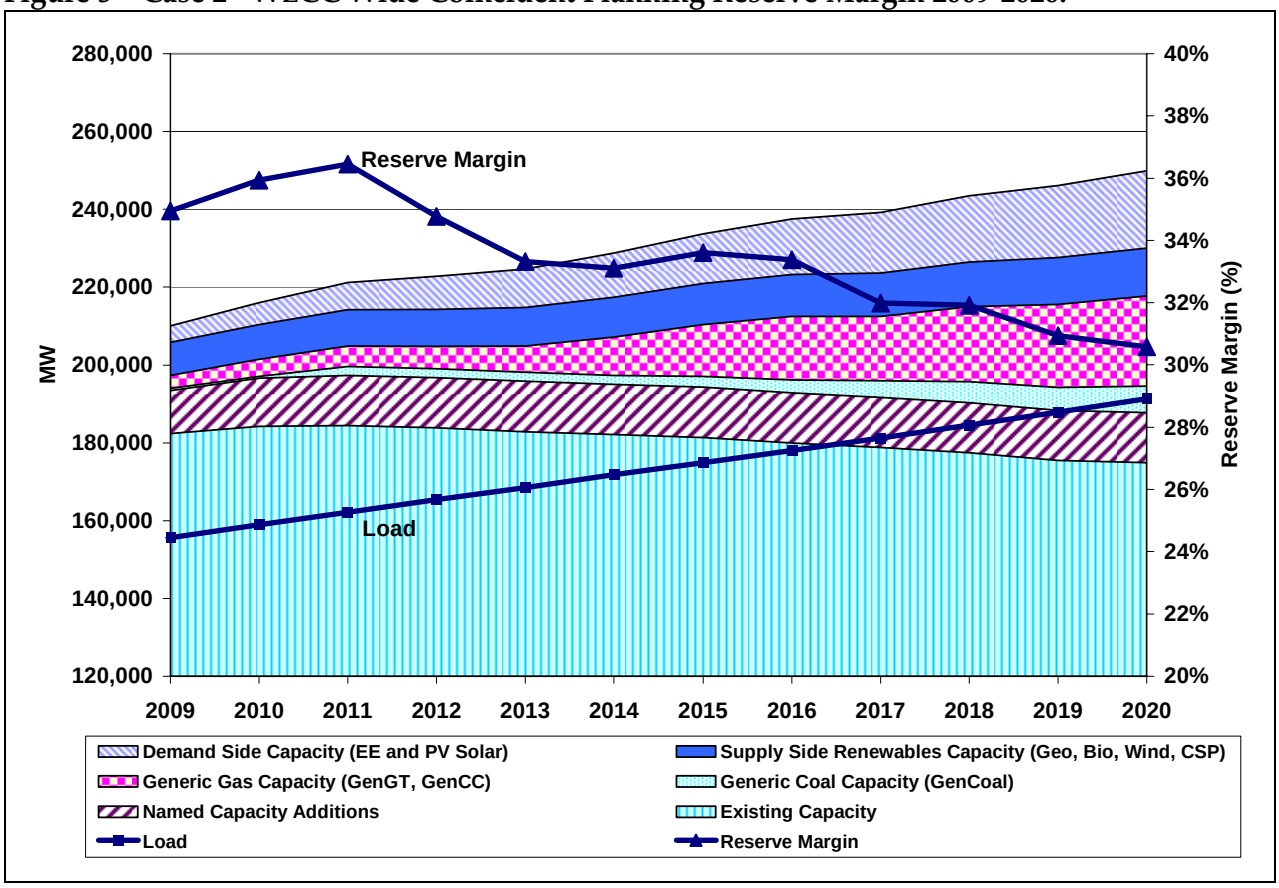
Figures 2 through 9 below illustrate WECC-wide planning reserve margins for each of the eight primary scenarios for 2009-2020. All show the same general pattern of slightly decreasing reserve levels ending up well above the levels generally considered necessary. Figure 9 showing Case 5b is the most extreme with its reserve level actually increasing slightly over time. Of course, Case 5b is the one in which high levels of energy efficiency and high levels of renewables on a WECC-wide basis were added together, so it would naturally have the greatest excess of resources.

Figure 2 – Case 1b - WECC Wide Coincident Planning Reserve Margin 2009-2020.



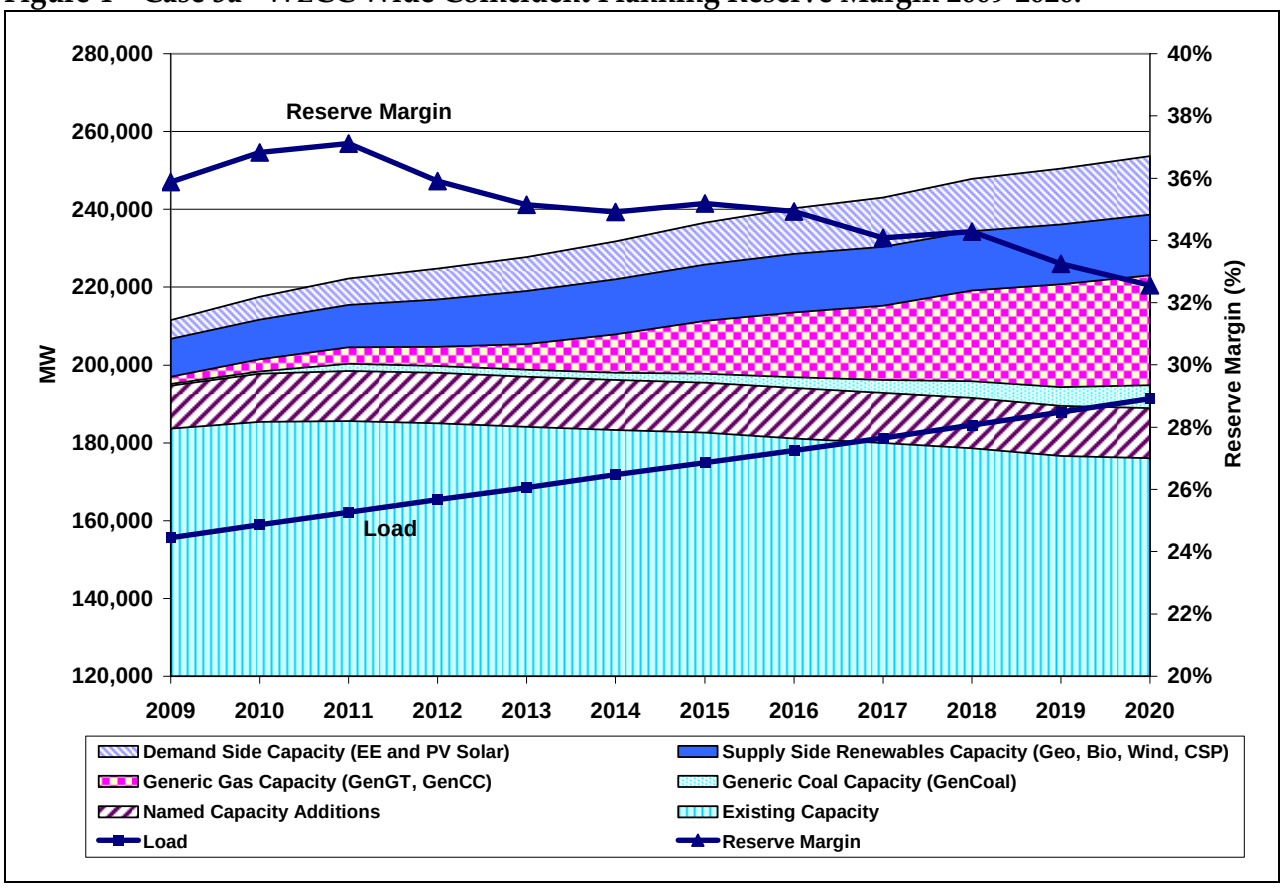
Source: Global Energy Decisions.

Figure 3 – Case 2 - WECC Wide Coincident Planning Reserve Margin 2009-2020.



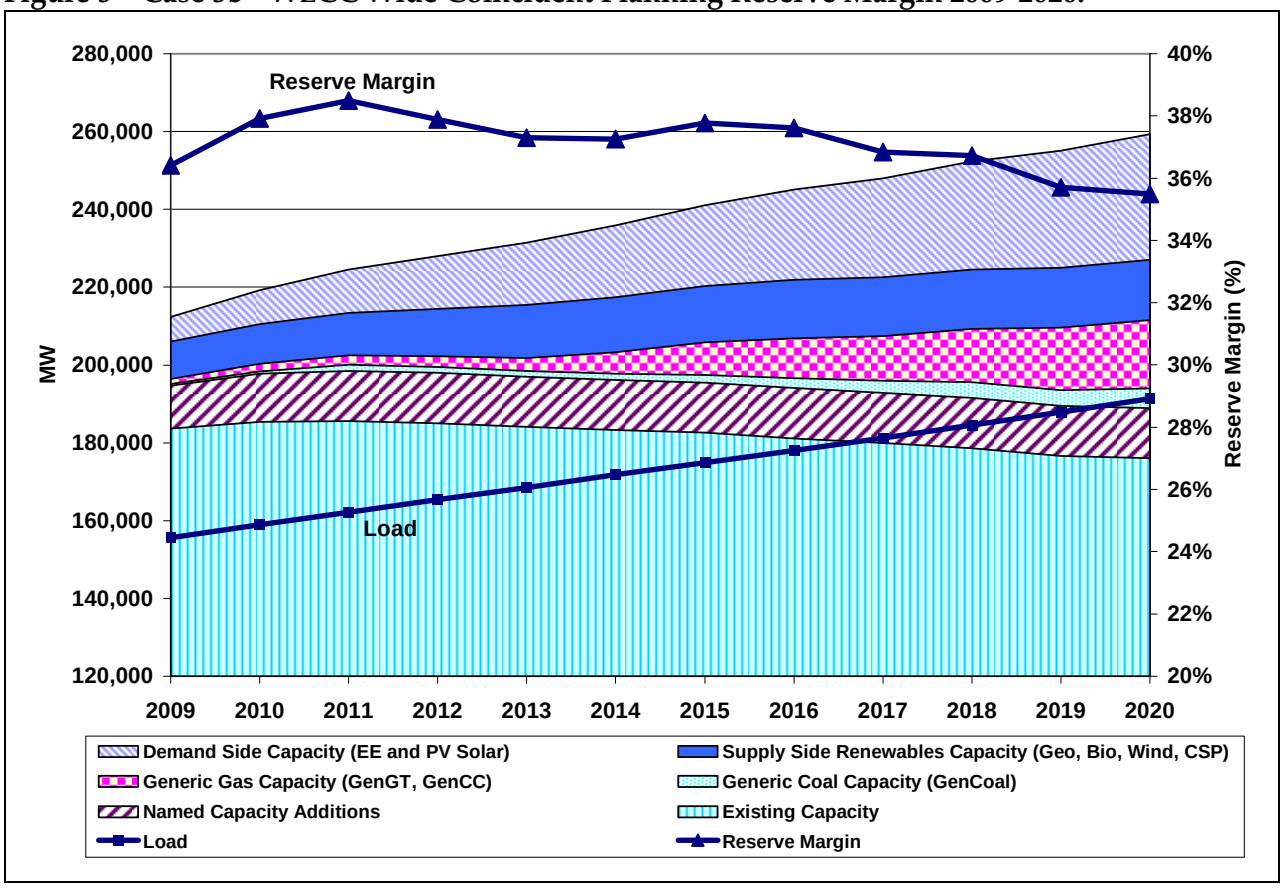
Source: Global Energy Decisions.

Figure 4 – Case 3a - WECC Wide Coincident Planning Reserve Margin 2009-2020.



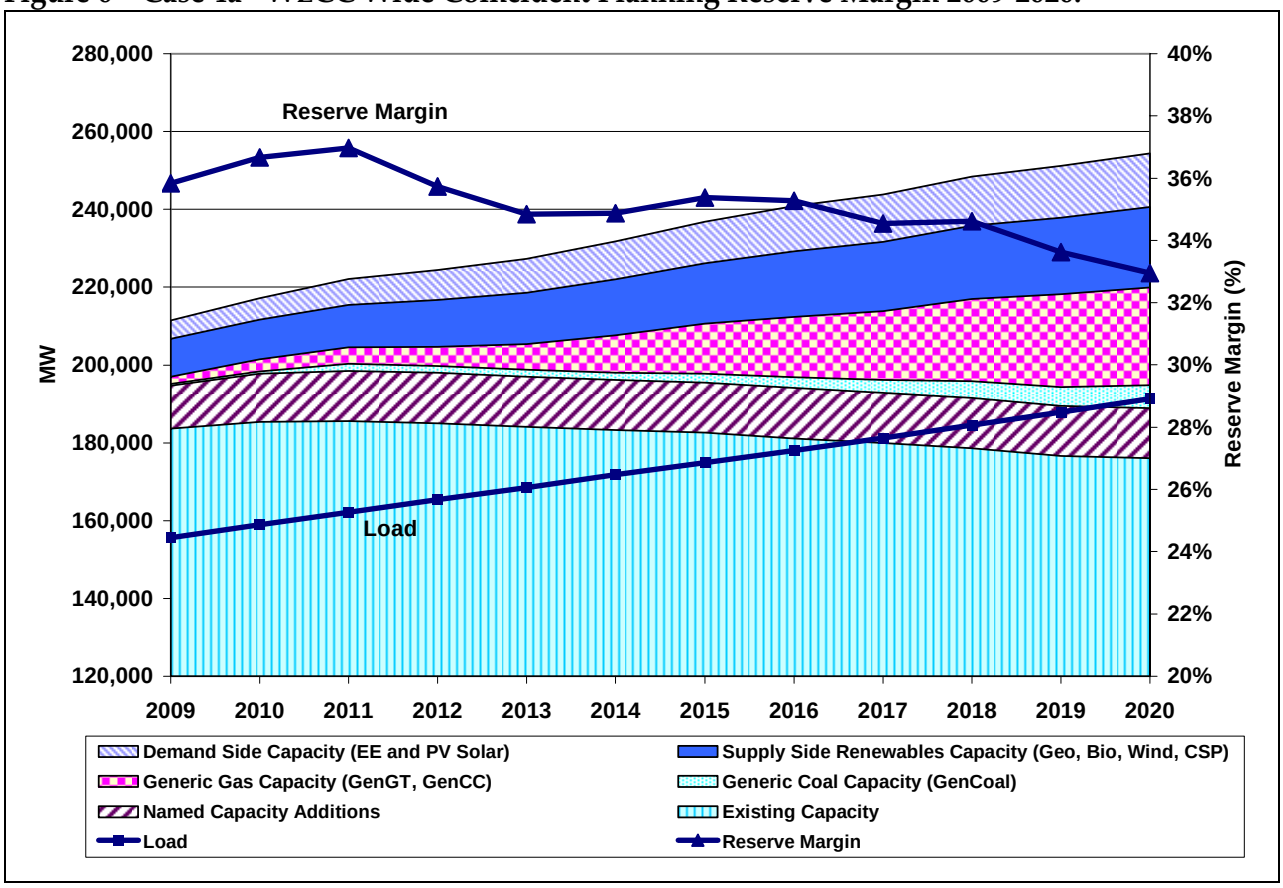
Source: Global Energy Decisions.

Figure 5 – Case 3b - WECC Wide Coincident Planning Reserve Margin 2009-2020.



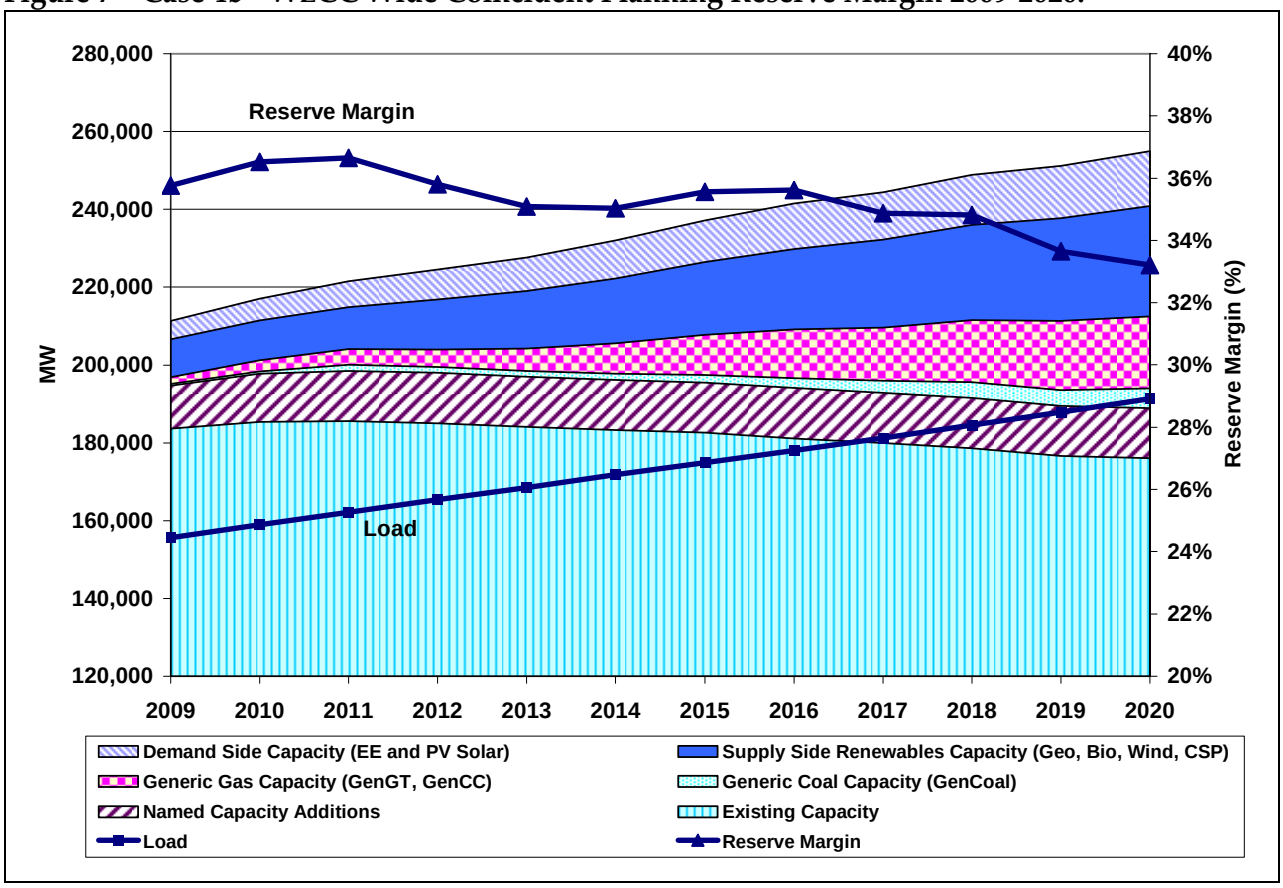
Source: Global Energy Decisions.

Figure 6 – Case 4a - WECC Wide Coincident Planning Reserve Margin 2009-2020.



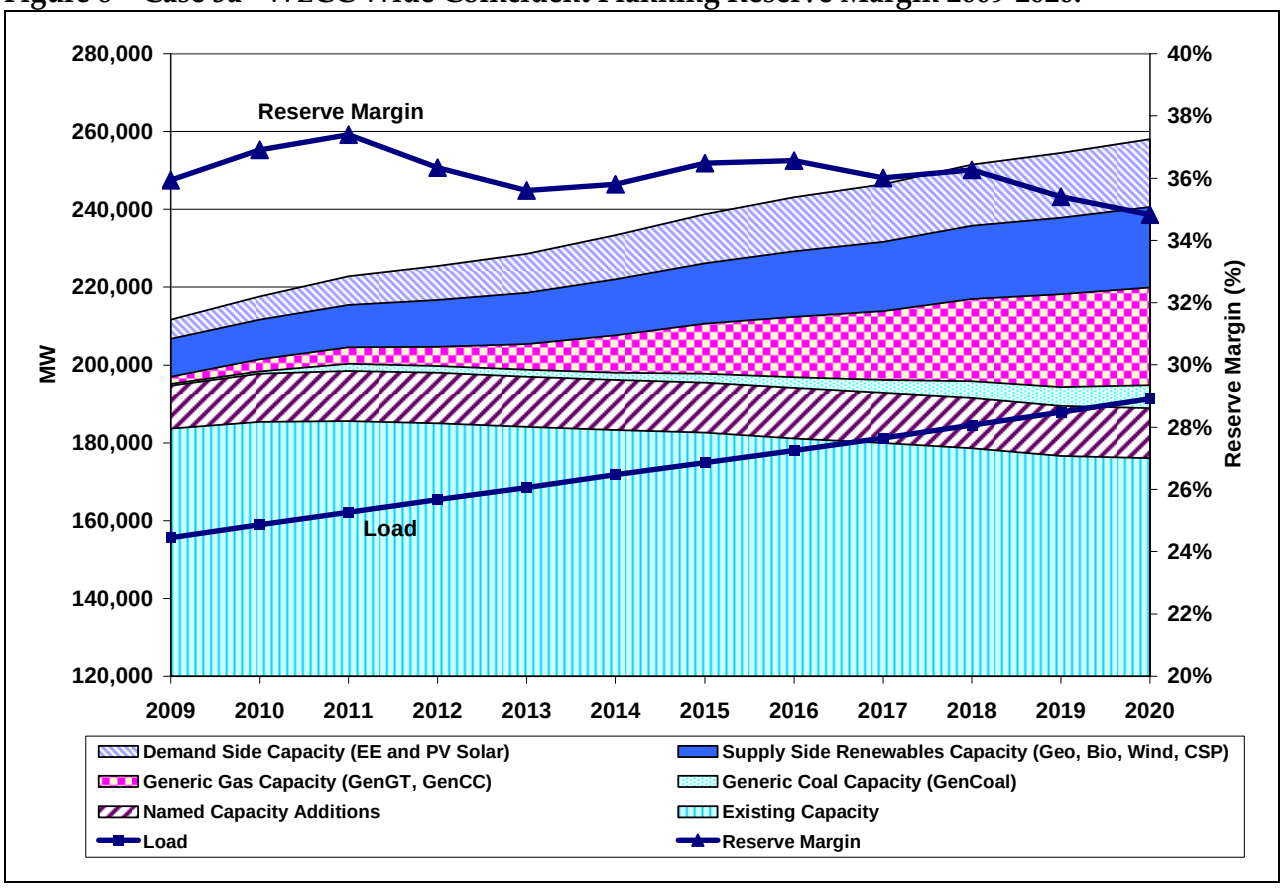
Source: Global Energy Decisions.

Figure 7 – Case 4b - WECC Wide Coincident Planning Reserve Margin 2009-2020.



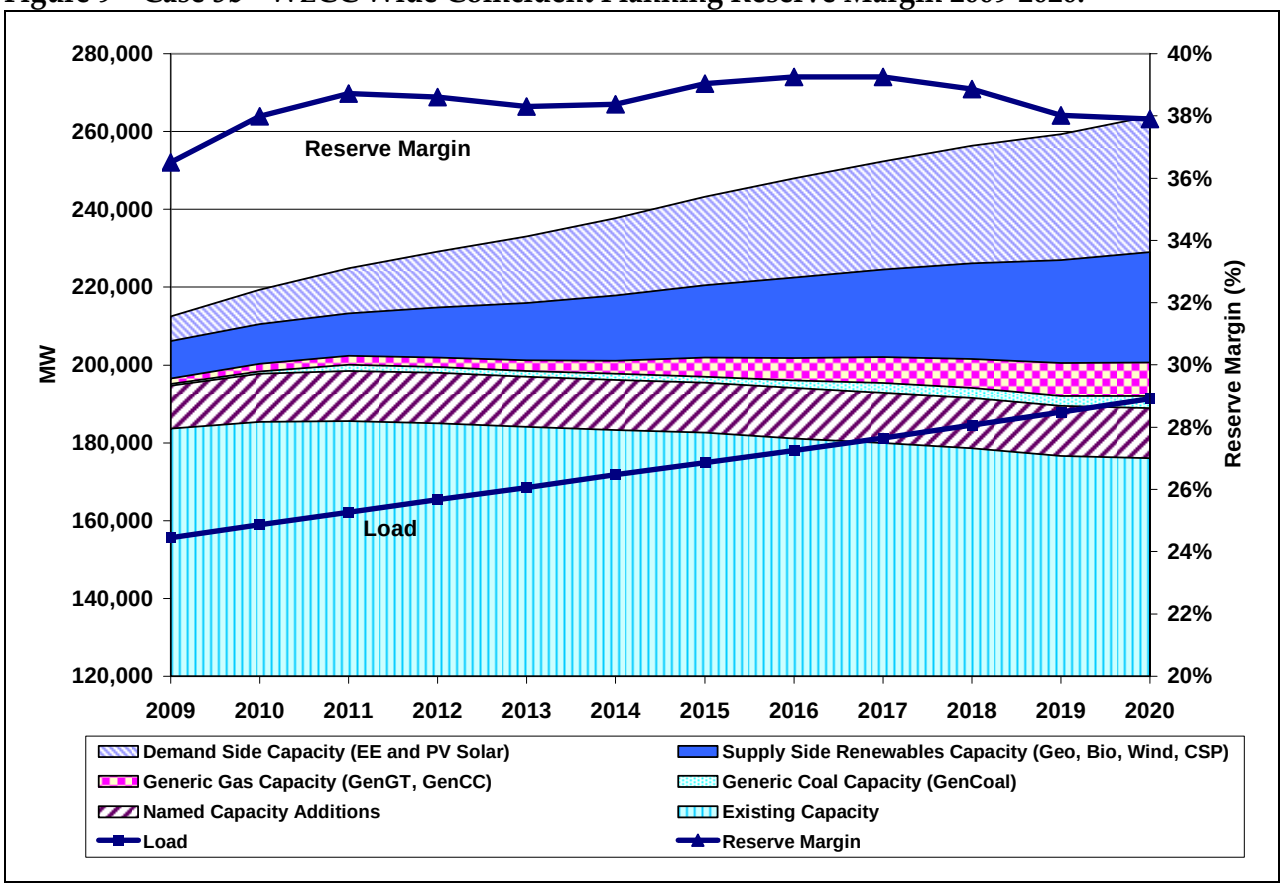
Source: Global Energy Decisions.

Figure 8 – Case 5a - WECC Wide Coincident Planning Reserve Margin 2009-2020.



Source: Global Energy Decisions.

Figure 9 – Case 5b - WECC Wide Coincident Planning Reserve Margin 2009-2020.



Source: Global Energy Decisions.