California Public Utilities Commission

Report to the Legislature in Compliance with Public Utilities Code Section 910

March 2013

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INTRODUCTION

Background

In April 2011, Governor Brown signed Senate Bill (SB) 2 (1X) (Simitian, 2011) codifying the state's longstanding 33 percent Renewables Portfolio Standard (RPS) goal. In addition to increasing the state's RPS goal from 20 percent in 2010 to 33 percent by 2020, SB 2 (1X) added Section 910 to the Public Utilities Code (Pub. Util. Code).[1] Section 910 requires the California Public Utilities Commission (CPUC or Commission) to provide an annual to report to the Legislature on electrical corporations' direct and indirect costs and costs avoided (savings) with the RPS program and distributed generation programs. Section 910 also requests decision numbers, changes in load, and qualitative and quantitative information about electrical corporations' diversity goals primarily related to its workforce directly involved in the RPS program. The complete text of Section 910 is provided as Appendix A.

In addition, SB 836 (Padilla, 2011)[2] requires the CPUC to report to the Legislature "the costs of all electricity procurement contracts for eligible renewable resources, including unbundled renewable energy credits, and all costs for utility-owned generation approved by the Commission." This report, referred to herein as the Padilla report, was first issued in February 2012 and will be issued annually thereafter.[3]

Section 910 covers a broad array of electrical corporations' operations. To gather data and other information for this report, Energy Division staff issued data requests to Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) and relied on other publically available information.

Section 910 applies to electrical corporations as defined in Section 218; namely, PG&E, SCE, SDG&E, PacifiCorp, California Pacific Electric Company, and Bear Valley Electric Service. This first report to the legislature pursuant to Section 910 only addresses California's three large electrical corporations: PG&E, SCE, and SDG&E.

Given the broad scope of Section 910, this report focuses primarily on 2011 because the legislatively mandated February reporting deadline makes it difficult to obtain and sufficiently review 2012 expenditures and other requested data. In contrast, the limited scope of the Padilla report allows the CPUC to report more recent 2012 RPS procurement expenditures. Setting reporting dates in the second quarter of the year would allow the Energy Division to report on the previous year and would allow for a single report to the Legislature. In subsequent reports, we hope to work with the Legislature to address this timing issue, as well as to update and further refine the scope of these reports.

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[1] All further references to sections refer to the Pub. Util. Code unless otherwise specified.

[2] Codified in Pub. Util. Code Section 911.

[3] Available at http://www.cpuc.ca.gov/NR/rdonlyres/3B3FE98B-D833-428A-B606-47C9B64B7A89/0/Q4RPSReporttotheLegislatureFINAL3.pdf.

Summary

This is the first report to the Legislature made pursuant to Section 910, referenced hereafter as the Section 910 Report. The scope of the information and data requested in Section 910 Report is broad. Section 910 requests historic cost information related to electrical corporations' compliance with the RPS, as well as costs associated with customer distributed generation programs, which may not directly impact the RPS program that involves the procurement of utility-scale renewables. Below is a brief summary of the report:

- 2011 RPS deliveries represented the following percentages of the utilities retail sales: 19.8 percent for PG&E, 21.1 percent for SCE and 20.8 percent for SDG&E. PG&E, SCE and SDG&E spent approximately $1,017 million $1,341 million and $170 million, respectively on direct RPS expenditures in 2011, for a combined total of $2,528 million. Direct RPS expenditures increased from $2,179 million in 2010 to $2,528 million in 2011; total procurement increased as well, from approximately 28,238 GWh to 32,695 GWh.
- The indirect expenditures of the RPS program include utility administrative costs, costs associated with the integration of renewable resources, and expenses associated with the utilities' transmission and distribution systems. Currently, these costs are orders of magnitude smaller than direct RPS expenditures. Many of the proposed transmission projects associated with renewable resource projects that will contribute to the state's 33 percent RPS requirement were not in service in 2011 and, thus, for the most part, the expenses were not yet included in rates. Typically, RPS-related transmission projects are built both for system reliability and to facilitate deliverability of renewable resources. As a result, it is not clear what portion of these expenses should be attributed to renewable resources vs. conventional generation resources that may also benefit from new transmission projects.
- There is not yet an adopted methodology for assessing the cost savings (benefits) of the RPS program. Average 2011 RPS expenses compare favorably when compared to a long-term energy and capacity benchmark and unfavorably when compared to short-term prices for energy and capacity.
- The electric portion of the Self-Generation Incentive Program (SGIP) and the California Solar Initiative (CSI) budgets for 2011 were $75 million and $240 million, respectively. The benefits of these programs have been assessed in a variety of other reports referenced herein. The Commission is in the process of conducting a net energy metering (NEM) study, which is mandated by Assembly Bill 2514 (Bradford, 2012) and due October 1, 2013.
- Bundled retail loads of PG&E, SCE and SDG&E have decreased for the past three years to 74,864 GWh, 73,377 GWh and 16,249 GWh, respectively, for 2011.
- PG&E, SCE and SDG&E all have programs in place to facilitate the development of a diverse workforce and the procurement of goods and services from diverse businesses,

but they do not track the number of women, minority, and disabled veterans trained and/or hired to work on the RPS program or those hired by firms with RPS contracts.

RENEWABLE PROGRAM COSTS AND SAVINGS

This section addresses the costs and savings (or costs avoided) associated with renewable resources, consistent with the requirements of Section 910(a)(1) and (2), including direct and indirect costs associated with renewable resources and the potential cost savings associated with utility procurement of renewable resources.

> Section 910(a)(1)
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> *[The report shall summarize the following information…] All electrical corporation revenue requirement increases associated with meeting the renewables portfolio standard, as defined in Section 399.12, including direct procurement costs for eligible renewable energy resources and renewable energy credits, administrative expenses for procurement, expenses incurred to ensure a reliable supply of electricity, and expenses for upgrades to the electrical transmission and distribution grid necessary to the delivery of electricity from eligible renewable energy resources to load.*

RPS Direct Expenditures

2011 RPS deliveries represented the following percentages of the utilities' retail sales: 19.8 percent for PG&E, 21.1 percent for SCE and 20.8 percent for SDG&E.[4] PG&E, SCE, and SDG&E spent approximately $1,017 million, $1,341 million and $170 million respectively, on direct RPS procurement in 2011 (see Table 1),[5] for a combined total of $2,528 million. For 2011, RPS expenditures represented approximately 8 percent of PG&E's total revenue requirement of $12,444 million, 12 percent of SCE's total revenue requirement of $11,121 million and 5 percent of SDG&E's revenue requirement of $3,150 million.[6] These percentages differ because of the overall size of the utilities' revenue requirement and because the cost of renewables depend upon technology type and geographical location.[7]

Total RPS expenditures have increased over time, as the utilities have increased their purchases of renewable resources and the mix of renewable resources has changed (see Table 2 - Table 10 at the end of this section of the report). Total procurement increased from approximately 28,238

[4] See PG&E, SCE, and SDG&E 2011 Preliminary Annual 33% RPS Compliance Reports, available at http://www.cpuc.ca.gov/PUC/energy/Renewables/.

[5] Direct procurement expenditures for RPS-eligible contracts include actual annual time of delivery adjusted payments. These figures also include the revenue requirements associated with utility-owned generation (UOG) and are estimated based on allocations of approved revenue requirements.

[6] For total utility revenue requirements for 2011, see the CPUC's "Electric and Gas Utility Cost Report," April 2012, Appendix A, available at http://www.cpuc.ca.gov/NR/rdonlyres/1C5DC9A9-3440-43EA-9C61-065FAD1FD111/0/AB67CostReport201.pdf.

[7] In addition, the figures above compare ***actual*** 2011 renewable expenditures with 2011 revenue requirements, which include ***forecasted*** fuel and purchase power expenditures; therefore, the comparisons will not be exact.

GWh in 2010 to 32,695 GWh in 2011; direct RPS expenditures increased as well, from $2,179 million in 2010 to $2,528 million in 2011. In 2011, the utilities' RPS portfolios (in dollar terms) were primarily comprised of geothermal (35 percent) and wind (34 percent) resources, followed by biomass (12 percent). This resource mix will change over time as additional renewable resources, including recently contracted for utility-scale solar photovoltaic (PV) and solar thermal facilities, are brought on line to meet the 33 percent by 2020 mandate.

Table 1. Direct RPS Procurement Expenditures for RPS for 2011 (In Millions of Dollars)[8]

	PG&E	SCE	SDG&E	Total
Biogas	15.4	45.0	10.7	71.1
Biomass	246.5	32.6	27.3	306.5
Geothermal	240.5	585.4	64.7	890.6
Small Hydro	82.0	26.1	0.8	108.9
Solar PV	33.4	6.2	0	39.6
Solar Thermal	0.0	124.9	0.0	124.9
Wind	340.7	443.0	66.3	850.0
UOG Hydro	52.1	46.5	0.0	98.6
UOG Solar	6.5	31.0	0.0	37.5
Direct Procurement	**1,017.0**	**1,340.7**	**169.7**	**2,527.6**

RPS Indirect Expenditures

In addition to direct RPS procurement expenditures, there are a variety of indirect costs that are potentially attributable to RPS resources, including utility administrative costs, costs associated with the integration of renewable resources, and expenses associated with upgrades to the utilities transmission and distribution systems.

In order to assess the magnitude of these expenditures, Energy Division sent data requests to the utilities requesting that they identify and quantify, to the extent possible, the indirect cost categories and the magnitude of these costs. Based on these responses, it does not appear that the utilities use a consistent methodology to track these expenditures, that these costs are tracked in a manner that allows clear attribution to the RPS program, or that it is always possible to determine what portion of the costs should be attributed to the RPS program (e.g., transmission costs). Below, we discuss each of these cost categories and the cost estimates provided by the utilities or that are publically available from other sources.

[8] These totals may not sum due to rounding error.

Administrative Expenditures

Administrative expenditures include utility or outside expenditures associated with administering the RPS program. PG&E identified 61 full-time equivalents (FTEs) that worked on RPS implementation in 2011, with expenses of approximately $8.6 million, and other administrative expenditures of $2.2 million.[9] SCE identified 90 FTEs working on RPS matters, with expenditures of $10.5 million, and additional administrative costs of $3.8 million.[10] SDG&E was unable to provide the number of staff working on RPS related matters.[11]

Integration Expenditures

The need for integration services, commonly referred to as operational flexibility, is driven by intermittent generating resources and variability in system load. Neither the California Independent System Operator (CAISO) nor the Commission has determined that there is a need for additional resources for operational flexibility or the extent to which this need is associated with an increase in intermittent renewable generation. Thus, it is not yet clear what integration costs are directly attributable to the RPS program. The CAISO is studying operating flexibility needs of the system to account for more intermittent renewable resources and variability in load. The results of this analysis will be incorporated into the CPUC's long-term procurement planning proceeding (R.12-03-014) and discussed in subsequent reports.

Nonetheless, in response to the Energy Division data request, the utilities identified the following integration costs for 2011 that may potentially be attributable to renewable resources:

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[9] PG&E identified 61 FTEs that worked on RPS implementation in 2011, including 39 FTEs in energy procurement, 5 FTEs in the law department, 6 FTEs in regulatory affairs, and 11 in electric transmission operations. PG&E estimates the expenses for these staff to be $8.6 million. In addition, PG&E identified additional administrative costs for 2011, including $361,572 for the Western Renewable Energy Generation Information System (WREGIS), $312,623 tracked in the Renewable Portfolio Standard Memo Account (RPSCMA), $542,339 for independent evaluator costs, and $1,017,007 for external law department fees and expenses.

[10] SCE identified FTEs in the following departments: 49 – Transmission and Distribution, 20 – Renewables and Alternative Power, 8 – Law, 7 – Renewable Resource Integration, 5 – Credit Risk & Collateral Management, 1 – Power Supply Finance. In the Transmission and Distribution section, SCE indicates that most of these employees work on interconnection studies and agreements and that these 49 FTEs work on both renewable and non-renewable projects, but that "the preponderance of activities in relation to interconnection studies and agreements in SCE's territory in recent years are for renewable generating facilities." In addition, SCE identified further administrative expenses, including $429,486 for WREGIS fees and $3.0 million for outside legal counsel work on specifically identified RPS related matters.

[11] SDG&E indicated that "[f]or the SDG&E procurement department as well as regulatory and legal SDG&E does not track staffing expenses for the RPS specifically." However, SDG&E identified administrative expenses of $150,741 associated with the Ocotillo Switchyard, a "Reliability Network Upgrade to accommodate the interconnection of the Ocotillo Express wind project."

- PG&E estimates that it incurred ISO charges totaling $4.5 million in 2011 that may be attributable to renewable resources. PG&E also estimates that there are $36 million of additional costs to integrate intermittent renewable resources (some of which may be reflected by CAISO cost categories) based on $7.50/MWh (in 2008$) integration charge escalated to 2011 at 2.5% per year multiplied by wind and solar generation. PG&E proposed the $7.50/MWh integration cost adder for intermittent renewable resources; however, this proposed methodology was not adopted by the Commission.
- SCE identified $3.1 million in CAISO costs and an additional $5.2 million associated with renewable integration that may be attributable to the RPS program in 2011.
- SDG&E estimates CAISO ancillary service costs of $78,500 in 2011 due to RPS contracts, Participating Intermittent Resource Program allocation costs of $435,679, and an additional $186,000 for the cost of fuel to supply CAISO ancillary services.

The Energy Division cannot verify these numbers this year.

Transmission Expenditures

Over the next decade, a number of new transmission projects will be brought on line, which will support the state's 33 percent RPS program. However, these projects will also increase reliability and provide transmission access for conventional resources, in addition to facilitating the delivery of renewable resources. Given the multiple benefits associated with these transmission projects, it is not yet clear how the costs of the transmission lines should be allocated between renewable resources and other conventional resources.

In 2011, the ISO estimated that the capital expenditures for these new transmission projects could approach $7.2 billion.[12] In addition, in response to data requests, SCE and SDG&E identified RPS transmission-related capital expenditures totaling $9.2 billion through 2020, including $6.4 billion for SCE and $2.9 billion for SDG&E. But it is not clear what role these lines will play in reducing the need for transmission projects elsewhere.

Capital-related transmission costs are typically collected through rates only when the projects are placed into service. Because most of the RPS related transmission projects identified by the CAISO and the utilities were not completed in 2011, most of the costs associated with these projects were not included in 2011 rates.

Moreover, the costs of these transmission projects are collected over time – up to 30 - 50 years for transmission-related assets. As a very general rule of thumb, the amount collected in rates each year is roughly equivalent to 15 percent to 18 percent of the total capital expenditures. In addition, expenditures for high voltage transmission lines are allocated to all ISO load – thus, all

[12] See, http://www.energy.ca.gov/2011_energypolicy/documents/2011-05-17_workshop/presentations/02_CalISO_Presentation.pdf.

customers, including PG&E customers will pay for the SCE and SDG&E RPS-related transmission projects.[13]

In subsequent reports, as these transmission projects are brought on line, we will attempt to allocate the costs associated with these transmission projects to the RPS program, to the extent possible, and to estimate their impact on rates.

Distribution Expenditures

In some cases, interconnection of new renewables resources may require the utilities to upgrade their distribution system. Both the CPUC-jurisdictional interconnection tariff (Rule 21) and the IOUs' FERC-jurisdictional tariff (WDAT) require distribution upgrades to be borne by the developer.[14] As a result, estimating these distribution costs separately would result in double counting, as these costs are likely to be included in the bid price and, therefore, included with direct RPS expenditures.

RPS "Cost Savings"

> Section 910(a)(2)
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> *[The report shall summarize the following information…] All cost savings experienced, or costs avoided, by electrical corporations as a result of meeting the renewables portfolio standard.*

It is difficult to quantify the cost savings, or costs avoided, associated with the RPS program. There is no standardized methodology for determining the cost savings or benefits of RPS procurement that has been adopted by the Commission (although this may be developed in a subsequent RPS or another CPUC proceeding). Moreover, the cost savings or avoided costs are a theoretical concept – what resources would have been used and/or built in the absence of the energy and capacity procured as a result of the RPS program and what would the resulting costs have been. While it may be fairly straight-forward to calculate the fuel or variable savings, based on the market price of electricity in the year under consideration, the capacity costs are considerably more difficult to determine, as it requires an assessment of whether the RPS program deferred and/or delayed construction of alternative generation facilities and the theoretical cost of the alternative resources. In addition, an added benefit may be that increased generation from renewable resources may put downward pressure on natural gas prices.

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[13] These costs are spread among all customers through the Transmission Access Charge, see http://www.caiso.com/Documents/HighVoltageAccessChargeRatesEffective3Jan_2013_Updated16Jan_2013.pdf.

[14] For example, PG&E indicates that "Interconnection Customer pays for the distribution system modifications triggered by the Interconnection Customer's generation project."

Given the difficulty inherent in assessing the "benefits," for purposes of this report, we assess the benefits using the market price referent (MPR), but also present short-term prices for energy and capacity proposed by the utilities. The advantages of the MPR are twofold. First, it represents a long-term benchmark for energy and capacity, which is more typically used to evaluate long-lived generation assets. Second, the Commission has used the MPR in the past to evaluate the costs of RPS resources.[15]

The MPR was developed in order for the Commission to determine whether an RPS contract selected from a competitive solicitation had above-market costs associated with it. The MPR modeled what it would cost to own and operate a baseload combined cycle gas turbine (CCGT) power plant over various time periods. The cost of electricity generated by such a power plant, at an assumed technical capacity factor and set of costs, was the proxy for the long-term market price of electricity established by this Commission.[16] At the same time, the Commission is currently evaluating other metrics for assessing RPS resources and may use different measures in subsequent reports.

The 10-year and 20-year MPRs for contracts with a 2011 start date are 8.8 cents per kWh and 10.1 cents per kWh, based on 2009 MPR calculations. While the 2011 adopted values are more current, and lower, they apply only to RPS contracts with start dates in 2012 and beyond. Using the 20-year MPR of 10.1 cents per kWh to evaluate the utilities 2011 RPS portfolios results in "benefits," or avoided costs of approximately $1,410 million for PG&E, $1,560 million for SCE, and $330 million for SDG&E.

By contrast, in response to Energy Division data requests, the utilities measured the 2011 costs savings using 2011 CAISO day-ahead market price (PG&E - 3.12 cents per kWh; SCE - 2.99 cents per kWh; SDG&E – 2.93 cents per kWh) and, in the case of PG&E and SCE, the cost of capacity in the CAISO market (PG&E - $67.60/kW-year, SCE - $41.50/kW-year; SDG&E - $39.49/kW-year). Using these estimates, the utilities calculate the following avoided costs: PG&E – $512 million or 3.7 cents per kWh, SCE – $516 million or 3.3 cents per kWh, and SDG&E -- $97 million[17] or 2.9 cents per kWh.

The concern with this approach is two-fold. First, using the measure of savings (or costs avoided) proposed by utilities, few, if any resources in any of the utilities portfolio would be considered cost-effective – even comparatively low-cost hydroelectric and nuclear resources. By way of comparison, the overall generation rates in 2011 were approximately 7.5 cents per kWh for both PG&E[18] and SCE,[19] meaning that the average cost of generation resources far

[15] However, some parties have argued that the MPR does not reflect actual market conditions in part because the input assumptions become quickly outdated.
[16] SB 2 (1X) includes new provisions for setting an RPS procurement expenditure limitation. The CPUC is implementing this in the RPS proceeding (R.11-05-005).
[17] SDG&E calculated the avoided costs based only on the avoided energy and did not include avoided capacity.
[18] PG&E Advice Letter 3727-E-A, Table 3, available at http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_3727-E-A.pdf

exceeded the avoided costs calculated by the utilities. Second, the utilities' calculations are based on short-run avoided costs and it seems unlikely that the utilities would be able to procure 20 percent of their portfolios accounted for by the RPS program at these prices.

Today, the utilities and the CPUC assess the reasonableness of RPS contracts based on the net market value, according to a least-cost, best-fit evaluation methodology that is required by statute and defined by the CPUC. The net market value methodology was recently standardized and refined in D.12-11-016 to include the significant costs and benefits associated with RPS procurement. The elements of the net market value calculation include the value for energy and capacity and the costs for transmission upgrades, congestion, integration and ancillary services. A net market value metric may be a useful method for assessing the avoided costs for the RPS program. Also, other benchmarks may be developed in the RPS proceeding, e.g., through the implementation of the new procurement expenditure limitation, or in other CPUC proceedings, and will be discussed in subsequent reports.

[19] SCE Advice Letter 2577-E, Appendix A, p. 10, available at http://www.sce.com/NR/sc3/tm2/pdf/2577-E.pdf and ERRA 2011 load of 74,323 GWh.

Table 2. SCE, RPS Expenditures ($), 2003 - 2011[20]

	2003	2004	2005	2006	2007	2008	2009	2010	2011
Biogas	49,239,752	55,218,581	58,024,700	55,842,748	46,391,310	45,669,901	41,319,957	46,567,994	45,003,728
Biomass	30,229,214	30,641,340	29,266,687	29,364,748	31,995,803	32,870,627	37,676,121	39,934,586	32,647,359
Geothermal	533,787,287	568,528,010	569,145,247	540,276,590	564,191,771	682,923,953	591,094,390	601,071,879	585,397,425
Small Hydro	14,680,635	13,351,784	23,129,437	22,350,522	11,682,561	17,217,269	12,197,656	19,239,880	26,057,270
Solar PV	2,303	1,077	574	111			116,015	6,014,872	6,175,717
Solar Thermal	109,767,959	109,176,941	102,333,401	100,464,297	108,126,446	118,442,549	118,633,943	122,739,976	124,859,719
Wind	150,501,168	168,906,414	164,098,293	158,644,762	185,560,185	211,157,917	197,306,648	298,846,815	443,074,749
UOG Sm. Hydro	18,919,069	20,783,330	22,004,724	25,476,773	28,921,419	29,624,912	32,852,293	35,084,449	46,523,880
UOG Solar						1,235,712	3,576,168	10,838,789	30,970,261
Total	**907,127,388**	**966,607,477**	**968,003,063**	**932,420,551**	**976,869,495**	**1,139,142,839**	**1,034,773,191**	**1,180,339,240**	**1,340,710,108**

Table 3. SCE, RPS Generation (MWh), 2003 - 2011

	2003	2004	2005	2006	2007	2008	2009	2010	2011
Biogas	722,947	777,313	771,018	752,412	586,739	546,885	493,538	513,196	505,968
Biomass	365,114	373,928	351,063	353,893	365,337	363,233	417,625	437,918	351,023
Geothermal	7,079,545	7,882,153	7,823,442	7,481,229	7,611,425	7,739,370	7,675,041	7,633,511	7,540,917
Small Hydro	236,477	246,678	325,255	348,374	195,899	182,280	138,137	219,776	301,589
Solar PV	40	18	7	1	0	0	1,372	51,389	53,433
Solar Thermal	756,941	739,291	622,100	613,050	666,865	730,264	839,802	879,082	889,066
Wind	2,366,579	2,313,236	2,275,706	2,232,833	2,374,031	2,383,538	3,038,798	4,142,353	5,218,540
UOG Sm. Hydro	531,486	465,390	541,593	597,759	359,983	343,045	421,038	441,279	616,689
UOG Solar						438	2,799	4,846	54,532
Total	**12,059,129**	**12,798,007**	**12,710,184**	**12,379,551**	**12,160,279**	**12,289,053**	**13,028,150**	**14,323,350**	**15,477,225**

[20] Southern California Edison Company's (U 338-E) Final 2012 Renewables Portfolio Standard Procurement Plan, Public Version, Rulemaking 11-05-005, November 29, 2012, Public Appendix D, available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M031/K734/31734669.PDF.

Table 4. SCE, RPS Costs (cents per kWh), 2003 - 2011

	2003	2004	2005	2006	2007	2008	2009	2010	2011
Biogas	6.8	7.1	7.5	7.4	7.9	8.4	8.4	9.1	8.9
Biomass	8.3	8.2	8.3	8.3	8.8	9.0	9.0	9.1	9.3
Geothermal	7.5	7.2	7.3	7.2	7.4	8.8	7.7	7.9	7.8
Small Hydro	6.2	5.4	7.1	6.4	6.0	9.4	8.8	8.8	8.6
Solar PV	5.8	5.9	8.5	8.4			8.5	11.7	11.6
Solar Thermal	14.5	14.8	16.4	16.4	16.2	16.2	14.1	14.0	14.0
Wind	6.4	7.3	7.2	7.1	7.8	8.9	6.5	7.2	8.5
UOG Sm. Hydro	3.6	4.5	4.1	4.3	8.0	8.6	7.8	8.0	7.5
UOG Solar[21]									
Average	**7.5**	**7.6**	**7.6**	**7.5**	**8.0**	**9.3**	**7.9**	**8.2**	**8.5**

[21] We have not included UOG Solar costs (in cents per kWh) here as the costs include the first year capital expenditures and do not represent the levelized costs in a manner that is comparable to the other resources.

Table 5. PG&E, RPS Procurement Expenditures ($), 2003 - 2011[22]

	2003	2004	2005	2006	2007	2008	2009	2010	2011
Biogas	25,762,000	23,856,000	25,623,000	22,823,000	24,126,000	23,379,000	23,769,000	18,079,000	15,390,000
Biomass	215,078,000	217,923,000	217,279,000	222,125,000	238,524,000	259,957,000	262,086,000	263,994,000	246,535,000
Geothermal	110,572,000	111,778,000	108,720,000	118,523,000	199,143,000	282,227,000	200,357,000	260,053,000	240,510,000
Small Hydro	50,609,000	45,442,000	78,618,000	88,033,000	52,827,000	61,144,000	43,289,000	55,600,000	81,951,000
Solar PV	358	270	310	205	51	51	2,554,000	10,180,000	33,365,000
Solar Thermal									
Wind	65,244,000	74,912,000	66,061,000	67,116,000	98,203,000	102,516,000	199,475,000	224,089,000	340,673,000
UOG Sm. Hydro	44,936,000	45,059,000	46,526,000	47,556,000	47,933,000	49,009,000	47,567,000	49,684,000	52,099,000
UOG Solar					227,000	452,000	473,000	1,520,000	6,506,000
Total	**512,201,358**	**518,970,270**	**542,827,310**	**566,176,205**	**660,983,051**	**778,684,051**	**779,570,000**	**883,199,000**	**1,017,030,000**

Table 6. PG&E, RPS Generation (MWh), 2003 - 2011[23]

	2003	2004	2005	2006	2007	2008	2009	2010	2011
Biogas	364,745	333,897	366,514	300,943	293,147	280,042	290,106	275,304	263,684
Biomass	2,839,795	2,961,633	2,858,643	2,770,398	2,751,813	2,813,819	3,122,048	2,990,615	3,048,222
Geothermal	1,674,702	1,753,043	1,687,360	1,790,870	2,701,970	3,350,232	3,411,798	3,766,700	3,780,681
Small Hydro	687,508	617,165	1,074,820	1,245,083	676,087	654,284	576,598	733,980	1,112,672
Solar PV	6	4	4	3	1	1	21,706	58,593	178,808
Solar Thermal									
Wind	940,239	1,078,579	1,060,926	1,019,451	1,374,337	1,439,796	2,557,988	2,981,660	4,253,963
UOG Sm. Hydro	1,382,934	1,267,084	1,403,130	1,437,196	984,607	993,266	1,103,017	1,157,077	1,254,638
UOG Solar					225	445	504	4,642	28,028
Total	**7,889,929**	**8,011,405**	**8,451,398**	**8,563,943**	**8,782,187**	**9,531,886**	**11,083,764**	**11,968,571**	**13,920,695**

[22] Pacifc Gas and Electric Company Renewables Portfolio Standard, 2012 Renewable Energy Procurement Plan (Final Version), Appendix 2, available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M031/K734/31734808.PDF. UOG Small Hydo and UOG Solar costs "represent an estimate of the annual costs attributable to PG&E's utility-owned hydroelectric and solar PV projects that are RPS-eligible." RPS Plan, p. 82. These data are rounded to thousands of dollars.

[23] According to PG&E, these energy volumes represent the kWh associated with payments for RPS-eligible deliveries, which can differ from the energy volumes PG&E claims for purposes of complying with California's RPS program. For example, some RPS contracts require PG&E to only pa for RPS-eligible deliveries based on scheduled energy, but entitle PG&E to all green attributes generated and metered by the facility. Since compliance with California's RPS program is based on metered generation, scheduled/paid volumes may not always match the metered/compliance volumes."

Table 7. PG&E, RPS Costs (cents per kWh), 2003 - 2011

	2003	2004	2005	2006	2007	2008	2009	2010	2011
Biogas	7.1	7.1	7.0	7.6	8.2	8.3	8.2	6.6	5.8
Biomass	7.6	7.4	7.6	8.0	8.7	9.2	8.4	8.8	8.1
Geothermal	6.6	6.4	6.4	6.6	7.4	8.4	5.9	6.9	6.4
Small Hydro	7.4	7.4	7.3	7.1	7.8	9.3	7.5	7.6	7.4
Solar PV	5.9	6.4	7.9	7.4	7.6	8.5	11.8	17.4	18.7
Solar Thermal									
Wind	6.9	6.9	6.2	6.6	7.1	7.1	7.8	7.5	8.0
UOG Sm. Hydro	3.2	3.6	3.3	3.3	4.9	4.9	4.3	4.3	4.2
UOG Solar					100.9	101.6	93.8	32.7	23.2
Average	**6.5**	**6.5**	**6.4**	**6.6**	**7.5**	**8.2**	**7.0**	**7.4**	**7.3**

Table 8. SDG&E, RPS Procurement Expenditures ($), 2003 - 2011[24]

	2003	2004	2005	2006	2007	2008	2009	2010	2011
Biogas	6,201,139	8,541,291	8,915,866	8,087,169	6,685,347	9,388,536	10,067,817	11,383,663	10,699,119
Biomass	18,888,387	18,693,045	17,205,462	16,965,465	12,237,997	22,995,311	24,605,914	27,430,655	27,275,365
Geothermal								20,906,408	64,699,721
Small Hydro					994,116	1,210,445	1,035,376	1,036,066	776,149
Solar PV									
Solar Thermal									
Wind	22,750	5,980,963	14,097,259	19,779,696	22,968,510	22,131,340	52,382,490	43,083,231	22,359,414
UOG Sm.									
UOG Solar									
REC							7,872,987	11,661,525	43,907,209
Total	**25,112,276**	**33,215,299**	**40,218,587**	**44,832,330**	**42,885,970**	**55,725,632**	**95,964,584**	**115,501,548**	**169,716,977**

Table 9. SDG&E, RPS Generation (MWh), 2003 - 2011

	2003	2004	2005	2006	2007	2008	2009	2010	2011
Biogas	124,012	171,351	176,880	159,428	130,602	173,248	180,326	193,236	179,373
Biomass	341,427	337,745	298,945	284,015	217,042	317,204	361,710	370,836	385,590
Geothermal								183,000	758,181
Small Hydro					17,516	22,894	20,213	20,205	15,083
Solar PV									
Solar Thermal									
Wind	550	119,365	284,745	402,129	463,714	444,101	860,274	720,971	428,334
UOG Sm. Hydro									
UOG Solar									
REC							339,589	458,091	1,530,678
Total	**465,989**	**628,461**	**760,570**	**845,572**	**828,874**	**957,447**	**1,762,112**	**1,946,339**	**3,297,239**

[24] San Diego Gas & Electric Company (U 902 E) 2012 Renewables Portfolio Standard Procurement Plan Compliance Filing (Public Version), November 29, 2012, available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M031/K734/31734808.PDF. Some figures above do not match the Compliance Filing – these figures were modified to include the costs associated with "contract for differences" contracts and to include a contract that was approved in 2012, but delivered in 2011.

Table 10. SDG&E, RPS Costs (cents per kWh), 2003 - 2011

	2003	2004	2005	2006	2007	2008	2009	2010	2011
Biogas	5.0	5.0	5.0	5.1	5.1	5.4	5.6	5.9	6.0
Biomass	5.5	5.5	5.8	6.0	5.6	7.2	6.8	7.4	7.1
Geothermal								11.4	8.5
Small Hydro					5.7	5.3	5.1	5.1	5.1
Solar PV									
Solar Thermal									
Wind	4.1	5.0	5.0	4.9	5.0	5.0	6.1	6.0	5.2
UOG Sm. Hydro									
UOG Solar									
REC							2.3	2.5	2.9
Average w/REC	**5.4**	**5.3**	**5.3**	**5.3**	**5.2**	**5.8**	**5.4**	**5.9**	**5.1**
Average w/o REC	**5.4**	**5.3**	**5.3**	**5.3**	**5.2**	**5.8**	**6.2**	**7.0**	**7.1**

DISTRIBUTED GENERATION COSTS AND SAVINGS

> Section 910(a)(3)
>
> *All costs incurred by electrical corporations for incentives for distributed and renewable generation, including the self-generation incentive program, the California Solar Initiative, and net energy metering.*
>
> Section 910(a)(4)
>
> *All cost savings experienced, or costs avoided, by electrical corporations as a result of incentives for distributed and renewable generation.*

This section addresses the costs and savings associated with customer distributed generation programs, consistent with the requirements of Section 910(a)(3) and 910(a)(4). The distributed generation programs addressed include the Self-Generation Incentive Program (SGIP) and the California Solar Initiative (CSI). This section also discusses net energy metering (NEM). Distributed generation includes renewable as well as non-renewable resources and does not directly count towards the 33 percent RPS standard.

Self-Generation Incentive Program (SGIP)

The Self-Generation Incentive Program (SGIP) provides incentives to support existing, new, and emerging distributed energy resources. The SGIP provides rebates for qualifying distributed energy systems installed on the customer's side of the utility meter. Qualifying technologies include wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, mircroturbines, gas turbines, fuel cells, and advanced energy storage systems.

The SGIP was initially conceived as a peak-load reduction program in response to the energy crisis of 2001. Assembly Bill 970 (Ducheny, 2000) designed the program as a complement to the California Energy Commission's Emerging Renewables Program, which focused on smaller systems than the SGIP. Since 2001, the SGIP has evolved significantly. It no longer supports solar photovoltaic technologies, which were moved under the purview of the California Solar Initiative after its launch in 2006. It has also been modified to include energy storage technologies, to support larger projects, and to provide an additional 20% bonus for California-supplied products.

Senate Bill 412 (Kehoe, 2009) modified the focus of the program to include greenhouse gas reductions. SB 412 directed the Commission to identify energy resources which will contribute to greenhouse gas reduction goals and to set appropriate incentive levels to encourage their adoption. The Commission took this opportunity to expand the portfolio of eligible technologies, modify the incentive approach, and to enact other operational requirements including warrantees and performance monitoring to ensure greenhouse gas reductions.

The budget for the SGIP program has been $83 million per year since 2007.[25] The annual budgets comprise a $36 million allocation to PG&E, $28 million to SCE, $11 to SDG&E and $8 million to Southern California Gas (SoCalGas).[26] Funding for the program is expected through January 1, 2016, at which point the enabling legislation directs the Commission to provide repayment of all unallocated SGIP funds to reduce ratepayer costs.

Table 11. Annual SGIP Budget (In Millions of Dollars)[27]

	PG&E	SCE	SDG&E	Annual Total
Annual Budgets, 2007 – 2014	$36	$28	$11	$75

The costs and the benefits of the SGIP program were evaluated in a 2011 report conducted by Itron.[28] This study evaluated the cost-effectiveness of distributed generation technologies using an economic model based on a Commission adopted cost-benefit methodology. The cost-effectiveness of distributed generation technologies was examined from three perspectives: society, participants, and program administrators. The societal version of the Total Resource Cost (STRC) test looks at the overall cost-effectiveness of DG technologies to society. The study concluded that, "[r]esults of the STRC test show that nearly all of the evaluated DG technologies are cost-effective to society at either 2010 or 2016 given the input assumptions used in the Base Scenario."[29]

California Solar Initiative (CSI)

The California Solar Initiative (CSI) is overseen by the Commission and provides incentives for solar system installations to customers of the state's three investor-owned utilities (IOUs): PG&E, SCE, and SDG&E. The CSI Program provides upfront and performance-based incentives for solar systems installed on existing homes, as well as existing and new commercial, industrial, government, non-profit, and agricultural properties within the service territories of the IOUs.

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[25] Prior to 2007, the Commission had authorized funding at $125 million per year in D.01-03-073.
[26] The $8 million is not included in the Table 1 because Section 910 only requests the costs incurred by electrical corporations and SoCalGas is a gas corporation.
[27] D.06-12-033, D.08-01-029, D.09-12-047, and D.11-12-030, December 15, 2011, Table 1, p. 3.
[28] Itron, "CPUC Self-Generation Incentive Program, Cost-Effectiveness of Distributed Generation Technologies, Final Report," February 9, 2011, available at http://www.cpuc.ca.gov/NR/rdonlyres/2EB97E1C-348C-4CC4-A3A5-D417B4DDD58F/0/SGIP_CE_Report_Final.pdf
[29] Ibid, p. 1-2.

The CSI Program was authorized by the CPUC through a number of regulatory decisions throughout 2006. In addition, the legislature expressly authorized the CPUC to create the California Solar Initiative in 2006 in Senate Bill 1 (Murray). When it launched in 2007, the CSI built upon nearly 10 years of state support for solar, including other incentive programs such as the California Energy Commission's Emerging Renewables Program (ERP) and SGIP.

The CSI Program has an electric budget of $2.367 billion over 10 years (see Table 2), and the goal is to reach 1,940 MW of installed solar capacity by the end of 2016. The goal includes 1,750 MW of capacity from the general market program, as well as 190 MW from the low income programs.

Table 12. Revised Annual CSI Revenue Requirements (In Millions of Dollars)[30]

	PG&E	SCE	SDG&E	Total
Transfer from SGIP on 12/31/2006	$0	$104.6	$37.2	$141.8
2007	$140	$147	$33	$320
2008	$140	$147	$33	$320
2009	$140	$0	$0	$140
2010	$43.75	$110	$25	$178.75
2011	$105	$110	$25	$240
2012	$120	$110	$0	$230
2013	$85	$74	$0	$159
2014	$85	$74	$29.67	$188.67
2015	$94	$82	$31.42	$207.42
2016	$94.45	$81.1	$31.41	$206.96
Interest/Forfeited funds	$11.0	$17.9	$5.3	$34.2
	$1,058.2	$1,057.6	$251	$2,366.8

The costs and the benefits of the CSI program were evaluated in a 2011 report conducted by Energy and Environmental Economics, Inc. (E3).[31] This study evaluated the cost-effectiveness of solar PV and the CSI program from the following perspectives: society, participants, ratepayers and program administrators. The study found that "solar PV installed through the

[30] D.11-12-019, December 1, 2011, Table 4, p. 12, as revised by D.12-12-018, Table 2, p. 7.

[31] E3, "California Solar Initiative Cost-Effectiveness Evaluation," April 2011, available at ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/csi/CSI%20Report_Complete_E3_Final.pdf

program is cost-effective from the perspective of participants"[32] but that it did not project the total resource cost test "to achieve a positive benefit/cost ratio during the study period."[33]

Net Energy Metering (NEM)

Customers who install small solar, wind, biogas, and fuel cell generation facilities (1 MW or less) to serve all or a portion of onsite electricity needs are eligible for the state's net energy metering programs. NEM allows a customer-generator to receive a financial credit for power generated by their onsite system and fed back to the utility. The credit is used to offset the customers' electricity bill. NEM is an important element of the policy framework supporting direct customer investment in grid-tied distributed renewable energy generation, including customer-sited solar PV systems. The vast majority of solar PV customer-generators choose to be on NEM tariffs, with over 120,000 residential and non-residential accounts enrolled in California's NEM program.

The Commission submitted a net metering status report to lawmakers in March 2005.[34] The Commission released an updated NEM cost effectiveness evaluation to the legislature in 2010[35] and is in the process of updating the NEM study for 2012-2013.[36] This new study is mandated by Assembly Bill 2514 (Bradford, 2012) and is due on October 1, 2013.

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[32] Ibid, p. 5.

[33] Ibid, p. 16.

[34] CPUC, "Update on Determining the Costs and Benefits of California's Net Metering Program as Required by Assembly Bill 58," March 29, 2005, available at http://docs.cpuc.ca.gov/WORD_PDF/REPORT/45133.PDF

[35] "Introduction to the Net Energy Metering Cost Effectiveness Evaluation," March 2010, available at http://www.cpuc.ca.gov/NR/rdonlyres/0F42385A-FDBE-4B76-9AB3-E6AD522DB862/0/nem_combined.pdf

[36] See http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_benefit_evaluation.htm

PENDING NUCLEAR, FOSSIL AND OTHER PROCUREMENT EXPENDITURES

> Section 910(a)(5)
>
> *All renewable, fossil fuel, and nuclear procurement costs, research, study, or pilot program costs, or other program costs for which an electrical corporation is seeking recovery in rates, that is pending determination or approval by the commission.*

This section addresses expenses that are pending determination or approval by the CPUC, consistent with Section 910(a)(5). As explained in the introduction, we have focused this report primarily on 2011 expenditures because the February deadline makes it difficult to obtain and sufficiently review 2012 expenditures. For this reason, however, many of the cases pending before the Commission at the end of 2011 have been resolved. For example, SCE's and SDG&E's 2012 ERRA forecasts for inclusion in 2012 rates were pending at the end of the 2011, but, at this time, have been decided.

Because so many decisions pending at the end of 2011 have subsequently been approved, and will be included in next year's report, we focus this section only on decisions that are currently pending before the Commission. These include the following:

- I.12-10-13. Order Instituting Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Services and Facilities of Southern California Edison Company and San Diego Gas and Electric Company Associated with the San Onofre Nuclear Generating Station Units 2 and 3.
- A.10-12-005. Application of San Diego Gas & Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2012. SDG&E has requested a 2012 increase of nearly $200 million in its electric distribution and utility-owned generation revenue requirement to $1,524 million.[37]
- A.12-08-001. Application of Southern California Edison Company for Approval of its Forecast 2013 ERRA Proceeding Revenue Requirement. SCE has requested an increase

[37] Revised Prepared Direct Testimony of Deborah A. Hiramoto on Behalf of San Diego Gas & Electric Company, July 2011, Table DH-2.

of $508 million for its 2013 fuel and purchased power expenditures, for a total of $4,389 million.[38]

- A.12-10-002. Application of San Diego Gas & Electric Company for Adoption of its 2013 Energy Resource Recovery Account Revenue Requirement and Competition Transition Charge Revenue Requirement Forecasts. SDG&E has requested an increase of $186 million for its 2013 fuel and purchased power expenditures, for a total of approximately $1,015 million, and a CTC revenue requirement of $42 million.[39]
- Renewable contracts currently pending are listed on the Commission's website.[40] The expenses associated with these projects are confidential at this time.
- A.11-05-023. Application of San Diego Gas & Electric Company for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power. SDG&E estimates the total cost of these contracts over the term of their life at $1,844,310,000, but with an annual revenue requirement of $88 million in 2015, excluding the cost of fuel, start-up charges, financing charges, and variable operating and maintenance.[41] The proposed decision and an alternate are currently under consideration by the Commission.

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[38] Energy Resource Recovery Account (ERRA) 2013 Forecast of Operations Updated Testimony, Public Version, November 16, 2012, p. 5.

[39] Amended Direct Testimony of Amanda D. Jenison, SDG&E, January 8, 2013, p. ADJ-2.

[40] RPS Project Status Table available at http://www.cpuc.ca.gov/PUC/energy/Renewables/, under the tab "Pending Approval."

[41] See SDG&E Notification of 2009 Request for Offers (RFO) New Generation Cost Recovery Application No. A11-05-023, available at http://www.sdge.com/sites/default/files/FINAL_1110041_Product2AppInsert.pdf.

DECISIONS

> Section 910(a)(6)
>
> *The decision number for each decision of the commission of recovery in rates of costs incurred by an electrical corporation since the preceding report.*

This section provides the decision numbers approving costs for recovery in rates, consistent with Section 910(a)(6) (see **Table 13**). This list includes only CPUC decisions, and not those issued by the Federal Energy Regulatory Commission (FERC) approving transmission rates, as specified in Section 910(a)(6).

The primary decisions affecting CPUC-jurisdictional utility rates are the general rate case (GRC) decisions and Energy Resource Recovery Account (ERRA) decisions. GRC decisions are issued every three to four years and approve an overall revenue requirement and yearly increases for costs associated with the utilities distribution system and utility-owned generation facilities, including expenses associated with operation and maintenance, administrative and general and customer service activities, depreciation, taxes, capital expenditures and return on capital expenditures placed into rate base. ERRA decisions are issued each year and approve the utilities' cost forecast for fuel and purchased power for the upcoming year. To the extent that the utilities spend more or less than forecasted on fuel and purchased power, this is tracked in a balancing account and reviewed in ERRA review proceedings in subsequent years.

In addition to the GRC and ERRA decisions, each year there are a host of other decisions that approve revenues for recovery in rates, including decisions authorizing expenditures on the California Solar Initiative, the Self-Generation Incentive Program, demand response programs, public purpose programs (energy efficiency, low-income energy efficiency, the CARE program), and DWR power and bond charges, among others.

We have not included the numerous decisions and resolutions approving individual power purchase agreements, including renewable, qualifying facility, resource adequacy, or fossil contracts or contract modifications. These expenses are ultimately included in the ERRA forecasts that the Commission reviews and approves each year.

Table 13. Major Decisions Approving Costs for Recovery in Rates for 2011

	PG&E	SCE	SDG&E
GRC	D.07-03-044 D.11-05-018	D.09-03-025	D.08-07-046
ERRA	D.10-12-007 D.09-03-026	D.10-02-019 D.11-04-006	D.10-04-010 D.11-07-041
OTHER:			
AMI/Smart Meter/Smart Connect	D.06-07-027	D.08-09-039	D.07-04-043
Energy Efficiency		D.09-09-047	
Energy Efficiency Incentives		D.10-12-049	
Low Income		D.08-11-031	
Demand Response		D.09-08-027	
SGIP		D.09-12-047	
CSI		D.10-09-046 D.11-07-031	
Solar PV	D.10-04-052	D.09-06-049	D.10-09-016
DWR Power and Bond Charge		D.10-12-006	
Nuclear	D.10-08-003 (Seismic Studies)	D.05-12-040 (Steam Gen. Replacement) D.10-07-047 (Decommissioning)	
Other	D.10-06-048 (Cornerstone) D.08-02-009 & D.11-01-036 (Smart AC) D.11-07-039 (ERRA Review) D.09-09-020 (2011 Retirement Plan) D.06-11-048 (LTPP) D.08-02-019 (Colusa)	D.09-12-014 (Hydrogen Electric CA) D.10-07-049 (ERRA Review)	D.10-12-053 (Z-Factor) D.09-01-008 (Miramar Energy) D.10-10-004 (Catastrophic Events) D.09-09-011 (Pensions) D.08-02-034 (Rates)

LOAD SERVED BY PG&E, SCE, AND SDG&E

> Section 910(a)(7)
>
> *Any change in the electrical load serviced by an electrical corporation since the preceding report.*

This section addresses the changes in electrical load served by PG&E, SCE, and SDG&E, consistent with the requirements of Section 910(a)(7). Table 14 provides bundled retail sales for PG&E, SCE, and SDG&E for the period 2003 through 2011. Retail sales is the basis for determining the RPS procurement requirement and includes only sales to bundled service customers for whom the IOUs supply power as well as provide transmission and distribution services.

As illustrated below, bundled retail sales have decreased for each of the IOUs for the past three years, likely due in part to the recession, increased implementation of energy efficiency and distributed generation technologies, and direct access migration.

Table 14. PG&E, SCE, and SDG&E Bundled Retail Sales, 2003 – 2011 (GWh)[42]

Annual Retail Sales (GWh)	PG&E	Annual Change (%)	SCE	Annual Change (%)	SDG&E	Annual Change (%)
2003	71,099	base year	70,617	base year	15,044	base year
2004	72,114	1.4%	72,964	3.3%	15,812	5.1%
2005	72,372	0.4%	74,994	2.8%	16,002	1.2%
2006	76,356	5.5%	78,863	5.2%	16,847	5.3%
2007	79,078	3.6%	79,505	0.8%	17,056	1.2%
2008	81,524	3.1%	80,956	1.8%	17,410	2.1%
2009	79,624	-2.3%	78,048	-3.6%	16,994	-2.4%
2010	77,485	-2.7%	75,141	-3.7%	16,283	-4.2%
2011	74,864	-3.4%	73,777	-1.8%	16,249	-0.2%

[42] PG&E, SCE and SDG&E reported historical retail sales amounts in their respective 2012 RPS Plans filed in the RPS proceeding (R.11-05-005).
SDG&E 2012 Renewables Portfolio Standard Procurement Plan Compliance Filing, November 29, 2012.
http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M031/K745/31745132.PDF
SCE Final 2012 Renewables Portfolio Standard Procurement Plan, November 29, 2012.
http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M031/K734/31734669.PDF
PG&E Renewables Portfolio Standard 2012 Renewable Energy Procurement Plan, November 29, 2012.
http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M031/K734/31734808.PDF

UTILITY WORKFORCE DIVERSITY

> Section 910(a)(8)
>
> *The efforts each electrical corporation is taking to recruit and train employees to ensure an adequately trained and available workforce, including the number of new employees hired by the electrical corporation for purposes of implementing the requirements of Article 16 (commencing with Section 399.11) of Chapter 2.3, the goals adopted by the electrical corporation for increasing women, minority, and disabled veterans trained or hired for purposes of implementing the requirements of Article 16 (commencing with Section 399.11) of Chapter 2.3, and, to the extent information is available, the number of new employees hired and the number of women, minority, and disabled veterans trained or hired by persons or corporations owning or operating eligible renewable energy resources under contract with an electrical corporation. This paragraph does not provide the commission with authority to engage in, regulate, or expand its authority to include, workforce recruitment or training.*

Section 910(a)(8) requests information on electrical corporation workforce recruitment and training, including goals for increasing women, minority, and disabled veterans trained and/or hired to work on the RPS program. PG&E, SCE and SDG&E have programs in place that facilitate the development of a diverse workforce and the procurement of goods and services from diverse businesses. However, the utilities do not track these diversity metrics at the programmatic level (for example, how many utility employees that are disabled veterans work on the RPS program). Below is a description of two successful programs that are driving the diversification of the California utility workforce and broader energy sector.

California Utilities Diversity Council[43]

The California Utilities Diversity Council (CUDC), was developed jointly by the Latino Journal and CPUC in 2003 to help promote and facilitate representation of minorities, women and service-disabled veterans at all levels within companies regulated by the CPUC. The Committee focuses on best practice efforts to recruit, develop and retain a talented, diverse workforce for California regulated utilities that reflects the demographics of California's labor market. PG&E, SCE and SDG&E participate in helping the CUDC achieve its goals

General Order 156[44]

Initiated in 1988, the CPUC's General Order 156 (GO 156) requires all investor-owned electric, gas, water and telecommunication utility companies with gross annual revenues in excess of

[43] Information about the CUDC, including access to the recent 2012 Annual Report, is available here: http://www.cudc.biz/

[44] Information about the CPUC's GO 156 Utility Supplier Diversity Program is available here: http://www.cpuc.ca.gov/puc/supplierdiversity/

$25 million and their regulated subsidiaries and affiliates, to develop and implement programs to increase the procurement of goods, services, and fuel from women, minority, and disabled veteran-owned business enterprises (WMDVBEs).

SCE, PG&E and SDG&E are meeting GO 156 goals and seeing annual increases in procurement from diverse suppliers. Collectively the three utilities directed over $3.5 billion in spending to WMDVBE businesses in 2011.

Section 910(a)(8) requests information about "The efforts each electrical corporation is taking to recruit and train employees to ensure an adequately trained and available workforce, including the number of new employees hired by the electrical corporation for purposes of implementing the requirements of Article 16 (commencing with Section 399.11) of Chapter 2.3."

Each of the IOUs assert that they have training programs for new and existing staff. SCE and PG&E provided the number of full-time equivalent staff working on the RPS program and generally described the work areas for these staff. The identified work areas are: energy procurement, power management, legal, regulatory and transmission. PG&E reported 9 and new employees hired in 2011 for the purposes of the RPS program, SCE reported 12 new employees hired during the 2010-2011. SDG&E does not track this information.

Section 910(a)(8) also requests information on "[T]he goals adopted by the electrical corporation for increasing women, minority, and disabled veterans trained or hired for purposes of implementing the requirements of Article 16 (commencing with Section 399.11) of Chapter 2.3."

Each of the IOUs assert that they work to ensure that their workforce reflects the multicultural environment in which they serve. SCE says that it provides equal opportunity in all aspects of its employment, including recruitment, training, compensation and promotion without discrimination. PG&E's goal is to hire in parity with the relevant market pool. SDG&E has a detailed Affirmative Action Plan that guides the company's recruiting and hiring practices.

However, none of the IOUs have specific goals for increasing women, minority, and disabled veterans trained or hired for purposes of implementing the RPS program.

Lastly, Section 910(a)(8), requests "[T]o the extent information is available, the number of new employees hired and the number of women, minority, and disabled veterans trained or hired by persons or corporations owning or operating eligible renewable energy resources under contract with an electrical corporation."

The utilities are actively engaged in the GO 156 supplier diversity program and the CUDC mission to increase the diversity of the regulated utility workforce. For example, through its supplier diversity program, SCE informs women, minority, and disabled veteran-owned business enterprises of its RPS programs so these individuals are aware of opportunities in the renewable energy market. However, in response to the Energy Division staff data request, the IOUs stated that they do not separately track the number of women, minority, and disabled veterans trained or hired by persons or corporations owning or operating eligible renewable energy resources under contract with an electrical corporation. The CPUC will work with the utilities to provide this information in future reports.

APPENDIX A

910. (a) By February 1 of each year, the commission shall prepare and submit to the policy and fiscal committees of the Legislature a written report summarizing the following information:

(1) All electrical corporation revenue requirement increases associated with meeting the renewables portfolio standard, as defined in Section 399.12, including direct procurement costs for eligible renewable energy resources and renewable energy credits, administrative expenses for procurement, expenses incurred to ensure a reliable supply of electricity, and expenses for upgrades to the electrical transmission and distribution grid necessary to the delivery of electricity from eligible renewable energy resources to load.

(2) All cost savings experienced, or costs avoided, by electrical corporations as a result of meeting the renewables portfolio standard.

(3) All costs incurred by electrical corporations for incentives for distributed and renewable generation, including the self-generation incentive program, the California Solar Initiative, and net energy metering.

(4) All cost savings experienced, or costs avoided, by electrical corporations as a result of incentives for distributed and renewable generation.

(5) All renewable, fossil fuel, and nuclear procurement costs, research, study, or pilot program costs, or other program costs for which an electrical corporation is seeking recovery in rates, that is pending determination or approval by the commission.

(6) The decision number for each decision of the commission of recovery in rates of costs incurred by an electrical corporation since the preceding report.

(7) Any change in the electrical load serviced by an electrical corporation since the preceding report.

(8) The efforts each electrical corporation is taking to recruit and train employees to ensure an adequately trained and available workforce, including the number of new employees hired by the electrical corporation for purposes of implementing the requirements of Article 16 (commencing with Section 399.11) of Chapter 2.3, the goals adopted by the electrical corporation for increasing women, minority, and disabled veterans trained or hired for purposes of implementing the requirements of Article 16 (commencing with Section 399.11) of Chapter 2.3, and, to the extent information is available, the number of new employees hired and the number of women, minority, and disabled veterans trained or hired by persons or corporations owning or operating eligible renewable energy resources under contract with an electrical corporation. This paragraph does not provide the commission with authority to engage in, regulate, or expand its authority to include, workforce recruitment or training.

(b) The commission may combine the information required by this section with the reports prepared pursuant to Article 16 (commencing with Section 399.11) of Chapter 2.3.