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Witness	:	Wilson

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Report on the Results of Operations for Southern California Edison Company General Rate Case Test Year 2012

Transmission and Distribution Business Unit
Capital Expenditures (Part 1 of 2)

San Francisco, California
May 11, 2011

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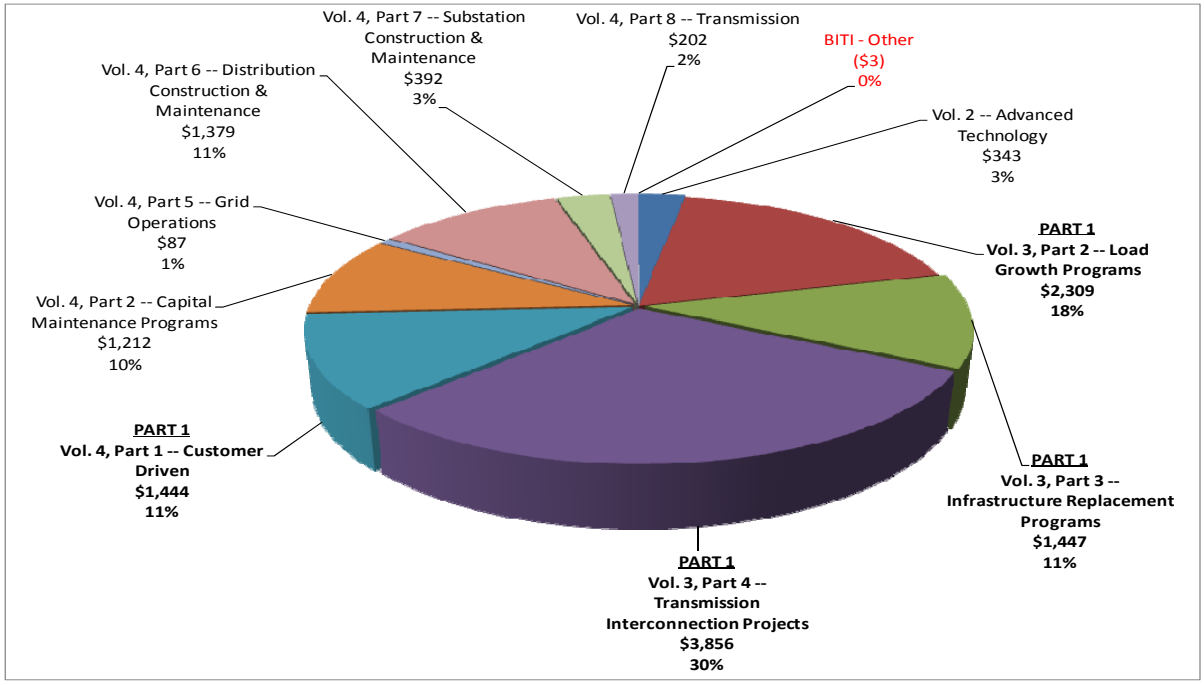
TRANSMISSION AND DISTRIBUTION BUSINESS UNIT CAPITAL EXPENDITURES (PART 1 OF 2)

I. INTRODUCTION

This exhibit presents the analyses and recommendations of the Division of Ratepayer Advocates (DRA) regarding Southern California Edison Company's (SCE or Edison) forecasts of certain Transmission and Distribution Business Unit (TDBU) capital expenditures for 2010, 2011, and Test Year (TY) 2012.

The chart below shows how SCE has subdivided TDBU capital expenditures into numerous parts. The chart also shows the cumulative amounts that SCE has proposed spending for each part over the five-year period 2010 through 2014, as well as the percentage of the total expenditures each part constitutes.

Figure 6-1[1]
SCE's TDBU Capital Expenditure Request
2010 – 2014 Forecast for Total Company
(in Millions of Direct Nominal Dollars)



[1] Ex. SCE-03, Vol. 03, Part 03, Chapters I-II, inside front cover.

The total of all 11 parts of the above figure is $12.668 billion. Stated another way, SCE is proposing to spend a total of $12.668 billion on TDBU capital projects over the 5-year period 2010 through 2014. By any definition, this constitutes an enormous capital outlay. DRA believes that SCE must provide a high level of justification in order to convince the Commission that proposed expenditures of this magnitude are warranted.

Several points should be discussed regarding Figure 6-1. First, as noted in the heading of the pie chart, this figure represents TDBU capital expenditures for the entire company. Included in the $12.668 billion total are expenditures that will be litigated in Federal Energy Regulatory Commission (FERC) proceedings. Therefore, many of the dollars reflected in the chart are not included (and are not discussed) in this General Rate Case (GRC); this is especially true for expenditures related to Transmission projects, which are generally part of FERC's jurisdiction. Nevertheless, it is important for the Commission to be aware of the entire capital obligation (CPUC plus FERC) that SCE is asking its ratepayers to bear. Second, the $12.668 billion includes expenditures through 2014. This exhibit only analyzes expenditures up to (and including) the 2012 test year. A separate DRA exhibit will discuss expenditures occurring in 2013 and 2014 – the so-called attrition years. Lastly, this exhibit only examines the four TDBU sections that constitute Part 1 (shown in bold in the above pie chart). The four TDBU categories that are the subject of this exhibit, along with the corresponding SCE-proposed total company expenditures over the period 2010 through 2014, are as follows:

- <u>Load Growth Programs</u> – capital expenditures associated with increased customer usage and interconnecting new generation to SCE's system. ($2.309 billion)
- <u>Infrastructure Replacement Programs</u> – capital expenditures used to replace major pieces of equipment (such as transformers, cables, switches, etc.) that have been identified as needing replacement using a risk/reliability-based approach. ($1.447 billion)

- Transmission Interconnection Projects – capital expenditures used to support grid reliability as well as to connect new generation. ($3.856 billion)
- Customer Driven Projects – capital expenditures used to connect new customers, underground existing overhead lines, and respond to customer requests. ($1.444 billion)

SCE's proposals regarding its TDBU capital expenditures associated with Advanced Technology, Capital Maintenance Programs, Grid Operations, Distribution Construction and Maintenance, Substation Construction and Maintenance, and Transmission are addressed in Exhibit DRA-7.

II. SUMMARY OF RECOMMENDATIONS

Up to this point, all discussions in this exhibit regarding capital expenditures have reflected "Total Company" estimates. Because FERC-related expenditures are not a part of this GRC, the forecasted amounts shown in Figure 6-1 are, in some instances, larger than what SCE is requesting for this case. Henceforth in this exhibit, all expenditures will be presented in a CPUC jurisdiction format. Stated another way, for the remainder of this exhibit, all expenditure figures will only include amounts for those dollars that are actually the subject of this GRC. The following bullets summarize DRA's recommended Part 1 adjustments (in CPUC jurisdictional dollars) to SCE's proposed TDBU capital expenditures for 2010, 2011, and 2012:

- SCE's 2010 forecast should be reduced by $4.123 million to reflect actual recorded 2010 capital expenditures.
- Expenditures for the Subtransmission Lines Plan should be reduced by $2.070 million in 2011 and by $3.829 million in 2012.
- Expenditures for the Distribution Substation Plan should be reduced by $25.155 million in 2011 and by $55.853 million in 2012.
- Expenditures for the Substation Equipment Replacement Program should be reduced by $2.000 million in 2012.
- Expenditures for the Plug-In Electric Vehicle Readiness Plan should be reduced by $1.955 million in 2011 and by $7.741 million in 2012.

- Expenditures for the Cable Replacement Program should be reduced by $27.694 million in 2012.
- Expenditures for the Cable-In-Conduit Replacement Program should be reduced by $9.255 million in 2011 and by $26.359 million in 2012.
- Expenditures for the A and B-Bank Transformers should be reduced by $10.622 million in 2012.
- Expenditures for Distribution Circuit Breakers should be reduced by $3.564 million for 2012.
- Expenditures for 4 kV Cutovers should be reduced by $9.734 million for 2012.
- Expenditures for the elimination of 4 kV Substations should be reduced by $34.286 million in 2012.
- Expenditures for Rule 20A Conversions should be reduced by $8.259 million in 2011 and by $8.461 million in 2012.
- Expenditures for Rule 20B Conversions should be reduced by $11.699 million in 2011 and by $18.702 million in 2012.
- Expenditures for Rule 20C Conversions should be reduced by $3.663 million in 2011 and by $5.991 million in 2012.

Table 6-1 (see page 5) provides a detailed listing of all the TDBU capital projects that are associated with its Load Growth Programs, Infrastructure Replacement Programs, Transmission Interconnection Projects, and Customer Driven Projects. It shows recorded TDBU capital expenditures for the years 2005 through 2010. It also compares DRA's and SCE's 2010 through 2012 forecasts of TDBU capital expenditures. As shown in column h (shaded), DRA was able to obtain 2010 recorded expenditures, eliminating the need to derive forecasts for that year. Numbers that are highlighted in columns j and l indicate forecasts where DRA is recommending adjustments to SCE's estimates. References to Table 6-1 are made periodically throughout this exhibit. Excerpts from this table are included at the beginning of each of the major section areas of this report (Load Growth Programs, Infrastructure Replacement Programs, and Customer Driven Programs).

Table 6-1
TDBU CAPITAL EXPENDITURES -- CPUC JURISDICTION
(000s of Direct Nominal Dollars)

Line #	Category	Recorded					Forecasted							
							2010		2011		2012			
		2005	2006	2007	2008	2009	SCE	DRA - Recorded	SCE	DRA	SCE	DRA	SCE ≥ DRA	%
		(a)	(b)	(c)	(d)	(e)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Load Growth:													
1	A-Bank Plan	$49,779	$38,017	$12,918	$27,843	$59,642	$81,976	$79,509	$83,380	$83,380	$101,955	$101,955	$0	0.00%
2	Subtransmission Lines Plan	$13,035	$4,158	$23,393	$8,931	$12,236	$50,485	$23,962	$52,684	$50,614	$33,419	$29,590	$3,829	12.94%
3	Subtransmission VAR Plan	$16,456	$11,487	$4,206	$2,749	$5,546	$6,106	$5,778	$3,844	$3,844	$1,050	$1,050	$0	0.00%
4	Distribution Substation Plan (DSP)	$50,843	$73,067	$59,663	$74,099	$118,523	$94,411	$101,749	$117,468	$92,313	$132,361	$76,508	$55,853	73.00%
5	Substation Equipment Replacement Program (SERP)	$980	$53	$948	$1,441	$447	$5,412	$3,683	$6,000	$6,000	$9,000	$7,000	$2,000	28.57%
6	DSP Circuits - Blanket Budget Items	$71,613	$99,155	$94,535	$107,186	$134,185	$114,413	$123,206	$121,400	$121,400	$112,600	$112,600	$0	0.00%
7	Distribution Plant Betterment - Blanket Budget Items	$7,643	$5,068	$5,548	$5,421	$9,181	$5,565	$18,304	$5,700	$5,700	$7,400	$7,400	$0	0.00%
8	Distribution VAR Plan - Blanket Budget Item	$3,517	$4,288	$3,487	$1,990	$2,606	$3,855	$5,550	$5,000	$5,000	$6,800	$6,800	$0	0.00%
9	Plug-In Electric Vehicle Readiness Plan	--	--	--	--	--	--	--	$2,089	$134	$8,523	$782	$7,741	989.90%
10	Generator Interconnection Program	($211)	$6,035	$3,658	$3,139	$5,003	$7,579	$8,323	$4,949	$4,949	$1,000	$1,000	$0	0.00%
11	Total	$213,655	$241,328	$208,356	$232,799	$347,369	$369,802	$370,064	$402,514	$373,334	$414,108	$344,685	$69,423	20.14%
	Infrastructure Replacement Programs													
12	Cable Replacement Program	$6,483	$4,716	$3,388	$11,443	$27,722	$29,636	$35,947	$38,874	$38,874	$74,514	$46,820	$27,694	59.15%
13	Worst Circuit Rehabilitation (WCR)	$1,732	$5,923	$7,569	$12,573	$17,015	$20,300	$24,607	$18,660	$18,660	$33,119	$33,119	$0	0.00%
14	Cable-In-Conduit (CIC) Replacement	--	--	--	--	$932	$3,290	$4,030	$13,357	$4,102	$30,560	$4,201	$26,359	627.52%
15	Cable Testing Pilot	--	--	--	--	--	--	--	--	--	$2,123	$2,123	$0	0.00%
16	Underground Oil Switch Replacement	$8,476	$18,363	$11,125	$11,751	$13,157	$14,095	$21,556	$6,479	$6,479	$10,615	$10,615	$0	0.00%
17	PMH-4 Switch Replacement	--	--	--	--	--	$3,480	--	$2,281	$2,281	$2,335	$2,335	$0	0.00%
18	Capacitor Bank Replacement	$4,985	$3,530	$6,364	$4,999	$5,257	$6,505	$7,667	$5,667	$5,667	$10,482	$10,482	$0	0.00%
19	Automatic Recloser Replacement	$557	$1,219	$1,446	$1,369	$1,583	$1,600	$1,536	$1,596	$1,596	$2,229	$2,229	$0	0.00%
20	PCB Transformer Replacement	--	--	--	$1	$916	$613	$1,783	$624	$624	$2,282	$2,282	$0	0.00%
21	A and B-Bank Transformers	$10,098	$22,652	$20,235	$13,390	$28,548	$33,336	$37,843	$34,201	$34,201	$65,097	$54,475	$10,622	19.50%
22	Distribution Circuit Breakers	$11,249	$14,631	$10,037	$11,790	$15,488	$10,236	$12,023	$15,296	$15,296	$22,000	$18,436	$3,564	19.33%
23	Protection and Control	$11,761	$10,300	$3,638	$1,618	$5,628	$1,204	$8,568	$2,554	$2,554	$5,372	$5,372	$0	0.00%
24	4kV Cutovers	--	$6,883	$8,623	$5,269	$10,234	$16,700	$24,376	$17,214	$17,214	$30,167	$20,433	$9,734	47.64%
25	4kV Substation Elimination	--	--	--	--	--	--	--	--	--	$34,286	$0	$34,286	0.00%
26	Total	$55,341	$88,217	$72,425	$74,203	$126,480	$140,995	$179,936	$156,803	$147,548	$325,181	$212,922	$112,259	52.72%
	Transmission Interconnection Projects													
27	Grid Reliability Projects	$0	$21,377	$4,683	$5,091	$9,413	$11,821	$15,562	$8,189	$8,189	$47,000	$47,000	$0	0.00%
28	Renewable Interconnection Projects	$0	$0	$788	$4,182	$3,795	$27,357	$18,394	$7,327	$7,327	$1,845	$1,845	$0	0.00%
29	Information Technology-Related Projects	$1,701	$2,098	$3,445	$3,336	$4,528	$9,659	$7,232	$8,550	$8,550	$4,150	$4,150	$0	0.00%
30	Projects Under $1 Million	--	--	--	--	--	$2,443	--	$1,338	$1,338	$1,223	$1,223	$0	0.00%
31	Total	$1,701	$23,475	$8,916	$12,609	$17,736	$51,280	$41,188	$25,404	$25,404	$54,218	$54,218	$0	0.00%
	Customer Driven													
32	Customer Growth - Residential	$133,773	$163,666	$173,231	$70,542	$50,775	$47,174	$38,182	$55,442	$55,442	$89,603	$89,603	$0	0.00%
33	Customer Growth - Commercial / Industrial	$62,669	$72,694	$102,872	$91,951	$67,867	$56,043	$48,789	$55,101	$55,101	$60,401	$60,401	$0	0.00%
34	Customer Growth - Agricultural	$1,624	$1,715	$2,231	$3,717	$4,477	$2,194	$3,542	$2,233	$2,233	$2,287	$2,287	$0	0.00%
35	Customer Growth - Street Light System	$30,420	$35,332	$35,004	$20,737	$13,352	$5,194	$10,698	$5,287	$5,287	$5,414	$5,414	$0	0.00%
36	Rule 20 A Conversions	$37,861	$33,461	$29,287	$24,213	$30,236	$30,050	$21,942	$30,594	$22,335	$31,332	$22,871	$8,461	37.00%
37	Rule 20 B Conversions	$36,220	$43,319	$40,277	$23,900	$25,312	$25,830	$15,078	$27,047	$15,348	$34,418	$15,716	$18,702	119.00%
38	Rule 20 C Conversions	$11,074	$10,667	$13,764	$9,951	$8,611	$8,610	$5,259	$9,016	$5,353	$11,473	$5,482	$5,991	109.30%
39	Customer Relocations	$29,497	$29,965	$33,478	$38,867	$30,077	$31,994	$31,460	$32,567	$32,567	$33,348	$33,348	$0	0.00%
40	Distribution Added Facilities	$7,921	$9,504	$7,425	$7,871	$8,264	$8,416	$7,321	$8,567	$8,567	$8,773	$8,773	$0	0.00%
41	Total	$351,059	$400,323	$437,569	$291,749	$238,971	$215,505	$182,271	$225,854	$202,233	$277,049	$243,895	$33,154	13.59%
42	**Grand Total**	$621,756	$753,343	$727,266	$611,360	$730,556	$777,582	$773,459	$810,575	$748,519	$1,070,556	$855,719	$214,837	25.11%

NOTE 1: CPUC jurisdictional data (recorded and forecast) was provided by SCE in response to DRA Data Request #94, Question 01.
NOTE 2: 2010 recorded data was provided by SCE in an e-mail dated 3/16/11.

III. GENERAL DISCUSSION

A. Background

Capital expenditures, once they become plant additions, are cumulative in nature. Expenditures made during one year are added to expenditures that were made in previous years. Therefore, DRA must analyze all of the proposed capital expenditures occurring from the end of the last recorded year (SCE included 2009 recorded data in its exhibits and workpapers) through the end of the test year (2012).

In order to eliminate estimating uncertainty, DRA obtains additional years of recorded plant data whenever possible. In this GRC, DRA was able to obtain recorded capital expenditures for 2010. A quick inspection of columns g and h in Table 6-1 shows that recorded 2010 expenditures differed from the estimates used by SCE. These differences were sometimes positive and sometimes negative, so that the net difference was actually quite small. Looking at the grand total on line 42 for the year 2010, it can be seen that 2010 recorded expenditures were actually only $4.123 million less than SCE had estimated.[2] As will be discussed in detail later, DRA is recommending that SCE's recorded 2010 capital expenditures be adopted for all capital areas discussed in this exhibit. This recommendation only applies to the capital expenditures contained in this testimony; other DRA capital witnesses have separately analyzed the reasonableness of using recorded 2010 data in their areas.

In its exhibits and workpapers, SCE has presented its capital expenditures in direct nominal dollars. "Direct" dollars refers to the fact that SCE's capital expenditure estimates do not include various loadings, such as the capitalized portions of Pensions and Benefits, Payroll Taxes, Injuries and Damages, Administrative and General Expenses, etc. These various loadings are estimated separately and are allocated to the various capital projects by the Results of Operations (RO) computer model. "Nominal" dollars refers to the fact that SCE's

[2] $777.582 million (estimated) less $773.459 million (recorded) equals $4.123 million.

forecasts are presented with estimates keyed to the year in which they occurred. For example, a 2011 capital expenditure will use 2011 dollars for its forecast, rather than presenting the estimate in constant dollars from a prior year. Because the exhibits, workpapers, and the RO computer model are all set up to use direct nominal dollars, DRA is presenting its analyses and estimates in the same manner.

As mentioned previously, many of the capital projects undertaken by SCE are, in part or in whole, allocated to FERC. In much of its testimony and workpapers, SCE discusses the total capital expenditures for its projects – both CPUC and FERC jurisdiction. The RO computer model splits off the FERC allocations, and the revenue requirement is derived using the CPUC jurisdiction. Hence, a large capital expenditure may have no impact in this case if it is eventually allocated to FERC. DRA requested that SCE remove all of the FERC allocated expenditures from its forecast. As previously stated, with the exception of Section I of this exhibit (the "Introduction"), only CPUC jurisdiction expenditures are shown.

B. Capital Expenditures Versus Capital Additions

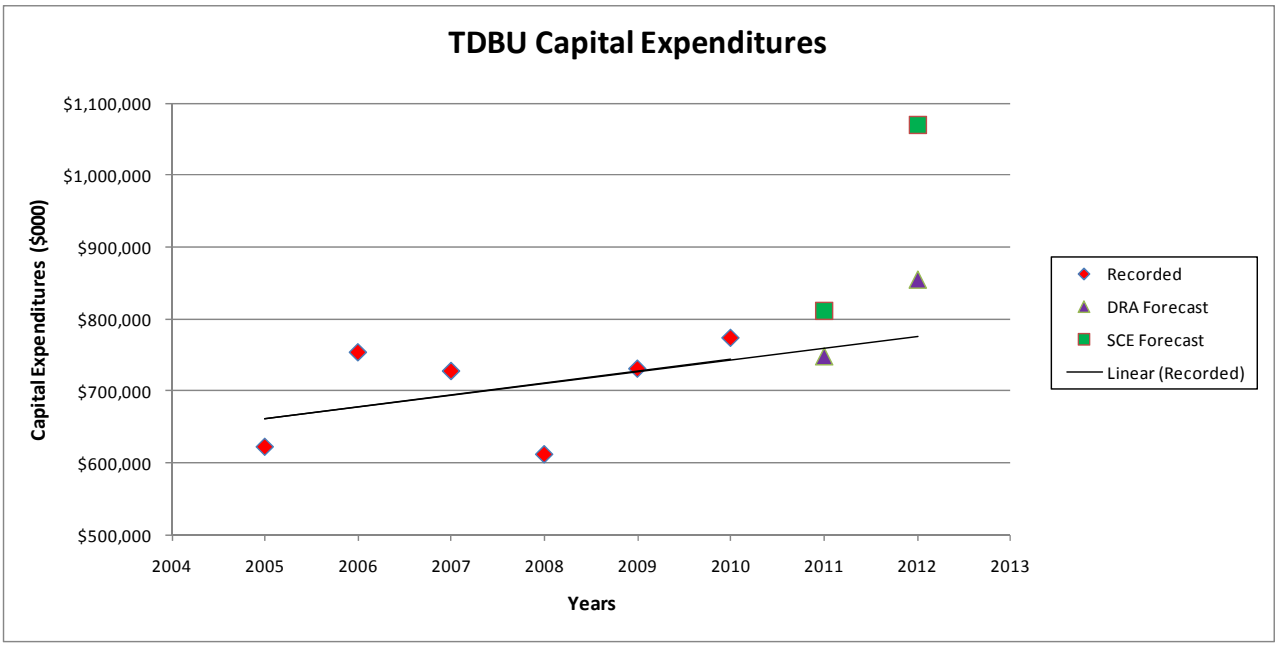
This exhibit (as well as SCE's exhibits) does not specifically address capital additions. SCE's capital exhibits and supporting workpapers (as well as its RO computer model) are organized around capital expenditures. The distinction between the two is important. Capital expenditures, as the term implies, reflect the capital dollars that SCE spends in a given year. No consideration is given as to whether or not those expenditures result in projects that are actually completed (and considered to be "used and useful") during the year. In contrast, capital additions reflect the dollar amount of projects that are completed during a given year, regardless of when the expenditures actually took place. SCE's capital witnesses provide testimony regarding the magnitude of the direct capital dollars that are estimated to be spent each year, not how much is actually being booked to plant. SCE relies on its RO computer model to manipulate these direct capital expenditures and calculate the corresponding capital additions. DRA has studied SCE's RO model, and believes that it properly calculates plant additions. Therefore, DRA's analyses and recommended direct capital adjustments are also stated in terms of capital expenditures.

When analyzing data in this format, the impact of recommended adjustments to capital expenditures may not show up in the year in which they are made. For example, suppose a capital project is scheduled to begin construction in 2011, but is not scheduled to be completed until 2012. If DRA recommends an adjustment to the 2011 expenditures, there will not be a revenue requirement impact until 2012, when the project is completed, is booked to plant-in-service, and begins earning a return.

C. Overview of TDBU Capital Expenditures

Earlier in this exhibit, Table 6-1 presented a detailed look at the capital expenditures being forecasted by SCE and DRA for the years 2010, 2011, and 2012. However, given the level of detail contained in that table, it may be difficult to visualize how the proposed expenditures compare to recorded data. The following graph compares the overall forecasts with the pattern of past recorded expenditures:

Graph 6-1
Historical and Forecasted TDBU Capital Expenditures
CPUC Jurisdiction -- Nominal Dollars ($000)



As this graph shows, DRA's 2011 estimate is very close to what would be expected given the pattern of historical expenditures, while the 2012 estimate is somewhat higher. For SCE, the 2011 estimate is higher than what would be expected, while the 2012 estimate is much larger than expected. It should be pointed out that neither SCE nor DRA utilized this graph to derive its estimates. However, Graph 6-1 provides a visual "reasonableness check" to judge whether or not the proposed expenditures comport with what would be expected given recent historical experience.

IV. DISCUSSION / ANALYSIS OF DRA'S ADJUSTMENTS

As Graph 6-1 indicates, SCE's forecasts for 2011 and 2012 are higher (much higher for 2012) than what the historical recorded data would indicate. SCE has given a variety of reasons for forecasting these increased levels of TDBU capital expenditures, including catching up on previously deferred capital expenditures, replacing aging infrastructure, and strengthening the distribution system to accommodate increased loads. DRA's investigation of these issues included carefully analyzing SCE's numerous volumes of testimony and workpapers, issuing a variety of data requests, and meeting with SCE personnel. In many instances, DRA has found SCE's forecasts to be reasonable. However, as shown on numerous lines of Table 6-1, DRA has not agreed with many of SCE's estimates. The following sections present DRA's analysis of a number of SCE's proposed projects, and discuss DRA's recommended adjustments for these capital projects.

A. Adjustment to Reflect 2010 Recorded Data

As discussed previously, DRA was able to obtain recorded 2010 TDBU capital expenditures from SCE.[3] This recorded information is shown on Table 6-1 in column h. Since capital expenditures are cumulative in nature (i.e., one year's capital additions are added to the next), in order to develop a test year rate base,

[3] 2010 recorded data obtained from SCE in an e-mail dated 3/16/2011.

capital expenditures must be developed for all estimated years. In this GRC, SCE's last recorded year was 2009, meaning it had to develop forecasts for 2010, 2011, and 2012. Since DRA was able to obtain 2010 recorded data, it only had to develop forecasts for 2011 and 2012. The only issue for DRA is how to best update the RO computer model so that it properly reflects the recorded data.

SCE includes over 1800 lines of in-depth capital project detail in the RO computer model; these cover all of the capital projects that SCE is proposing for this GRC. All of the 2010 expenditures currently included in the model in these 1800+ lines reflect SCE's estimates, not actual recorded data. DRA does not have access to all of the detailed 2010 recorded expenditure data on a project-by-project basis. The level of recorded data obtained by DRA for this exhibit only extends to the capital categories shown on Table 6-1, not the 1800+ project categories contained in the RO model. It is therefore impossible for DRA to update each of the lines in the model. Nevertheless, DRA believes that it can accurately reflect the impact that the 2010 recorded data will have on the revenue requirement by judiciously adjusting a representative subset of the projects listed in the model.

In this particular instance, DRA's task is made easier because the difference between SCE's total 2010 estimate (for the capital projects included in this exhibit) and the recorded amount is only $4.123 million. The differences (either positive or negative) between actual and estimated expenditures are evenly distributed among the project categories previously shown on Table 6-1; for 16 of the categories listed, the recorded expenditures are lower than SCE had estimated, while 18 are higher. Therefore, DRA has concluded that the most logical way to make an adjustment to the RO model is to reduce the project category that has the largest positive difference between the estimated and recorded expenditures (i.e., reduce the project category where SCE has the largest overestimation of actual expenditures). A careful examination of Table 6-1 shows that the category for Subtransmission Lines Plan (line 2) has a difference of $26.523 million in 2010, by far the largest disparity

on the table.[4] Therefore, DRA simply examined all of the capital projects that make up the Subtransmission Line category, selected the single project with the largest cost,[5] and deducted $4.123 million from the estimated 2010 capital expenditure for that project.

No single adjustment to the RO computer model will exactly duplicate every aspect (construction durations, depreciation rates, etc.) of a detailed 1800+ line-by-line update. However, DRA believes that the adjustment that has been made will give a good approximation of the revenue requirement impact made by using 2010 recorded expenditures for these TDBU areas.

B. Adjustments to Load Growth Projects

Capital expenditures in the Load Growth area are primarily designed to accomplish two objectives: 1) strengthen the system to accommodate projected growth in demand due to the addition of new customers and/or existing customers increasing their current loads, and 2) interconnect new generating plants to SCE's system. As Table 6-1 shows, there are 10 project categories that make up the Load Growth area. Of these 10 categories, DRA is recommending adjustments to four of them. Each of these proposed adjustments is discussed in the following sections. SCE presents its Load Growth testimony in Exhibit SCE-03, Volume 03, Part 01 and 02, Chapters I-II. All references to SCE's testimony in the Load Growth sections that follow refer to that specific SCE exhibit. The following excerpt from Table 6-1 includes the lines that are referenced in the subsequent discussions on DRA's recommended adjustments to projects in the Load Growth Projects area.

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[4] See Table 6-1, line 2, columns g and h. $50.485 million (SCE estimated) minus $23.962 million (recorded) equals $26.523 million.

[5] The Valley-Ivyglen 115 kV project is the single largest Subtransmission Line project proposed by SCE in this GRC, with an estimated total cost of $33.424 million.

Table 6-1 (Excerpt)

Line #	Category	Forecasted						
		2010		2011		2012		
		SCE	DRA - Recorded	SCE	DRA	SCE	DRA	SCE ≥ DRA
		(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Load Growth:							
1	A-Bank Plan	$81,976	$79,509	$83,380	$83,380	$101,955	$101,955	$0
2	Subtransmission Lines Plan	$50,485	$23,962	$52,684	$50,614	$33,419	$29,590	$3,829
3	Subtransmission VAR Plan	$6,106	$5,778	$3,844	$3,844	$1,050	$1,050	$0
4	Distribution Substation Plan (DSP)	$94,411	$101,749	$117,468	$92,313	$132,361	$76,508	$55,853
5	Substation Equipment Replacement Program (SERP)	$5,412	$3,683	$6,000	$6,000	$9,000	$7,000	$2,000
6	DSP Circuits - Blanket Budget Items	$114,413	$123,206	$121,400	$121,400	$112,600	$112,600	$0
7	Distribution Plant Betterment - Blanket Budget Items	$5,565	$18,304	$5,700	$5,700	$7,400	$7,400	$0
8	Distribution VAR Plan - Blanket Budget Item	$3,855	$5,550	$5,000	$5,000	$6,800	$6,800	$0
9	Plug-In Electric Vehicle Readiness Plan	--	--	$2,089	$134	$8,523	$782	$7,741
10	Generator Interconnection Program	$7,579	$8,323	$4,949	$4,949	$1,000	$1,000	$0
11	Total	$369,802	$370,064	$402,514	$373,334	$414,108	$344,685	$69,423

1. Subtransmission Lines Plan

SCE presents a list of its proposed Subtransmission Lines capital projects in Table II-6 (page 48) of its testimony. SCE provides a concise discussion of each of the 27 projects in the pages that follow Table II-6. Upon reviewing SCE's description of these projects, DRA noted that four of them had been previously approved by the Commission in SCE's 2009 GRC, but had been deferred to this current GRC due to delays in obtaining permits. For example, lines 14 through 16 on page 49 describe how the Valley-Auld 115 kV Line has been delayed from prior GRCs due to problems in acquiring necessary permits.

SCE acknowledges these deferrals in Table II-3 on page 27. In that table, SCE lists all of the Subtransmission Line projects (as well as the Substation projects) that were deferred from the last GRC. As part of its analysis of this area, DRA sought to determine whether such delays might occur with any of the 27 Subtransmission Line projects that are being requested in this GRC.

During the capital review process of a GRC, DRA seeks to determine whether the requesting utility has adequately justified the need for each of its proposed capital projects. If so, DRA then seeks to determine that the estimated cost of each project is reasonable. For power line projects (as well as for substation projects, which will be analyzed later in this exhibit), utilities have an additional regulatory requirement that must be met. General Order (GO) 131-D states, in part, the following in Section III.B:

> "No electric public utility shall begin construction in this state of any <u>electric power line facilities</u> or substations which are designed for immediate or eventual operation at any voltage between 50 kV or 200 kV or new or upgraded substations with high side voltage exceeding 50 kV without this Commission's having first authorized the construction of said facilities by issuance of a permit to construct in accordance with the provisions of Sections IX.B, X, and XI.B of this General Order." (Emphasis added.)

In later portions of GO 131-D, there is a list of a number of exemptions to this Order. This DRA exhibit is not meant to be a complete instruction manual on environmental regulation. However, it is important to note that as part of its regulatory burden, for each Subtransmission Line project exceeding 50 kV, SCE must either obtain a Permit To Construct (PTC) or a Certificate of Public Convenience and Necessity (CPCN) from the Commission, or it must determine that the project falls under one of the exempt categories, which excludes the project from compliance with the PTC portions of the Order.

To investigate this matter further, DRA issued Data Request DRA-223-GAW. (DRA has included a copy of this data request (DR) in Appendix A of this exhibit.) The thrust of this DR is to obtain, for each of the 27 Subtransmission Line projects, an explanation of what authority SCE was operating under in order to proceed with these capital projects. DRA expected to receive a list showing that each project had either: 1) received some type of authority from the Commission allowing the project to go forth, or 2) fallen under one of the exemptions listed in GO 131-D. In responding to this DR, SCE notes in its reply to Question 1.c, that many of these projects are exempt from GO 131-D requirements. (This response is included in Appendix A.) As part of its DR response, SCE also included a spreadsheet that provided the detailed project-by-project authorization information that DRA had requested. (This spreadsheet is also included in Appendix A.) For many of the projects, the last column of the spreadsheet (the "Comments" column) identifies the specific exemption category that SCE claims the project falls under.

SCE claims that many of the proposed Subtransmission Line projects are exempt from the permitting process. DRA is not at this time challenging any of the exemptions being proposed by SCE. However, DRA also noted that for five of the

27 projects, SCE has neither provided any authorization that allows it to proceed with the project, nor provided any claim of exemption. This appears to be a direct violation of the GO 131-D language quoted previously. SCE should not be allowed to proceed with any power line project without having complied with the requirements of this General Order.

DRA is questioning each of the five projects for which SCE has failed to provide authorization details. Absent any approval to proceed from the Commission, and absent any claim that these projects fall under one of the exemption categories contained in GO 131-D, DRA can ascertain no reason why funding for these five should be allowed. Consequently, DRA is recommending no ratepayer funding for all capital expenditures associated with these projects, resulting in the reduced forecasts shown on line 2 of Table 6-1. The net result of DRA's recommendations is a reduction of $2.070 million in 2011 Subtransmission Lines capital expenditures, with an additional $3.829 million reduction in 2012.

2. Distribution Substation Plan (DSP)

SCE presents a list of its proposed Distribution Substation capital projects in Table II-8 (page 70) of its testimony. SCE provides a concise discussion for each of the 75 projects in the pages that follow Table II-8. Upon reviewing SCE's description of these projects, DRA noted that several of them had been previously approved by the Commission in SCE's 2009 GRC, but had been deferred to this current GRC due to delays in obtaining permits. For example, lines 3 through 5 on page 74 describe how the Kimball 66/12 kV Substation project has been delayed from prior GRCs due to problems in acquiring necessary permits.

SCE acknowledges these deferrals in Table II-3 on page 27. In that table, SCE lists all of the Substation projects (as well as the Subtransmission Line projects) that were deferred from the last GRC. As part of its analysis of this area, DRA sought to determine whether such delays might occur with any of the 75 DSP projects that are being requested in this GRC.

During the capital review process of a GRC, DRA seeks to determine whether the requesting utility has adequately justified the need for each of its proposed capital projects. If so, DRA then seeks to determine that the estimated cost of each

project is reasonable. For substation projects, utilities have an additional regulatory requirement that must be met. General Order (GO) 131-D states, in part, the following in Section III.B:

> "No electric public utility shall begin construction in this state of any electric power line facilities or substations which are designed for immediate or eventual operation at any voltage between 50 kV or 200 kV or new or upgraded substations with high side voltage exceeding 50 kV without this Commission's having first authorized the construction of said facilities by issuance of a permit to construct in accordance with the provisions of Sections IX.B, X, and XI.B of this General Order." (Emphasis added.)

In later portions of GO 131-D, there is a list of a number of exemptions to this Order. This DRA exhibit is not meant to be a complete instruction manual on environmental regulation. However, it is important to note that as part of its regulatory burden, for each Distribution Substation project with a high side voltage exceeding 50 kV, SCE must either obtain a Permit To Construct (PTC) or a Certificate of Public Convenience and Necessity (CPCN) from the Commission, or it must determine that the project falls under one of the exempt categories, which excludes the project from compliance with the PTC portions of the Order.

To investigate this matter further, DRA issued Data Request DRA-223-GAW. (DRA has included a copy of this data request (DR) in Appendix B of this exhibit.) The thrust of this DR was to obtain, for each of the 75 DSP projects, an explanation of what authority SCE was operating under in order to proceed with these capital projects. DRA expected to receive a list showing that each project had either: 1) received some type of authority from the Commission allowing the project to go forth, or 2) fallen under one of the exemptions listed in GO 131-D. In responding to this DR, SCE notes in its reply to Question 2.c, that many of these projects are exempt from GO 131-D requirements. (This response is included in Appendix B.) As part of its DR response, SCE also included a spreadsheet that provided the detailed project-by-project authorization information that DRA had requested. (This spreadsheet is also included in Appendix B.) For many of the projects, the last

column of the spreadsheet (the "Comments" column) identifies the specific exemption category that SCE claims the project falls under.

SCE claims that many of the proposed DSP projects are exempt from the permitting process. DRA is not challenging any of the exemptions being proposed by SCE at this time. However, DRA also noted that for 35 of the 75 projects, SCE has neither provided any authorization that allows it to proceed with the project, nor provided any claim of exemption. This appears to be a direct violation of the GO 131-D language quoted previously. SCE should not be allowed to proceed with any substation project without having complied with the requirements of this General Order.

DRA is questioning each of the 35 projects for which SCE has failed to provide authorization details. For at least one of these 35 projects (the Thornhill 115/12 kV line), SCE has now determined that the project is no longer necessary and has cancelled it. Absent any approval to proceed from the Commission, and absent any claim that these projects fall under one of the exemption categories contained in GO 131-D, DRA can ascertain no reason why funding for these 35 should be allowed. Consequently, DRA is recommending no ratepayer funding for all capital expenditures associated with these projects, resulting in the reduced forecasts shown on line 4 of Table 6-1. The net result of DRA's recommendations is a reduction of $25.155 million in 2011 DSP capital expenditures, with an additional $55.853 million reduction in 2012.

While DRA's total recommended adjustments is quite large, it is actually less than the total costs of the deferred distribution substation projects that are listed in Table II-3 (page 27) of SCE's testimony.[6] DRA's proposed reductions are quite modest when compared to the total cost of these previously authorized substations that were deferred. It is clear that Distribution Substation projects are subject to delays, and DRA expects that trend to continue in this GRC.

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[6] The total cost of the nine deferred substation projects listed in Table II-3 is $116.659 million. Note that this is a "total" cost, meaning that it is the sum of all the capital expenditures that occurred over the total multi-year construction period.

3. Substation Equipment Replacement Program (SERP)

The Substation Equipment Replacement Program (SERP) evaluates the adequacy of substation terminal equipment and system protection devices. SCE discusses SERP beginning on page 115 of its testimony. Based on this discussion, SCE states that it needs to replace various quantities of several different types of circuit breakers.

On page 117 of its testimony, SCE includes Table II-9, which provides additional details regarding the types of circuit breakers that are being replaced, their unit costs, and the total capital expenditures SCE is proposing per year. In order to more easily analyze this information, DRA rearranged the data and included recorded information going back to 2005. This has resulted in Table 6-2, shown on the next page. Note that for the recorded years 2005 through 2009, only the total recorded costs are available, and are highlighted in columns n and o.

The first thing to note regarding Table 6-2 is how total expenditures (columns n and o) abruptly increase starting in 2010. Prior to that year, the highest recorded expenditure was $1.441 million in 2008. For 2012, SCE is forecasting $9.000 million, over six times higher than the previous largest expenditure. By any definition of the word, this is a “significant” proposed increase.

Also worth noting on Table 6-2 is how the number of proposed 66 kV circuit breaker replacements is increasing by 10 starting in 2012 (column b). On lines 2 through 5 on page 116, SCE states that it has identified 211 circuit breakers that need replacing, which it intends to do over the period 2010 through 2014. DRA agrees that the circuit breakers will need replacing, but believes that doing so over a slightly longer period of time is more reasonable.

Table 6-2
SUBSTATION EQUIPMENT REPLACEMENT PROGRAM (SERP)
Adjustments to 66 kV Circuit Breaker Installations
CPUC Jurisdiction (Thousands of Direct Nominal Dollars)

Line #	Year	66 kV Circuit Breakers						12/16 kV Circuit Breakers						Total	
		Units		Unit Cost ($000)		Total		Units		Unit Cost ($000)		Total			
		SCE	DRA	SCE	DRA	SCE	DRA	SCE	DRA	SCE	DRA	SCE	DRA	SCE	DRA
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	2005													$980	$980
2	2006													$53	$53
3	2007													$948	$948
4	2008													$1,441	$1,441
5	2009													$447	$447
6	2010	27		$190		$5,130		18		$106		$1,908		$7,038	$3,683
7	2011	26	26	$193	$193	$5,018	$5,018	9	9	$107	$107	$963	$963	$5,981	$6,000
8	2012	36	26	$198	$198	$7,128	$5,148	17	17	$110	$110	$1,870	$1,870	$9,000	$7,000
9	2013	36	26	$204	$204	$7,344	$5,304	28	28	$113	$113	$3,164	$3,164	$10,508	$8,468
10	2014	36	26	$210	$210	$7,560	$5,460	38	38	$117	$117	$4,446	$4,446	$12,006	$9,906

= recorded data

As can be seen in columns h and i of Table 6-2, DRA does not take issue with SCE's proposed replacement schedule for the 12/16 kV circuit breakers. However, as shown in columns b and c, DRA is proposing adjustments to the 66 kV replacements. As shown in column b, SCE proposes to replace 26 of the 66 kV circuit breakers in 2011, and replace 36 per year thereafter through 2014. The total number of replacements for those four years equals 134.[7] DRA's recommendation is to replace 26 circuit breakers each year (see column c), which means that replacing 134 breakers will take a little over five years.[8]

SCE is not required or mandated to complete these replacements in four years, nor has SCE demonstrated an operational need to complete these replacements in its proposed time frame. In 2010, SCE proposes replacing 27 breakers, and in 2011, 26 more. If SCE considered these replacements to be a matter of some urgency, at the very least it would have proposed replacing 36 breakers per year beginning in 2010 (not 2012). In DRA's judgment, replacing 26 of the 66 kV circuit breakers per year is reasonable; not only is the work load evenly distributed over all the years, but an abrupt expenditure jump is avoided in 2012. As can be seen on line 5 of Table 6-1, DRA's recommendation results in a $2.000 million decrease in 2012 SERP capital expenditures.

4. Plug-In Electric Vehicle Readiness Program

Beginning on page 127 of its testimony, SCE discusses the impact that increasing numbers of plug-in electric vehicles (PEVs) will likely have on its electrical system. SCE states that these PEVs represent a significant load on its system – as much as two or three times that of a typical household load. However, the exact impact these vehicles will have on SCE's system is a matter of much speculation. As SCE acknowledges, many important factors remain unknown – the total number of PEVs that will be purchased, the battery size of the vehicles, the potential for

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[7] 26 circuit breakers (for 2011) + 36 circuit breakers times 3 (for the years 2012, 2013, and 2014) = 134.

[8] 134 circuit breakers ÷ by 26 replacements per year = 5.15 years to replace them all.

geographic clustering of these vehicles, and the charging behavior of the vehicles' owners are all subject to widely differing estimates.

Because of these uncertainties, SCE developed three sets of infrastructure improvement estimates (low, medium, and high forecasts) depending on the degree of market penetration of PEVs in its service territory. In its request for this GRC, SCE uses the "medium" estimate (the impact of which is shown in columns i and k on row 9 of Table 6-1). DRA has concluded that infrastructure improvement forecasts associated with the "low" market penetration are more reasonable, given the current uncertainty associated with the PEV market.

DRA is concerned that the initial purchase price of PEVs will keep demand for these cars low. DRA acknowledges that fuel costs have gone up, which would tend to increase the popularity of PEVs. However, there are a variety of high mileage non-PEV cars that are much less expensive than plug-ins. In DRA's judgment, the economic conditions in California are likely to curtail the purchase of these cars.

DRA's recommended use of the "low" estimate has been bolstered by the ongoing tragedies impacting Japan. Numerous articles have discussed how the Japanese car market is going to be negatively impacted by the earthquake/tsunami and the resultant power problems. For example, AutoGuide has reported that the crisis in Japan is continuing to impact automakers and the entire auto industry, even American companies.[9] The Japanese plant that builds the high-tech transmission for the Chevy Volt has been shut down in the wake of the earthquake and nuclear problems. It is becoming increasingly obvious that there simply will be fewer PEVs available for sale than had originally been assumed. Combining these supply problems with the continuing economic issues, DRA believes that it is reasonable to use the "low" estimate of PEV market penetration to estimate infrastructure improvement estimates.

As stated previously, SCE's forecasts were predicated on the "medium" assumption for PEV market penetration. In a verbal data request, DRA requested

[9] March 18, 2011 article in AutoGuide.com by Blake Z. Rong.

that SCE provide the infrastructure improvement estimates that it had developed based on the "low" assumption. As expected, SCE's response to this data request[10] shows that the "low" estimates are considerably smaller than the ones it used in this GRC. SCE's revised estimates of $0.134 million for 2011 and $0.782 million for 2012 are used by DRA and are shown on line 9 of Table 6-1. The use of these revised estimates results in a reduction of the capital expenditures for the PEV Readiness Plan of $1.955 million in 2011 and $7.741 million in 2012.

C. Adjustments to Infrastructure Replacement Projects

As equipment ages, the risk of experiencing failures generally increases. The capital projects included under the Infrastructure Replacement area seek to replace pieces of equipment prior to their failure based on a risk/reliability evaluation. Stated another way, these programs preemptively replace pieces of equipment that are still operational, based on various studies that show they may soon fail. As Table 6-1 shows, there are 14 project categories that make up the Infrastructure Replacement area. Of these 14 categories, DRA is recommending adjustments to six of them. Each of these proposed adjustments is discussed in the following sections. SCE presents its Infrastructure Replacement testimony in Exhibit SCE-03, Volume 03, Part 03, Chapters I-II. All references to SCE's testimony in the Infrastructure Replacement sections that follow refer to that specific SCE exhibit. The following excerpt from Table 6-1 includes the lines that are referenced in the subsequent discussions on DRA's recommended adjustments to projects in the Infrastructure Replacement Projects area.

[10] SCE response to DRA Verbal Data Request #58, Question 1, Attachment 1 of 2.

Table 6-1 (Excerpt)

Line #	Category	Forecasted						
		2010		2011		2012		
		SCE	DRA - Recorded	SCE	DRA	SCE	DRA	SCE ≥ DRA
		(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Infrastructure Replacement Programs							
12	Cable Replacement Program	$29,636	$35,947	$38,874	$38,874	$74,514	$46,820	$27,694
13	Worst Circuit Rehabilitation (WCR)	$20,300	$24,607	$18,660	$18,660	$33,119	$33,119	$0
14	Cable-In-Conduit (CIC) Replacement	$3,290	$4,030	$13,357	$4,102	$30,560	$4,201	$26,359
15	Cable Testing Pilot	--	--	--	--	$2,123	$2,123	$0
16	Underground Oil Switch Replacement	$14,095	$21,556	$6,479	$6,479	$10,615	$10,615	$0
17	PMH-4 Switch Replacement	$3,480	--	$2,281	$2,281	$2,335	$2,335	$0
18	Capacitor Bank Replacement	$6,505	$7,667	$5,667	$5,667	$10,482	$10,482	$0
19	Automatic Recloser Replacement	$1,600	$1,536	$1,596	$1,596	$2,229	$2,229	$0
20	PCB Transformer Replacement	$613	$1,783	$624	$624	$2,282	$2,282	$0
21	A and B-Bank Transformers	$33,336	$37,843	$34,201	$34,201	$65,097	$54,475	$10,622
22	Distribution Circuit Breakers	$10,236	$12,023	$15,296	$15,296	$22,000	$18,436	$3,564
23	Protection and Control	$1,204	$8,568	$2,554	$2,554	$5,372	$5,372	$0
24	4kV Cutovers	$16,700	$24,376	$17,214	$17,214	$30,167	$20,433	$9,734
25	4kV Substation Elimination	--	--	--	--	$34,286	$0	$34,286
26	Total	$140,995	$179,936	$156,803	$147,548	$325,181	$212,922	$112,259

1. Cable Replacement Program

SCE begins its discussion of the Cable Replacement Program on page 15 of its testimony. These capital expenditures are used for the proactive replacement (i.e., replacing before they fail) of underground cables. SCE states that this program attempts to identify the poorest performing electrical circuits and preemptively implements improvements to those circuits where they are needed most. SCE has devoted a significant amount of time and resources analyzing Cable Replacement projects, going so far as to retain an outside consultant, Quanta Technology (Quanta) to study how aging underground cables are likely to impact the future reliability of SCE's electrical system. In its workpapers, SCE has included a copy of the report prepared by Quanta. This report, *"Impact of Aging Infrastructure on System Reliability"* examines how system reliability in 2030 will be impacted under various equipment replacement scenarios.

The proactive replacement of underground cables primarily takes place in three Infrastructure Replacement capital project categories. The first of these projects is the Cable Replacement Program, which is the subject of this analysis; it is shown on line 12 of Table 6-1. Two additional projects, the Worst Circuit Rehabilitation (WCR) and the Underground Oil Switch Replacement, also contribute to the replacement of underground cable; they are shown on lines 13 and 16.

The Cable Replacement Program is complex due to the nature of its linkage to, and interaction with, other Infrastructure Replacement programs. The Quanta report, which utilizes the results from the Cable Replacement Program as well as another program (the Worst Circuit Rehabilitation Program), adds another layer of complexity to the analysis. Because of the way these different Infrastructure Replacement programs are linked to each other and to the Quanta report, DRA concludes that a straight-forward and logical approach to analyze this capital category is to first determine a reasonable quantity (in circuit miles) of underground cable to be replaced each year. Once that total is derived, one can then determine how that quantity of replacements should be allocated among the various capital projects and to calculate reasonable expenditure levels.

In subsequent paragraphs, DRA will explain why its estimates for total underground cable replacement are reasonable, how these replacements are allocated to the three different capital project categories, how costs are determined, and how DRA's recommendations impact system reliability. Table 6-3, shown on the next page, begins the process, and shows how these three projects combine to produce the total amount of underground cable that is being proposed for proactive replacement each year. This is the first step in calculating reasonable Cable Replacement forecasts for 2011 and 2012.

The easiest way to understand this table is to begin at the far right (columns i and j) and work towards the left. The far right columns show the total amount of underground cable (in circuit miles) that SCE and DRA are proposing should be proactively replaced each year. As the table shows, up through 2008, the total amount of underground cable replacement for all three projects combined never reached 100 circuit miles in any year. In 2009, the recorded total nearly tripled to 270 circuit miles. Beginning in 2012, SCE proposes another significant increase, to 489 circuit miles, while DRA recommends 350 circuit miles.

Table 6-3
Preemptive Underground Cable Replacement
Circuit Miles Replaced Under the Cable Replacement, the Oil Switch Replacement, and the Worst Circuit Rehabilitation (WCR) Programs

Line #	Year	Cable Replacement Program						Worst Circuit Replacement (Circuit Miles)		Total Miles of Replacement (Circuit Miles)	
		Cable Replacement (Circuit Miles)		Oil Switch (Circuit Miles)		Sub-Total (Circuit Miles)					
		SCE	DRA	SCE	DRA	SCE	DRA	SCE	DRA	SCE	DRA
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**2005**	64	64	0	0	64	64	0	0	64	64
2	**2006**	20	20	0	0	20	20	11	11	31	31
3	**2007**	25	25	0	0	25	25	27	27	52	52
4	**2008**	13	13	31	31	44	44	55	55	99	99
5	**2009**	116	116	81	81	197	197	73	73	270	270
6	**2010**	53	53	102	102	155	155	74	74	229	229
7	**2011**	154	154	46	46	200	200	67	67	267	267
8	**2012**	300	161	74	74	374	235	115	115	489	350
9	**2013**	300	161	74	74	374	235	115	115	489	350
10	**2014**	300	161	74	74	374	235	115	115	489	350

DRA accepts SCE's 2011 estimate of replacing 267 circuit miles of underground cable; it is in line with previous levels of replacement. DRA also agrees with SCE's proposal to increase the quantity of replacements starting in 2012. However, in DRA's judgment, replacing 489 circuit miles per year beginning in 2012 (as SCE proposes) is not reasonable. The highest recorded amount of underground cable replacement occurred in 2009, when 270 circuit miles were replaced. DRA's 2012 recommendation of 350 circuit miles is 30% higher than that previous total. Not only is DRA's recommendation reasonable (even generous) when compared to historical levels of replacement, it is also reasonable from the standpoint of maintaining system reliability, the main issue discussed in the Quanta report. This issue of system reliability will be discussed in greater detail later in this section.

Continuing with the examination of Table 6-3, the next step is determining how to allocate the total underground cable replacements among the three Infrastructure Replacement categories: the Cable Replacement Program, the Worst Circuit Rehabilitation (WCR) Program, and the Underground Oil Switch Replacement Program. The allocation among the three categories could potentially be made in a number of ways. However, as shown on lines 13 and 16 of Table 6-1, DRA accepts SCE's capital expenditure estimates for the WCR Program and the Underground Oil Replacement Program, which also means that DRA accepts the forecasted number of circuit miles of underground cable replacements associated with those programs. Therefore, moving to the left in Table 6-3, DRA's replacement forecasts in columns d and h are the same as SCE's. By the mathematical process of elimination, the only area where DRA's adjustment (to the total recommended level of underground cable replacements) can be reflected is the Cable Replacement Program, column b. As shown in that column, DRA's 2012 replacement estimate is 161 circuit miles, versus SCE's estimate of 300.[11]

[11] To derive the 2012 allocation: 350 total miles minus 115 WCR miles minus 74 oil switch miles equals 161 miles remaining for the Cable Replacement Program.

Having now discussed the development of the total amount of underground cable to be proactively replaced each year, and having allocated that total among the three capital programs, the next step is to calculate the 2011 and 2012 capital costs. This can best be done by looking at Table 6-4 on the following page.

The first thing to note about that table is that the Worst Circuit Rehabilitation Program is no longer included. The capital forecasts for that program (see line 13 on Table 6-1) include the costs for replacing the associated underground cables; no further calculations are necessary. This is in contrast to the capital forecasts for the Underground Oil Switch Replacement Program, shown on line 16 of Table 6-1. For some reason, the cost of that program only covers the cost of the switch replacements; the cost of the associated underground cable replacements is <u>not</u> included in that forecast.

As shown on Table 6-4, SCE combines the cable replacement levels for the Cable Replacement Program as well as the Oil Switch Replacement Program (columns e and f) when it calculates the capital costs for the Cable Replacement Program. Stated another way, the forecasts for the Cable Replacement Program also include the costs for the cable replacements associated with the Oil Switch Replacements.

On Table 6-4, the replacement amounts shown in columns a through f have simply been transferred from the corresponding columns in Table 6-3. The only new information contained in Table 6-4 is the unit cost data (columns g and h). DRA has examined the unit cost estimates developed by SCE and does not take issue with them. The last piece of this lengthy analysis is to simply multiply the mileage totals (listed in columns e and f) by the unit costs (shown in columns g and h) to derive the final Cable Replacement forecasts (columns i and j). The net result of all this is shown on line 12 of Table 6-1 – DRA accepts SCE's 2011 forecast for this program, but is recommending a reduction of $27.694 million for 2012.

Table 6-4
Preemptive Underground Cable Replacement Program -- Excluding Worst Circuit Rehabilitation (WCR) Program
(000s of Direct Nominal Dollars -- CPUC Jurisdiction)

Line #	Year	Preemptive Underground Cable Replacement Program (Excludes WCR Program)									
		Cable Replacement (Circuit Miles)		Oil Switch (Circuit Miles)		Circuit Miles Sub-Total		Unit Cost		Total Cost	
		SCE	DRA	SCE	DRA	SCE	DRA	SCE	DRA	SCE	DRA
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**2005**	64	64	0	0	64	64	$101	$101	$6,483	$6,483
2	**2006**	20	20	0	0	20	20	$236	$236	$4,716	$4,716
3	**2007**	25	25	0	0	25	25	$136	$136	$3,388	$3,388
4	**2008**	13	13	31	31	44	44	$260	$260	$11,443	$11,443
5	**2009**	116	116	81	81	197	197	$141	$141	$27,722	$27,722
6	**2010**	53	53	102	102	155	155	$191	$191	$29,636	$29,636
7	**2011**	154	154	46	46	200	200	$194	$194	$38,874	$38,874
8	**2012**	300	161	74	74	374	235	$199	$199	$74,514	$46,820
9	**2013**	300	161	74	74	374	235	$205	$205	$76,676	$48,179
10	**2014**	300	161	74	74	374	235	$211	$211	$79,045	$49,667

Having finally derived its estimates for this capital program, the last portion of DRA's analysis examines how these recommendations impact the reliability of SCE's system, as detailed in the Quanta report. As stated previously, Quanta investigated what impact an aging underground cable population would have on SCE's overall reliability. Quanta investigated four scenarios: 1) making no proactive replacements of underground cables, 2) annually proactively replacing 150 circuit miles, 3) annually proactively replacing 415 circuit miles, and 4) annually proactively replacing 700 circuit miles. For each scenario, Quanta attempts to measure the reliability impact on SCE's electrical system in 2030 by calculating to what degree SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) levels would change.

It is important to note that when Quanta performed its analyses of these four scenarios, underground cable replacements associated with the Oil Switch Replacement program were not factored in. SCE confirms this in footnote 12 on page 22 of its testimony. SCE states that it does not believe that replacements associated with the Oil Switch program have as significant an impact on reliability as the other types of underground cable replacements. The omission of the underground cable replacements associated with the Oil Switch Replacement program seems puzzling, and such an omission casts a shadow on the credibility of the analyses performed by Quanta. As indicated by the quantities listed in columns c and d on Table 6-3, a significant amount of underground cable is associated with the Oil Switch Replacement program. It is erroneous to assume that omitting such volumes of replacements will have no impact on SAIDI and SAIFI. In effect, SCE (and Quanta) are ignoring columns c and d on Table 6-3 when the reliability of the system is being analyzed. While DRA disagrees with this omission, it does show how the 415-mile replacement figure was derived, and why it was used as one of the scenarios; by excluding columns c and d from Table 6-3, the resulting replacement total for 2012 (and beyond) for SCE equals 415 circuit miles.[12]

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[12] From Table 6-3: 300 circuit miles (from column a) plus 115 circuit miles (from column g) equals 415 circuit miles, the amount found reasonable by SCE.

SCE has included some excerpts from the Quanta report in its testimony. On pages 23 and 24, SCE presents four graphs that show how SAIDA and SAIFI would change with no annual replacements, with 415 circuit miles of annual replacements, and with 700 circuit miles of annual replacements. SCE did not include a graph showing the impact of annually replacing 150 circuit miles, one of the scenarios analyzed by Quanta. The important thing to note regarding these four graphs is that reliability is forecasted to decrease; SAIDI and SAIFI are projected to steadily increase through the year 2030. Whether 700 circuit miles are replaced each year, whether no circuit miles are replaced each year, or whether any amount between those two extremes is replaced, the result is the same – SAIDI and SAIFI are going up. The question therefore boils down to what level of increase is acceptable.

In the Quanta report, SAIDI and SAIFI levels for 2030 can be found for each of the replacement scenarios. The following tabulation shows how much SAIFI is projected to increase by 2030 (over the levels occurring in 2010) for three different replacement scenarios:

Increases In SAIFI by 2030 (Events)		
0 Miles	**150 Miles**	**415 Miles**
0.70	0.61	0.47

As previously stated, SCE has concluded that replacing 415 circuit miles per year of underground cable (which excludes the replacement amounts associated with the Oil Switch Replacement program) is reasonable. A comparable calculation using DRA's estimates is 276 circuit miles.[13] As shown in the above tabulation, Quanta estimates that by 2030, SAIFI will be 0.47 higher than it is currently if 415 circuit miles are proactively replaced each year, meaning that the reliability of SCE's

[13] From Table 6-3: 161 circuit miles (from column b) plus 115 circuit miles (from column h) equals 276 circuit miles (which excludes the replacement amounts associated with the Oil Switch Replacement program).

electrical system will be lower than it is today. Using DRA's estimate of 276 circuit miles, the comparable SAIFI increase by 2030 would be somewhat less than 0.61.[14]

What do these figures mean, and what is their significance? Using the figures in the above tabulation, increasing the annual level of proactive underground cable replacements from 150 circuit miles to 415 circuit miles will cause SAIFI to experience a decrease of 0.14 outages per year, on average, by the year 2030.[15] Stated another way, increasing the yearly proactive replacements from 150 circuit miles to 415 circuit miles will result in the average customer experiencing only <u>one</u> less outage every 7.14 years by 2030.[16]

The small improvement in reliability obtained by increasing the amount of yearly proactive underground cable replacements from 150 circuit miles to 415 circuit miles does not warrant the additional costs. The average SCE customer would not even be aware of any degradation in reliability if they experienced one additional outage every 7+ years. These calculations are all based on the change from 150 circuit miles to 415 circuit miles. Since DRA's actual recommendation (omitting the Oil Switch Replacement amounts) is for replacing 276 circuit miles (not 150), the real reliability improvement in SAIFI in going to 415 circuit miles is even smaller than the 0.14 increase calculated earlier.

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[14] The larger the annual proactive replacement, the lower the increase that SAIDI will experience by 2030. Since DRA's replacement estimate of 276 circuit miles is larger than the 150 circuit mile amount shown in the tabulation, the resulting SAIFI increase will be somewhat smaller than the 0.61 increase shown for 150 circuit miles.

[15] 0.61 events less 0.47 events equals a decrease of 0.14 events.

[16] Using a simple example to illustrate this concept, suppose that SAIFI is reduced from 1.00 to 0.90. Before the reduction, on average, a customer could expect to experience 1 outage per year. After the reliability improvement, on average, a customer could expect to experience 0.90 outages per year. Over a 10-year period, the average customer would experience 1 fewer outage (10 outages over that period before the improvement versus 9 outages over that period after the improvement). The general formula for calculating the length of time it would take for the average customer to experience 1 fewer outage is (1 ÷ SAIFI Reduction). In this particular case, with a SAIFI reduction of 0.14, it would take on average 7.14 years for the typical customer to experience 1 less outage.

The reasonableness of DRA's 2012 forecast can be evaluated in several ways. If the reasonableness of DRA's forecast is judged by how many total circuit miles of underground cable are to be replaced, DRA's estimate will be found to be prudent, even generous, considering that DRA is recommending a total replacement level that is 30% higher than any previous recorded year. On the other hand, if the reasonableness of DRA's forecast is based on how SCE's system reliability is impacted, DRA's estimate will again be found to be prudent – one additional outage over a period of 7+ years will likely not be noticed by the average customer. It is also important to consider that the time horizon being analyzed is almost 20 years in the future; numerous GRCs will occur between now and 2030, during which appropriate program modifications can be evaluated if warranted. Therefore, no matter which criterion is used as a measure, DRA's forecast of $46.820 million in 2012 capital expenditures for the Cable Replacement Program is reasonable. This recommendation results in a $27.694 million reduction to SCE's 2012 forecast (shown in row 12 of Table 6-1).

2. Cable-In-Conduit (CIC) Replacement

SCE begins its discussion of the Cable-In-Conduit (CIC) Replacement program on page 34 of its testimony. SCE states that in the 1960s, it began installing a type of underground cable that was loosely housed inside a plastic pipe. This so-called Cable-In-Conduit (CIC) eventually developed corrosion problems, and has proven to be unreliable. SCE estimates that it has over 10,000 conductor-miles of this CIC-type cable, and it wants to begin proactively replacing it.

SCE often experiences difficulties when it attempts to replace this type of cable. Frequently, the cable binds up inside the pipe that surrounds it, and it cannot be removed. SCE states that better equipment and better methods of removal must be developed if the replacement of this quantity of cable is to be made affordable.[17] The capital expenditures that SCE is requesting for this project through 2014 will be used for a pilot program to investigate new approaches for replacing this cable.

[17] Exhibit SCE 03, Volume 03, Part 03, Chapters I-II, page 36, lines 2 and 3.

DRA does not object to the creation of a pilot program. As the CIC-type cable continues to age, more and more failures will likely occur. SCE and its ratepayers would want these replacement costs be as economical as possible. Table II-5 on page 37 of SCE's testimony shows that SCE began funding this pilot program in 2009, having spent $0.932 million. As shown on Table 6-1 (row 14, column h), SCE spent an additional $4.030 million in 2010. However, beginning in 2011, SCE is requesting a dramatic increase in the capital expenditures for this pilot program. As shown on line 14 of Table 6-1 (columns i and k), SCE is requesting $13.357 million for 2011 and $30.560 million in 2012.

The Oxford dictionary defines the word "pilot" to be "*an experimental undertaking or test, especially in advance of a larger one.*" In DRA's judgment, SCE's requests for 2011 and 2012 go beyond what is necessary for an "experimental undertaking or test." It is important to carefully determine the most efficient and economical method to replace the CIC-type cables; that is, after all, the purpose of having this pilot program. SCE's request to greatly expand its expenditures in 2011 and 2012 suggests that SCE will be "locking in" a methodology before the pilot program is completed in 2014. DRA recommends that the $4.030 million spent in 2010 should be carried forward (with yearly escalation) into 2011 and 2012. Before SCE dramatically increases the level of capital expenditures for the CIC replacements, it should be certain that it has determined the most efficient way to undertake these replacements. This pilot program can then be evaluated in the next GRC. As shown on line 14 of Table 6-1, DRA forecasts $4.102 million in 2011 and $4.201 million in 2012 for capital expenditures for the CIC Program. DRA's recommendations result in a reduction to SCE's forecasts of $9.255 million in 2011 and $26.359 million in 2012.

3. A and B-Bank Transformers

Transformers are major pieces of equipment that are used to change the voltage of electricity. Transformers are used to increase voltage in order to reduce energy losses during transmission over long distances. Conversely, they are also used to reduce voltage to a level that is usable to SCE's customers. A-bank transformers are located in major substations where they take high voltage electricity

and typically transform it down to 66 kV. B-bank transformers are located in neighborhood substations where they transform 66 kV electricity down to a level that can be sent out into the distribution circuits. A and B-bank transformer replacements are discussed in SCE's testimony beginning on page 67.

On page 70 of its testimony, SCE includes Table II-20. That table provides historical data regarding A-bank transformers. As shown in the first column of data, the number of A-bank replacements scheduled for 2011 and 2012 seems to be consistent with the number of replacements that have occurred in prior years. Similarly, the unit costs for these transformers appear to be reasonable. Therefore, DRA is not recommending any adjustments to SCE's A-bank forecasts.

The details for B-bank transformer replacements are provided on Table II-21 on page 74 of SCE's testimony. As shown in the first column of data, SCE has historically preemptively replaced between 4 and 14 transformers each year. For 2010, SCE estimated that it would replace 20 transformers; the actual recorded number was 14.[18] SCE is estimating that it will replace 16 B-bank transformers in 2011. This is slightly higher than what has occurred historically, but appears reasonable to DRA. However, in 2012, SCE's replacement estimate jumps to 40, nearly three times higher than the previous highest recorded replacement level.[19]

On page 76 of its testimony (lines 6 through 9), SCE derives a theoretical replacement level of 45 transformers per year based on a probability of failure curve. This number is apparently used to justify SCE's estimate of preemptively replacing 40 transformers in 2012. DRA notes several important points regarding SCE's proposal. First, SCE's statistical derivation of 45 transformer failures per year is subject to variation from year to year. As SCE notes, 33% of the B-bank transformers are older than the mean wear-out time, and 270 are older than 80 years.[20] There is obviously no way to know with certainty how many transformers

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[18] Response to Data Request DRA-199-GAW, Question 1.b.

[19] 40 replacements (in 2012) ÷ 14 replacements (previous highest) = 2.86.

[20] Exhibit SCE-03, Volume 03, Part 03, Chapters I-II, page 76, lines 3 through 5.

will fail in any given year. In none of its forecast year estimates (through 2014) is SCE proposing to preemptively replace 45 transformers. DRA's second point is that these are preemptive replacements. As mentioned previously, all the capital projects included under the Infrastructure Replacement Program (including the A and B-bank transformer replacements) seek to replace pieces of equipment prior to their failure based on a risk/reliability evaluation. Stated another way, these programs preemptively replace pieces of equipment that are still operational, based on various studies that show they may soon fail. The cost of "in service" failures (pieces of equipment that fail while they are still being used) are not included as part of the forecasts for this capital program. Combining these two points leads to the following conclusion: the number of B-bank transformers failing each year cannot be predicted with any certainty, and even if they could, SCE is not attempting to eliminate all in service failures since it is proposing to preemptively replace fewer transformers than it predicts will fail (40 replacements versus 45 predicted failures).

DRA tends to be cautious when utilities request sudden dramatic increases for capital expenditures in the test year. As shown on Graph 6-1 of this exhibit, SCE's proposed 2012 capital expenditures are much higher than the historical trend, indicating that SCE is indeed requesting those types of dramatic test year increases. For this particular capital category, the fact that SCE has never recorded more than 14 B-bank capital replacements indicates that SCE does not consider the preemptive replacement of B-bank transformers to be an urgent matter; if it did, SCE would have replaced more than 14 in 2010, and may have requested more than 16 replacements in 2011.

SCE has not shown why 40 replacements are reasonable for 2012. Assuming that SCE actually replaces the 16 B-bank transformers it forecasts for 2011, the jump to 40 replacements in 2012 represents a 150% increase over the 2011 level.[21] DRA's recommended number of replacements for 2012 is 30, considerably lower than SCE's request but much higher than any other recorded

[21] The formula for this calculation is: [(40 – 16) ÷ 16] x 100 = 150%

year. In DRA's judgment, this is a reasonable estimate and represents a very large increase over SCE's estimate of 16 in 2011. DRA's recommended increase (to 30 replacements in 2012) represents an 87.5% increase over the prior year.[22] DRA's recommendation reflects the uncertainty in the actual number of B-bank transformers that are likely to fail, yet recognizes SCE's concern that increasing levels of preemptive replacements are warranted due to the increasing age of the B-bank population.

As shown on Table II-21 of SCE's testimony, once a reasonable level of B-bank transformer replacements is derived, the last step in calculating a total cost is to multiply the number of replacements by the unit costs. DRA has reviewed the unit costs shown on Table II-21 and finds them reasonable. Therefore, the only difference between SCE's and DRA's estimates for total costs for this capital category is that DRA has a lower estimate for 2012 replacements. By reducing the number of B-bank replacements from 40 to 30, DRA's recommended 2012 capital expenditure forecast for A and B-bank transformer replacements is $10.622 million lower than the comparable SCE estimate, as shown on line 21 of Table 6-1.

4. Distribution Circuit Breakers

SCE begins its discussion of Distribution Circuit Breaker Replacements on page 78 of its testimony. Circuit breakers perform the vital task of shutting off the flow of electricity to a circuit that encounters a "fault." When a conductor comes into contact with the ground, such as with a downed wire, a circuit breaker stops the flow of electricity. If these faults are left uncorrected, massive amounts of current will be drawn through the downed wire, possibly destroying cables, switches, and transformers located above the fault, and posing a safety risk to anyone who comes into contact with a live wire.[23]

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[22] The formula for this calculation is: [(30 – 16) ÷ 16] x 100 = 87.5%

[23] SCE 03, Volume 03, Part 03, Chapters I-II, page 79, lines 6 through 9.

SCE has 10,411 distribution circuit breakers in its system. On page 82 of its testimony, SCE provides a calculation that shows that with an average age of 28 years, an estimated 75 breakers will fail each year based on a probability of failure curve. SCE is proposing to preemptively replace far more breakers each year than the 75 that it predicts will fail. Based on the discussion on page 83 of its testimony, SCE also wants to begin replacing breakers that are no longer supported by the original manufacturer, and are consequently difficult to maintain because of a scarcity of spare parts.

To help with its analysis of this capital program, DRA prepared Table 6-5, shown on the next page. As can be seen on that table, there are three categories of distribution circuit breakers: 115 kV, 66 kV, and 12 kV. SCE estimates different levels of replacements for each category, and has derived different unit costs for each. For the years 2005 through 2009, SCE did not provide details regarding the breakdown for breaker replacements or unit costs. It did provide the total number of breakers replaced each year, as well as the total cost.

DRA began its analysis by examining SCE's estimates for total breaker replacements (column m). In DRA's judgment, SCE's estimate of 147 total circuit breaker replacements in 2011 is reasonable; it is of the same magnitude as previous replacements, and is actually slightly less than the 159 replacements that occurred in 2009. However, as with other capital programs previously discussed, SCE is proposing a large increase for the test year. As mentioned earlier, SCE estimates that 75 circuit breakers will fail each year, yet SCE is estimating 215 replacements for 2012 (column m). DRA pays special attention to test year estimates that show sudden dramatic increases for capital expenditures as compared to the previous year. For this particular capital category, the fact that SCE has never recorded more than 159 distribution circuit breaker replacements indicates that SCE does not consider the preemptive replacement of these breakers to be an urgent matter; if it did, SCE would have proposed to replace more than 62 in 2010, and would likely be requesting more than 147 replacements in 2011.

Table 6-5
COST DATA FOR DISTRIBUTION CIRCUIT BREAKER REPLACEMENTS
CPUC Jurisdiction (Thousands of Direct Nominal Dollars)

Line #	Year	115 kV Circuit Breaker Replacements				66 kV Circuit Breaker Replacements				12 kV Circuit Breaker Replacements				Total Circuit Breaker Replacements		Total Cost ($000s)	
		# of Replacements		Unit Costs ($000s)		# of Replacements		Unit Costs ($000s)		# of Replacements		Unit Costs ($000s)					
		SCE	DRA	SCE	DRA	SCE	DRA	SCE	DRA	SCE	DRA	SCE	DRA	SCE	DRA	SCE	DRA
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	2005													101	101	$11,249	$11,249
2	2006													95	95	$14,631	$14,631
3	2007													56	56	$10,037	$10,037
4	2008													137	137	$11,790	$11,790
5	2009													159	159	$15,488	$15,488
6	2010	10	10	$288	$288	30	30	$183	$183	22	22	$84	$84	62	62	$10,236	$12,023
7	2011	6	6	$293	$293	14	14	$187	$187	127	127	$86	$86	147	147	$15,296	$15,296
8	2012	7	7	$301	$301	15	15	$191	$191	193	153	$88	$88	215	175	$22,000	$18,436
9	2013	7	7	$310	$310	15	15	$197	$197	190	153	$91	$91	212	175	$22,402	$19,048
10	2014	7	7	$321	$321	15	15	$204	$204	190	153	$94	$94	212	175	$23,177	$19,689

= recorded data

DRA understands SCE's desire to begin replacing breakers that are no longer supported by the original manufacturer; when spare parts are no longer being produced, breakers can be difficult and expensive to maintain. Nevertheless, SCE has not shown that it is reasonable to preemptively replace 215 circuit breakers in 2012. Assuming that SCE actually replaces the 147 breakers it forecasts for 2011, the jump to 215 replacements in 2012 represents a 46% increase over the 2011 level.[24] DRA's recommended number of replacements for 2012 is 175, considerably lower than SCE's request but higher than any other recorded year. In DRA's judgment, this is a generous and large increase over SCE's estimate of 147 in 2011. This estimate reflects 100 more breaker replacements than SCE expects will actually fail (175 replacements recommended by DRA versus the 75 that SCE is forecasting will fail each year), and is 10% higher than the highest previous number of replacements (159 in 2009).[25] DRA's recommended increase (to 175 replacements in 2012) represents a 19% increase over the prior year.[26]

Once a reasonable forecast for the total number of distribution circuit breakers has been determined, it is necessary to distribute that amount among the three categories of breakers shown in Table 6-5. Theoretically, these total replacements can be distributed in any number of ways. However, as can be seen in columns a and e in Table 6-5, for the 115 kV and the 66 kV breakers, SCE's forecasts for replacements are remarkably constant over the period 2011 through 2014, and are actually less than the 2010 forecast. DRA does not object to these estimates, which means that DRA's recommended decrease in the total number of 2012 replacements must be reflected in the 12 kV category (column j on Table 6-5). DRA's recommended forecast for 12 kV breaker replacements in 2012 is 153 (column j). This number is mathematically derived, and is simply the number that, when added to the 115 kV estimate (7 replacements shown in column b) and the 66

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[24] The formula for this calculation is: [(215 – 147) ÷ 147] x 100 = 46.26%

[25] The formula for this calculation is: [(175 – 159) ÷ 159] x 100 = 10.06%

[26] The formula for this calculation is: [(175 – 147) ÷ 147] x 100 = 19.05%

kV estimate (15 replacements shown in column f) equals the total estimate for circuit breaker replacements (175 replacements in column n).

With the yearly number of circuit breaker replacements determined for each of the three categories, the last step in this calculation is to multiply the number of replacements by the unit costs. As shown in Table 6-5, DRA is accepting SCE's unit cost estimates. Therefore, all the pieces needed for the calculation are known. The only difference between SCE's and DRA's estimates for total costs for this capital category is that DRA has a different (lower) estimate for replacements in 2012 for 12 kV circuit breaker replacements. After reducing the number of 12 kV replacements, the resulting calculation causes DRA's recommended 2012 capital expenditure forecast for distribution circuit breaker replacements to be $3.564 million lower than the comparable SCE estimate, as shown on line 22 of Table 6-1.

5. 4 kV Cutovers

SCE begins its discussion of its 4 kV cutover program on page 88 of its testimony. SCE has approximately 4,800 electrical circuits in its system, roughly 1,100 of which are operating at a voltage of 4 kV (or less). The design standards for these circuits were originally developed over a century ago when electrical consumption by each customer was much lower than it is today. SCE states that by today's standards, 4 kV circuits are inefficient, requiring more amps to supply the same amount of power as a more modern circuit.[27]

As load growth continues in its system, SCE has developed a process whereby customers on the outer edges of a 4 kV circuit are transferred to neighboring (larger) circuits. The net result of this "cutover" program is that the load on the 4 kV circuits is reduced to a level that is within its capacity. Of all the scenarios available to handle this problem, SCE states that the 4 kV cutover

[27] Exhibit SCE 03, Volume 03, Part 03, Chapters I-II, page 87, lines 26 and 27.

program is by far the most cost effective way to handle the problem of increasing loads on these older circuits.[28]

To provide the details necessary to see how the costs for the cutover program are derived, SCE includes Table II-24 on page 90 of its testimony. As can be seen on that table, the computational mechanics for calculating the yearly costs are quite simple – it is simply a matter of multiplying the yearly forecast of the number of amps (that will be transferred to neighboring circuits) by the annual cost per amp. DRA has looked closely at SCE's estimates for both the numbers of amps being transferred and the costs per amp. DRA concludes that the costs per amp are reasonable and is not recommending any changes to those estimates. However, as described below, DRA does have some concerns regarding the reasonableness of the forecasts for the number of amps being transferred.

On page 91 of its testimony, SCE discusses two of the cutover milestones that it alleges are critical to maintaining reliability. The first milestone is that SCE wants to transfer 16,330 amps from its most heavily loaded 4 kV circuits "as soon as possible."[29] SCE does not define the term "as soon as possible." However, by examining Table II-24 and summing the transfer estimates in the second column of data, the 16,330 figure is not reached until 2014.[30] SCE's second milestone is to transfer an additional 11,194 amps from overloaded 4 kV circuits by the year 2020. Combining these two milestones, SCE would like to transfer 27,524 amps by the year 2020.[31] In order to analyze all this information, DRA created Table 6-6 on the next page.

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[28] Exhibit SCE-03, Volume 03, Part 03, Chapters I-II, page 89, line 26 and 27.

[29] Exhibit SCE-03, Volume 03, Part 03, Chapters I-II, page 91, lines 2 through 4.

[30] On Table II-24, the second column of data shows the number of amps that SCE wants to transfer each year. Through the year 2013, the sum of the proposed transfers totals 15,876 amps. Therefore, the milestone of 16,330 will be reached sometime in 2014.

[31] 16,330 amps (milestone 1 by 2014) + an additional 11,194 amps (milestone 2 by 2020) = 27,524 total amps.

Table 6-6
4kV CUTOVERS -- TOTAL AMPS TRANSFERRED AND TOTAL COSTS
CPUC Jurisdiction (Thousands of Direct Nominal Dollars)

Line #	Year	Transferred Amps			Cost Per Amp		Total Cost	
		SCE	DRA	DRA Sum	SCE	DRA	SCE	DRA
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	2010	2,982	2,982	2,982	$5,601	$5,601	$16,702	$16,702
2	2011	3,019	3,019	6,001	$5,702	$5,702	$17,214	$17,214
3	2012	5,168	3,500	9,501	$5,838	$5,838	$30,171	$20,433
4	2013	4,707	3,500	13,001	$6,007	$6,007	$28,275	$21,025
5	2014	4,345	3,500	16,501	$6,193	$6,193	$26,909	$21,676
6	2015		3,500	20,001				
7	2016		3,500	23,501				
8	2017		3,500	27,001				
9	2018		3,500	30,501				
10	2019		3,500	34,001				
11	2020		3,500	37,501				

= points where SCE's milestones are met.

Table 6-6 rearranges some of the data contained in SCE's Table II-24, and adds a column (column d) that keeps a running total of the cumulative number of amps that have been transferred using DRA's estimates. Column d was added in order to determine whether both of SCE's milestones could be reached using different estimates for the yearly amp transfers. Unlike previous tables, DRA has extended this one out to the year 2020. This was done in order ascertain whether milestone 2 would be reached by that year. It should also be noted that historical data is not included in Table 6-6. In Data Request DRA-197-GAW, DRA had requested that SCE provide the number of amps that had been transferred in previous years. SCE responded that that information was not readily available.

As shown in column b, SCE's proposed number of amps to be transferred in 2011 is only slightly higher than the 2010 estimate. Because recorded data were not provided, DRA was unable to compare these estimates with recorded amounts. Nevertheless, the closeness of the two estimates gives DRA some degree of confidence that these numbers are reasonable, and DRA is accepting SCE's estimate. However, the estimate for 2012 is another story. Once again, SCE is proposing a sudden large increase for the test year, and once again, DRA views this proposal with caution. SCE's 2012 forecast of 5,168 amps to be transferred is a 71% increase over the 2011 estimate (3,019 amps).[32] In DRA's judgment, SCE has not justified such a large increase. DRA notes that SCE is not estimating increased transfers in 2011, indicating that cutting over 4 kV circuits is not a high priority.

Regardless of the priority one might assign to this capital program, DRA proposes an alternate replacement strategy that meets the two milestone goals of SCE, and has the added benefit of lowering costs. Beginning in 2012, DRA sought to find a transfer strategy that met SCE's goal of transferring 16,330 amps by 2014 (milestone 1), as well as transferring a total of 27,524 amps by 2020 (milestone 2). As shown in column c, DRA found that if 3,500 amps were transferred annually beginning in 2012, both milestones would be achieved. As shown in column d, the

[32] The formula for this calculation is: [(5,168 – 3,019) ÷ 3,019] x 100 = 71.18%.

first milestone (of transferring 16,330 amps) occurs right on schedule in 2014; this is indicated by the first shaded cell in that column, which shows that 16,501 amps will be transferred by the end of 2014. The same is true for the second milestone (transferring 27,524 amps by 2020). The second shaded cell in column d indicates that 30,501 amps will be transferred by 2018, two years prior to SCE's 2020 goal. Table 6-6 clearly shows that the adoption of an annual transfer of 3,500 amps will meet (or exceed) both of SCE's milestones. Therefore, DRA recommends that 3,500 amps be used as the annual level of amps to be transferred.

With all of the pieces of Table 6-6 in place, it is a simple matter to multiply the annual transfers by the unit costs to obtain the total annual 4 kV cutover costs. DRA agrees with SCE's 2011 forecast, but is recommending a $9.734 million reduction for 2012 capital expenditures for the 4 kV Cutover program. This reduction can be seen in row 24 of Table 6-1.

6. 4 kV Substation Elimination

This section is analogous to the previous one. The main difference is that instead of transferring part of the load of 4 kV circuits, SCE proposes to transfer the entire load from 4 kV substations, thereby closing down those substations. This would eliminate the need to replace the equipment in the substations, which would then be removed. SCE begins its discussion of this capital program on page 93 of its testimony.

Because of the age of these 4 kV substations, SCE expects many failures in the near future. Rather than waiting for these failures to occur, SCE is proposing that the substations be preemptively replaced. SCE states that waiting for failures to occur, and then replacing the failed parts with modern equipment, is sometimes impossible because modern equipment is often larger and does not fit into the existing space.[33] SCE includes Table II-28 on page 97 of its testimony. That table shows that beginning in 2012, SCE proposes to begin replacing these 4 kV

[33] Exhibit SCE-03, Volume 03, Part 03, Chapters I-II, page 96, lines 5 through 7.

substations; the first year of the replacement program is budgeted at $34.286 million.

The 4 kV Substation Elimination Program is yet another example of SCE proposing a large test year increase to its capital budget. DRA has carefully reviewed the arguments SCE has put forward to support the commencement of this program. DRA understands and agrees with SCE's concerns. Nevertheless, DRA is recommending that the 4 kV Substation Elimination Program not be undertaken at this time. In spite of its arguments, in DRA's opinion, SCE has not presented any persuasive reasons that this program should begin now.

As an example of its concern, DRA recommends that Table II-27 (on page 95 of SCE's testimony) be carefully studied. That table presents a partial list of the 4 kV substations that contain the oldest equipment. The first substation on the list is Carpinteria. That substation contains at least one transformer that is 97 years old, and at least one circuit breaker that is 53 years old. In this lengthy list of substations, the one with the youngest transformer is Beaumont, with at least one transformer that is 62 years old. The purpose of this discussion of Table II-27 is to point out that that aging 4 kV substations are nothing new. The transformers in the Carpinteria substation were probably considered to be old 30 years ago. The operational problems that SCE discusses in its testimony have not just suddenly appeared for the first time. In spite of these problems, SCE has managed to keep these old 4 kV substations running; SCE has not shown why it cannot continue to keep them running.

In a perfect scenario, DRA agrees that it might be desirable to begin replacing these old 4 kV substations. However, we do not live in an ideal world. The economy in California is depressed, and unemployment remains in double digits. Many ratepayers are struggling to make ends meet. In this economic environment, SCE is proposing to spend $1.071 billion in capital expenditures in 2012 for Part 1 of TDBU. (See line 42, column k, on Table 6-1.) Without compelling evidence that this replacement program is absolutely necessary, and that it must begin in 2012, DRA cannot recommend that it be undertaken at this time.

As shown on line 25 of Table 6-1, DRA's recommendation that the 4 kV Substation Elimination Program not begin in 2012 results in a reduction of $34.286 million as compared to SCE's 2012 forecast.

D. Adjustments to Customer Driven Projects

A large portion of the work undertaken by the Transmission and Distribution Business Unit is generated by requests from SCE's customers. Projects of this type fall into the Customer Driven Projects area. Examples of this type of work include installing new service connections for new customers, converting overhead lines to underground, and relocating facilities to accommodate customers. As Table 6-1 shows, there are nine project categories that make up the Customer Driven Projects area. Of these nine categories, DRA is recommending adjustments to three of them. Each of these proposed adjustments is discussed in the following sections. SCE presents its Customer Driven Projects testimony in Exhibit SCE-03, Volume 04, Part 01 and 02, Chapters I-II. All references to SCE's testimony in the Customer Driven sections that follow refer to that specific SCE exhibit. The following excerpt from Table 6-1 includes the lines that are referenced in the subsequent discussions on DRA's recommended adjustments to projects in the Customer Driven Projects area.

Table 6-1 (Excerpt)

Line #	Category	Forecasted						
		2010		2011		2012		
		SCE	DRA - Recorded	SCE	DRA	SCE	DRA	SCE ≥ DRA
		(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Customer Driven							
32	Customer Growth - Residential	$47,174	$38,182	$55,442	$55,442	$89,603	$89,603	$0
33	Customer Growth - Commercial / Industrial	$56,043	$48,789	$55,101	$55,101	$60,401	$60,401	$0
34	Customer Growth - Agricultural	$2,194	$3,542	$2,233	$2,233	$2,287	$2,287	$0
35	Customer Growth - Street Light System	$5,194	$10,698	$5,287	$5,287	$5,414	$5,414	$0
36	Rule 20 A Conversions	$30,050	$21,942	$30,594	$22,335	$31,332	$22,871	$8,461
37	Rule 20 B Conversions	$25,830	$15,078	$27,047	$15,348	$34,418	$15,716	$18,702
38	Rule 20 C Conversions	$8,610	$5,259	$9,016	$5,353	$11,473	$5,482	$5,991
39	Customer Relocations	$31,994	$31,460	$32,567	$32,567	$33,348	$33,348	$0
40	Distribution Added Facilities	$8,416	$7,321	$8,567	$8,567	$8,773	$8,773	$0
41	Total	$215,505	$182,271	$225,854	$202,233	$277,049	$243,895	$33,154

1. Rule 20A Conversions

SCE's discussion of this capital program begins on page 47 of its testimony. Overhead power lines are converted to underground lines pursuant to several Tariff Rules, one of which is Rule 20A. Under that tariff, SCE's Rule 20A capital budget dollars are allocated to governmental agencies within SCE's service territory, and each agency has an allocation planning account. Because of the way this rule is governed, cities and municipalities are the main drivers of spending for this program. SCE states that it anticipates that conditions will remain generally similar for cities and municipalities from 2010 through 2014, and uses the amount last authorized by the Commission in the 2009 GRC ($29.507 million plus escalation) for its estimates of annual Rule 20A capital expenditures during the forecast period.[34]

DRA took a different approach with its analysis of this capital program. Decision Nos. 73078 and 82-01-018 in Case 8209 require SCE to file an annual underground conversion report with the Commission every March. In Data Request DRA-207-GAW, DRA asked SCE to provide copies of this report for the three previous years, and to provide a copy of the 2010 report when it became available. SCE furnished the requested materials, and DRA carefully reviewed them. As part of these filings, SCE includes a table showing the accounting reconciliation of its Rule 20A expenditures. DRA has included copies of the earliest (2007) and the latest (2010) reconciliation tables in Appendix C of this exhibit. Of particular interest to DRA are three lines on those tables. Line 3 shows SCE's total allocations for Rule 20A underground conversions from 1968 through the end of the reporting period. Line 8 shows the total amount of capital expenditures that have been made for conversions over the same period. Line 10 indicates whether SCE has spent more or less than its allocation. As part of its Rule 20A analysis, DRA reviewed how the line 10 balance had changed from 2007 to 2010. As can be seen in the 2007 report, line 10 shows that SCE had cumulatively spent $181.061 million <u>less</u> than its

[34] Exhibit SCE-03, Volume 04, Part 01 and 02, Chapters I-II, page 48, lines 4 through 7.

allocations during the period 1968 through 2007; in the 2010 report, that figure had increased to $204.293 million.

In DRA's judgment, the growth in the line 10 balance indicates that SCE is continuing to overestimate the amount of Rule 20A funding it forecasts it will spend each year. DRA believes that SCE's forecasts for 2011 and 2012 will continue this pattern. This belief is supported by an examination of the table below.

Table 6-7
Recorded Rule 20A Expenditures
CPUC Jurisdiction (000s of Direct Nominal Dollars)

Category	2005	2006	2007	2008	2009	2010
	(a)	(b)	(c)	(d)	(e)	(f)
Rule 20A	$37,861	$33,461	$29,287	$24,213	$30,236	$21,942

A visual inspection of the recorded data in Table 6-7 (excerpted from line 36 of Table 6-1) indicates that Rule 20A expenditures are generally trending downward. As mentioned earlier, SCE states that municipalities and cities are the main driver for this program. With all of the budgeting and economic issues currently occupying the attention of local governments, it is not surprising that less consideration is currently being given to underground conversion projects. As shown in Table I-17 on page 47 of its testimony, SCE estimated that $30.050 million would be spent on Rule 20A expenditures in 2010. However, as the above table indicates, the actual amount spent for 2010 was $21.942 million. Clearly, the pattern of SCE overestimating the amount of its Rule 20A expenditures is continuing.

As previously mentioned, SCE anticipates that conditions will remain generally similar for cities and municipalities from 2010 through 2014. This is one area where SCE and DRA agree; DRA does not anticipate that there will be a sudden surge in interest by local governments to undertake undergrounding projects. In DRA's judgment, using the 2010 recorded expenditure level of $21.942 million (plus yearly escalation) for the 2011 and 2012 forecasts for Rule 20A expenditures is reasonable. As shown on line 36 of Table 6-1, the use of DRA's

lower estimates results in a reduction to SCE's forecasts for the Rule 20A Conversion program of $8.259 million in 2011 and $8.461 million in 2012.

2. Rule 20B Conversions

SCE discusses Rule 20B conversion expenditures beginning on page 48 of its testimony. Tariff Rule 20B provides for SCE's funds to be used to partially pay for undergrounding projects. Unlike Rule 20A, where the utility subsidizes the entire undergrounding project, Rule 20B subsidies only cover an amount equal to the cost of an equivalent overhead electrical system. Since a typical overhead system is usually only one-fifth the cost of an underground system, parties that request Rule 20B funding end up paying the majority of the undergrounding costs themselves. According to SCE, Rule 20B undergrounding projects typically arise when a developer of a new project wishes to remove existing overhead lines for visual appeal.

In deriving its Rule 20B forecasts, SCE first develops combined estimates for the number of miles it believes it will underground each year for Rule 20B and Rule 20C (which is analyzed in the following section). Those figures are then multiplied by a yearly estimate of the cost per mile to accomplish the undergrounding. SCE then allocates a portion of the resultant capital forecasts to the Rule 20B capital program. Tables I-18 and I-19, on pages 50 and 51 of its testimony, show the details of SCE's calculations.

DRA has studied the estimating approach used by SCE. While DRA understands the methodology, it does not believe that SCE's approach completely captures the impact that the slowdown in the economy has on the demand for undergrounding expenditures. This can be more easily shown by an examination of Table 6-8.

Table 6-8
Recorded Rule 20B Expenditures
CPUC Jurisdiction (000s of Direct Nominal Dollars)

Category	2005	2006	2007	2008	2009	2010
	(a)	(b)	(c)	(d)	(e)	(f)
Rule 20B	$36,220	$43,319	$40,277	$23,900	$25,312	$15,078

The recorded expenditure data shown in Table 6-8 (excerpted from line 37 of Table 6-1) shows that Rule 20B spending decreased abruptly in 2008, with 2010 expenditures being particularly reduced. As shown in Table I-19 (on page 51 of SCE's testimony), SCE originally estimated 2010 Rule 20B expenditures to be $25.830 million. As the above table indicates, actual recorded expenditures for 2010 were $15.078 million. SCE's estimating methodology has not reflected the dramatic downturn in spending for 2010.

Undergrounding overhead lines in order to improve the visual impact of a project can, in many instances, properly be considered a discretionary expenditure. DRA is not surprised by the level of spending that occurred in 2010. With the slowdown in the California economy, and with unemployment in the state in double digits, it is understandable that Rule 20B undergrounding projects are not as prevalent as in the past, especially since the applicant is required to pay for much of the undergrounding cost. DRA recommends using the 2010 recorded level of $15.078 million (plus yearly escalation) as the forecast for 2011 and 2012; DRA does not expect 2011 and 2012 expenditures to vary significantly from 2010 levels. As shown on line 37 of Table 6-1, DRA's forecast of $15.348 million in 2011 and $15.716 million in 2012 results in recommended adjustments of $11.699 million in 2011 and $18.702 million in 2012 to SCE's forecasts for the Rule 20B Conversion program.

3. Rule 20C Conversions

Rule 20C conversions differ from Rule 20B conversions only to the degree to which SCE subsidizes the undergrounding project. For Rule 20C, the requesting applicant pays the entire cost of the project. Rule 20C projects generally occur when an individual property owner wishes to remove existing overhead lines.

The SCE methodology described in the previous section to develop estimates for Rule 20B expenditures is the same methodology SCE uses to develop its Rule 20C forecasts; the only difference is that once the total estimates for the combined

Rule 20B and 20C undergrounding costs are derived, the percentage of the total allocated to Rule 20C is lower.

As discussed in the prior section, DRA disagrees with SCE's estimating approach. While DRA understands SCE's estimating methodology, SCE's approach does not completely capture the impact that the slowdown in the economy has on the demand for undergrounding expenditures. This can be more easily shown by an examination of Table 6-9.

Table 6-9
Recorded Rule 20C Expenditures
CPUC Jurisdiction (000s of Direct Nominal Dollars)

Category	2005	2006	2007	2008	2009	2010
	(a)	(b)	(c)	(d)	(e)	(f)
Rule 20C	$11,074	$10,667	$13,764	$9,951	$8,611	$5,259

The recorded capital expenditure data shown in Table 6-9 (excerpted from line 38 of Table 6-1) shows that Rule 20C spending decreased starting in 2008, with 2010 expenditures being significantly reduced relative to prior years. As shown in Table I-19 (on page 51 of SCE's testimony), SCE originally estimated 2010 Rule 20C expenditures to be $8.610 million. As the above table indicates, actual recorded expenditures for 2010 were $5.259 million. SCE's estimating methodology has not reflected the dramatic downturn in spending for 2010.

Undergrounding overhead lines in order to improve the visual impact of a project can, in many instances, properly be considered a discretionary expenditure. DRA is not surprised by the level of spending that occurred in 2010. With the slowdown in the California economy, and with unemployment in the state in double digits, it is understandable that Rule 20C undergrounding projects are not as prevalent as they once were, especially since the applicant is required to pay for all of the undergrounding cost. DRA recommends using the 2010 recorded level of $5.259 million (plus yearly escalation) as the forecast for 2011 and 2012; DRA does not expect 2011 and 2012 expenditures to vary significantly from 2010 levels. As shown on line 38 of Table 6-1, DRA's forecast of $5.353 million in 2011 and $5.482

million in 2012 results in recommended adjustments of $3.663 million in 2011 and $5.991 million in 2012 to SCE's forecasts for the Rule 20C Conversion program.

APPENDIX A

Subtransmission Lines Plan
Data Requests and Data Responses

DRA

Division of Ratepayer Advocates
California Public Utilities Commission
State of California

DATA REQUEST

Southern California Edison Test Year 2012 GRC
A.10-11-015

Date: March 25, 2011

Responses Due: April 8, 2011

To: Russ Worden
Russell.Worden@sce.com
(626) 302-4177

From: Clayton Tang, Project Coordinator
Division of Ratepayer Advocates
505 Van Ness Avenue, Room 4205
San Francisco, CA 94102

Originated by: Greg Wilson
Phone: (415) 703-2159
Email: gaw@cpuc.ca.gov

Data Request No: DRA-223-GAW

Exhibit Reference: SCE-03, Vol. 03, Part 01 & 02, Chapter I-II

Subject: Subtransmission and Substation Projects

Please provide the following:

1. On Table II-6 on page 48 of the above referenced testimony, SCE lists 27 subtransmission projects with operational dates varying between 2010 and 2014. For each of the 27 projects, as delineated by the line number on Table II-6, please provide the following:

    a. The date on which the Permit To Construct (PTC) or the Certificate of Public Convenience and Necessity (CPCN) was approved by the Commission. Please also provide the decision number pertaining to the approval.

b. If no PTC or CPCN was approved, please provide the Commission approved Advice Letter (AL).

c. If no PTC, CPCN, or AL was approved by the Commission, please explain under what authority SCE proceeded with construction or is planning on proceeding with construction.

d. Please provide DRA with any changes to the proposed operational dates.

2. On page 70, Table II-8 of SCE-03, Vol. 03, Part 01 & 02, Chapter I-II, SCE lists 75 substation projects with operational dates varying between 2010 and 2014. For each of the 75 projects, as delineated by the line number on Table II-8, please provide the following:

a. The date on which the Permit To Construct (PTC) or the Certificate of Public Convenience and Necessity (CPCN) was approved by the Commission. Please also provide the decision number pertaining to the approval.

b. If no PTC or CPCN was approved, please provide the Commission approved Advice Letter (AL).

c. If no PTC, CPCN, or AL was approved by the Commission, please explain under what authority SCE proceeded with construction or is planning on proceeding with construction.

d. Please provide DRA with any changes to the proposed operational dates.

Provide two copies of the above information as it becomes available but no later than the due date identified above. If you are unable to provide the information by this date, please provide a written explanation to the data request Originator seven calendar days before the due date as to why the response date cannot be met and your best estimate of when the information can be provided. Please identify the person who provides the response and his (her) phone number.

Provide electronic responses if possible, and set of hard copy responses with your submittal to the data request originator and the DRA Project Coordinator(s). All data responses need to have each page numbered, referenced, and indexed so worksheets can be followed. If any number is calculated, include a copy of all electronic files so the formula and their sources can be reviewed.

If you have any questions regarding this data request, please call the originator at the above phone number.

Southern California Edison
2012 GRC A.10-11-015

DATA REQUEST SET DRA-SCE-223-GAW

To: DRA
Prepared by: Jeff Shiles
Title: Manager 2
Dated: 03/25/2011

Question 01.c:

Originated by: Greg Wilson

Exhibit Ref: SCE-03, Vol. 03, Part 01 & 02, Chapter I-II

Subject: Subtransmission and Substation Projects

Please provide the following:

1. On Table II-6 on page 48 of the above referenced testimony, SCE lists 27 subtransmission projects with operational dates varying between 2010 and 2014. For each of the 27 projects, as delineated by the line number on Table II-6, please provide the following:

    c. If no PTC, CPCN, or AL was approved by the Commission, please explain under what authority SCE proceeded with construction or is planning on proceeding with construction.

Response to Question 01.c:

GO 131-D does not require noticing or Advice Letter filings for projects exempt from CPCN requirements or for projects exempt from PTC requirements by qualifying for exemptions b, c, d, e, or h. Many of SCE's projects fit into these categories.

Line No.	Project No.	Project Name	2012 GRC Op Date	Current Proposed Op Date	PTC Approval Date	CPUC Decision #	CPUC Advice Letter #	Comments
1	05316	Alder-Declez 66 kV	6/1/2010	12/31/2011				Exemption d. No Advice Letter necessary.
2	05344	Valley-Auld 115 kV	6/1/2010	6/1/2010			AL 2249-E (later withdrawn). Resubmitted under AL 2368-E	Project placed in service 7/14/2010.
3	06054	Citrus-Dalton-Kirkwall 66 kV	6/1/2010	6/1/2011				Exemption b. No Advice Letter necessary.
4	06423	Valley-Auld-Pauba 115 kV	6/1/2010	6/1/2010			AL 2249-E (later withdrawn). Resubmitted under AL 2368-E	Project placed in service 7/14/2010.
5	06645	Tipton Substation 66 kV Capacitor Bank	6/1/2010	6/1/2010				Substation Modification as defined in GO 131-D, Section III.B. Exempt from notice and Advice Letter requirements in GO 131-D Section XI.B. CPUC has reaffimred this in D. 03-08-033 (Santee decision). Project placed in service 7/29/2010.
6	04853	Gould-La Canada 66 kV	6/1/2011	12/31/2011				Exemption b and c determination to be issued in April 2011. No Advice Letter required.
7	05304	Etiwanda-Declez No.1 & No.2 66 kV	6/1/2011	6/1/2011				Exemption b. No Advice Letter necessary.
8	05329	Moorpark-Newbury 66 kV	6/1/2011	12/31/2011			AL 2272-E, Energy Division Resolution E4225, Commission Resolution 4243	
9	05360	Devers-Mirage 115 kV System Split	6/1/2011	6/1/2011 (Phase 1) 6/1/2012 (Phase 2)	June 3, 2010	D.10-06-014		
10	05391	Poplar Substation 66 kV Capacitor Bank	6/1/2011	6/1/2011				Substation Modification as defined in GO 131-D, Section III.B. Exempt from notice and Advice Letter requirements in GO 131-D Section XI.B. CPUC has reaffimred this in D. 03-08-033 (Santee decision).
11	06448	Victor-Savage 115 kV	6/1/2011	6/1/2012			To be filed in fall 2011 -Exemption g	
12	06818	Brookhurst Substation 66 kV Capacitor Bank	6/1/2011	6/1/2011				
13	04518	Goleta 220 kV N-2 Line Contingency System Upgrade	6/1/2012	6/1/2012				Under review for exemption determination and/or licensing requirements.
14	04891	Arrowhead Reconfiguration Project	12/31/2012	12/31/2012				Exemption b. No Advice Letter necessary.
15	06028	Etiwanda-Alder-Randall 66 kV	6/1/2012	6/1/2012				Exemption b. No Advice Letter necessary.
16	06030	Valley-Ivyglen 115 kV	6/1/2012	6/1/2012 (Phase 1) 6/1/2013 (Phase 2)	August 12, 2010	D. 10-08-009		
17	06392	Santiago-Borrego-Morro 66 kV	6/1/2012	6/1/2012				Under SCE review for exemption determination and/or licensing requirements.
18	06647	Vestal-Pixley 66 kV	6/1/2012	6/1/2014	PTC not yet submitted	PTC not yet submitted		
19	06667	Saugus-Colossus-Lockheed-Pitchgen 66 kV	6/1/2012	6/1/2012				Under SCE review for exemption determination and/or licensing requirements.
20	05364	Weldon Substation 66 kV Capacitor Bank	6/1/2013	6/1/2013				
21	06389	Rector-Goshen-Liberty 66 kV	6/1/2013	6/1/2013			AL 2510-E	
22	06660	Villa Park-Burpit-Canyon-Yorba Linda 66 kV	6/1/2013	6/1/2013				
23	06698	Elizabeth Lake-Pitchgen 66 kV	6/1/2013	6/1/2013				Under SCE review for exemption determination and/or licensing requirements.
24	06853	Saugus-Appgen-Newhall & Appgen-North Oaks 66 kV	6/1/2013	6/1/2013				Under SCE review for exemption determination and/or licensing requirements.
25	04992	Rio Hondo-Dalton-Liquid 66 kV	6/1/2014	6/1/2014				
26	06380	Goleta-Carpenteria-Desal-Santa Barbara 66 kV	6/1/2014	6/1/2014				Under SCE review for exemption determination and/or licensing requirements.
27	01079	Corporate Real Estate (CRE) Load Growth Projects	2010-2014	2010-2014				

APPENDIX B

Distribution Substation Plan (DSP)
Data Requests and Data Responses

DRA

Division of Ratepayer Advocates
California Public Utilities Commission
State of California

DATA REQUEST

Southern California Edison Test Year 2012 GRC
A.10-11-015

Date: March 25, 2011

Responses Due: April 8, 2011

To: Russ Worden
Russell.Worden@sce.com
(626) 302-4177

From: Clayton Tang, Project Coordinator
Division of Ratepayer Advocates
505 Van Ness Avenue, Room 4205
San Francisco, CA 94102

Originated by: Greg Wilson
Phone: (415) 703-2159
Email: gaw@cpuc.ca.gov

Data Request No: DRA-223-GAW

Exhibit Reference: SCE-03, Vol. 03, Part 01 & 02, Chapter I-II

Subject: Subtransmission and Substation Projects

Please provide the following:

1. On Table II-6 on page 48 of the above referenced testimony, SCE lists 27 subtransmission projects with operational dates varying between 2010 and 2014. For each of the 27 projects, as delineated by the line number on Table II-6, please provide the following:

    a. The date on which the Permit To Construct (PTC) or the Certificate of Public Convenience and Necessity (CPCN) was approved by the Commission. Please also provide the decision number pertaining to the approval.

b. If no PTC or CPCN was approved, please provide the Commission approved Advice Letter (AL).

c. If no PTC, CPCN, or AL was approved by the Commission, please explain under what authority SCE proceeded with construction or is planning on proceeding with construction.

d. Please provide DRA with any changes to the proposed operational dates.

2. On page 70, Table II-8 of SCE-03, Vol. 03, Part 01 & 02, Chapter I-II, SCE lists 75 substation projects with operational dates varying between 2010 and 2014. For each of the 75 projects, as delineated by the line number on Table II-8, please provide the following:

a. The date on which the Permit To Construct (PTC) or the Certificate of Public Convenience and Necessity (CPCN) was approved by the Commission. Please also provide the decision number pertaining to the approval.

b. If no PTC or CPCN was approved, please provide the Commission approved Advice Letter (AL).

c. If no PTC, CPCN, or AL was approved by the Commission, please explain under what authority SCE proceeded with construction or is planning on proceeding with construction.

d. Please provide DRA with any changes to the proposed operational dates.

Provide two copies of the above information as it becomes available but no later than the due date identified above. If you are unable to provide the information by this date, please provide a written explanation to the data request Originator seven calendar days before the due date as to why the response date cannot be met and your best estimate of when the information can be provided. Please identify the person who provides the response and his (her) phone number.

Provide electronic responses if possible, and set of hard copy responses with your submittal to the data request originator and the DRA Project Coordinator(s). All data responses need to have each page numbered, referenced, and indexed so worksheets can be followed. If any number is calculated, include a copy of all electronic files so the formula and their sources can be reviewed.

If you have any questions regarding this data request, please call the originator at the above phone number.

Southern California Edison
2012 GRC A.10-11-015

DATA REQUEST SET DRA-SCE-223-GAW

To: DRA
Prepared by: Jeff Shiles
Title: Manager 2
Dated: 03/25/2011

Question 02.c:

Originated by: Greg Wilson

Exhibit Ref: SCE-03, Vol. 03, Part 01 & 02, Chapter I-II

Subject: Subtransmission and Substation Projects

Please provide the following:

2. On page 70, Table II-8 of SCE-03, Vol. 03, Part 01 & 02, Chapter I-II, SCE lists 75 substation projects with operational dates varying between 2010 and 2014. For each of the 75 projects, as delineated by the line number on Table II-8, please provide the following:

   c. If no PTC, CPCN, or AL was approved by the Commission, please explain under what authority SCE proceeded with construction or is planning on proceeding with construction.

Response to Question 02.c:

GO 131-D does not require noticing or Advice Letter filings for projects exempt from CPCN requirements or for projects exempt from PTC requirements by qualifying for exemptions b, c, d, e, or h. Many of SCE's projects fit into these categories.

Line No.	Project No.	Project Name	2012 GRC Op Date	Current Proposed Op Date	PTC Approval Date	CPUC Decision #	CPUC Advice Letter #	Comments
1	04414	Trophy 66/12 kV Substation	6/1/2010	6/1/2010				Project placed in service 5/20/2010.
2	04427	Estrella 66/12 kV Substation	6/1/2010	6/1/2010				Project placed in service 5/4/2010.
3	04734	Mira Loma 66/12 kV Substation	6/1/2010	6/1/2010				Project placed in service 7/12/2010.
4	04771	Tenaja 115/12 kV Substation	6/1/2010	6/1/2010			AL 2367-E	Project placed in service 10/14/2010.
5	05176	Kimball 66/12 kV Substation	8/31/2010	8/31/2010	July 30, 2009	D. 07-09-040		Project placed in service 8/31/2010.
6	05286	Coso 115/12 kV Substation	8/1/2010	8/1/2010			AL 2418-E	Project placed in service 9/30/2010.
7	05293	Narrows 66/12 kV Substation	6/1/2010	6/1/2010				Project placed in service 5/7/2010.
8	05372	Devers 115/12 kV Substation	6/1/2010	6/1/2010				Substation Modification as defined in GO 131-D, Section III.B. Exempt from notice and Advice Letter requirements in GO 131-D Section XI.B. CPUC has reaffimred this in D. 03-08-033 (Santee decision). Project placed in service 6/30/2010.
9	05401	Barre 66/12 kV Substation	6/1/2010	6/1/2010				Project placed in service 5/1/2010.
10	06008	Elizabeth Lake 66/16 kV Substation	6/1/2010	6/1/2010				Project placed in service 6/26/2010.
11	06013	Palmdale 66/12 kV Substation	6/1/2010	6/1/2010				Substation Modification as defined in GO 131-D, Section III.B. Exempt from notice and Advice Letter requirements in GO 131-D Section XI.B. CPUC has reaffimred this in D. 03-08-033 (Santee decision). Project placed in service 11/30/2010.
12	06022	Aqueduct 115/12 kV Substation	6/1/2010	6/1/2010				Project placed in service 5/29/2010.
13	06068	Irvine 66/12 kV Substation	6/1/2010	6/1/2010				Substation Modification as defined in GO 131-D, Section III.B. Exempt from notice and Advice Letter requirements in GO 131-D Section XI.B. CPUC has reaffimred this in D. 03-08-033 (Santee decision). Project placed in service 7/16/2010.
14	06108	Etiwanda 66/12 kV Substation	6/1/2010	6/1/2010				Project placed in service 3/24/2010.
15	06321	Cabrillo 66/12 kV Substation	6/1/2010	6/1/2010				Project placed in service 5/7/2010.
16	06562	Bradbury 66/16 kV Substation	6/1/2010	6/1/2010				Project placed in service 7/16/2010.
17	06746	MacArthur 66/12 kV Substation	6/1/2010	6/1/2010				Project placed in service 4/13/2010.
18	05061	Sun City 115/12 kV Substation	6/1/2011	6/1/2011				
19	05289	Fogarty 115/12 kV Substation	6/1/2011	12/1/2011	August 12, 2010	D. 10-08-009		
20	05291	Corona 66/33 kV Substation	6/1/2011	6/1/2011				
21	05353	Triton 115/12 kV Substation	6/1/2011	10/1/2011	September 23, 2010	D. 10-09-025		
22	05479	Oasis 66/12 kV Substation	5/1/2011	5/1/2011				Substation Modification as defined in GO 131-D, Section III.B. Exempt from notice and Advice Letter requirements in GO 131-D Section XI.B. CPUC has reaffimred this in D. 03-08-033 (Santee decision).
23	06216	Oceanview 66/12 kV Substation	6/1/2011	6/1/2011				
24	06226	Niguel 66/12 kV Substation	6/1/2011	6/1/2011				
25	06229	Lafayette 66/12 kV Substation	6/1/2011	6/1/2011				
26	06287	Bunker 115/12 kV Substation	6/1/2011	6/1/2011				Substation Modification as defined in GO 131-D, Section III.B. Exempt from notice and Advice Letter requirements in GO 131-D Section XI.B. CPUC has reaffimred this in D. 03-08-033 (Santee decision).

Line No.	Project No.	Project Name	2012 GRC Op Date	Current Proposed Op Date	PTC Approval Date	CPUC Decision #	CPUC Advice Letter #	Comments
27	06362	Bliss 66/12 kV Substation	6/1/2011	6/1/2011				Combined Exemption: Exemption b for subtrans work outside substation. Substation Modification as defined in GO 131-D, Section III.B. Exempt from notice and Advice Letter requirements in GO 131-D Section XI.B. CPUC has reaffimred this in D. 03-08-033 (Santee decision).
28	06568	Little Rock 66/12 kV Substation	6/1/2011	6/1/2011				Combined Exemption: Exemption b for subtrans work outside substation. Exemption c for interset pole. Substation Modification as defined in GO 131-D, Section III.B. Exempt from notice and Advice Letter requirements in GO 131-D Section XI.B. CPUC has reaffimred this in D. 03-08-033 (Santee decision).
29	06612	Tipton 66/12 kV Substation	6/1/2011	6/1/2011				Substation Modification as defined in GO 131-D, Section III.B. Exempt from notice and Advice Letter requirements in GO 131-D Section XI.B. CPUC has reaffimred this in D. 03-08-033 (Santee decision). Project placed in service 11/30/2010.
30	06809	Cudahy 66/16 kV Substation	6/1/2011	6/1/2011				Substation Modification as defined in GO 131-D, Section III.B. Exempt from notice and Advice Letter requirements in GO 131-D Section XI.B. CPUC has reaffimred this in D. 03-08-033 (Santee decision).
31	06815	Morro 66/12 kV Substation	6/1/2011	6/1/2011				
32	06933	Downs 33/12 kV Substation	6/1/2011	6/1/2011			Anticipated to be filed in April 2011 - Exemption g	
33	06934	Bassett 66/12 kV Substation	6/1/2011	6/1/2011				
34	04422	Las Lomas 66/12 kV Substation	6/1/2012	6/1/2012			Anticipated to be filed in summer 2011	Pending Exemption f determination through CEQA Consistency determination at the City of Irvine relating to EIR for Irvine Company development.
35	04445	Glen Avon 66/12 kV Substation	6/1/2012	12/31/2012				
36	04605	Narod 66/12 kV Substation	6/1/2012	6/1/2012				
37	05023	El Sobrante 33/12 kV Substation	6/1/2012	12/31/2012				
38	05194	Presidential 66/16 kV Substation	6/1/2012	6/1/2013	PTC under review at CPUC	PTC under review at CPUC		
39	05396	Mascot 66/12 kV Substation	6/1/2012	6/1/2012	December 16, 2010	D.10-12-039		
40	06300	Chestnut 66/12 kV Substation	6/1/2012	6/1/2012				
41	06577	Devers 115/12 kV Substation	6/1/2012	6/1/2012				
42	06586	Laurel 66/12 kV Substation	6/1/2012	6/1/2012				Substation Modification as defined in GO 131-D, Section III.B. Exempt from notice and Advice Letter requirements in GO 131-D Section XI.B. CPUC has reaffimred this in D. 03-08-033 (Santee decision)
43	06827	Ely 66/12 kV Substation	6/1/2012	6/1/2012				
44	06829	Vera 66/12 kV Substation	6/1/2012	6/1/2012				
45	06831	Jefferson 66/12 kV Substation	6/1/2012	6/1/2012				

Line No.	Project No.	Project Name	2012 GRC Op Date	Current Proposed Op Date	PTC Approval Date	CPUC Decision #	CPUC Advice Letter #	Comments
46	06858	Telegraph 66/12 kV Substation	6/1/2012	6/1/2012				
47	06948	Carodean 115/12 kV Substation	6/1/2012	6/1/2012				
48	04458	Pepper 115/12 kV Substation	6/1/2013	6/1/2013				
49	04469	Wimbledon 66/12 kV Substation	6/1/2013	6/1/2013				
50	04581	Mayberry 115/12 kV Substation	6/1/2013	6/1/2013				
51	05027	Saticoy 66/16 kV Substation	5/1/2013	5/1/2013				
52	05034	Douglas Park 66/12 kV Substation	6/1/2013	6/1/2013				
53	05403	Colonia 66/16 kV Substation	6/1/2013	6/1/2014				
54	05411	Lakeview 115/12 kV Substation	6/1/2013	6/1/2013	PTC under review at CPUC	PTC under review at CPUC		
55	05432	Roadway 115/12 kV Substation	6/1/2013	6/1/2013				Under SCE review for substation modification determination and applicable determination for new pole(s) (expect to be issued in April 2011).
56	06220	Fillmore 66/16 kV Substation	6/1/2013	6/1/2013				
57	06587	Nelson 115/12 kV Substation	6/1/2013	6/1/2013				
58	06605	La Habra 66/12 kV Substation	6/1/2013	6/1/2013				
59	06619	Banducci 66/12 kV Substation	6/1/2013	6/1/2013	PTC not yet filed	PTC not yet filed		
60	06828	Lennox 66/16 kV Substation	6/1/2013	6/1/2015				
61	06854	Thornhill 115/12 kV Substation	6/1/2013	project cancelled				
62	04624	Brea 66/12 kV Substation	6/1/2014	6/1/2014				
63	05186	Moreno 115/12 kV Substation	6/1/2014	6/1/2014				
64	05315	Tulare 66/4 kV Substation	6/1/2014	6/1/2014				
65	05389	Levy 66/16 kV Substation	6/1/2014	6/1/2014				
66	05397	Falcon Ridge 66/12 kV Substation	6/1/2014	6/1/2014	PTC under review at CPUC	PTC under review at CPUC		
67	06076	Genamic 66/12 kV Substation	6/1/2014	6/1/2014				Under SCE review for exemption determination and/or licensing requirements.
68	06371	Ojai 66/16 kV Substation	6/1/2014	6/1/2020				
69	06575	Circle City 66/12 kV Substation	6/1/2014	6/1/2016	PTC not yet filed	PTC not yet filed		
70	06598	Shawnee 66/12 kV Substation	6/1/2014	6/1/2014				
71	06691	Downs 115/12 kV Substation	6/1/2014	6/1/2014	PTC under review at CPUC	PTC under review at CPUC		
72	06847	Guardian 66/12 kV Substation	6/1/2014	6/1/2016	PTC not yet filed	PTC not yet filed		
73	06857	Walteria 66/16 kV Substation	6/1/2014	6/1/2014				
74	06958	Pebbly Beach Generating Station	7/31/2014	6/1/2014				
75	04837	Substation Automation Upgrades	2010-2014	2010-2014				

APPENDIX C

Rule 20A Conversions

Annual Report to the Commission on Rule 20A Conversions

EXHIBIT A
REPORT OF R20A CONVERSIONS

UTILITY: Southern California Edison — REPORT YEAR ENDING: 2007

ALLOCATIONS FOR CONVERSIONS			
1 Total Allocations Through Report Year	1968-2006		$1,100,059,681
2 Report Year's Allocation	2007	$40,974,197	
3 Total Allocations Through Report Year	1968-2007 (1+2)		$1,141,033,878
EXPENDITURES FOR CONVERSIONS			
4 Total Expended For Completed Conversions	1968-2006	$815,696,954	
5 Total Report Year Expended For Completed Conversions	2007	$42,704,093	
6 Total Expended For Completed Conversions Through Report Year	1968-2007 (4+5)		$858,401,047
7 Total Expended On Conversions Not Completed By Report Year End - 2007		$101,571,852	
8 Total Expended (6+7)			$959,972,899
TOTAL UNEXPENDED FUNDS (3-8) [1]			
9 If Expenditures Are Greater Than Allocations			$0
10 If Allocations Are Greater Than Expenditures (One of the above, 9 or 10, will always be "0")			$181,060,979
FUNDS COMMITTED			
11 Total Funds Authorized To Complete Partially Completed Jobs Shown On Line 7		$52,708,855	
12 Funds For Jobs Not Under Construction Where U.G. Districts Have Been Formed Under Enabling Legislation		$129,394,297	
13 Total Committed (11 + 12)			$182,103,152
ADDITIONAL FUNDS COMMITTED			
14 Funds Required For Identified Projects Under Study By Active U.G. Communities As Of Report Year Ending		$227,345,591	
MEMO INFORMATION			
15 Advances For Specific Communities Beyond Current Allocations			$ 119,385,276
16 Reserve Funds Held For Specific Communities For Which No Specific Current Projects Are Under Study As Of Report Year End			$ 118,343,103
17 Expenditures To Case 9365 (Transmission Dollars Which Are Included In Total Cost Above In Line 8)			$124,958,507

[1] This calculation, required by D.90-05-032, is an artificial one, since the allocation figure is unfunded and actual expenditures may vary annually and be affected by exogenous factors.

EXHIBIT A
REPORT OF RULE 20A CONVERSIONS

UTILITY: SOUTHERN CALIFORNIA EDISON REPORT YEAR ENDING: 2010

ALLOCATIONS FOR CONVERSIONS

1	Total Allocations Through Prior Years	1968-2009		$ 1,216,306,250
2	Report Year's Allocation	2010	$ 33,515,671	
3	Total Allocations Through Report Year	1968-2010 (1+2)		$ 1,249,821,921

EXPENDITURES FOR CONVERSIONS

4	Total Expended For Completed Conversions	1968-2009	$ 909,586,155	
5	Total Report Year Expended For Completed Conversions	2010	$ 7,034,856	
6	Total Expended For Completed Conversions Through Report Year	1968-2010 (4+5)		$ 916,621,011
7	Total Expended On Conversions Not Completed By Report Year End - 2010		$ 128,907,570	
8	Total Expended (6+7)			$ 1,045,528,581

TOTAL UNEXPENDED FUNDS (3-8) [1]

9	If Expenditures Are Greater Than Allocations	$ -
10	If Allocations Are Greater Than Expenditures (One of the above, 9 or 10, will always be "0")	$ 204,293,340

FUNDS COMMITTED

11	Total Funds Authorized To Complete Partially Completed Jobs Shown On Line 7	$ 91,482,085	
12	Funds For Jobs Not Under Construction Where U.G. Districts Have Been Formed Under Enabling Legislation	$ 69,205,607	
13	Total Committed (11 + 12)		$ 160,687,692

ADDITIONAL FUNDS COMMITTED

14	Funds Required For Identified Projects Under Study By Active U.G. Communities As Of Report Year Ending	$ 128,694,500

MEMO INFORMATION

15	Advances For Specific Communities Beyond Current Allocations	$ 88,746,874
16	Reserve Funds Held For Specific Communities For Which No Specific Current Projects Are Under Study As Of Report Year End	$ 132,352,523
17	Expenditures To Case 9365 (Transmission Dollars Which Are Included In Total Cost Above In Line 8)	$ 131,901,057

[1] This calculation, required by D.90-05-032, is an artificial one, since the allocation figure is unfunded and actual expenditures may vary annually and be affected by exogenous factors.