I.

POWER PRODUCTION DEPARTMENT O&M EXPENSE AND CAPITAL EXPENDITURE FORECASTS

A. Overview

SCE is engaged in the business of generating, transmitting and distributing electric energy in portions of central and southern California. In addition to its properties in California, SCE owns, jointly with others, generating facilities located in Arizona and New Mexico, its share of which produces electric energy for the use of its customers in California.

Specifically, in various locations throughout California, SCE owns and operates 33 hydroelectric plants (Hydro), five gas-fired peaking units (Peakers), one combined-cycle gas plant with two generating units (Mountainview), a diesel-driven electric generating plant (Catalina Pebble Beach), and 24 rooftop solar photovoltaic (SPV) plants and one ground-based SPV plant. SCE does not operate, but owns 15.8 percent interest in Palo Verde Nuclear Generating Station Units 1, 2, and 3 (PVNGS) located in Arizona, and owns 48 percent interest in the Four Corners Generating Station Units 4 and 5 located in New Mexico (Four Corners).

SCE also operates and owns 78.21 percent interest in San Onofre Nuclear Generating Station (SONGS) Units 2 and 3 located in Southern California, and SCE is in the process of retiring these units. SCE also jointly owns and is in the process of decommissioning the Mohave coal fired power plant in Nevada, which ceased operations on December 31, 2005. The decommissioning of Mohave is expected to be completed in the second quarter of 2013, and it is anticipated that oversight of the plant site will continue to be required beyond 2015 for site security and continued ground water monitoring.

The Power Production Department (PPD) operates and maintains the SCE hydroelectric and peaker facilities and plants, the Mountainview Generating Station, the SCE Solar Photovoltaic plants, and the Mohave Generating Station. PPD also oversees SCE's ownership share in the Four Corners Generating Station. PPD plans, manages, and implements capital projects for these assets, including the decommissioning of Mohave. PPD also manages SCE's oversight of the demonstration Fuel Cell power plants located on the campuses of California State University San Bernardino (CSUSB) and University

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1 Exhibit SCE-2, Vol. 5 summarizes and addresses the facilities operated and maintained by the Power Production Department. Catalina Pebble Beach is managed by SCE’s T&D Operating Unit, and SCE’s testimony on this facility is in SCE-2, Vol. 10 and not addressed in this testimony. Likewise, SONGS is managed by SCE’s Nuclear Operating Unit and is also not addressed in this testimony.

Exhibit No. SCE-02 / Generation / Vol. 05
Witness: T. Ware
of California at Santa Barbara (UCSB). PPD “home office” divisions provide support to all of these
efforts, and consist of the Operations Support and Performance Improvement Division (OS&PI) and the
Engineering & Technical Services Division (E&TS). These divisions also provide engineering and
chemical services support to other areas of SCE.

To comply with SB 1368 and the Commission’s Greenhouse Gas Emissions Performance
Standard, SCE entered into an agreement to sell its share of the coal-fueled Four Corners plant to co­
owner and plant operator Arizona Public Service Company (APS), as approved by the Commission in D.12-03-034. Sale closure is contingent upon APS successfully concluding negotiations on a coal contract so that APS and the other remaining owners can continue to operate the plant after the current coal contract expires in July 2016. Sale closure is currently forecast to occur in 2013.2 While SCE expects that the sale will successfully close, this cannot be assured. Therefore, SCE is including in this GRC the forecast cost of continued Four Corners operations, including O&M expense and capital expenditures necessary to safely and reliably operate the plant until July 2016. SCE will remove the forecast of Four Corners costs from this 2015 GRC, should the sale close prior to 2015 as expected.

Accordingly, our 2015 GRC forecast assumes that the sale does not close, and SCE will continue to participate in Four Corners operations. We further assume that Four Corners will cease operations in July 2016 (i.e., the termination date of the existing co-ownership agreements and coal contract and the plant owners will then proceed to decommission the plant. Our forecast includes expenses to operate up until that date, as well as expenses that are expected to be incurred after the plant shuts down, such as employee severance costs, ongoing site lease costs (the plant site is leased from the Navajo Nation), the closing out of spare parts and other material inventories, and other costs related to exiting the site. As required by the Commission, our Four Corners O&M Expense and Capital Expenditure forecasts are in service of this decommissioning.3 Our forecast also assumes that all future major overhauls (that would otherwise normally be undertaken) are canceled.

2 On June 17, 2013 APS issued a Form 8-K Current Report with the US Securities & Exchange Commission indicating that APS currently expects that it will not be in a position to close the Four Corners purchase transaction with SCE until the Arizona Corporations Commission’s (ACC) intentions with regard to pursuing deregulation in Arizona become clearer. This was in response to the ACC’s announcement in May 2013 their intent to re-examine possible deregulation of the retail electric market in Arizona. However, in September 2013, the ACC closed this docket, effectively foreclosing the possibility of retail access deregulation impeding sale closure. SCE and APS continue to work on the remaining issues that could delay or prevent final sale closure.
3 D.12-11-051, Conclusion of Law 30, p. 823 (SCE 2012 GRC).
Our Hydro plants continue to be among our most cost-effective generating resources. Our Hydro O&M Expense and Capital Expenditure forecasts presented in this GRC are consistent with recorded costs. Our forecast includes funding for maintaining these important assets to continue operating at historic levels of reliability for the duration of their FERC licenses, many of which are in the process of being renewed.

Four of our five gas-fueled Peaker plants began commercial operation in July 2007, and the fifth, McGrath, became operational in November 2012. The addition of the McGrath Peaker causes an increase in Peaker O&M expenses, and our forecast appropriately accounts for this fact. As a result of market conditions, Peakers also continue to experience increasing levels of dispatch (i.e., higher operating hours) in each successive year. Our Peaker O&M Expense forecast includes costs for ongoing permit fees, air quality monitoring expenses, reporting and testing expenses, chemicals and other consumables, water, water treatment and waste water disposal, repair parts and other items. Our Peaker Capital Expenditure forecast includes adding a multi-purpose building and a second gas compressor to McGrath for the same reasons these additions were made to the other four Peakers after they entered commercial operation. The second gas compressor improves Peaker reliability, and the multipurpose building facilitates Peaker equipment future repairs, which will become increasingly important as plant equipment items experience their first round of overhauls.

The funding request for our gas-fueled Mountainview plant includes the ongoing operations and maintenance for that plant, consistent with recorded costs. Our request also includes the anticipated “Tier 1 to Tier 2” pricing fee increase contained in the maintenance contract (i.e., Contract Services Agreement) we have for the plant with the turbine/generator supplier, General Electric (GE). This fee increase is contractually triggered when we reach the 60,000 operating hour milestone on the plant’s turbines, which we expect will occur in mid-2014. In addition, our Mountainview request includes annualized cost (i.e., the average annual cost during 2015 through 2017) to perform Hot Gas Path Inspection overhauls on both units that are forecast for 2016, as well as the six-month-ahead pre-payment payable to GE in 2015 for the Unit 3 Hot Gas Path overhaul forecast for early 2016. These costs will increase O&M expense significantly in years 2015 and 2016 as compared to year 2017 as no overhaul costs are forecast in 2017. Overhauls are conducted on Mountainview units approximately every three years. SCE averages the cost of these overhaul expenses over the three year rate case cycle.
of 2015 through 2017 consistent with how similar Mountainview overhaul costs were averaged in SCE's 2012 GRC.4

As of mid-2013, SCE is in the process of completing construction on 91 MW (dc) of Solar PV power plants, consistent with the Commission's most recent decision governing our Solar program.5 We expect to complete this construction during 2013, resulting in a total SCE Solar PV fleet of twenty-four roof mount plants, totaling 84.7 MW, and one ground mount plant at 6.8 MW. Our funding request includes the estimated O&M expense to operate these plants including roof lease payments. It also includes the 2013 capital expenditures needed to finish the construction, along with a small amount of capital during 2014 through 2017 to fund any equipment replacement needs that arise during that time (e.g., for replacing failed inverters).

During 2012, SCE completed the construction of the UCSB Fuel Cell. As of mid-2013, SCE is working to complete the construction of the CSUSB Fuel Cell, and to begin the planned ten year operation of these demonstration plants. SCE's funding for these fuel cells was approved by the Commission in D.10-04-028 and D.12-04-011. Our GRC forecast is consistent with these prior Commission decisions.

B. Power Production Department O&M Forecast

Our 2015 Test Year O&M expense forecast for the PPD SPV, Fuel Cell, Hydro, Gas and Coal-fueled generating stations totals $163.6 million as summarized in Table I-1 below. The table also summarizes the recorded costs we incurred during 2008 through 2012.

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4 D.09-03-025, pp. 31-33.
5 D.13-05-033.
Table I-1
Power Production Department 2008-2012 Recorded and 2015 Test Year O&M Expense Forecast
(Constant 2012 $Million (SCE Share))

<table>
<thead>
<tr>
<th></th>
<th>Recorded</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th>Forecast</th>
</tr>
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<tr>
<td></td>
<td>2008</td>
<td>2009</td>
<td>2010</td>
<td>2011</td>
<td>2012</td>
<td>2015</td>
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<tr>
<td>Hydro</td>
<td>44.8</td>
<td>51.4</td>
<td>53.8</td>
<td>60.1</td>
<td>49.2</td>
<td>53.2</td>
</tr>
<tr>
<td>Mountainview</td>
<td>46.5</td>
<td>51.3</td>
<td>31.8</td>
<td>28.8</td>
<td>31.1</td>
<td>50.3</td>
</tr>
<tr>
<td>Peakers</td>
<td>9.2</td>
<td>9.6</td>
<td>8.9</td>
<td>9.1</td>
<td>9.1</td>
<td>10.4</td>
</tr>
<tr>
<td>Mohave</td>
<td>13.1</td>
<td>3.5</td>
<td>3.9</td>
<td>1.8</td>
<td>0.3</td>
<td>0.3</td>
</tr>
<tr>
<td>Four Corners</td>
<td>50.7</td>
<td>43.7</td>
<td>51.6</td>
<td>46.2</td>
<td>41.9</td>
<td>44.4</td>
</tr>
<tr>
<td>Solar PV</td>
<td>0.5</td>
<td>1.7</td>
<td>2.1</td>
<td>15.5</td>
<td>6.9</td>
<td>4.3</td>
</tr>
<tr>
<td>Fuel Cells</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.7</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>164.8</td>
<td>161.2</td>
<td>152.1</td>
<td>161.5</td>
<td>138.5</td>
<td>163.6</td>
</tr>
</tbody>
</table>

Our 2015 O&M expense forecast for Hydro is based on our analysis of 2008-2012 recorded spending. This will require that we continue to mitigate, as we did in 2012, cost drivers that would otherwise continue to increase Hydro costs as we experienced during 2008 through 2011. Our 2015 forecast is higher than our 2012 recorded O&M expense because our 2012 recorded non-labor costs were low compared to prior years. This resulted from normal year to year variations in these non-labor costs, primarily associated with maintenance work. We forecast that future maintenance non-labor costs will be consistent with average annual maintenance levels experienced over the past five years.

Our 2015 O&M expense forecast for Mountainview is based on our analysis of past recorded costs, the anticipated increase in our GE Contract Services Agreement costs related to the Tier 1 to Tier 2 pricing increase, and our forecast cost for major maintenance planned for 2015 through 2017. As in past years, Mountainview O&M expense is expected to continue to significantly fluctuate year to year because of the normal fluctuations in our annual major maintenance expense. Approximately every three to four years, each of the two generating units at Mountainview undergoes major maintenance. This major maintenance consists of Hot Gas Path Inspection (HGPI) overhauls and Major Overhauls. HGPI overhauls were performed on both units in 2009, including a six month prepayment occurring in 2008, which explains the higher costs recorded in 2008 and 2009, as compared to 2010-2012. Major overhauls are being performed on both units in 2013. HGPI overhauls are forecast for both
units in 2016, with a pre-payment forecast in 2015. Consistent with prior GRCs, our approved 2012
Mountainview funding level included one-third of the cost for the 2013 major overhauls (i.e., our 2012
Test Year forecast included the average annual amount of overhaul costs we expected to incur during the
2012 through 2014 rate cycle). Likewise, our 2015 Test Year forecast includes one-third of the forecast
costs for the planned 2016 HGPI overhauls.

Our 2015 O&M expense forecast for Peakers is based on past recorded costs, as well as the
addition of the McGrath peaker. Managing future Peaker expense at our forecast level will be
challenging, as the Peakers have experienced, and continue to experience, increasing levels of dispatch
(i.e., a higher number of start-ups and operating hours) compared to earlier years, due to changing
market conditions.

Our 2015 O&M expense forecast for Mohave reflects our estimated cost for ongoing site
maintenance that results from the many years of power generating operations at the site. This work
includes continued groundwater monitoring and management of the ash landfill. We propose to end the
Mohave Balancing Account (MBA). This account was approved in SCE's 2006 GRC because at that
time Mohave's future was uncertain. The MBA has continued since then because plant dispositioning
had not yet been completed. Now that dispositioning and decommissioning are essentially complete, as
part of our 2015 GRC ratemaking proposal we propose to recover future Mohave site management costs
in GRC base rates.

As noted above, a 2015 O&M Expense forecast for Four Corners is being included as we cannot
yet assure that the SCE-APS plant share sale will close in 2013 as planned. If the plant sale does not
close, we assume SCE will remain a plant participant until operations cease in July 2016. Our forecast
assumes plant decommissioning would begin at that time, and our forecast also funds anticipated
expenses related to exiting the site that are in addition to decommissioning costs (e.g., employee
severance and material inventory close out). This forecast is based on our analysis of Four Corners past
recorded expense, our experience in shutting down and decommissioning Mohave, and our assumption
that no further major overhauls need be conducted at the plant between now and the end of plant
operations in July 2016.

Four Corners major overhauls have been historically performed approximately every six years on
each of the two units. They were last performed in 2008 on Unit 5, and 2010 on Unit 4, which explains
the higher costs recorded in 2008 and 2010 as compared to 2009, 2011, and 2012. Our forecast assumes that plant fuel efficiency and reliability performance can continue to be maintained at or close to recent historic levels up until July 2016, even though Unit 5 will be operating well beyond its normal six year major overhaul interval, and Unit 4 will be near or at its six year interval. However, we also recognize that we will likely experience a combination of equipment break down repairs and increased preventative maintenance in lieu of conducting any further major overhauls. Therefore, maintaining our expenses at the 2015 forecast level will be challenging, as the forecast does not include any funding for major overhauls or for increased costs for equipment break down repairs or added preventative maintenance.

Recognizing that the sale could be delayed, the Commission approved the Four Corners Memorandum Account (FCMA) to track expenses incurred after September 2012 and up until the delayed date that the sale closes. As our 2015 Test Year forecast assumes that sale closure cannot be achieved, and that SCE therefore participates in the plant until it is decommissioned, we also propose to end the FCMA and to recover these forecast Four Corners costs in GRC base rates.

Future O&M expense for our Solar PV program will decrease below recent recorded levels as we conclude construction during 2013, at which time O&M expense incurred by the SPV program team will cease. However, this will be partially offset by the increase in plant site O&M expense as the remaining SPV plants enter operation during 2013. Our 2015 forecast for SPV plant site O&M expense is based on the same “O&M expense per MW” factors used in our 2012 GRC forecast, as our experience since that time has not revealed any significant inaccuracies in our earlier forecasts on a per MW basis. As we now transition from completion of construction into a stable operations period, we also propose to end the SPV Balancing Account, and to collect future SPV costs in GRC base rates.

Our O&M expense forecast for Fuel Cells provides the needed funding for the Long Term Services Agreement (LTSA) with the respective fuel cell manufacturers for the two sites. It also provides for operations and miscellaneous work not covered by the LTSA.

Four Corners Units 1, 2 and 3 are wholly owned by APS.

D.12-11-051, Conclusion of Law 31, p. 823.

Whether or not our proposal to end the SPV Program Balancing Account is adopted, all SPV Capital Expenditures incurred to construct the SPV plants will continue to be subject to potential reasonableness review as required in D.09-06-049.
In summary, our Test Year expense forecasts for the continued operation and maintenance of our PPD SPV, Fuel Cell, Hydro, Gas, and Coal-fueled generating stations are consistent with recent past recorded costs, with appropriate adjustments for recent and planned future events including the addition of the McGrath Peaker, routine periodic major maintenance at Mountainview, the pricing terms of our Mountainview Contract Services Agreement with GE, and the completion of construction of our Solar PV plants. Approval of our Test Year forecast will help assure the continued safe and reliable operation of these power generating assets, in compliance with environmental objectives and other regulatory requirements. Further details regarding our PPD O&M expense forecasts are provided in Testimony Volumes 6 through 10.

C. Power Production Department Capital Forecast

As summarized in Table I-2 below, our 2013 through 2017 forecast capital expenditures for our PPD Hydro, Mountainview, Peaker, Coal-fueled, Solar, and Fuel Cell generating stations totals $539.2 million. This is significantly less than the $979.9 million of capital expenditures we recorded during 2008 through 2012. The main reasons for this reduction are: (1) McGrath Peaker construction is now complete, (2) we are nearing the completion of our Solar plant and Fuel Cell construction programs and Mohave plant decommissioning, (3) reduced Four Corners capital spending commensurate with the end of power generation operations in July 2016, and (4) issues that were not addressed during the initial construction of Mountainview Units 3 and 4 have now largely been addressed (i.e., decommissioning of San Bernardino Units 1 and 2, and miscellaneous improvements to facilitate long-term operations and maintenance). These reductions are partially offset by a forecast increase in Hydro expenditures, for a variety of reasons including needed dam improvements. These dam improvements include required modifications to meet increased minimum stream release flow rates that we anticipate will be required in the new FERC licenses we expect to receive during this GRC rate cycle.

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9 This does not include our forecast cost for Four Corners decommissioning that will be incurred during 2015 through 2018. The 2012 GRC authorized amount for Four Corners included an additional $8.548 million for projects completed prior to 2010 that were not authorized in SCE's 2009 GRC pending resolution of Four Corners conflicts with the Commission's Greenhouse Gas Emissions Performance Standard.

10 Mountainview Units 3&4 were constructed at the former San Bernardino Generating Station site.
### Table I-2

**Power Production Department 2008-2017 Recorded, Forecast and Adopted Capital Expenditures**  
(Nominal (Work Order Level) - $Million (SCE Share))

<table>
<thead>
<tr>
<th></th>
<th>2008-12 Recorded</th>
<th>2013-17 Forecast</th>
<th>2012</th>
<th>Recorded</th>
<th>Adopted</th>
<th>Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro</td>
<td>377.2</td>
<td>438.3</td>
<td>2012</td>
<td>377.2</td>
<td>85.7</td>
<td>83.5</td>
</tr>
<tr>
<td>Mountainview</td>
<td>43.6</td>
<td>13.8</td>
<td>2012</td>
<td>43.6</td>
<td>9.2</td>
<td>19.5</td>
</tr>
<tr>
<td>Peakers</td>
<td>41.5</td>
<td>13.8</td>
<td>2012</td>
<td>41.5</td>
<td>1.7</td>
<td>2.0</td>
</tr>
<tr>
<td>McGrath</td>
<td>38.3</td>
<td>0.0</td>
<td>2012</td>
<td>38.3</td>
<td>28.6</td>
<td>20.0</td>
</tr>
<tr>
<td>Mohave</td>
<td>39.5</td>
<td>0.6</td>
<td>2012</td>
<td>39.5</td>
<td>8.1</td>
<td>0.0</td>
</tr>
<tr>
<td>Four Corners</td>
<td>93.0</td>
<td>33.2</td>
<td>2012</td>
<td>93.0</td>
<td>8.4</td>
<td>1.9</td>
</tr>
<tr>
<td>Solar PV</td>
<td>335.6</td>
<td>38.9</td>
<td>2012</td>
<td>335.6</td>
<td>32.2</td>
<td>88.0</td>
</tr>
<tr>
<td>Fuel Cells</td>
<td>11.2</td>
<td>0.6</td>
<td>2012</td>
<td>11.2</td>
<td>5.0</td>
<td>4.0</td>
</tr>
<tr>
<td>Total</td>
<td>979.9</td>
<td>539.2</td>
<td></td>
<td>979.9</td>
<td>178.9</td>
<td>218.9</td>
</tr>
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</table>

Table I-2 also shows our recorded 2012 capital expenditures as compared to those authorized by the Commission in our 2012 GRC. In aggregate, our recorded expenditures were $40.0 million less than adopted. This was primarily due to Solar PV plant construction expenditures being $55.8 million less, as we reduced the number of plants being constructed commensurate with D.12-02-035 and D.13-05-033. Mountainview 2012 expenditures were also significantly less than adopted, mostly because the ongoing, $15.0 million gas turbine compressor upgrade project did not finish in 2012 as originally forecasted. This project is being completed in 2013 as part of the 2013 Mountainview major overhauls.

Hydro 2012 expenditures were higher than adopted, primarily because of cost increases experienced in the buildings refurbishment area. McGrath Peaker construction 2012 expenditures were higher because of additional legal fees related to city of Oxnard challenges to McGrath's construction, and other costs related to the additional project delays experienced because of these challenges. The Commission is currently reviewing the reasonableness of McGrath's construction cost in A.12-12-028. Our 2012 expenditures for the other four Peakers was slightly less than the adopted amount, due to the delay of the Variable Inlet Guide Vane project.

Mohave Decommissioning expenditures were higher than adopted, primarily because of additional work items that were not foreseen at the time of our 2012 GRC forecast. These items...
included the need to remove additional sub-surface structures that were not identified in the plant's original construction drawings, and required improvements to our ash landfill. Partly because of this additional work, the Mohave Decommissioning also took longer than had been forecast; in our 2012 GRC we had forecast its completion prior to 2012. The costs that record to the Mohave Balancing Account are reviewed in SCE's ERRA Annual Review Phase proceedings.

Four Corners 2012 expenditures were also higher than adopted. As SCE explained during the course of the 2012 GRC proceeding, this is because of expenditures that were necessary to continue the plant's basic operations that were not foreseen at the time of the 2012 GRC forecast. These unforeseen expenditures included the sudden failure of an auxiliary power transformer which required replacement, replacement of damaged boiler flue gas duct expansion joints, addressing repeated failures of the plant's compressed air system, and other similar needs. As required by the Commission's decision in our 2012 GRC, we have provided additional information concerning our Four Corners post-2011 capital expenditures in SCE-02, Volume 6, Part 2.11

Further information and discussion of our 2008 through 2012 recorded capital expenditures, and their comparison to GRC adopted capital forecasts, can be found in SCE-2, Volumes 6 through 10. Our PPD 2013 through 2017 Capital Expenditure forecast of $539.2 million is further summarized in Table I-3 below. As noted above, this figure does not include the cost of Four Corners decommissioning, which is forecast at $49.5 million for 2013 through 2018.

### Table I-3

Power Production Department 2013-2017 Forecast Capital Expenditures  
(Nominal (Work Order Level) - $M illion (SCE Share))

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2014</th>
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<th>2016</th>
<th>2017</th>
<th>Total</th>
</tr>
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<tbody>
<tr>
<td>Hydro</td>
<td>82.1</td>
<td>72.7</td>
<td>99.2</td>
<td>103.8</td>
<td>80.5</td>
<td>438.3</td>
</tr>
<tr>
<td>Mountainview</td>
<td>9.6</td>
<td>1.3</td>
<td>1.1</td>
<td>1.0</td>
<td>0.8</td>
<td>13.8</td>
</tr>
<tr>
<td>Peakers</td>
<td>1.1</td>
<td>3.0</td>
<td>3.0</td>
<td>3.2</td>
<td>3.5</td>
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<tr>
<td>Mohave Decom</td>
<td>0.6</td>
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<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.6</td>
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<tr>
<td>Four Corners</td>
<td>14.7</td>
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<td>6.0</td>
<td>2.0</td>
<td>0.0</td>
<td>33.2</td>
</tr>
<tr>
<td>Solar PV</td>
<td>31.5</td>
<td>0.4</td>
<td>1.0</td>
<td>0.3</td>
<td>5.7</td>
<td>38.9</td>
</tr>
<tr>
<td>Fuel Cells</td>
<td>0.6</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.6</td>
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<tr>
<td>Total</td>
<td>140.2</td>
<td>87.9</td>
<td>110.3</td>
<td>110.3</td>
<td>90.5</td>
<td>539.2</td>
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</table>

11 D.12-11-051, p. 55.  

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Witness: T. Ware
The completion of Solar plant construction and the ongoing capital needs of our Hydro fleet accounts for approximately 88 percent of our total forecast. This funding is needed so that SCE can meet Commission directives governing our Solar program. SCE's Hydro capital expenditure forecast funds a wide variety of needed work. This includes the ongoing FERC relicensing of many of the hydroelectric facilities that will allow us to continue to operate these facilities for many years into the future for the benefit of SCE customers. We also must continue to refurbish our aging hydro equipment and infrastructure, to assure these plants continue to operate with high reliability. This includes overhauls of the turbines and generators, as well as replacement of aging equipment at sub-stations which serve our SCE customers and are managed by our Hydro division. This work also includes needed refurbishment to dams and flowlines to help assure their continued safe operation.

Our forecast for Mountainview includes completing the 2013 major overhauls including upgrading the combustion turbines to help sustain continued high reliability of this large plant. This funding will also allow us to complete other plant upgrades, including replacing and re-routing the aging waste water disposal pipeline which has served the power plant site for many decades. Our forecast for Peakers includes adding a multipurpose building and a second gas compressor to the McGrath unit to facilitate future maintenance for this new plant, and to help assure future reliability and minimize gas compressor maintenance costs. These upgrades were performed on the other four Peakers after they entered commercial service.

Our forecast for Four Corners is for work that is reasonable and necessary to continue safe and reliable operations until July 2016 and is in service of Decommissioning. This includes replacing deteriorated power transformers, feedwater heaters, gas piping, electrical cables, and switchgear needed to sustain safe and reliable operations until the plant permanently shuts down in July 2016. This includes work needed for continued regulatory compliance for the remaining years of operation, including replacing worn filter bags that remove ash from the plants combustion exhaust gases, installing equipment to measure mercury emissions, and assuring plant security conforms to power grid reliability regulations.

Adoption of our capital expenditure forecast will help assure the continued safe and reliable operation of these power generating assets, in compliance with environmental objectives and other

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12 Mountainview Units 3&4 were constructed at the former San Bernardino Generating Station site.
regulatory requirements. Further details regarding our PPD Capital expenditure forecasts are provided in Testimony Volumes 6 through 10.
II. POWER PRODUCTION DEPARTMENT POWER PLANT RELIABILITY

The Power Production Department tracks power plant reliability with a Generation Reliability Index (GRI), which measures our Hydroelectric, Mountainview, and Peaker reliability performance, including both planned and forced outages. GRI increases as our generating assets reduce total outage time, as measured by Equivalent Availability Factor (EAF) performance, and experience fewer hours of forced outages, as measured by Equivalent Forced Outage Factor (EFOF). EAF is the percentage of time that a generating asset is available for operation, whether or not it is dispatched to operate. EFOF is the percentage of time that a generating asset is not available to operate, because it is undergoing a forced outage.

To achieve the maximum possible GRI of 100, the Mountainview and Peaker generating assets must achieve an EAF of 100 percent, the Hydro fleet must achieve an EAF of 95 percent, and all three assets must achieve an EFOF of zero percent. However, achieving a perfect score of 100 percent EAF and zero percent EFOF is not practical, as generating assets must be periodically removed from service to conduct routine maintenance, and because it is not cost effective to design and maintain a power plant to the level required to fully mitigate against all of the possible problems that can cause forced outages.

Our GRI is a composite index allocates 100 points based on the generating asset MW capacity, and other roles the generation asset provides in addition to capacity (MW) and energy (MWh). For the Peakers this includes blackstart and fast-start peaking capabilities. Specifically, the GRI allocates 40...
points to Mountainview reliability performance, 20 points for the combined reliability of the five Peakers and 40 points for Hydro fleet reliability. These points are then further subdivided between EAF and EFOF performance for each of these three sets of assets.17

Our goal is to maintain a GRI of 82 points or higher, during 2015 through 2017, as measured on a three-year rolling average.18 This is an ambitious goal and one that requires our generating assets to perform at or above historic reliability levels. As shown in Table II-4 below, this requires us to maintain EFOF levels to one percent or better, and to maintain the Hydro and Peaker EAF approximately three percent higher than the average achieved during 2008 through 2012. Our Peaker and Hydro fleet already have very good reliability performance, and these goals seek to achieve further incremental improvement. Mountainview reliability performance has been excellent since it began commercial operation. Our goal for Mountainview EAF is slightly less than the 2008-2012 recorded average, to account for the outage time needed to conduct its planned 2016 overhaul.

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<th>Power Production Department Reliability Indexes</th>
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<tr>
<td>Annual Average EAF</td>
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17 The 40 points for Mountainview is split between summer and winter EAF, and annual EFOF. Since the summer reliability generally has greater importance for SCE customers than winter reliability (as electrical demand is generally higher in summer), as somewhat offset by the fact that summer comprises only four months while winter comprises eight months, the summer EAF performance is allocated 20 points (i.e., half of the Mountainview total allocation). Mountainview winter EAF, and annual EFOF, are each allocated 10 points. For the Peakers the summer EAF gets 10 points and the winter EAF gets 5 points, and the Peaker annual EFOF another 5 points. Hydro is assigned 30 points for EAF and 10 points for EFOF. We do not distinguish between summer and winter EAF for Hydro, as much of the Hydro generation coincides with the high snow melt water flows that occur during spring run-off, which typically begins several weeks before the summer season.

18 Our GRI goal for individual calendar years varies above and below 82 points because planned capital project construction and other major maintenance work requires different power plant outage durations from one year to the next.
To achieve our GRI goal, our power plant engineers and technicians must manage and complete an extensive amount of maintenance and capital project work within aggressive planned outage durations. Some of the challenges we face in doing this work include handling any unforeseen equipment problems and other emergent repairs that we encounter, obtaining sufficient contractor resources (particularly during our busy power plant outage seasons of spring and fall), and getting timely delivery of parts and materials.

During the 2015-2017 three year rate cycle, our planned outage work includes the 2016 HGPI overhauls on both units at Mountainview. Our planned outage work also includes significant refurbishment work at several of our Hydroelectric dams and on other Hydro generation infrastructure. Achieving our GRI target requires that we undertake only short annual planned outages at our Peaker plants. The target does not provide for any extended planned outages of our Peaker plants. In addition, GRI goal achievement will require that we respond quickly and aggressively to forced outages that occur in order to minimize their durations to the extent practical.

While much of SCE's power is purchased, reliability of the SCE-owned power plants is important to SCE customers. It supports the overall reliability of electrical service. Electricity generated by the SCE plants is often less costly than power available for purchase, therefore outages of SCE plants can result in higher overall costs to SCE customers.

While we will work hard to meet or exceed our GRI target, it should be noted that it is a stretch goal and we might not achieve it for all of the 2015-2017 forecast period. The length of time needed to accomplish the planned and emergent work that is undertaken during scheduled outages can be affected by a variety of circumstances. Likewise, forced outages are an inherent part of cost effective power plant operations and maintenance strategies. Further details regarding our PPD power plant outages and reliability performance is provided to the Commission in our ERRA Annual Review Phase proceedings. As extensively discussed therein, our Hydro, Mountainview, and Peaker reliability performance has been and continues to be very good compared to the industry average for these respective types of generating plants. Approval of our forecast O&M expense and Capital expenditure forecasts in this GRC will help assure that we sustain acceptable levels of power plant reliability performance in the future.
### EXHIBIT SCE-02, Vol. 05 – Power Production Generation Policy

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Authority to, Among Other Things, Increase Its Authorized Revenues For Electric Service in 2012, And to Reflect That Increase In Rates.

(See Appendix A for Service List)

DECISION ON TEST YEAR 2012 GENERAL RATE CASE FOR SOUTHERN CALIFORNIA EDISON COMPANY
twelve months of forecast O&M expenses which SCE will not be obligated to pay after the sale. It is more reasonable to authorize $30.065 million for nine months of 2012 O&M expenses ($44,343 - $4,257 x .75 = $30.065 million) and no costs for 2013 or 2014.

SCE shall limit funding of post-2011 capital projects to the Decommissioning Case. If SCE does not complete the sale of Four Corners as authorized, SCE shall include in its 2015 GRC a showing that each post-2011 expenditure is reasonable, necessary, and in service of Decommissioning. The showing of necessity shall include an analysis of expected failure and available less costly alternatives. Although we agree that the sale might not close in 2012, we find that the policy objectives of EPS require that, going forward, SCE only be eligible for rate recovery for O&M and capital expenditures identified in the Decommissioning Case that it reached in consultation with its co-owners.

For 2012, the Commission finds reasonable and adopts O&M of $30,065 million and capital expenditures of $1,888 million. If completion of the sale is delayed, SCE may establish a memorandum account to track expenses between October 1, 2012 and the sale date and to apply to the Commission for cost recovery subject to the established standards of reasonableness review for Four Corners.

4.3. Hydroelectric Generation

SCE’s Hydroelectric (Hydro) generating facilities are forecast to provide an aggregate of 1,176 MW of power in TY2012. SCE operates and maintains 33 Hydro generating plants consisting of 76 generating units, 33 dams, 46 stream diversions, and 143 miles of tunnels, conduits, flumes, and flow lines. All but five of the Hydro plants operate under FERC licenses. About 86% of the generation comes from the Northern, or Big Creek, region. The Eastern region
23. SCE’s forecast TY2012 O&M, and forecast 2011-2012 capital expenditures for Palo Verde are reasonable and adopted.

24. SCE’s forecast TY2012 O&M, and forecast 2011-2012 capital expenditures, for the Mohave Generating Station are reasonable and adopted.

25. Continuation of the Mohave Balancing Account is reasonable so that costs will be subject to a reasonableness review, and to provide ratepayers protection against unknown cost.

26. SCE established the reasonableness and necessity of the expenditures as required for its pre-2012 Four Corners capital projects, and addressed the viability of its continued ownership of Four Corners.

27. Replacement equipment lasting beyond 2016 does not equate with plant life extension because ownership agreements, fuel supply contract, and land leases expire that year.


29. SCE’s estimated 2012 O&M should be reduced to $30.065 million to reflect sale on October 1, 2012 and to exclude pro rata costs of the Unit 5 overhaul scheduled for 2014. No O&M costs are authorized for 2013 or 2014.

30. If the Four Corners sale does not occur, SCE should limit post-2011 funding to O&M and capital expenditures identified in the Decommissioning Case and include in the 2015 GRC a showing that each post-2011 expenditure is reasonable, necessary and in service of Decommissioning.

31. If the Four Corners sale is delayed, SCE should be authorized to establish a Four Corners Memorandum Account to track expenses incurred between October 1, 2012 and the delayed sale date.
Decision 09-03-025 March 12, 2009

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of SOUTHERN CALIFORNIA EDISON COMPANY (U338E) for Authority to, Among Other Things, Increase Its Authorized Revenues For Electric Service in 2009, And to Reflect That Increase In Rates.

And Related Matter.

Application 07-11-011 (Filed November 19, 2007)

Investigation 08-01-026

(See Appendix A for a list of appearances.)

ALTERNATE DECISION OF PRESIDENT PEEVEY ON TEST YEAR 2009 GENERAL RATE CASE FOR SOUTHERN CALIFORNIA EDISON COMPANY
A.07-11-011, 1.08-01-026 COM/MP1/rbg/hkr

requests a reduction of $23,333 for the Rush Creek Heliport Brush Clearing and $230,000 for Big Creek Vegetation Management, for a total reduction of $253,333 to SCE’s TY 2009 forecast. In response, SCE explains that the project recorded in FERC Account 539 will involve more than brush clearing. The helicopter landing site must be moved and a new heliport site constructed, which requires that vegetation be removed and the site graded and covered with rock. Based on the information provided by SCE, the amount requested is reasonable.

2.4. Gas–Fired Generation

2.4.1. Mountainview O&M Expenses

Consistent with D.03-12-059, D.04-03-037 and D.04-04-019, SCE acquired Mountainview Power Company, LLC (MVL) as a wholly-owned SCE subsidiary and executed a Power Purchase Agreement (PPA) for cost recovery with MVL for electricity from MVL’s Mountainview Generating Station (Mountainview).\footnote{Mountainview has a nominal output of 1,050 MW. It went into initial commercial service in December 2005 and full commercial service in January 2006. It also includes two retired units (Units 1 & 2) that SCE plans to decommission in 2009. Mountainview currently recovers capital, and non-fuel O&M expenses and A&G expenses associated with Units 3 & 4 through a FERC approved PPA with SCE. SCE is responsible for dispatching Mountainview, purchasing fuel, and any decommissioning costs.}

In this proceeding, SCE asks the Commission for permission to include Mountainview in rate base and allow recovery of Mountainview’s operating costs through its TY 2009 forecast. In addition, Mountainview’s capital costs would no longer be recovered as purchased power costs, through the operation of the ERRA, but would instead be recovered in SCE’s authorized base generation revenue requirement and through rates. The fuel costs and availability and heat rate incentive payments will still be recovered through the
A.07-11-011, 1.08-01-026 COM/MP1/rbg/hkr

annual operation of the ERRA balancing account process. SCE states if the Commission does not approve of its request now, it will not terminate the PPA and, instead, continue to recover its Mountainview operating costs through the FERC-jurisdictional PPA.71 SCE’s TY 2009 forecast for Mountainview O&M is $42,505 million (constant 2006$). SCE made future adjustments totaling $13,779 million to 2006 recorded costs to compute its TY 2009 forecast.

In response to SCE’s request to operate Mountainview as a utility-owned generation facility, DRA raises various concerns related to SCE’s proposed cost recovery, not to the transfer of ownership. TURN’s recommendations for Mountainview are related to SCE’s request for peaker O&M and related capital and will be addressed in a separate section of this decision.

DRA recommends $41.5 million in O&M expenses for TY 2009 for Mountainview. DRA reduces SCE’s TY 2009 forecast by $1 million to remove $0.454 million for additional staff and $0.5 million for “Additional Future Projects (Unforeseen).”72 According to DRA, the Commission should not increase funding in TY 2009 for retirements that may occur over “the next several years” and for Additional Future Projects (Unforeseen) that in DRA’s view are an unsupported contingency.

SCE defends the cost of seven additional employees, all of whom SCE hired in 2008, to address increased workload at Mountainview. Regarding the amounts forecasted in Additional Future Projects (Unforeseen), SCE says the funding is needed for projects to address areas of concern that have arisen since

71 A.07-11-011, pp. 4-5.
72 Exhibit SCE-2N, p. 42.
mid-2007 and would be reflected in recorded cost history if Mountainview were an older plant.\textsuperscript{73}

We find that SCE has adequately explained and justified the additional employees and the Unallocated Future O&M projects. Thus, we find SCI’s TY 2009 O&M forecast for Mountainview reasonable. However, we do not anticipate approving any amounts for Additional Future Projects (Unforeseen) in SCE’s next GRC because historical data should reflect these expenses. In addition, we approve the transfer of ownership. While the Commission in D.03-12-059 found “… that unless Edison decides to purchase Mountainview as utility owned generation, a CPCN is not necessary,”\textsuperscript{74} we addressed all necessary CPCN and CEQA matters in A.03-07-032. When finalized, this transfer will place Mountainview under Commission-jurisdictional ratemaking. However, this change in ratemaking cannot occur until FERC issues a decision approving termination of the existing power purchase contract.

2.4.2. Peaker O&M - FERC Accounts 546, 548, 549, 551, 553, 554

SCE proposes O&M expenses of $9.7 million in TY 2009 to operate its five new peakers (constant 2006$).\textsuperscript{75} The TY 2009 forecast includes $3.214 million for labor expense. In total, SCE’s TY 2009 forecast for non-labor costs, which

\textsuperscript{73} Exhibit SCE-16E, p. 6.
\textsuperscript{74} D.03-12-059, p. 22 and p. 57.
\textsuperscript{75} SCE filed a separate application in late 2007, A.07-12-029. That application is pending and seeks approval and recovery in rates of the initial capital costs for these five new peakers. This separate application also requests recovery of O&M expenses starting from plant commercial operation up to the effective date of a decision in that proceeding. This 2009 GRC considers recovery of (1) the O&M expenses commencing on the effective date of a decision in that proceeding and (2) capital expenditures incurred after start-up.
BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Authority to Implement and Recover in Rates the Cost of its Proposed Solar Photovoltaic (PV) Program.

Application 08-03-015
(Filed March 27, 2008)

DECISION PARTIALLY GRANTING SOUTHERN CALIFORNIA EDISON COMPANY’S PETITION FOR MODIFICATION OF DECISION 12-02-035 (SOLAR PHOTOVOLTAIC PROGRAM)

1. Summary

This decision partially grants Southern California Edison Company’s (SCE) petition for modification of Decision (D.) 12-02-035 regarding the Solar Photovoltaic Program (SPVP).

The SPVP, adopted in 2009 (D.09-06-049), is a 500 megawatt (MW) solar photovoltaic generation program, with 250 MW utility-owned generation (UOG) and 250 MW owned by independent power producers (IPP). As modified by D.12-02-035, the total program remains at 500 MW, but with no more than 125 MW designated for utility ownership, no more than 125 MW designated for IPP ownership, and 250 MW transferred to the Renewable Auction Mechanism (RAM) program.

SCE now petitions to reduce the utility ownership portion from 125 MW to 91 MW, with the 34 MW differential transferred to the RAM program. We grant the petition as to the reduction of the UOG portion of the SPVP and the reallocation of the 34 MW to RAM. As modified, the UOG portion of the
A.08-03-015 COM/MF1/acr/jt2

program will be no more than 91 MW of utility ownership, with 34 MW direct
current (31 MW alternating current) procured through the RAM program. We
do this to reduce costs, promote simplicity and maximize program efficiency.
We reduce our previous finding of the total amount of reasonable program costs
to track the program changes adopted here. We also make conforming changes
to the RAM program by modifying D.10-12-048. SCE's petition also requested
that the Commission, under Rule of Practice and Procedure 16.4(h), issue an
immediate order staying SCE's UOG obligations pending the disposition of its
petition. This request is now moot and is therefore denied. This proceeding is
closed.

2. Background

On June 22, 2009, we adopted a Solar Photovoltaic Program (SPVP) for
Southern California Edison Company (SCE). (See Decision (D.) 09-06-049 in
Application 08-03-015.) The SPVP is a five-year program to develop
500 megawatts MW) of direct current (DC) electricity procured from solar
photovoltaic (PV) facilities on existing commercial rooftops using plants
generally in the size range of one to two MW per project. As originally approved
the SPVP was composed of 250 MW of utility-owned generation (UOG) and
250 MW of power purchase agreements with independent power producers
(IPP).

On December 17, 2010, we adopted the Renewable Auction Mechanism
(RAM) as part of the Renewables Portfolio Standard (RPS) program. (See
D.10-12-048 in Rulemaking 08-08-009.) RAM is a procurement mechanism for
utility purchases from IPPs of alternating current (AC) electricity generated by