Economic Review of Scenarios Associated with the Replacement of Steam Generators at the San Onofre Nuclear Plant

Prepared testimony of
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PREPARED TESTIMONY OF WILLIAM B. MARCUS

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I. Introduction

This testimony is presented by William B. Marcus, Principal Economist of JBS Energy, Inc., on behalf of The Utility Reform Network (TURN). Mr. Marcus has over 25 years of experience on energy utility issues. He has testified before this Commission on more than 75 occasions and has also provided testimony or formal comments to approximately 40 federal, state, provincial, and local regulatory bodies and courts in the U.S. and Canada. His qualifications are included as Attachment A.

This testimony has two purposes.

First, the testimony presents the results of a series of analyses that compared two separate cases under varying assumptions of performance and cost at San Onofre (SONGSD) units 2 and 3. In the first case, the steam generator is replaced on the schedule suggested by Edison. In the second case, the steam generator is not replaced and the plant is operated, at diminishing capacity factors (that reflect potential impacts of midcycle outages, output reductions, and even earlier closure than forecast), until it closes in 2012 for unit 2 and 2014 for unit 3 (the 50th percentile probability of required closure without steam generator repair provided by Edison in SCE-2, pp. 14-15). To prepare both of these cases, a year-by-year revenue requirements model for Edison's capital expenditures was prepared, which enables the analyst to see the year-by-year impacts of costs on utility revenue requirements.[1]

[1] One caveat must be added. In the cases where SONGS is assumed to close prematurely, the revenue requirement for capital additions costs to the date of shutdown are assumed to be recovered over the period until 2022 with a rate of return, to reflect that SCE would be expected to request a return on unrecovered capital investments under those conditions. Including the return in this calculation for purposes of economic analysis does not mean that TURN would endorse granting a return on the undepreciated balance under conditions of premature closure.

Mr. Schlissel is providing the overall context of future plant operations and will speak to the reasonableness of considering these particular scenarios.

Second, the testimony comments on Edison's proposed ratemaking treatment if the repair is approved. It recommends (a) denial of Edison's request for Construction Work in Progress in the rate base prior to operation of the steam generator repair, (b) recovery of cost of removal for the steam generator from 2006-2022 with normalized tax treatment of the revenues and expenses, and (c) provides a discussion of a potential benefit cap proposal.

II. Cost-Effectiveness Analysis

A. Description of Base Case

The base case largely uses Edison's information regarding most parameters, particularly relating to plant operation. It uses Edison's capacity factor after replacement (88%), data from Edison regarding base and refueling O&M expenses (reflecting the latest information from the 2006 TY GRC),[2,3] Edison's allowances for insurance and variable A&G (workers compensation and incentive bonus payments) nuclear fuel expenses and capital expenditures.

Edison's base O&M cost (before payroll loaders at the 100% level) was estimated as $199.8 million (2000 dollars) in its analysis of steam generator cost-effectiveness based on information from the 2003 TY GRC. The current estimate is $236.3 million (2003 dollars) for the 2006 TY GRC).[4] After taking inflation into account, this is approximately an 8-10% increase in real terms. One of the largest reasons for this increase was a doubling in estimated security costs between the

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[2] Relevant pages from the 2003 TY GRC and 2006 TY NOI are attached as Attachment B.

[3] Information that Edison provided to the City of Anaheim in 2003 is also generally more consistent with the new GRC figures than the 2003 TY GRC figures that Edison used in its filing in this case – almost six months after giving the higher figures to Anaheim. (Anaheim Response to ORA DR 2)

[4] NOI for TY 2006 TY GRC, SONGS O&M Ch. XVI-XVII, p. 39.

2003 and 2006 GRCs.[5] The TURN base case uses Edison's figures of $310 million and adjustments for common O&M costs to take into account the 2006 GRC information.

Edison estimates refueling outage costs of $53 million (2004 dollars), based on the estimate from its last GRC. The last two unit refueling outages, excluding plugging and sleeving of steam generators, have averaged $63.2 million (2003 dollars), and Edison's projection for a TY 2006 outage at Unit 3 (again excluding steam generator plugging and sleeving) is $73.7 million. By comparison, the costs of the two previous outages, which Edison used to develop its estimate of $52.5 million (2004 dollars) that is filed in the SG replacement application, averaged only $51.6 million (excluding steam generator costs).[6] Large amounts of additional one-time activities have been occurring at each outage – unrelated to the steam generator. These activities have been raising costs. This information from the 2006 GRC thus suggests a reasonable base case outage cost is about 20% higher than Edison. We have thus used Edison's figures (2004 dollars) provided in Exhibit 14 for outage costs in our revised base case, even though the underlying data could support a somewhat higher figure due to the trend of cost increases in recent refueling outages.

It is likely that base case O&M expenses are somewhat low (even after accounting for the 2006 GRC information), because it is not apparent that the full amount of incremental A&G costs is included for the plant. Costs of certain corporate functions may be reduced by the loss of a large complex powerplant comprising about 5-10% of Edison's workforce.

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[5] Compare A. 02-05-004, Ex. 88 (SONGS 2 and 3 O&M Chapters IX-XVIII), p. 89, with NOI for TY 2006 TY GRC, SONGS O&M Ch. XVI-XVII, p. 40.

[6] NOI for TY 2006 TY GRC, SONGS O&M Ch. XVI-XVII, p. 52.

To analyze capital expenditures on a year-by-year basis, I ran a revenue requirements model for capital expenditures taking into account book and tax depreciation, return, income taxes, and property taxes. The base case used the capital figures presented by Edison based on the 2006 GRC. The assumed end of project life for both units was 2022. The model was run through 2027 to capture differences in the first years of shut-down O&M. Shut-down O&M was assumed to be 80% of basic O&M in the first year after a shutdown, 50% in year 2, and 10% in years 3 and beyond, based on the 1994 San Onofre settlement.[7]

One key difference between TURN's analysis and Edison's was the assumption that the plant could in fact run beyond 2009 if the steam generators were not replaced. Such an assumption is based on information provided by Edison in SCE-2 pages 13-14, which showed that several years of additional life, particularly for Unit 3, would be likely to occur. In my base case, the plant was assumed to end its life in 2012 for Unit 2 and 2014 for Unit 3. These figures represent the 50th percentile of when the plant would be expected to be closed without a steam generator replacement, as shown in SCE-2, pp. 14-15. [8]

The base case alternative where the steam generator is not replaced assumes that capital expenditures can be reduced in the later years of the plant's life. The pattern of percentage reductions in capital expenditures from 2018-22 that Edison assumed if the steam generator were replaced was assumed for 2008-2012 for Unit 2 and 2010-2014 for Unit 3. Table 1 shows capital expenditures (excluding the steam generator) used in the base case.

[7] Southern California Edison Company and Division of Ratepayer Advocates. Settlement Agreement (California PUC App. 93-12-025), November 1994, page A-6.

[8] In material provided to Anaheim (Anaheim Response to ORA DR 2), Edison assumed that the plant would run through 2010, not 2009.

Table 1: Base Case Projections of Capital Spending (Excluding Steam Generator – Table Revised for 2006 GRC)

Non-SG Capital Spending per Edison with SG Replacement		TURN early closure 2012/2014						
	Total	Unit 2 % of 2008	Unit 3 % of 2008	Total % of 2008	Unit 2	Unit 3	Total	Excess Capital Cost with SG
2004	143,000							
2005	92,000							
2006	89,000							
2007	90,000							
2008	94,000							
2009	83,000	84%	101%	92%	39,378	47,439	86,818	(3,818)
2010	92,000	65%	104%	84%	30,486	48,757	79,243	12,757
2011	90,000	39%	87%	63%	18,207	40,850	59,058	30,942
2012	93,000	20%	67%	44%	9,315	31,626	40,941	52,059
2013	95,000		40%	20%	0	18,888	18,888	76,112
2014	97,000		21%	10%	0	9,664	9,664	87,336
2015	103,000							
2016	107,000							
2017	108,000							
2018	111,000							
2019	93,000							
2020	72,000							
2021	43,000							
2022	22,000							

Base and refueling O&M costs were assumed to be 10% higher than in the case where the steam generator is replaced to cover costs of sleeving, plugging, and midcycle outages. Refueling costs are assumed not to occur in the year when a unit is retired.

The capacity factor was assumed to decline from 85% in 2009 to 65% for each unit in the year of closing to reflect extra downtime and potential deratings.

To value replacement power, Edison used separate capacity and energy calculations. This created a mismatch, because combined cycle capacity was combined with market energy, which was more expensive than the energy generated by the combined cycle. It also assumes that if the plant operates at a lower than expected capacity factor, only bare energy costs will be saved. Consistent with PG&E's analysis of Diablo Canyon, I used a base case replacement power price equal to the cost of a combined cycle operated at a 90% capacity factor, using Edison's figures for initial capital costs and fixed O&M costs per kW,[9] $2/MWh for variable O&M, and gas energy at a 7000 Btu/kWh

[9] Because the combined cycle is deferred from the year of closure to 2023, I used a real fixed charge rate to estimate the deferral value of the combined cycle capital costs in each year. Analytically, it should produce a similar present value of capital costs to Edison's method, but with less computational effort.

heat rate using Edison's gas price forecast in real terms escalated to nominal dollars.

Edison quantified a gas price adder to California that would allegedly result if the SONGS steam generator were not replaced. iIt appears that Edison is selectively discussing such adders as benefits for its own nuclear generation but is not including them when analyzing the procurement of renewables and efficiency. Furthermore, replacement of a significant portion of SONGS by a mix of renewables and efficiency (or even new modern coal-fired generation) at a similar cost to gas would reduce or eliminate any potential gas price increase. Finally, the configuration of the state's gas system, and in particular, potential availability of LNG delivered directly to the West could potentially change this figure dramatically.

For avoided transmission costs, the base case analysis removed the cost of the new 500 kV line modeled by SCE in light of information from SDG&E that suggests that the line is not incremental to the SONGS-out case but is likely to be needed in some form regardless of whether SONGS is replaced or not. The analysis used a cost of $120 million for voltage support (the average cost of Edison's Scenarios 2 and 3 in SCE-5, pp. 28 and 30).

Base case economic and ratemaking assumptions included

- 2.5% inflation,
- a discount rate of 9.75% to present value all costs to 2009,[10]
- AFUDC accounting (instead of CWIP in rate base) for the new steam generator investment,
- simply applying the costs (rather than making a revenue requirement calculation) for costs of removal, given the uncertainty of ratemaking treatment for that part of the project.

[10] TURN rejects Edison's argument that its incremental cost of equity exceeds 13% and thus rejects Edison's discount rate of 10.5%. This factor in isolation renders our results more favorable to the steam generator project (higher net benefits or lower net costs) than had we used Edison's 10.5% discount rate.

TURN's base steam generator investment using AFUDC accounting is calculated in Table 2.

Table 2: Steam Generator Capital Costs (AFUDC Accounting)

	Unit 2			Unit 3		
	Capital	AFUDC	Total EOY	Capital	AFUDC	Total EOY
2004	10.0	0.5	10.5	8.0	0.4	8.4
2005	36.0	2.8	49.3	31.0	2.3	41.7
2006	37.0	6.6	92.9	31.0	5.6	78.3
2007	43.0	11.2	147.0	36.0	9.4	123.7
2008	38.0	16.2	201.2	32.0	13.6	169.3
2009	156.0	27.2	384.4	44.0	18.7	232.0
2010	36.0		420.4	95.0	4.6	331.6
2011			420.4	2.0		333.6
	356.0			277.0		

9.75% AFUDC Rate

B. Sensitivity Analyses: Total Plant Costs

Sensitivity analyses were run on the following parameters, singly and in combination, as recommended by Mr. Schlissel:

- capacity factor after steam generator replacement (average over remaining life from 88% to 75%)
- O&M costs and capital spending (whether real escalation in O&M and higher capital spending occur as a potential result of aging or other mechanisms)
- whether a one-year outage with $100 million of capital spending might occur if the steam generator is not replaced (modeled to be in 2017, approximately midway between 2009 and the end of the plant's life)
- whether the plant might close early (again modeled in 2017, at the midpoint) after the steam generator is replaced.

None of these scenarios explicitly account for the possibility of major seismic retrofits, significant new terrorism-related security costs, or accidental releases of significant quantities of radioactive materials into the environment during the extended life of the facility. Any of these occurrences could cause an otherwise cost-effective steam generator replacement project to become uneconomic. Several other variables were also included in scenarios.

- PG&E's estimate of replacement power costs for baseload power as developed in the Diablo Canyon steam generator case was used in some cases. These were approximately 9% below our estimates of Edison's combined cycle power costs.

- A case with 20% higher O&M cost (except common O&M) and a 50% higher capital cost was run, consistent with Edison's calculation of such a case.

- Transmission cost of $60 million (half of Edison's average figure for voltage support) to reflect the potential (raised by SDG&E) that the amount of required equipment may be overstated or the potential that costs of static var compensation may be lower than those estimated by Edison.

- To understand the impact of the difference between the Edison 2006 and 2003 rate cases, a lower O&M scenario, based on Edison's 2003 GRC O&M costs was also run.[11]

C. Sensitivity Analyses: Edison Ratepayer Perspective

Two different sets of assumptions were run from the perspective of Edison ratepayers on several of the system scenarios.

- Edison would spend 97.5% of the steam generator capital costs and 82.5% of other costs and receive 82.5% of the energy in the replacement case (generally consistent with SDG&E's basic position that the co-owners who do not pay for the steam generator replacement should receive a significant share of capacity), but would spend 75% of costs for 75.05% of energy in the no-replacement case.

[11] This scenario is outdated and no longer applicable, even though it was the basis for Edison's original base O&M estimates.

- Edison would spend 97.5% of the steam generator capital costs and 97.5% of other costs and receive 97.5% of the energy in the replacement case (consistent with Edison's basic position that the co-owners who do not pay for the steam generator replacement should receive a significant share of capacity), but would spend 75% of costs for 75.05% of energy in the no-replacement case.

D. Results

In all, 34 cases were prepared, which are identified in Table 3 below. 21 of these cases represent sensitivity analyses for the entire plant. The other 12 scenarios examine Edison ratepayers' position in six of the initial 21 scenarios run for the system as a whole, as it would be affected by the ownership share that non-participant minority owners would receive after a steam generator replacement. Six cases were run for each of two outcomes that generally represent SDG&E's and Edison's positions respectively in the upcoming SDG&E-Edison arbitration. A scenario with a negative number shows that steam generator replacement would be cost-effective, while a positive number shows that it would be uneconomic.

Under the base case system scenario, the project is economic by about $213 million. Benefits would have been over $735 million with the outdated 2003 GRC O&M and capital cost figures used in Edison's analysis. About $62 million of the difference arises from the capital forecast and the remaining $450 million from the O&M forecast. However, with PG&E energy costs, the project is uneconomic by $63 million. Cutting the transmission cost in half also reduces benefits by $38 million. Under other scenarios (particularly involving early closure of SONGS, a one year outage, and a lower capacity factor and/or higher costs which could result from aging of other plant components) the steam generator replacement is much less cost-effective or even not cost-effective at all. At an 84% capacity factor, or with 1% real escalation and 10% more capital above

Edison's cost estimates, the plant is break-even or worse. The project is cost-effective in five of the system scenarios and not cost-effective in sixteen scenarios.

When **Edison** ratepayers are considered, the question raised by SDG&E – as to its appropriate share of SONGS if Edison goes it alone with a steam generator replacement – becomes even more critical. Edison's share of the project ends up much less cost-effective than simply holding 75% of the whole project if the non-participating minority owners end up with 15% of the plant, while the participating owners (Edison and the City of Riverside) pay all of the steam generator costs. The project returns net benefits of $141 million, less than 20% of the cost of the steam generator under the base case. At capacity factors lower than 85% or costs higher than expected by Edison, the project is breakeven or worse.

On the other hand, if Edison ends up with 97.5% of the project and 97.5% of costs (all but the City of Riverside's share), the project is still less economic to Edison ratepayers than if Edison could hypothetically hold 75.05% of the total project. Low-capacity-factor and high-cost cases are worse for Edison ratepayers than if Edison held 75% of output and 75% of costs or even if Edison had 82.5% of the output and costs after a steam generator repair.

In sum, while some benefits are apparent in the base case, they are much less than projected by Edison, and the results are not robust at all. Any significant deterioration of Edison's cost position or capacity factor will tip the project to break-even or uneconomic. This problem is accentuated if SDG&E were to prevail in the arbitration regarding ownership shares and a significant portion of the project remained under SDG&E ownership after a steam generator replacement, as the project would be uneconomic to Edison ratepayers with PG&E energy prices, 1% real escalation in O&M and 10% more capital, or capacity factors below about 85%.

The base cost-effectiveness of SONGS steam generator replacement is less than for Diablo Canyon and a larger number of scenarios are not cost-effective, in large part because SONGS is more expensive to operate than Diablo Canyon. Our base case O&M expenses for SONGS (even excluding common O&M) are about 40% higher than those estimated by PG&E, and even Edison's 2003 figures are 31% higher than PG&E's.

Table 4 provides an example of the model run on which the analysis is based, and Table 5 provides an example of the revenue requirements calculation used for capital additions. Table 3 shows the stream of 2009 capital-related revenue requirements – including the Unit 2 steam generator and other costs.

Table 3: Scenario Summary Results (Revised)

		Closure with SG	Closure w/o SG	O&M	Capital	Energy	Year long outage	cap factor after SG	Replace SG	Do Not replace	Difference Repl. Power	Difference
1	SONGS Base Case (updated for 2006 GRC)	2022	2012/2014	Base	Base	Edison	None	88%	$ 7,311	$ 3,236	$ (4,287)	$ (213)
2	SONGS Base Case, PG&E Energy	2022	2012/2014	Base	Base	PG&E	None	88%	$ 7,311	$ 3,236	$ (4,012)	$ 63
3	SONGS Base Case except Early Closure	2017	2012/2014	Base	Base	Edison	None	88%	$ 5,818	$ 3,236	$ (2,345)	$ 237
4	SONGS Base Case Except One-Year Outage	2022	2012/2014	Base	Base	Edison	2017	88%	$ 7,296	$ 3,236	$ (3,836)	$ 223
5	SONGS Base Case, Edison 2003 GRC O&M	2023	2012/2015	Base	Base	Edison	2017	88%	$ 6,450	$ 2,897	$ (4,287)	$ (735)
6	Base CF, 1% real O&M, 10% more capital	2022	2012/2014	1% real	10% more	Edison	None	88%	$ 7,881	$ 3,417	$ (4,287)	$ 177
7	Base CF, 2% real O&M, 20% more capital	2022	2012/2014	2% real	20% more	Edison	None	88%	$ 8,493	$ 3,609	$ (4,287)	$ 597
8	Base CF, 20% higher base and refueling O&M all years, 50% more non SG capital (Edison's sensitivity case)	2022	2012/2014	20% more	50% more	Edison	None	88%	$ 8,584	$ 3,859	$ (4,287)	$ 437
9	SONGS Base Case except 60MM transmission	2022	2012/2014	Base	Base	Edison	None	88%	$ 7,138	$ 3,197	$ (4,287)	$ (347)
10	85% Capacity Factor, otherwise Base Case	2022	2012/2014	Base	Base	Edison	None	85%	$ 7,280	$ 3,236	$ (4,105)	$ (61)
11	85% capacity factor, early closure	2017	2012/2014	Base	Base	Edison	None	85%	$ 5,798	$ 3,236	$ (2,220)	$ 342
12	85% Capacity Factor, otherwise Base Case	2022	2012/2014	Base	Base	Edison	None	85%	*Same as #10 -- not a separate scenario*			
13	80% capacity factor	2022	2012/2014	Base	Base	Edison	None	80%	$ 7,229	$ 3,233	$ (3,771)	$ 225
14	80% capacity factor PG&E Energy	2022	2012/2015	Base	Base	PG&E	None	80%	$ 7,229	$ 3,233	$ (3,523)	$ 473
15	80% capacity factor, early closure	2017	2012/2014	Base	Base	Edison	None	80%	$ 5,765	$ 3,233	$ (2,005)	$ 527
16	80% CF, One-Year Outage	2022	2012/2014	Base	Base	Edison	None	80%	$ 7,221	$ 3,233	$ (3,344)	$ 643
17	80% CF, 1% real O&M, 10% more capital	2022	2012/2014	1% real	10% more	Edison	None	80%	$ 7,800	$ 3,337	$ (3,848)	$ 615
18	80% CF, 2% real O&M, 20% more capital	2022	2012/2014	2% real	20% more	Edison	None	80%	$ 8,444	$ 3,538	$ (3,848)	$ 1,058
19	80% CF, 2% real O&M, 20% more capital PG&E Energy	2022	2012/2014	2% real	20% more	PG&E	None	80%	$ 8,444	$ 3,538	$ (3,595)	$ 1,311
20	80% CF, 2% real O&M, 10% more capital, One-Year Outage	2022	2012/2014	2% real	10% more	Edison	2017	80%	$ 8,259	$ 3,586	$ (3,136)	$ 1,536
21	80% CF, 2% real O&M, 10% more capital, Early Closure	2017	2012/2014	2% real	10% more	Edison	None	80%	$ 5,966	$ 3,586	$ (2,211)	$ 169
22	75% CF	2022	2012/2014	Base	Base	Edison	None	75%	$ 7,156	$ 3,212	$ (3,427)	$ 517

NOTE: Cases with year long outage in 2017 also have $100 million in capital spending added in that year

Ratemaking Cases Edison Only -- 97.5% SG cost, 82.5% output and other costs

23	SONGS Base Case	2022	2012/2014	Base	Base	Edison	None	88%	$ 6,047	$ 2,422	$ (3,767)	$ (141)
24	SONGS Base Case PG&E Energy	2022	2012/2014	Base	Base	PG&E	None	88%	$ 6,047	$ 2,422	$ (3,528)	$ 97
25	Base CF, 1% real O&M, 10% more capital	2022	2012/2014	1% real	10% more	Edison	None	88%	$ 6,518	$ 2,558	$ (3,767)	$ 193
26	85% capacity factor	2022	2012/2014	Base	Base	Edison	None	85%	$ 6,022	$ 2,422	$ (3,600)	$ 0
27	80% capacity factor	2022	2012/2014	Base	Base	Edison	None	80%	$ 5,980	$ 2,420	$ (3,122)	$ 438
28	80% CF, 2% real O&M, 20% more capital	2022	2012/2014	2% real	20% more	Edison	None	80%	$ 7,059	$ 2,753	$ (3,122)	$ 1,184

Ratemaking Cases Edison Only -- 97.5% SG cost, 97.5% output and other costs

29	SONGS Base Case	2022	2012/2014	Base	Base	Edison	None	88%	$ 7,128	$ 2,422	$ (4,842)	$ (136)
30	SONGS Base Case PG&E Energy	2022	2012/2014	Base	Base	PG&E	None	88%	$ 7,128	$ 2,422	$ (4,542)	$ 164
31	Base CF, 1% real O&M, 10% more capital	2022	2012/2014	1% real	10% more	Edison	None	88%	$ 7,684	$ 2,558	$ (4,842)	$ 285
32	85% capacity factor	2022	2012/2014	Base	Base	Edison	None	85%	$ 7,098	$ 2,422	$ (4,644)	$ 32
33	80% capacity factor	2022	2012/2014	Base	Base	Edison	None	80%	$ 7,049	$ 2,420	$ (4,059)	$ 570
34	80% CF, 2% real O&M, 20% more capital	2022	2012/2014	2% real	20% more	Edison	None	80%	$ 8,326	$ 2,753	$ (4,059)	$ 1,515

Table 4
Example of Single Scenario Result (Revised Base Case)

SONGS base case

WITH SG REPLACEMENT

	Capacity Factor	Basic O&M	Insurance, Worker comp, incentives	Refuel	Nuclear Fuel	Fuel + O&M	Per MWh	Capital Rev Req	Total Rev Req.	per MWh	Transmission	Capacity factor diff.	Rep. Power Cost	Replacement Power	SG Disposal	Total
2009	75.0%	337.2	19.8	66.8	86.4	510.1	36.1	91.45	601.5	42.6					36	$637.5
2010	75.0%	359.5	20.3	68.4	96.2	544.4	38.5	197.24	741.7	52.5					64	$805.7
2011	88.0%	391.1	20.8	77.3	114.7	603.8	36.4	208.06	811.9	49.0					48	$859.9
2012	88.0%	400.9	21.3	80.4	125.8	628.4	37.9	219.46	847.9	51.2					2	$849.9
2013	88.0%	410.9	21.9	73.7	129.2	635.6	38.3	231.31	866.9	52.3						$866.9
2014	88.0%	421.1	22.4	75.5	139.6	658.7	39.7	243.73	902.4	54.4						$902.4
2015	88.0%	431.7	23.0	85.3	143.3	683.2	41.2	258.00	941.2	56.8						$941.2
2016	88.0%	442.5	23.5	88.8	152.5	707.2	42.7	273.90	981.1	59.2						$981.1
2017	88.0%	453.5	24.1	164.0	159.5	801.2	48.3	290.84	1,092.0	65.9						$1,092.0
2018	88.0%	464.9	24.7	-	167.4	657.0	39.6	310.62	967.7	58.4						$967.7
2019	88.0%	476.5	25.4	186.8	179.8	868.5	52.4	326.47	1,194.9	72.1						$1,194.9
2020	88.0%	488.4	26.0	87.6	184.0	786.0	47.4	327.94	1,114.0	67.2						$1,114.0
2021	88.0%	518.9	26.6	89.8	199.5	834.8	50.4	330.90	1,165.7	70.3						$1,165.7
2022	88.0%	531.8	27.3	-	203.4	762.6	46.0	246.72	1,009.3	60.9						$1,009.3
2023	0.0%	436.1				436.1		-	436.1							$436.1
2024	0.0%	279.4				279.4		-	279.4							$279.4
2025		57.3				57.3			57.3							$57.3
2026		58.7				58.7			58.7							$58.7
2027		60.2				60.2			60.2							$60.2
NPV at	9.75%													$0.0		$7,310.9
NO SG REPLACEMENT																
	Capacity Factor	O&M	Insurance, Worker comp, incentives	Refuel	Nuclear Fuel	Fuel + O&M	Per MWh	Capital Rev Req	Total Rev Req.	per MWh	Transmission	Capacity factor diff.	Rep. Power Cost	Replacement Power		Total
2009	82.5%	370.9	19.8	73.4	94.9	559.0	36.0	30.6	589.6	37.9		-7.5%	46.39	($65.2)		$524.5
2010	80.0%	395.5	20.3	75.3	102.6	593.6	39.4	60.1	653.7	43.4		-5.0%	48.36	($45.2)		$608.5
2011	75.0%	430.2	20.8	77.1	97.7	625.9	44.3	83.9	709.8	50.2		13.0%	51.23	$125.4		$835.2
2012	70.0%	440.9	21.3		100.1	562.3	42.7	96.1	658.5	49.9	13.4	18.0%	53.11	$180.1		$851.9
2013	35.0%	369.8	19.0	81.1	51.4	521.2		65.1	586.2		13.7	53.0%	54.96	$548.6		$1,148.6
2014	32.5%	315.9	15.0	-	51.6	382.4		57.8	440.2		14.0	55.5%	56.61	$591.7		$1,045.9
2015		194.3		-	-	194.3			194.3		14.4	88.0%	58.76	$973.8		$1,182.5
2016		132.7		-	-	132.7			132.7		14.8	88.0%	60.70	$1,006.0		$1,153.4
2017		45.4		-	-	45.4			45.4		15.1	88.0%	62.41	$1,034.3		$1,094.8
2018		46.5		-	-	46.5			46.5		15.5	88.0%	64.26	$1,065.1		$1,127.1
2019		47.6		-	-	47.6			47.6		15.9	88.0%	66.17	$1,096.7		$1,160.3
2020		48.8		-	-	48.8			48.8		16.3	88.0%	68.04	$1,127.6		$1,192.7
2021		51.9		-	-	51.9			51.9		16.7	88.0%	69.95	$1,159.3		$1,227.9
2022		53.2		-	-	53.2			53.2		17.1	88.0%	72.03	$1,193.7		$1,264.0
2023		54.5			-	54.5			54.5			0.0%	-	$0.0		$54.5
2024		55.9			-	55.9			55.9			0.0%	-	$0.0		$55.9
2025		57.3				57.3			57.3							$57.3
2026		58.7				58.7			58.7							$58.7
2027		60.2				60.2			60.2							$60.2
NPV	9.75%													$4,287.4		$7,523.5
DIFFERENCE																
2009		(33.7)	-	(6.7)	(8.6)	(49.0)		60.9	11.9		$0.0			$65.2	$36.0	$113.1
2010		(36.0)	-	(6.8)	(6.4)	(49.1)		137.1	88.0		$0.0			$45.2	$64.0	$197.1
2011		(39.1)	-	0.1	16.9	(22.1)		124.2	102.1		$0.0			($125.4)	$48.0	$24.7
2012		(40.1)	-	80.4	25.7	66.1		123.3	189.4		($13.4)			($180.1)	$2.0	($2.0)
2013		41.1	2.9	(7.4)	77.8	114.4		166.2	280.6		($13.7)			($548.6)		($281.7)
2014		105.3	7.4	75.5	88.0	276.3		185.9	462.2		($14.0)			($591.7)		($143.5)
2015		237.4	23.0	85.3	143.3	489.0		258.0	747.0		($14.4)			($973.8)		($241.2)
2016		309.7	23.5	88.8	152.5	574.5		273.9	848.4		($14.8)			($1,006.0)		($172.3)
2017		408.2	24.1	164.0	159.5	755.8		290.8	1,046.7		($15.1)			($1,034.3)		($2.8)
2018		418.4	24.7	-	167.4	610.6		310.6	921.2		($15.5)			($1,065.1)		($159.4)
2019		428.8	25.4	186.8	179.8	820.8		326.5	1,147.3		($15.9)			($1,096.7)		$34.7
2020		439.6	26.0	87.6	184.0	737.2		327.9	1,065.1		($16.3)			($1,127.6)		($78.8)
2021		467.0	26.6	89.8	199.5	782.9		330.9	1,113.8		($16.7)			($1,159.3)		($62.2)
2022		478.7	27.3	-	203.4	709.4		246.7	956.1		($17.1)			($1,193.7)		($254.7)
2023		381.6	-	-	-	381.6		-	381.6		$0.0			$0.0		$381.6
2024		223.5	-	-	-	223.5		-	223.5		$0.0			$0.0		$223.5
2025		-	-	-	-	-		-	-		$0.0			$0.0		$0.0
2026		-	-	-	-	-		-	-		$0.0			$0.0		$0.0
2027		-	-	-	-	-		-	-		$0.0			$0.0		$0.0
NPV	9.75%					$2,490.2		$1,532.3	$4,022.5		($77.2)			($4,287.4)		($212.6)

Table 5
Example of Fixed Charge Rate Model (Revised 2009 Capital Figure)

INPUT ASSUMPTIONS			
TYPE OF PLANT	Nuclear Incremental Capital		
UTILITY NAME	Edison		
TYPE OF UTILITY	IOU		
REFERENCE YEAR		2009	
INFLATION RATE		2.5%	
NET SALVAGE		0.0%	
BOOK LIFE		14.00	YEARS
DEPRECIATION % PER YEAR			
DISCOUNT RATE	9.7%		
RETURN	9.7%		
DEBT	8.2%	47.0%	
COMMON	11.6%	48.0%	
PREFERRED	6.5%	5.0%	
FED INCOME TAX		35.0%	
STATE INCOME TAX		8.8%	
PROPERTY TAX		1.1%	
PLANT SIZE (MW)		2150	
INITIAL INVESTMENT (NOM)		467434	

CALCULATED FIGURES — Edison — Nuclear Incremental Capital

LEVELIZED NOMINAL FIXED CHARGE RATE 16.34%

REAL FIXED CHARGE RATE 14.37%

PRESENT VALUE OF REVENUE REQUIREMENTS 1.2790 times capital cost

COLUMNS 2 THROUGH 13 GIVE FIGURES PER THOUSAND DOLLARS INVESTED

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Year	Deprec. Book	Net Plant	Deprec. Fed. Tax.	Deferred Taxes	Deprec. State Tax	Flow-thru depr.	Rate Base	Return	Income Taxes (current)	Capital Additions	Property Taxes	Fixed Rev. Req. Per 1000	Fixed Rev. Req. Per kW	Fixed Rev. Req. $ million
midyear	2009	71.43	964.29	72.19	0.27	68.88	-2.55	964.15	93.94	19.68	0.00	10.61	195.65	42.54	91.45
	2010	71.43	892.86	66.77	-1.63	63.96	-7.47	893.41	87.04	36.64	0.00	9.83	204.93	44.56	95.79
	2011	71.43	821.43	61.77	-3.38	59.39	-12.04	824.48	80.33	34.11	0.00	9.07	194.93	42.38	91.12
	2012	71.43	750.00	57.13	-5.00	55.15	-16.28	757.25	73.78	31.62	0.00	8.33	185.16	40.26	86.55
	2013	71.43	678.57	52.85	-6.50	51.21	-20.22	691.57	67.38	29.19	0.00	7.61	175.60	38.18	82.08
	2014	71.43	607.14	48.88	-7.89	47.55	-23.88	627.34	61.12	26.80	0.00	6.90	166.25	36.14	77.71
	2015	71.43	535.71	45.22	-9.17	44.16	-27.27	564.44	54.99	24.44	0.00	6.21	157.07	34.15	73.42
	2016	71.43	464.29	44.62	-9.38	41.00	-30.43	502.29	48.94	22.10	0.00	5.53	148.00	32.18	69.18
	2017	71.43	392.86	44.62	-9.38	38.07	-33.36	440.25	42.89	19.76	0.00	4.84	138.92	30.20	64.94
	2018	71.43	321.43	44.62	-9.38	35.35	-36.08	378.21	36.85	17.40	0.00	4.16	129.84	28.23	60.69
	2019	71.43	250.00	44.62	-9.38	32.83	-38.60	316.16	30.80	15.03	0.00	3.48	120.74	26.25	56.44
	2020	71.43	178.57	44.62	-9.38	30.48	-40.95	254.12	24.76	12.65	0.00	2.80	111.63	24.27	52.18
	2021	71.43	107.14	44.62	-9.38	28.30	-43.13	192.08	18.71	10.26	0.00	2.11	102.52	22.29	47.92
	2022	71.43	35.71	327.50	89.62	403.67	332.24	80.53	7.85	-15.83	0.00	0.89	64.33	13.99	30.07
	2023														
	2024														

III. Ratemaking Issues

Edison has made two unorthodox ratemaking proposals that require ratepayers to pay in excess of $200 million before the new steam generator comes into service – a proposal to require ratepayers to pay for construction work in progress before the project is completed ($149 million in advance payments, including $79 million by the end of 2008) and a proposal to recover the cost of removal of the old steam generator over six years (not over the remaining life of the project). These proposals generate early cash flow for Edison, but also (as designed by Edison) have the effect of generating large amounts of tax revenue for the IRS relatively early, with payback over longer periods of time. Even if it approves the steam generator project, the Commission should deny these requests for extraordinary rate relief.[12]

In addition, if it approves the project, the Commission should require a minimum benefit level for Edison's ratepayers who are taking significant risks on the project.

A. Construction Financing Costs – Uphold Commission Precedents Denying Construction Work in Progress (CWIP) in the Rate Base

Edison is requesting that the Commission authorize the inclusion in current rates of the financing cost of Construction Work in Progress on the new steam generator. The CPUC's long-standing practice of excluding CWIP in the rate base as a general rule was established in the 1920s and 1930s.[13] This is the first time that such a request has been made for a large construction project[14] since PG&E's 1982 TY General Rate Case – A. 60153. At that time,

[12] The use of AFUDC accounting for the steam generator was incorporated into my cost-effectiveness analysis, as it is fundamental to understanding revenue requirements. Only cost figures were included for the steam generator removal, as alternative ratemaking treatments for removal differ in present value by only a few million dollars, even though there are significant differences in the time patterns of expenditures.

[13] 33 Cal. Railroad Commission 737 (Pacific Telephone and Telegraph). The exclusion of CWIP from the rate base was upheld in the federal appeals courts and the U.S. Supreme Court in the 1930s in a case involving a predecessor of Edison. Los Angeles Gas and Electric Corporation vs. Railroad Commission of California (D,C, 1932) 58 F, 2d 256; affirmed 53 S. Ct. 637. 289 U.S. 287, 77 L. Ed. 1180.

[14] CWIP was allowed to be amortized in the three 1996-1997 nuclear stranded cost cases (as Edison indicated in its response to TURN DR 4-3), but that CWIP was likely to come on line very soon after, and the CWIP amortization was

PG&E was in the throes of financial difficulty due to delays in bringing Diablo Canyon on line, faced significant construction expenditures at Helms, and expected that even more money would be spent to begin construction of the Harry Allen-Warner Valley Coal plant, while double-digit inflation made it difficult for the utility to earn its authorized rate of return. Even under those circumstances that were far more extreme than those faced by Edison now, the Commission rejected inclusion of CWIP in the rate base.[15]

In its direct testimony, Edison has made no extensive showing of financial hardship to prove that CWIP is necessary. Edison claimed that its capital budget is relatively high – stating that it will spend $1 to $1.25 billion per year on distribution upgrades and may need to spend money to ($720 million) to bring Mohave back into service. However, these figures were not compared to any projections of total capitalization, of income, or of internal cash flow from operations. No showing was made as to the amount of debt and equity that Edison would be required to issue to fund its construction program. Tellingly, Edison never told us in its testimony on steam generator replacement how much cash it had -- $2.43 billion in the holding company as a whole as of September 30, 2004. Under the conditions imposed on SCE and Edison International as part of the original Commission decision approving the formation of the holding company, the parent company is obligated to place first priority on the capital needs of the utility.[16]

SCE currently has a CWIP-to-capitalization ratio of less than 6% ($737 million of CWIP out of $13,065 million of total utility plant in its 10-Q for the quarter ending September 30, 2004). By comparison, in the early 1980s, Edison's CWIP-to-capitalization ratio exceeded 25%. Even with steam generator construction and even assuming construction leading to the restart of

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done specifically to allow a bright line to be created between sunk costs as of a specific date (which were amortized) and going forward capital costs (which were expensed under ICIP). The Commission has also occasionally allowed CWIP for short-lead-time projects less than one year from completion on a few occasions to deal with issues of regulatory lag. (See CPUC Decision 92366 re: General Telephone Company (October 1980), slip op. at 92-94a.

[15] Decision 93887.

[16] 27 CPUC2d at 376, Ordering Paragraph 12. ("The capital requirements of the utility, as determined to be necessary to meet its obligation to serve, shall be given first priority by the Board of Directors of Edison's parent holding company and Edison.") The Commission adopted an expansive interpretation of this obligation in D.02-01-039.

the problematic Mohave unit – which may never happen at all, the worst case CWIP-to-capitalization ratio is likely to remain well under 15% for the remainder of the decade.[17]

Edison International's stock is selling at about 180% of book value at the present time – a far different picture from stock prices below book value in the early 1980s due to high interest rates and massive construction programs. Its third quarter earnings press release stated:

> "During the third quarter, the company took a major step to secure the financial recovery of MEHC by selling, at a substantial gain, its interest in Contact Energy and making excellent progress towards completion of the sale of the remaining international projects. This step, coupled with constructive prior regulatory decisions for SCE, set a foundation for an increase in our dividend and a 5-year outlook for earnings growth substantially above our peers' average," commented John Bryson, Chairman, Edison International.[18]

While much of the credit for improvement admittedly is related to the restructuring of some of Edison International's unregulated projects, this statement simply is inconsistent with claims of financial weakness requiring extraordinary rate relief.

In sum, Edison simply cannot make a showing of financial weakness that would justify such an extraordinary ratemaking step of making customers pay $150 million in advance to finance its steam generators.

Even if it approves the steam generator project, the Commission should nevertheless deny the request to provide extraordinary rate relief by allowing current recovery of financing costs of Edison's Construction Work in Progress.

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[17] If one starts with the $737 million of CWIP existing at the end of the third quarter of 2004, a peak CWIP level including both the steam generator and Mohave would be in the range of $2.4 billion after adding $1.6 billion (for steam generator and Mohave at peak of construction, plus escalation in short-term CWIP for transmission and distribution projects). Starting with $13.1 billion of capitalization at the end of the third quarter, subtracting existing CWIP, adding $600 million per year of new net plant per year (a figure generally consistent with utility net plant additions of $478 million for the first three quarters of 2004), and $2.4 billion for the total CWIP with both SONGS and Mohave yields $17.7 billion, or a worst-case CWIP-to-capitalization ratio of about 13.5%.

[18] "Edison International Reports Financial Results for the Third Quarter of 2004," November 5, 2004. http://www.edison.com/media/indiv_pr.asp?bu=&year=0&id=5328

B. Recovery of Cost of Removal of Old Steam Generator – Deny Accelerated Depreciation and Tax Gross-Up; Adopt 17 Year Remaining Life and Deferred Tax Accounting

Edison proposes to recover the cost of removal of the old steam generators at units 2 and 3 over a six-year period from 2006-2011. Edison also proposes flow-through tax treatment of the cost of removal, which requires a tax gross-up of approximately $15 million in each of the first three years, with payback through the tax deductibility of cost of removal over the next three years.[19]

If the steam generator replacement is approved, TURN recommends that the Commission reject Edison's depreciation proposal and allow recovery this cost through a conventional depreciation structure for this cost – to recover it over the remaining life of the plant, beginning in 2006. TURN also recommends that the state and federal taxes associated with this cost and its recovery be normalized (i.e., recovered with a deferred tax liability before the removal occurs and a declining deferred tax asset after the removal).

Other than the relatively obvious appearance that Edison wants to collect cash quickly, there is no justification for a six-year recovery period for this cost. Edison points to the fact that it has collected nothing for interim removal, but ignores the even larger fact that it has already depreciated over 80% of the pre-1996 cost of SONGS and expensed capital costs during the ICIP period. As a result, as of the 2003 GRC, its undepreciated nuclear capital was only about 10% of its gross plant as shown on Edison's books for ratemaking purposes, and even less for book purposes given the expensing of capital costs through ICIP. Even with new capital installed in 2004-2005, the amount of depreciation reserve for SONGS is thus far

[19] The figures shown in Exhibit SCE-6 are apparently in real, not nominal dollars. Nominal dollar figures were developed using Edison's depreciation request of $24.892 million per year shown in its cost-effectiveness workpapers using the same methods shown in Exhibit SCE-6.

The revenue requirement figures for steam generator removal in SCE-4 and Edison's cost-effectiveness workpapers are also incorrect (even if the depreciation figures are right), because Edison computed the tax gross-up improperly in those workpapers and calculated rate base with an end-of-year convention instead of the appropriate mid-year calculation, thereby understating early year costs and overstating later year costs. Table 7 contains Edison's calculation and a corrected version with the proper tax and rate base calculations.

greater than the average nuclear plant that had reached about 20 years of age (about half of its useful life), because of past stranded cost recovery. The fact that none of these costs were explicitly labeled as "net salvage for interim retirements" does not mean that Edison's total nuclear investment is underdepreciated and must be increased by the unconventional measure of recovering new costs over a period that is less than the remaining life of the plant.

TURN therefore believes that the appropriate recovery period is from 2006 through the remaining life of the plant. Therefore, the Commission should establish a depreciation rate adjustment to recover the currently projected nominal dollar removal and disposal costs over 17 years (2006-2022) if it approves the project.

Edison's tax flow-through and gross-up also collects large amounts of cash for Edison early on, at the expense of rate instability because of high costs in 2006-2008 before the project comes into service. Edison's proposal means that the early collection of cost of removal is treated as taxable income and grossed up for income taxes. The cost of removal deduction is applied at the end of the period. TURN believes that the rate treatment for this component should be smoothed as a matter of policy by using a deferred tax approach. The collection purely involves tax timing differences. Money is collected in money in 2006-2008 (and 2012-2022 under TURN's approach of a longer depreciable life when it is not deductible. The deductions for cost of removal are largely taken in 2009-2011. As a matter of policy, TURN believes that the taxes should be normalized through a deferred tax approach and not flowed through to produce large rate impacts in 2006-2008.

On Table 6, TURN presents an illustrative revenue requirement for steam generator removal with a 17-year depreciable life and Edison's cost and return parameters. It reflects TURN's recommendation for ratemaking if the project is approved. However, by using Edison's cost and return parameters here, TURN is not endorsing them. Table 7 (following Table 6), shows Edison's erroneous calculation of revenue requirements for a six-year life in its cost-effectiveness workpapers; a corrected version of that calculation, which shows costs about 5%

higher than Edison estimated on a present value basis, with even greater early year impacts; and a six-year life with normalized taxes.

In sum, if the steam generator project is approved, TURN recommends conventional rate treatment of the cost of removal, with no acceleration of depreciation and no tax gross-up.

Table 6: Steam Generator Ratemaking

TURN'S SEVENTEEN YEAR DEPRECIATION -- NORMALIZED TAXES
($ in thousands)

Description	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Revenue Requirement	8,350	7,280	6,209	7,332	12,353	18,187	20,123	19,053	17,983	16,912	15,842	14,772	13,701	12,631	11,561	10,491	9,420
FF&U	94	82	70	82	139	204	226	214	202	190	178	166	154	142	130	118	106
Depreciation	8,785	8,785	8,785	8,785	8,785	8,785	8,785	8,785	8,785	8,785	8,785	8,785	8,785	8,785	8,785	8,785	8,785
Bond interest	(101)	(303)	(504)	(293)	654	1,753	2,118	1,916	1,714	1,513	1,311	1,109	908	706	504	303	101
Current Income Taxes	(173)	(519)	(864)	(502)	1,120	3,005	3,631	3,285	2,939	2,593	2,248	1,902	1,556	1,210	864	519	173
Operating Expenses	8,605	8,046	7,486	8,073	10,698	13,748	14,760	14,200	13,641	13,081	12,522	11,962	11,403	10,843	10,284	9,724	9,165
Net Operating Revenue	(255)	(766)	(1,277)	(741)	1,655	4,439	5,363	4,852	4,342	3,831	3,320	2,809	2,299	1,788	1,277	766	255
Cost of Removal	-	-	-	36,000	64,000	49,352	-	-	-	-	-	-	-	-	-	-	-
Deferred Tax Accrual	3,547	3,547	3,547	(10,986)	(22,290)	(16,377)	3,547	3,547	3,547	3,547	3,547	3,547	3,547	3,547	3,547	3,547	3,547
Rate Base	(2,619)	(7,858)	(13,097)	(7,602)	16,974	45,532	55,007	49,768	44,530	39,291	34,052	28,813	23,574	18,336	13,097	7,858	2,619
Depreciation	(4,393)	(13,178)	(21,964)	(12,749)	28,466	76,356	92,247	83,461	74,676	65,891	57,105	48,320	39,534	30,749	21,964	13,178	4,393
Deferred Tax	1,773	5,320	8,867	5,147	(11,491)	(30,825)	(37,240)	(33,693)	(30,146)	(26,600)	(23,053)	(19,506)	(15,960)	(12,413)	(8,867)	(5,320)	(1,773)
Rate of Return	9.75%	9.75%	9.75%	9.75%	9.75%	9.75%	9.75%	9.75%	9.75%	9.75%	9.75%	9.75%	9.75%	9.75%	9.75%	9.75%	9.75%

Table 7: Alternative Steam Generator Ratemaking Using a Six-Year Life

(Reformatted to improve readability, no substantive change)

Revenue Requirement for SGR Removal and Disposal Costs
EDISON'S ORIGINAL COMPUTATION FROM COST-EFFECTIVENESS WORKPAPERS
($ in millions)

Description	2006	2007	2008	2009	2010	2011
Depreciation	24.892	24.892	24.892	24.892	24.892	24.892
Removal	-	-	-	36.000	64.000	50.000
Depreciation reserve	24.892	49.783	74.675	63.566	24.458	(0.651)
Rate Base	(24.892)	(49.783)	(74.675)	(63.566)	(24.458)	0.651
Earnings	-	(2.614)	(5.227)	(7.841)	(6.674)	(2.568)
Tax on earnings	-	(1.045)	(2.091)	(3.136)	(2.670)	(1.027)
Tax on cash	9.957	9.957	9.957	(4.443)	(15.643)	(10.043)
Revenues	34.848	31.189	27.530	9.471	(0.096)	11.253
Revenues w/ FF&U	35.257	31.555	27.853	9.582	(0.097)	11.385

EDISON COMPUTATION CORRECTED FOR TAX GROSS-UP AND MID-YEAR RATE BASE
($ in millions)

Description	2006	2007	2008	2009	2010	2011
Depreciation	24.892	24.892	24.892	24.892	24.892	24.892
Removal	-	-	-	36.000	64.000	49.349
Depreciation reserve	24.892	49.783	74.675	63.566	24.458	-
Rate Base	(12.446)	(37.337)	(62.229)	(69.120)	(44.012)	(12.229)
Earnings	(1.307)	(3.920)	(6.534)	(7.258)	(4.621)	(1.284)
Bond interest	(0.477)	(1.430)	(2.383)	(2.647)	(1.686)	(0.468)
Common and preferred stock earnings	(0.830)	(2.490)	(4.151)	(4.610)	(2.936)	(0.816)
Tax Gross-Up	1.677	1.677	1.677	1.677	1.677	1.677
Tax on common and preferred stock earnings	(0.408)	(1.224)	(2.040)	(2.266)	(1.443)	(0.401)
Tax on cash	16.852	16.852	16.852	(7.520)	(26.476)	(16.558)
Revenues	40.028	36.599	33.169	7.847	(7.649)	6.649
Revenues w/ FF&U	40.498	37.028	33.558	7.939	(7.739)	6.727

EDISON'S SIX YEAR DEPRECIATION -- NORMALIZED TAXES
($ in thousands)

Description	2006	2007	2008	2009	2010	2011
Revenue Requirement	24,143	22,080	20,017	19,445	21,526	24,161
FF&U	271	248	225	218	242	271
Depreciation	24,892	24,892	24,892	24,892	24,892	24,892
Bond interest deduction	(286)	(857)	(1,429)	(1,587)	(1,010)	(281)
Current Income Taxes	(296)	(889)	(1,482)	(1,646)	(1,048)	(291)
Operating Expenses	24,867	24,251	23,635	23,464	24,085	24,872
Net Operating Revenue	(724)	(2,171)	(3,618)	(4,019)	(2,559)	(711)
Cost of Removal	-	-	-	36,000	64,000	49,352
Deferred Tax Accrual	10,049	10,049	10,049	(4,484)	(15,788)	(9,875)
Rate Base	(7,422)	(22,265)	(37,108)	(41,217)	(26,246)	(7,293)
Depreciation	(12,446)	(37,338)	(62,230)	(69,122)	(44,014)	(12,230)
Deferred Tax	5,024	15,073	25,122	27,905	17,768	4,937
Rate of Return	9.75%	9.75%	9.75%	9.75%	9.75%	9.75%

C. Guaranteed Net Benefits Proposal

TURN generally believes that a significant ratepayer net benefit should be guaranteed if the steam generator replacement goes forward, given Edison's claims that benefits will be significant and TURN's finding that the project may show benefits under base case assumptions, but those benefits are not robust, and may prove to be a net cost to ratepayers under any number of deviations from the base case. A minimum net benefit calculation should be developed. Edison's estimate of benefits (excluding transmission) was slightly under $800 million present-valued to 2004.[20] TURN's base estimate, including $78 million of transmission benefits, is only $320 million. Because of this major difference in calculation, if the project goes forward, the Commission should require a minimum benefit of at least 50% of <u>the total benefits adopted by the Commission</u>, multiplied by Edison's ultimate ownership share, to protect ratepayers from the project-related uncertainties.

The benefit is uncertain for a number of reasons, including future fuel prices, future operations (costs and capacity factor) of SONGS after steam generator replacement, as well as how fast the steam generators degrade if they are not replaced, and avoided transmission costs. TURN suggests that the benefit calculation needs to include only observable factors. We specifically cannot observe the length of time that the plants will continue to run if the steam generator is not replaced, nor could we observe any alleged gas price premia identified by Edison. We therefore recommend that the benefit be calculated generally using parameters developed above – that in the absence of a steam generator replacement, the plant would continue to run for several years with lower capital costs and capacity factors and then would be shut down in about 2012 for Unit 2 and 2014 for Unit 3 (50th percentile values). This leads to two separate time streams for analyzing benefits – through shutdown for each unit and after shutdown.

Through assumed shutdown, the costs and benefits should be analyzed based on continued operation of the plant at diminishing capacity factors. This leads to the following calculation.

[20] $1,527-$1,807 million gross benefits, less $129-$321 million of transmission less $707 million in steam generator costs equals $779 to $791 million. See Exhibit SCE-4, page 11.

1. Before Closure

a) Costs

1. Edison's share of annual ratemaking costs of steam generator replacement, identified by Edison as required to extend the life of the project through 2022.

2. Edison's share of annual revenue requirements associated with steam generator removal and disposal (depends on adopted method).

3. Edison's share of annual ratemaking costs of excess capital costs (reflecting pattern of declining capital spending leading up to shutdown that Edison shows in 2018-22) prior to early shutdown (See Table 1).

4. In 2009/2010, extra replacement power cost for difference between capacity factor with steam generator replacement and without (based on actual steam generator replacement days in excess of normal refueling) and Edison's 88% capacity factor (replacement power minus nuclear fuel cost) based on SP-15 7X24 costs.

b) Benefits

1. 10% of actual O&M expense computed separately for units 2 and 3 to reflect lower costs after replacement, up through the Unit 2 refueling in (or closest to) 2012 and the unit 3 refueling in (or closest to) 2014 respectively.

2. Replacement power cost minus nuclear fuel cost costs (including carrying costs of unburned nuclear fuel and tax impacts) associated with reduced production if steam generator not replaced in 2010-2014 (difference between actual capacity factor achieved and capacity factor of 85% in 2010 declining as shown in the base case Table 4 to 2012/2014 – not less than zero). Through 2014, replacement power should be based on NP-15 7X24 costs.

After 2012/2014, the costs and benefits (reflecting plant retirement) should be calculated based on complete closure.

2. After Closure

a) Costs

1. Ratemaking cost of capital additions for steam generator replacement and excess capital costs through 2014 and for all capital costs after 2014.

2. Ratemaking costs of steam generator removal and disposal.

3. Plant O&M costs, including all A&G directly assigned to the plant or allocated to the plant. (e.g., human resources costs allocated by number of employees or payroll)

4. Nuclear fuel costs (including carrying costs of unburned nuclear fuel and tax impacts).

5. If either SONGS unit closes early after receiving a new steam generator, O&M costs will be the shutdown O&M for the first two years only, and the treatment of the cost of post-2009 capital additions and cost of removal will follow the ratemaking treatment of the undepreciated balance adopted by the Commission at the time.

b) Benefits after expected closure

1. Replacement power costs at the actual capacity factor at which the plant operates in any given year.

2. An allowance equal to 80% of Edison's base O&M costs in the first 12 months after closure of any unit, 50% in the second 12 months, and 10% in future years, and 80% of Edison's common O&M costs (total) after expected closure of one unit and 50% after expected closure of both units.

3. A figure for deferred transmission costs consistent with the Commission's decision in this proceeding regarding transmission costs would be included beginning in 2012. A real fixed charge rate would be applied to adopted capital costs to reflect the deferral.

3. Calculation of Post 2012/2014 Replacement Power Costs after Closure

In 2010, the replacement power resource would be determined in 2010 based on the cheaper of the expected total fixed and variable costs of renewable resources or combined cycle gas turbine costs. The 2010 costs would be used to compute the fixed cost of the chosen resource for future years. A real economic carrying charge would be used to take deferral into account. Capacity requirements would be equal to the SONGS capacity. Cost to be based on an energy cost in cents per kWh calculated based on the fixed cost of the resource with the cheaper total cost (combined cycle or renewable resource), plus variable costs based on the cheaper of 24X7 NP15 market energy or the variable costs of the chosen resource (whether combined cycle or renewable) at the SONGS actual capacity factor.

4. Other Issues (Discount Rate and Costs Collected Prior to 2009)

1. To keep track of benefits over time, a discount rate of 9.75% (approximately equal to current return on rate base) should be used.

2. To assure that all costs are accounted for, the present value (in 2009 $) of all costs included in rates before 2009 for any CWIP financing or steam generator removal costs collected must be added to the costs.

Attachment A

William B. Marcus

Principal Economist,
JBS Energy, Inc.

William B. Marcus, Principal Economist, has over 25 years of experience in electric and gas utility issues.

Mr. Marcus graduated from Harvard College with an A.B. magna cum laude in economics in 1974 and was elected to Phi Beta Kappa. In 1975, he received an M.A. in economics from the University of Toronto.

In July 1984, Mr. Marcus became Principal Economist for JBS Energy, Inc. In this position, he is the Company's lead economist for utility issues.

Mr. Marcus is the co-author of a book on electric restructuring prepared for the National Association of Regulatory Utility Commissioners. He wrote a major report on Performance Based Ratemaking for the Energy Foundation. He has analyzed restructuring and stranded cost issues in eight states and provinces for consumer, environmental, and independent power clients.

Mr. Marcus has prepared testimony and formal comments submitted to the Federal Energy Regulatory Commission, the National Energy Board of Canada, the Bonneville Power Administration, the U.S. Bureau of Indian Affairs, U.S. District Court in San Diego, Nevada County Municipal Court, legislative committees in Ontario and California, the California Energy Commission (CEC), the Sacramento Municipal Utility District (SMUD), the Transmission Agency of Northern California, the State of Nevada's Colorado River Commission, environmental boards in Ontario, Manitoba, and Nova Scotia; and regulatory commissions in Alberta, Arizona, Arkansas, British Columbia, California, Colorado, Connecticut, District of Columbia, Hawaii, Manitoba, Maryland, Massachusetts, Nevada, New Jersey, New Mexico, North Carolina, Northwest Territories, Nova Scotia, Ohio, Oklahoma, Ontario, Oregon, South Carolina, Texas, Utah, Vermont, Virginia, Washington, Wisconsin, and Yukon. He testified on issues including utility restructuring, stranded costs, Performance-Based Ratemaking, resource planning, load forecasts, need for powerplants and transmission lines, environmental effects of electricity production, evaluation of conservation potential and programs, utility affiliate transactions, mergers, other revenue issues, avoided cost, and electric and gas cost of service and rate design.

From 1975 to 1978, Mr. Marcus was a research analyst at the Kennedy School of Government, Harvard University.

From July 1978 through April 1982, Mr. Marcus was an economist at the CEC, first in the energy development division and later as a senior economist in the CEC's Executive Office. He prepared economic studies of purchased power pricing, transmission projects, renewable resources, and conservation programs, and managed interventions in utility rate cases.

From April 1982, through June 1984, he was the principal economist at California Hydro Systems, Inc., an alternative energy consulting and development company. He prepared financial analyses of projects, negotiated utility contracts, and provided consulting services on utility economics and resources.

Attachment A

Mr. Marcus served on the 1991-92 SMUD Rate Advisory Committee, which made cost allocation and rate design recommendations to the SMUD Board. He has served for a number of years on advisory committees for Woodland Community College and the City of Woodland, California.

Attachment B

San Onofre 2 and 3 Cost Data from 2003 and 2006 GRC Filings

Application No.: ______
Exhibit No.: SCE-3, Vol. 2, Ch. IX-XVIII
Witnesses: J. L. Perez

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2003 General Rate Case

Generation
SONGS 2 & 3 Operation & Maintenance
Chapters IX-XVIII
And Witness Qualifications

Before the

Public Utilities Commission of the State of California

Rosemead, California

Table XVI-8

Test Year 2003 Base O&M Adjusted Costs By Functional Group

(Constant 2000 Dollars X 1000, SCE Share)

Functional Groups	Base O&M Expenses
Operations	17,613
Maintenance	47,587
Engineering	41,601
Site Projects	12,460
RadChemical Control	13,653
Regulatory Affairs	7,105
Security	13,914
Training	7,625
Nuclear Support	49,077
Corporate Support	(13,668)
Participants	(49,143)
TOTAL	147,824

$196,967 at 100%

Table XVI-9 shows the Test Year 2003 SONGS 2 & 3 Base O&M Estimate by FERC Account and Functional Group.

Table XVI-9
Test Year 2003 Base O&M Adjusted Costs By FERC Account/Functional Group

(Constant 2000 Dollars X 1000, SCE Share)

	Operations.	Maintenance	Engineering	Site Projects	RadChemical Control	Regulatory Affairs	Security	Training	Nuclear Support	Corporate Support	Participants	TOTAL
517	879	0	19,707	6,390	347	2,341	1,126	0	16,173	0	(11,717)	35,246
519	655	0	0	0	0	0	0	0	0	0	(163)	492
520	4,213	0	128	0	10,851	0	0	0	1,850	0	(4,252)	12,790
523	5,882	0	0	0	193	0	0	0	0	0	(1,516)	4,559
524	5,984	3,494	5,927	0	2,262	4,764	12,788	7,625	19,219	(12,266)	(12,424)	37,373
525	0	0	0	0	0	0	0	0	1,110	0	(277)	833
528	0	9,713	3,729	0	0	0	0	0	2,295	0	(3,926)	11,811
529	0	5,870	0	0	0	0	0	0	3,871	0	(2,430)	7,311
530	0	7,772	6,402	0	0	0	0	0	0	0	(3,536)	10,638
531	0	9,427	3,390	0	0	0	0	0	0	0	(3,198)	9,619
532	0	11,311	2,318	6,070	0	0	0	0	4,559	(1,402)	(5,703)	17,153
Total	17,613	47,587	41,601	12,460	13,653	7,105	13,914	7,625	49,077	(13,668)	(49,143)	147,824

Table XVII-10
PTYR Outage Cost Development
(Constant 2000 Dollars X 1000, 100% Level)

MAJOR ACTIVITIES:	Actual U2C11	Actual U3C11	2002 U2C12	Test Yr 2003 U3C12	Attrition Years 2004 U2C13	Attrition Years 2005 U3C13
1. Incremental O&M Historical Costs (YOE $)	53,000	45,800				
2. Adjustments to Cycle 11 Outages:						
- Steam Generator Sleeving	600					
- RCP Oil Leakage / Seal Repair	500	500				
- Overhaul Valve Actuator	150	150				
- Main Generator Overhaul	800	800				
- MSR. Chevrons and Bellows	3,750	3,000				
- Main / Reserve Transformer Work	200	200				
- Plant Mods SIPC	1,300	675				
- Conversion to 2000 $	0	450				
3. Adjusted U2&3 Cycle 11 Outages (in 2000 $)	45,700	40,025				
4. Permanent Unit 3 Mob / Experience Factor / Timing		3,000				
5. Cycle 11 Adjusted /Outage Starting Point (in 2000 $)	**45,700**	**43,025**			**45,700**	**43,025**
6. Adjustment Calculation of One-Time Activities						
- Steam Generator Sleeving	600					
- RCP Oil Leakage / Seal Repair	500	500				
- Overhaul Valve Actuator	150	150				
- Main Generator Overhaul	800	800				
- MSR Chevrons and Bellows	3,750	3,000				
- Main / Reserve Transformer Work	200	200				
- Plant Mods SIPC	1,300	675				
- Conversion to 2000 $	0	450				
- Increased Steam Generator Tube Pulls, Analysis, & Robots			1,100	1,100		
- Steam Generator Sleeving			500			
- Pressurizer Heater Replacement				100		
- Alloy 600 Nozzle Inspections/Replacement			1,300	1,300		
- Reactor Head Inspection			2,000	2,000		
- Opti Flow Bolt Changeout			1,000			
- RCP Overhaul			1,500			
- Plant Mods SIPC			700	700		
- Flow Accelerated Corrosion- Piping Systems			1,000	1,000		
- 3P002 Hydrostatic Bearing Insp./ Element Replacement				1,000		
- Condenser Modifications			1,000	1,000		
- Labor Premium due to Shortage			500	500		
6. Subtotal Cycle One-Time Activities	7,300	5,775	10,600	8,700		
7. Average of One-Time Activities			8,100		8,100	8,100
8. TOTAL INCREMENTAL OUTAGE O&M ESTIMATE (2000$) Unit Specific					53,800	51,125
9. PTYR Outage Cost						$\boxed{52,462}$
PTYR Outage Cost - SCE Share						$\boxed{39,500}$

The PTYR outage estimate is $52.5 million per outage, 100% level costs. The SCE Share of the outage request is $39.5 million per outage.

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2006 General Rate Case

Workpapers

SCE-2 Generation
Volume 2 SONGS 2 & 3 Operation & Maintenance
Chapters XVI - XVII

August 2004

Table XVI-6
Test Year 2006 Base O&M Costs By Functional Group
(Constant 2003 Dollars X 1000)

Functional Groups	Base O&M Expenses	
Operations	20,991	
Maintenance	56,701	
Engineering	45,295	
Site Projects	13,576	
RadChemical Control	15,934	100%
Regulatory Affairs	7,515	Level = $ 236,279
Security	26,115	
Training	9,011	
Nuclear Support	55,611	
Corporate Support	(14,470)	
Participants	(58,953)	
Total SCE Share	177,326	SCE Share

Table XVI-7 shows the Test Year 2006 SONGS 2 & 3 Base O&M Estimate by FERC Account and Functional Group.

Table XVI-7
Test Year 2006 Base O&M Costs
By FERC Account/Functional Group
(Constant 2003 Dollars X 1000)

FERC	Operations	Maintenance	Engineering	Site Projects	RadChemical Control	Regulatory Affairs	Security	Training	Nuclear Support	Corporate Support	Participants	TOTAL
517	0	0	38,924	0	0	2,457	0	0	16,919	0	(14,546)	43,754
519	0	0	0	0	0	0	0	0	0	0	0	0
520	14,348	0	0	0	13,147	0	0	0	0	0	(6,860)	20,635
523	0	0	0	0	0	0	0	0	0	0	0	0
524	6,643	0	6,371	0	2,787	5,058	26,115	9,011	27,597	(12,156)	(17,821)	53,605
525	0	0	0	0	0	0	0	0	1,374	0	(343)	1,031
528	0	17,947	0	0	0	0	0	0	5,594	0	(5,873)	17,668
529	0	6,397	0	0	0	0	0	0	0	0	(1,597)	4,800
530	0	0	0	0	0	0	0	0	0	0	0	0
531	0	0	0	0	0	0	0	0	0	0	0	0
532	0	32,357	0	13,576	0	0	0	0	4,127	(2,314)	(11,913)	35,833
Total	20,991	56,701	45,295	13,576	15,934	7,515	26,115	9,011	55,611	(14,470)	(58,953)	177,326

100% Level = $ 236,279

SCE Share

Table XVII-8
Test Year RFO Estimate
(Constant 2003 Dollars X 1000, 100% Level)

Major Activities	Actual U2C11 2000/01	Actual U3C11 2000/01	Actual U2C12 2002/03	Actual U3C12 2002/03	Incurred U2C13 2003/04	Test Year Forecast U3C14 2006	Average
1 O&M Historical Cost (YOE $)	53,200	45,000	62,900	61,500	72,000		
2 Adjustments to Historical Outages:							
- Steam Generator Sleeving and Plugging	(600)		(1,300)		(4,290)		
- Inspect Reactor Head			(3,385)	(3,100)	(3,315)		
- Repair Reactor Coolant Pump (RCP) Oil Leakage / Seal Repair	(500)	(500)					
- Overhaul Valve Actuator	(150)	(150)					
- Overhaul Main Generator	(800)	(800)					
- Main Steam Reheater Repair	(3,750)	(3,000)	(370)	(615)	(490)		
- Main & Reserve Transformer Work	(200)	(200)					
- Plant Projects approved by Site Integrated Project Committee	(1,300)	(675)		(170)	(70)		
- Reactor Vessel 10 Year In-Service-Inspection (ISI)			(585)	(595)			
- Reactor Vessel Scratch Resolution				(50)			
- Temperature Detector (RTD) Thermowell Replacement			(490)	(545)			
- Unit 3 RCP 2 Hydrostatic Bearing Insp / Element Replacement				(2,360)			
- Replace Low Pressure Turbine Casing Studs			(920)				
- Feedwater Heater Tube Cleaning				(190)	(820)		
- Replace Heated Junction Thermocouple				(270)	(330)		
- Replace Reactor Vessel Head Insulation			(605)	(775)	(315)		
- Replace a Portion of Main Steam Piping				(400)			
- Modification to Remove Breaker D501				(155)			
- Replace Failed Pressurizer Heater				(145)			
- Pressurizer Sleeve Mechanical Clamp Program				(175)	(120)		
- Repower DC Turbine Generator Lube Oil Pump				(100)			
- Replace Non-Safety Related Snubbers					(50)		
- Modify Reactor Vessel Thimble Support Plate					(685)		
- Replace In-Core Instruments (ICI)					(1,235)		
- Modify Iso-Phase Bus and Replace Bushings					(1,300)		
- Replace TG Steam Supply Valve Accumulator					(30)		
- Replace Steam Generator and RCP Snubbers					(1,325)		
- Repair Reactor Vessel Head Nozzles					(300)		
- Repair Reactor Coolant System RTDs					(355)		
- Conversion to 2003 $	3,015	950	1,320	270	(1,740)		
3 Adjusted Outages (in 2003$)	48,915	40,625	56,565	52,125	55,230		
4 Adjustments							
Non-Labor Escalation Premium	3,300	3,300	3,300	3,300	3,300		
Bechtel Construction Supplemental Labor Contract Changes	750	750	750	750	750		
O&M Reduction Due to Change in Capitalization Criteria	(3,800)	(3,800)	(3,800)	(3,800)	(3,800)		
5 Typical Adjusted Outage CORE (in 2003 $)	49,165	40,875	56,815	52,375	55,480		50,940
6 Adjustment Calculation of One-Time Activities (YOE)							
- Inspect Reactor Vessel Head						3,990	
- Replace Reactor Coolant System RTD Thermowells						500	
- Increased Sleeving and Plugging of Steam Generators						720	
- Replace Pressurizer Heater Sleeves (30)						7,655	
- Reliability Preventative Maintenance Optimization						530	
- Replace Reactor Vessel Thimbles (56)						10,380	
- Replace In Core Instruments in coordination with Thimble Replacement						1,500	
- Modify Oil Lift Pump Piping on Reactor Coolant Pump						80	
- Unit Auxiliary Transformer Oil Filter On-line Bypass						120	
- Replace Loss of Voltage Relays with Solid State Relays						45	
- SONGS 3 Charging Pump Pulsation Dampener						40	
- Conversion to 2003$						(2,060)	
One-Time Activities TOTAL (2003$)						23,500	23,500
7 TOTAL OUTAGE O&M Estimate (2003 $)							74,440

$ 254,710 ÷ 5 = 50,942

The Test Year 2006 RFO estimate is $74.4 million ($50.9 million for core costs plus $23.5 million for one-time activities) for SONGS 3 Fuel Cycle 14, 100 percent level costs. SCE's Share of the Test Year 2006 RFO forecast is $55.8 million.