Application of Southern California Edison)
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(SONGS 2 & 3) steam generators; (2))
establish ratemaking for cost recovery; and)
(3) address other related steam generator)
replacement issues.)
______________________________________)

Application No. 04-02-026
Exhibits Nos.: __, __, __ and __ (SDG&E-1, 2, 3 and 4)
Witnesses: Avery, Sheaffer, Vengrin and Schneider

PREPARED DIRECT TESTIMONY OF

SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

DECEMBER 13, 2004

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James Avery

Application of Southern California Edison Company (U 338-E) for Authorization: (1) to replace San Onofre Nuclear (SONGS 2 & 3) steam generators; (2) establish ratemaking for cost recovery; and (3) address other related steam generator replacement issues.

Application No. 04-02-026
Exhibit No. __ (SDG&E-1)
Witness: James Avery

PREPARED DIRECT TESTIMONY
OF JAMES AVERY
ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

December 13, 2004

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PREPARED DIRECT TESTIMONY
OF JAMES AVERY
ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

I. INTRODUCTION

The purpose of my testimony on behalf of San Diego Gas & Electric Company ("SDG&E") is to provide the policy basis supporting the sale of SDG&E's entire 20% Ownership Share in San Onofre Nuclear Generating Station ("SONGS") to Southern California Edison Company ("SCE") as a cost effective means of best serving both SDG&E's and SCE's customers. Alternatively, I summarize why SDG&E's election not to participate in the Steam Generator Replacement Project ("SGRP") is in the best interests of SDG&E's customers and shareholders.. I address a claim raised by SCE in its June 1, 2004 Augmented Testimony that for insufficiently explained reasons SCE's customers would be subsidizing SDG&E's customers should SDG&E's Ownership Share be reduced. Finally, in the event of Ownership Share changes flowing from the Operating Impairment, I summarize why it is desirable both for SDG&E and SCE to structure their legal relations for tax purposes only in a fashion that avoids potential tax costs so as not to have any effect on the cost effectiveness evaluation of the SGRP both for SDG&E and SCE.

My testimony will not, however, address other issues that do not pertain to the cost effectiveness evaluation of the SGRP. For example, it will not present a discussion of the manner in which SDG&E or SCE propose to calculate their respective Ownership Share changes that would result from not participating in the SGRP pursuant to the Second Amended San Onofre Operating Agreement ("Operating Agreement").

This issue involving the respective values of SONGS capacity to each party is to be arbitrated pursuant to the Operating Agreement, commencing January 17, 2005. The arbitration is expected to take no more than three to five days and the arbitrator's award is currently contemplated to issue by the end of February after which SDG&E contemplates filing an application for approval of this Ownership Share reduction. It will also not address any issue involving matters involving the Nuclear Regulatory Commission ("NRC").

II. BACKGROUND AND OVERVIEW

SDG&E has supported SONGS beginning in the 1960's when SCE and SDG&E ("Companies") submitted applications with the Commission for a Certificate of Public Convenience and Necessary ("CPCN") for the SONGS Unit 1 project. Our support for this project has been steadily reaffirmed since then during CPCN proceedings for the SONGS Units 2 & 3 and various other proceedings before this Commission. This support was premised on several factors, including the good working relations with representatives at Camp Pendleton that allowed the Companies to obtain a lease on favorable terms for this project. SONGS has also provided SDG&E with a source of fuel diversity and has allowed SDG&E and SCE to avoid air emissions.

Today SDG&E's continued participation in SONGS as a co-owner is not in our customers' or shareholders' best interests:

- Continued co-ownership in SONGS presents unnecessary cost risks to our customers and shareholders; and

- The cost of continued co-ownership in SONGS is unacceptably high to our customers under cost-of-service ratemaking principles.

III. CONTINUED CO-OWNERSHIP IN SONGS PRESENTS UNNECESSARY COST RISKS TO OUR CUSTOMERS AND SHAREHOLDERS

A. In Today's Cost-of-Service Ratemaking Environment, Continued Joint Ownership of SONGS Is No Longer Acceptable

SDG&E's reluctance to continue its participation in SONGS as an owner is based on the experience learned from the SONGS Settlement that was accepted by the Commission in 1996. As a result of this settlement, the Companies were allowed an innovative rate recovery mechanism known as "ICIP" for a period extending from early 1996 through 2003. Prior to the Commission's acceptance of this settlement, rate recovery occurred through the traditional cost-of-service filings that did not provide an incentive for cost control and maintenance of high plant capacity factors. The settlement, however, provided the Companies a financial incentive (and penalty) that served to cause SCE as the operator to more rigorously control capital and operations costs. It also provided an incentive to SCE as the operator to keep the SONGS Units 2 & 3 operating at as high a capacity factor as possible while maintaining plant safety.

The ICIP settlement provided an incentive for SCE to make decisions over capital and operations expenditures and plant operations that were adequately controlled because traditional cost-of-service ratemaking was not present to provide a backstop that allowed a pass through of incurred costs. Additionally, the average plant capacity factor during the 8-year ICIP period (1996-2003) was 89.6% compared to the average plant capacity factor during the 8-year period prior to ICIP (1988-1995) of 81.0%. Reinforcing this point is SCE's performance since the end of the ICIP period. In 2004 the Units 2 & 3 capital and O&M budgets have increased significantly by approximately 50% over the ICIP years average and the 2004 plant capacity factor for these two units is expected to be no greater than 80.2%. Table 1 below shows the yearly capital and O&M expenditures during pre-ICIP, ICIP and post-ICIP years.

TABLE 1: SONGS YEARLY EXPENDITURES
100% Level excluding Overheads
(2004$ in Millions)

Year	Description	Capital Expenditures	O&M Expenditures	Total Yearly Expenditures
1993	Pre-ICIP	$166	$375	$541
1994	Pre-ICIP	$111	$278	$389
1995	Pre-ICIP	$113	$335	$449
1996	ICIP	$37	$251	$288
1997	ICIP	$49	$358	$407
1998	ICIP	$65	$332	$397
1999	ICIP	$39	$360	$399
2000	ICIP	$19	$298	$317
2001	ICIP	$25	$277	$302
2002	ICIP	$29	$339	$367
2003	ICIP	$47	$309	$357
2004	Post-ICIP	$145	$377	$522

SDG&E is not suggesting that SCE is undertaking its operations responsibilities at SONGS in an imprudent manner. To the contrary, SDG&E applauds SCE for its superior conduct as the operating agent of SONGS – a responsibility for which the nuclear industry acknowledges SCE as one of the best in the United States.

However, in today's cost-of-service based regulatory environment, SCE simply does not have a sufficient incentive as was true under the settlement to control its costs or to operate the plant on a basis that is acceptable to SDG&E or its customers.

Let me be clear. Cost-of-service ratemaking contemplates that in exchange for committing property to public service and accepting a regulated return on its investment, a utility is entitled to recover its actual reasonable costs of providing its customers with reliable electric service. Yet SDG&E has advocated in support of its performance based ratemaking mechanism, and this Commission has accepted, that substantial cost savings can be achieved if the customers' and the shareholders' interests are aligned. If the Commission provides a utility a financial incentive to "beat the benchmarks," then both customers and shareholders will benefit. The present cost-of-service based ratemaking applicable to SONGS does not sufficiently encourage SCE to operate this plant in a fashion that encourages it to control its capital and operating budgets even though the costs SCE incurs (as does SDG&E as a minority owner in this project) are otherwise reasonable and prudent.

The Operating Agreement contemplates that SDG&E and the other minority owners have certain rights, e.g. to approve budgets, which must be done on a unanimous basis. A dispute involving a budget requires the owners to continue to advance funds and proceed through an arbitration process. This arbitration process, including the standards that would govern an arbitrator's awards, allows SCE to continue operating under proposed budgets and requires an expensive, lengthy and risky process for SDG&E to contest SCE's expenditures after the fact. Moreover, SDG&E as a minority owner has no control over the actual expenditures made by SCE.

Tight cost control existed at SONGS during the ICIP period, but SCE's projections of post-ICIP capital costs have steadily grown. For example, in January 2000, SCE first provided to the co-owners a forecast of the 2004 (Post-ICIP) capital expenditures (excluding overheads and steam generator replacement costs) of $37 million. SCE now forecasts the 2004 capital expenditures to be $145 million. This represents an error of nearly 400% in forecasting costs less than five years into the future, a fact which is particularly disturbing since the SGRP is scheduled for construction five years from now! Similarly, SCE first forecasted the 2005 and 2006 capital expenditures to be $50 million and $80 million respectively. SCE now forecasts the capital expenditures for those years to be substantially higher at $104 million and $133 million, respectively.

SCE is now proposing the SGRP at an estimated subtotal (including escalation but not financing costs) of approximately $782 million, of which SDG&E's share, excluding AFDUC, would be approximately $156 million. Based on past history described above, SDG&E has little confidence in SCE's forecast of costs for a project that is not forecast to take place until 2009-2010.

Further, SCE has been operating with an operating budget for calendar year 2004 that is $40 million (SDG&E's 20% share of this amount is $8 million) above that included in their 2003 General Rate Case (GRC) before the CPUC (SDG&E rates are set at levels authorized by the CPUC based on SCE's GRC). SDG&E had authorized SCE to proceed with this budget provided SCE declare an Operating Impairment for the SGRP and if SCE agreed to work on ways to reduce actual expenditures down to the levels authorized in rates. SCE has notified SDG&E that is has been unable to reduce its actual expenditures without jeopardizing reliability and safety. While it is commendable that SCE is concerned with reliability and safety, this is just one more example of the risk that SDG&E faces with continued ownership at SONGS. SDG&E has absolutely no control over this risk as is evidenced in part by SCE's underestimation of what it would cost to operate and maintain SONGS in 2004 and SDG&E is now faced with an expense shortfall. This risk is exacerbated because SDG&E has no control over individual budget items not related to plant safety and reliability.

This history is instructive. This risk of substantial cost overruns related to the SGRP is more pronounced at SONGS because this plant was not designed to allow the replacement of the steam generators, as witnessed by SCE's need to cut large openings in the dome-like containment structures and release the highly tensioned steel cables that serve to reinforce these structures. SCE advises us that it has successfully performed, at the shut down Rancho Seco plant, tests of the process it intends to utilize at SONGS, which may serve to minimize public safety and cost risks for the SGRP. However, an assessment of SCE's plans for SGRP performed for SDG&E by Sargent & Lundy concluded that SCE's plan to cut an opening in the containment structure is feasible, but represents significant risk factors, and project budgets and schedules do not appear to provide sufficient contingencies to cover these risks. In my opinion, the potential for severe cost increases or other consequences to the structure cannot be ignored.

B. SDG&E Can No Longer Accept SCE's Customary Practice of Dealing With The SONGS Co-Owners

SCE's pattern of dealing with its co-owners in SONGS causes SDG&E unacceptable concern that continuing to own a share of SONGS is not in its customers' best interests. This project should have been taken to the owners for approval before the present application was submitted in February 2004. It was only after SDG&E forced SCE to acknowledge that this project was Restoration Work associated with an Operating Impairment that SDG&E was allowed its contractual right to elect not to participate in the SGRP. The manner by which SCE has treated the SONGS' minority owners in connection with the SGRP is typical of a long history of dealings with the SONGS co-owners. SCE most recently filed 8-Q submitted to the Securities Exchange Commission in which for the first time SCE formally expressed its intention that the reactor vessel heads would be replaced during the refueling outages at the same time as the SGRP was completed. SCE had earlier indicated informally to the minority owners that the approximate $66 million head replacement project would be required at some point. However, it did not inform SDG&E of SCE's intention to make commitment of this additional expenditure at that time. SCE has never taken this project, which appears to involve another Operating Impairment, to the co-owners for approval. These instances are reflective of SCE's unreasonable manner of dealing with its co-owners in disregard of the terms of the Operating Agreement. This type of behavior is no longer acceptable to SDG&E, particularly on decisions, projects and expenditures of the magnitude of the SGRP.

C. There Are Two Alternatives To Continued Minority Ownership In SONGS That Are Cost-Effective For SDG&E.

For the reasons described by SDG&E's Mr. Schneider in Exhibit No. __ (SDG&E-4), SDG&E's preferred alternative – selling its SONGS interest to SCE and taking back a PPA of the sort described below is cost-effective. SDG&E's other alternative of reducing its Ownership Share to some level in lieu of participating in the

SGRP is also cost-effective under the following conditions. Building a gas-fired combustion turbine combined-cycle ("CTCC") base load plant to replace SDG&E's reduction in SONGS would be cost effective regardless of the amount of SDG&E's Ownership Share reduction. Acquiring power through a PPA with geothermal developers to replace SDG&E's reduction in SONGS could be cost effective depending on the amount of SDG&E's Ownership Share reduction. Both the SCE-SDG&E PPA and the SDG&E-geothermal developer PPA alternatives offer the added benefit of allowing SDG&E to continue to diversify its fuel mix although only one of these alternatives would provide SDG&E the added benefit of meeting or exceeding its renewable requirements. The increased value of SDG&E adding substantial amounts of renewable geothermal power in its resource mix in 2010 should be favorably taken into account by the Commission in assessing the cost-effectiveness of this type of resource alternative to SDG&E's existing 20% level of participation in the SGRP.

1. SDG&E Prefers That SCE Purchase SDG&E's Ownership Share and Take Back a Purchase Power Contract Containing SONGS Cost and Performance Incentives

SDG&E prefers that SCE purchase SDG&E's interest in SONGS and has offered SCE over a year ago a term sheet that would be used as a basis for such a sale. Nothing has come of that offer. This term sheet offered to sell SDG&E's 20% Ownership Share of SONGS to SCE at a price equal to SDG&E's book value of SONGS, including M&S and fuel inventories. This term sheet also expressed a willingness to enter into a five-year power purchase agreement (PPA) subject to the jurisdiction of the Federal Energy Regulatory Commission by which SDG&E would purchase 430 MW of SONGS output (an amount equivalent to SDG&E's current capacity entitlement). For purposes of Mr. Schneider's economic analysis, he assumed a term through 2022. This PPA would be priced equivalent to SCE's forecasted cost of operating SONGS over the term of the PPA. These pricing terms in effect would serve like the ICIP to set a fixed rate that allows SCE to recover its SONGS capital costs, including the SGRP costs, at a level that creates a financial incentive for SCE to control capital and operating costs and maintain a high plant capacity factor after the SGRP is completed.

This PPA proposal is not only in the customers' of SDG&E best interests but is also in the customers' of SCE best interest because it would provide effective cost management incentives that align SCE's shareholders' and customers' interests. Moreover, SCE's Mr. Fohrer was recently reported to have said to a Los Angeles Times reporter that SCE has confidence in its estimated cost for this project that "are a fair estimate of what it is going to take" to finish the SGRP.[1] Mr. Fohrer's comments indicate that SCE would have no basis to object to this appropriate incentive.

When viewed as a SCE resource acquisition, this proposal for SCE to purchase SDG&E's interest in SONGS is an economically superior alternative for SCE's customers when compared to the Ownership Share reduction alternative. The reason for this is quite simple. Under Ownership Share reduction, SCE would pay SDG&E's share of SGRP costs in return for only a portion of SDG&E's Ownership Share. Whereas, if SCE purchases SDG&E's entire 20% Ownership Share, it's cost on a dollars per kilowatt basis is much less. For example, if SDG&E does not participate in the SGRP, SCE will be contractually required to pay SDG&E's 20% share of the $680 million (2004$) SGRP cost in exchange for a reduction in SDG&E's Ownership Share. If we assume for the moment that SDG&E's Ownership Share would be reduced to 15%, SCE would receive

[1] Los Angeles Times, December 6, 2004.

107 MW for $136 million (2004$), which is equivalent to $1265/kW. Thus, the result of SCE's Ownership Share change could have an adverse impact SCE's customers. Whereas, if SCE purchases SDG&E's entire 20% Ownership Share, then it would sell the generation from that portion of SONGS Units 2 & 3 and the payment stream from SDG&E would have no impact on SCE's customers. As mentioned earlier, SCE's shareholders and customers would also benefit because the PPA would provide effective cost management incentives that align SCE's shareholders' and customers' interests..

2. Alternatively, SDG&E's Other Cost Effective Options Involving An Ownership Share Reduction In SONGS Include Entering Into A PPA With a Geothermal Developer or Owning a Gas-Fired CTCC.

Alternatively, if the Commission concludes that it is not cost effective for SCE to purchase SDG&E's interest in SONGS, SDG&E will exercise its contractual right to elect the reduction of its Ownership Share in lieu of participating in the SGRP. SDG&E has determined it is cost effective for its customers to replace a portion of its present 20% Ownership Share with renewable geothermal power that can provide continued desirable fuel diversity and avoid air emissions similar to a nuclear project. It would provide SDG&E the added benefit of meeting or exceeding its renewable requirements. This type of project can be cost-effective because it would allow SDG&E to avoid a portion -- based on the amount of Ownership Share reduction -- of the substantial uncertainty over the cost of continued ownership in a nuclear project.

Another resource alternative to participation in the SGRP is a gas-fired CTCC base load power plant. As SDG&E's Mr. Schneider in Exhibit No. __ (SDG&E-4) explains in detail, this alternative is also a cost-effective means for SDG&E's customers to replace a portion of SDG&E's present 20% Ownership Share in comparison to participation in the SGRP and maintaining our continued 20% Ownership Share of SONGS.

IV. SCE'S ASSERTION THAT A SHARE REDUCTION WILL CREATE A SUBSIDY THAT BENEFITS SDG&E'S CUSTOMERS IS UTTERLY INCORRECT

SCE asserts that "a reduction in SDG&E's ownership share would create a subsidy of SDG&E's ratepayers, unless a compensation mechanism was put in place." It continues by stating that the "Commission would have to address this issue if SDG&E elected not to participate and applied for Commission approval to transfer all or a portion of its share to SCE."[2] SDG&E is at a loss how it should take into consideration through its cost-benefit analysis any such mechanism because SCE hasn't stated what it believes is appropriate. Perhaps SCE in its rebuttal testimony can inform us what it intends with sufficient specificity for SDG&E to be able to address it during the hearings through cross-examination of its witnesses and the presentation of SDG&E's witnesses.

However, as described by Mr. Sheaffer, using SCE's study cases presented in its testimony (as well as a historical example cited by Mr. Sheaffer for data collected for the second half of 2003) show that when SONGS Units 2 & 3 are operating, the flow of voltage support (MVARs) from the units is disproportionate to SCE's and SDG&E's Ownership Shares. Specifically, SCE receives far more voltage support from SONGS than its Ownership Share would represent and SDG&E receives less. Further, an examination of operations records for a recent circumstance when both SONGS Units 2 & 3 were not operating is also illustrative that it is SDG&E's system that is generally providing voltage support to SCE. SCE's assertion to the contrary is utterly wrong and if

[2] SCE's Augmented Testimony, dated June 21, 2003, Exhibit SCE-9 at page 3, lines 4-15; see also Exhibit SCE-5, pages 14-24 and 31-34.

there is any shred of merit in SCE's argument, it is SDG&E that should be proposing to file at FERC a revision to its Transmission Owner Tariff that allows recovery of appropriate charges for the these voltage support services it has been providing to SCE.

In the past, SDG&E and other utilities have not sought recovery for such services because they occur as a result of the interconnected nature of the transmission grid. The benefits of such interconnection balance the costs involved in such interconnected operations.

Moreover, SCE's position respecting SDG&E's customers taking a free ride off of SCE's transmission grid that allegedly supports the reliability of SDG&E's system is made irrelevant in any case since by 2010 SDG&E will be paying its proportionate share of SCE's transmission revenue requirements for its existing and new high voltage transmission through the ISO's TAC on file with the Federal Energy Regulatory Commission. In this circumstance there would be no reason why SDG&E's customers should pay for any grid support to its grid that may be provided from SCE's transmission systems.

V. ANY LEVEL OF OWNERSHIP SHARE CHANGE MAY CAUSE AVOIDABLE TAX COSTS TO SDG&E AND SCE

As described by SDG&E's Ms. Marina Vengrin in Exhibit No. __ (SDG&E-3), the co-owners of SONGS apparently never contemplated and correspondingly did not contractually deal with the potential income tax effects that an Ownership Share change might entail for SDG&E and SCE. However, these concerns can largely be resolved favorably for tax purposes in a manner that avoids these tax effects. Because a failure to undertake the necessary remedial measures may result in unnecessary tax costs to SDG&E and SCE, the Commission should be apprised of these effects in order to take them into account in its determinations about the cost effectiveness of the SGRP.

Ms. Vengrin also discusses tax issues related to SDG&E's Nuclear Decommission Trust ("Qualified Fund" and "Non-Qualified Fund"). SDG&E will need to maintain its entire Nuclear Decommissioning Trust, both the Qualified Fund and Non-Qualified Fund, even in the event that its interest in SONGS is reduced to zero only because it remains liable for a portion of the cost to decommission SONGS under the terms of the Operating Agreement. In this event, however, SDG&E would be willing to consider transferring all of its Nuclear Decommissioning Trust to SCE's Nuclear Decommissioning Trust fund on the condition that SDG&E be relieved of any liability for the cost to decommission SONGS. This would, of course, require a modification of the Operating Agreement. This subject will be the topic of another proceeding before the Commission involving approval of any Ownership Share reduction in SONGS Units 2 & 3.

VI. QUALIFICATIONS

My name is James P. Avery. My business address is 8330 Century Park Court, San Diego, California, 92123. I am employed by San Diego Gas & Electric Company (SDG&E) as Senior Vice President – Electric. I oversee the company's electric and gas procurement, generation business unit, electric transmission engineering, grid operations, construction and maintenance, and electric distribution operations. I attended Manhattan College, New York City, New York, graduating with a Bachelor of Engineering Degree in Electrical Engineering with a major field of study in Electric Power. Prior to that, I attained an Associates Degree in the field of Electrical Engineering from New York City

Community College. Prior to joining SDG&E in 2001, I was a consultant with R.J. Rudden Associates, one of the nation's leading management and economic consulting firms specializing in energy and utility matters. Prior to that, I functioned as the chief executive officer of the electric and gas operations at Citizens Utilities Company, a multi-service organization that provided electric, gas, telecom, water and wastewater services in over 20 states across the nation. I am currently on the Board of Directors of the California Power Exchange, and R.J. Rudden Associates, and I also served as a member of the Board of Directors of Vermont Electric Power Company, a transmission only company serving the state of Vermont, and I held positions at American Electric Power Service Corporation. I have previously testified before this Commission.

This concludes my prepared direct testimony.

Richard Sheaffer

Application of Southern California Edison Company (U 338-E) for Authorization: (1) to replace San Onofre Nuclear (SONGS 2 & 3) steam generators; (2) establish ratemaking for cost recovery; and (3) address other related steam generator replacement issues.)

Application No. 04-02-026
Exhibit No. __ (SDG&E-2)
Witness: Richard Sheaffer

PREPARED DIRECT TESTIMONY
OF RICHARD SHEAFFER
ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

DECEMBER 13, 2004

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PREPARED DIRECT TESTIMONY

OF RICHARD A. SHEAFFER

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

I. INTRODUCTION

The purpose of this testimony is to demonstrate that the decision of Southern California Edison Company ("SCE") to undertake a non-collaborative technical study process resulted in numerous material inaccurate modeling assumptions. These incorrect assumptions critically impeach any credibility in SCE's technical study conclusions. I describe why the need for a new 500 kV transmission line within the San Diego Gas & Electric Company ("SDG&E") service territory is needed regardless whether San Onofre Nuclear Generating Station ("SONGS") continues to operate or is shut down. I explain why SCE's system separation scenario used to justify and allocate cost responsibility incorrectly ignores NERC fundamental principles of system interconnection and therefore should be disregarded. My testimony contains a discussion of the results of SDG&E's studies that were derivative from the joint studies abandoned by SCE. Based on SDG&E's studies, I explain why there would be significant cost savings for SCE and SDG&E ratepayers as compared to SCE's study conclusions.

II. SCE'S STUDY PROCESS WAS UNNECESSARILY A NON-COLLABORATIVE EFFORT

SCE and SDG&E (the "Companies") began a joint planning study by mutual agreement between the Transmission Planning Departments of the Companies in the second quarter of 2003 to evaluate possible transmission mitigation alternatives if SONGS Units 2 & 3 were shut down in 2010. Such a shutdown is an alternative that could possibly occur (in that year or some other year) in place of the steam generator replacement project ("SGRP") proposed by SCE.

From the time the joint study plan was developed in May, 2003, until SCE filed its application to commence this proceeding, SCE led SDG&E to believe that there existed between the Companies a spirit of cooperation. The Companies' lead technical engineers were exchanging data assumptions, jointly reviewing base cases and held several meetings to review the progress of the study. At the December 2, 2003 joint study meeting, SDG&E challenged certain study assumptions that SCE had assumed in that joint study, such as SDG&E load and schedules on the East-of-the-River path. SDG&E was surprised to see SCE's application it filed in this proceeding, because SCE apparently had been performing its own studies while at the same time continuing the appearance of a joint study process with SDG&E. SCE's study used assumptions that were not mutually-agreed upon. SCE's study obviously did not contain mutually-agreed upon conclusions. In hindsight, SCE's appearance of a willingness to complete a joint study with SDG&E was a charade that continued past SCE's filing of its application in this proceeding, and study assumptions to be used in the joint study (which was eventually abandoned) were never resolved and mutually-agreed.

III. SCE'S TRANSMISSION ALTERNATIVES AND ASSOCIATED COSTS STUDY RESULTS ARE INVALID DUE TO EXTENSIVE MODELING ERRORS

Exhibit SCE-5 contains SCE's Transmission Alternatives And Associated Costs Study results. The results from this study, based on inaccurate system modeling and invalid input assumptions, are not credible. Some of these erroneous conclusions are being used as the critical justifications for the SGRP and must accordingly be disregarded. The significance of each of these errors is discussed below.

A. SCE Inappropriately Considers The Addition Of A New 500 kV Transmission Line As A Mitigation Alternative

SCE's transmission study developed five base cases, derived from one 2010 Heavy Summer case. One case illustrated a "Base Case" scenario with SONGS Units 2 and 3 remaining in service ("SONGS On"). Another case was run to illustrate the impact of removing SONGS Units 2 and 3 without mitigation ("SONGS Off"). Three other cases illustrated mitigations for the absence of SONGS if the SGR were not to proceed and SONGS Units 2 and 3 were assumed to shut down in 2010. Specifically, these cases were:

- "SONGS On" Case;
- "SONGS Off" Case ("Off" meaning that SONGS Units 2 and 3 were removed from the case as if permanently out-of-service);
- "SONGS Off with No New SDG&E 500 kV Line" Case;
- "SONGS Off with Imperial Valley – Ramona 500 kV Line" Case; and
- "SONGS Off with Rainbow - Valley 500 kV Line" Case.

Although SCE did assume that a new Palo Verde – Devers #2 500 kV Line would be added to its own system by 2010 (thus its cost would not be included as an "absence of SONGS" mitigation), SCE assumed in all of its cases that there would not already be a new 500 kV line into the SDG&E system. This assumption is critically mistaken. Based on current planning assumptions, as reflected in SDG&E's long term resource plan filed with this Commission, and ongoing discussions with the Southwest Transmission Expansion Plan ("STEP") group, SDG&E will face a grid reliability deficiency beginning in 2010. A new 500 kV transmission line is SDG&E's proposed means by which it will meet this grid reliability deficiency.[1] Therefore, SCE's assumption that a new 500 kV line to SDG&E (and the associated cost) is a mitigation alternative if SONGS were to be shut down is incorrect and not relevant to the SGRP analysis. Therefore, SCE should have assumed a new 500 kV line was constructed as a starting point of its cases, rather than including it (or additional voltage support in the case of the "No New SDG&E 500 kV Line"), and the associated costs, as a mitigation for the absence of the SONGS Units.

B. SCE's Modeling of the Otay Mesa Generator Interconnection Inaccurately Adds Additional Congestion at the Miguel Substation

Another critical assumption made in SCE's Transmission Alternatives And Associated Costs Study involved its modeling of the new Otay Mesa generation interconnection. SCE assumed the interconnection would be as shown in Figure 1-1. These assumptions are incorrect. The proper interconnection[2] is shown in Figure 1-2. The correct interconnection was designed to bypass the Miguel bottleneck and to strengthen the SDG&E system significantly. The interconnection modeled in SCE's filing incorrectly simulated much more stress into the Miguel bottleneck than what is proposed.

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[1] For example, please refer to the July 9, 2004 testimony of Linda P. Brown in R.04-04-003, page 14 regarding "Adoption of 500 kV Transmission Expansion is a Key Element of SDG&E's Long-Term Resource Plan". Please also refer to the Dec. 26, 2003 draft "Southwest Transmission Expansion Plan 2003 Report", pages 45-48, the October 17, 2003 "Imperial Valley San Diego Expansion Plan (ISEP) Study" and many STEP group documents at http://www.caiso.com/docs/2002/11/04/2002110417450022131.html.

[2] Direct Testimony of David M. Korinek in Order Instituting Rulemaking to establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development, R.01-10-024, dated October 7, 2003.

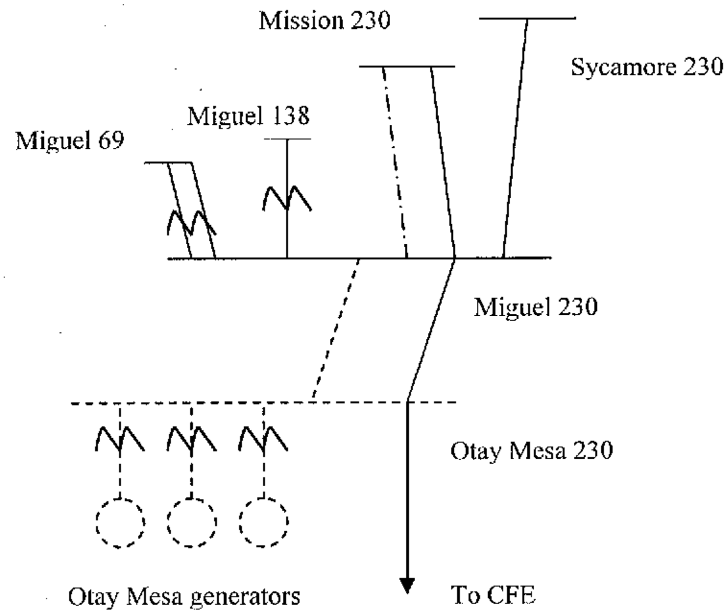

Figure 1-1: Incorrect Otay Mesa Interconnection Represented in SCE Filing Cases

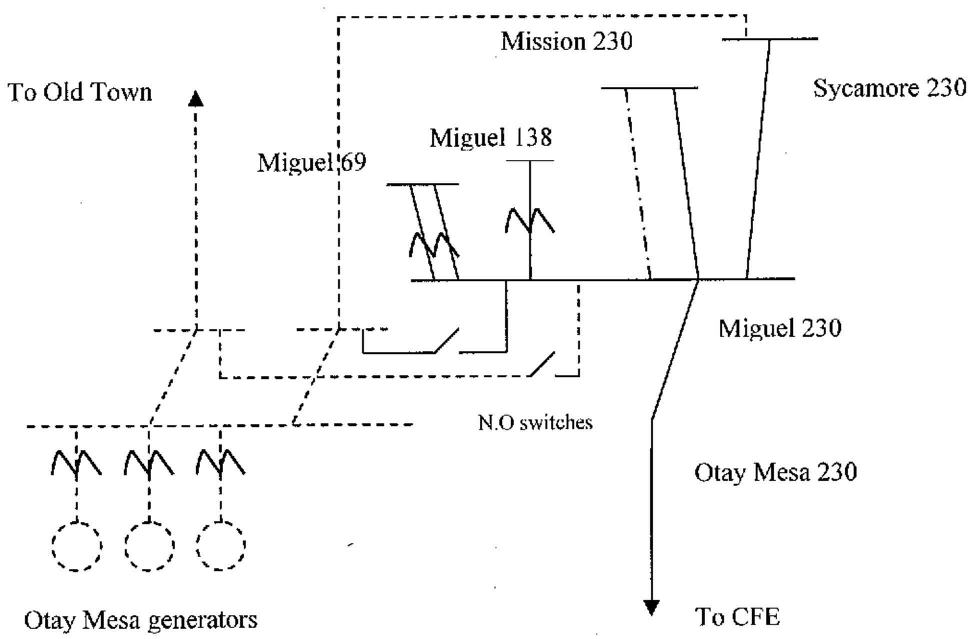

Figure 1-2: Correct Otay Mesa Interconnection Cases

C. SCE's Modeling of the Palomar Generation Interconnection Results in Erroneous Conclusions

Another critical assumption made in SCE's Transmission Alternatives And Associated Costs Study involved its modeling of the Palomar generation and associated interconnection. SCE used these incorrect assumptions in the study cases it utilized in Exhibit SCE-5. In the SCE "SONGS On" case, the Palomar generation was not shown as running. In the other four SCE cases, the 551 MW (and corresponding reactive flow up to 306 MVAR) of Palomar generation was directly tied into the Escondido 230 bus as one large unit. Such a simplifying representation was undoubtedly easier for modeling purposes, but incorrectly placed the Palomar generation output onto SDG&E's existing 230/138/69 kV system. As a result, this model results in unrealistic power flows and other system stresses within SDG&E's system that would lead to substantially erroneous conclusions.

The correct representation for the Palomar generation and associated interconnection is to accurately represent the Palomar power plant as three distinct units (two Combustion Turbines or "CTs" and one Steam unit). Further, the units are to be connected to a Palomar 230 kV bus that has the existing Escondido – Sycamore 230 kV line looped into it (presently planned by October 2005), shown below in Figure 2-1.[3] Additionally, the nearby 138 kV system needs to be modeled as being reinforced as well for reliability reasons in preventing overloads (presently planned by June 2006), as shown below in Figure 2-2. The following diagram represents these planned system additions, including a new transformer at Sycamore Canyon Substation, which are not

[3] Direct Testimony of David M. Korinek in Order Instituting Rulemaking to establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development, R.01-10-024, dated October 7, 2003.

represented properly in SCE's cases. SCE's incorrect modeling in this area also contributed to showing what appears to be "absence of SONGS" stresses, which in fact are not due to the absence of SONGS but rather due to failing to show system additions and changes that SDG&E plans to make irregardless of the status of the SONGS units.

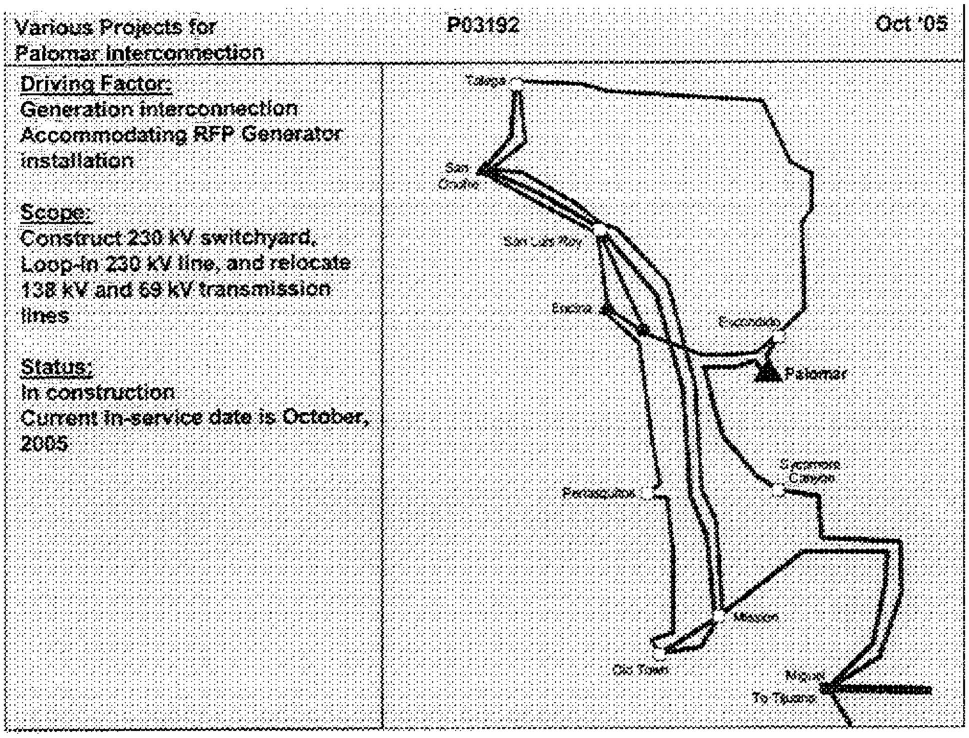

Figure 2-1

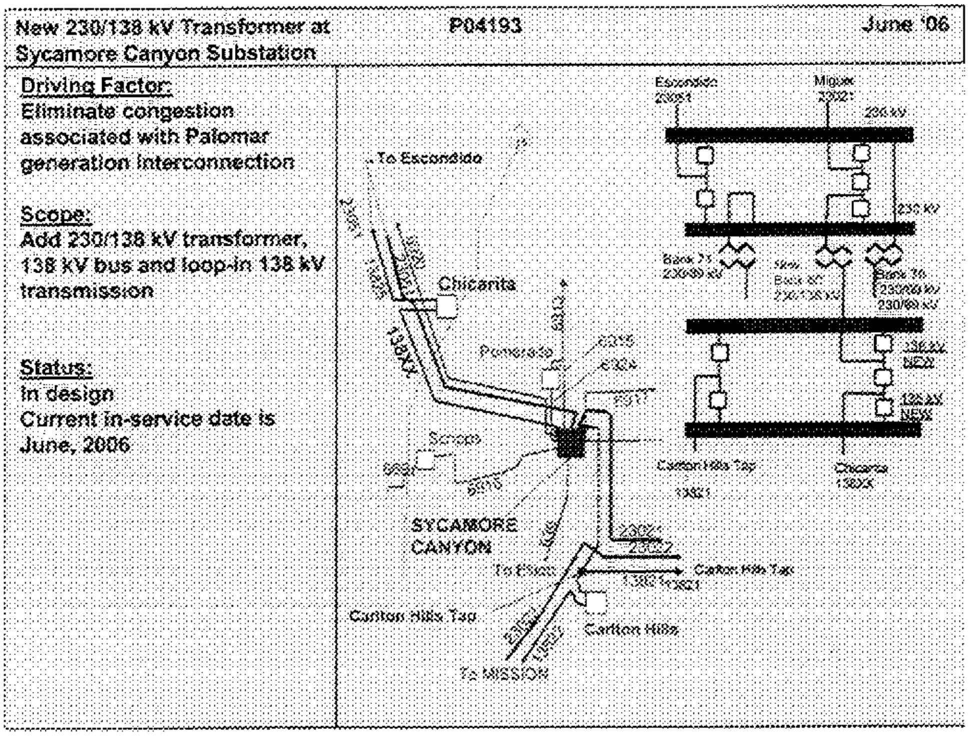

Figure 2-2

D. SCE Incorrectly Adds Excessive Load to SDG&E's Model

For the year 2010, SDG&E's projected load and loss is 4924 MW, as in the Long Term Resource Plan filed with the CPUC. SCE contends in its Exhibit SCE-5 is that "San Diego Gas & Electric Company's (SDG&E) Transmission Planning department provided information that SCE used to model SDG&E's transmission system in future year 2010". Not only does this not make reference to the fact that this information was obtained for purported joint study purposes, but also infers that SDG&E agrees with the way that SCE used this data, which SDG&E does not. SCE's Transmission Alternatives And Associated Costs Study incorrectly added losses again to this load number, thus double-counting the losses and representing SDG&E's load and loss quantity to be 5044 MW. This additional 120 MW, which essentially acts as 120 MW of load above and beyond what is expected in SDG&E's area, unrealistically stresses SDG&E's system, mistakenly giving the appearance that certain mitigations are needed, when in fact those mitigations are not needed. Therefore, the conclusions pertaining to this aspect of SCE's study are not accurate or credible.

E. SCE's Inaccurate Modeling of Voltage Control Devices Results in Excess Need for Voltage Support

All five cases used in SCE's Transmission Alternatives And Associated Costs Study modeled Heavy Summer peak load and high Southwest Powerlink ("SWPL") flow. Based on those conditions, SCE incorrectly modeled many voltage control devices as being on-line when in fact they should have been off. These types of devices are needed for light loading conditions, when the MVAR "charging" of long transmission lines causes voltage to rise excessively. Conversely, for heavy loading conditions (such as those modeled in SCE's and SDG&E's studies), these types of devices need to be removed to avoid degrading the voltage. Specifically, these included:

- two 114 MVAR line reactors on the Hassayampa (Palo Verde area) – North Gila 500 kV Line;
- one 114 MVAR line reactor at the Imperial Valley side of the North Gila – Imperial Valley 500 kV Line; and
- one of the Miguel 45 MVAR tertiary shunt reactors.

These reactors are used to regulate the voltage at these substations, and the simulation of these reactors on-line, when in fact they should be off, artificially creates the apparent, erroneous "need" for additional Static VAR Compensators ("SVCs"). The same type of erroneous assumptions also occurred in regard to the line reactors at both ends of the existing Palo Verde – Devers 500 kV Line. Separate from other data errors pointed out by SDG&E, the reactor errors described here alone account for about 640 MVAR of excessive need for SVCs seen in SCE's transmission study.

F. SCE's modeling assumptions on major path flow schedules result in unreasonable mitigation costs

As described in detail below, all of the base cases used in SCE's analysis assumed unreasonable path flows on major paths, such as the East of River ("EOR"), West of River ("WOR"), and SCIT ("Southern California Import Transmission") paths. Such unreasonable dispatches greatly damage the credibility of SCE's study results. Additionally, as SCE advised SDG&E in its data request response (Data Request Set SDG&E-SCE-01, Question 038), SCE did not perform any reactive resource optimization, which omission forces even more mitigation requirements. SCE characterized such study as "premature", yet has submitted quantitative results in its filing upon which it expects the Commission to act. Such studies, if and when performed, would likely have the effect of reducing the amount of reactive support actually seen to be needed, thus reduce the cost-effectiveness that SCE has presented in this case.

In all of SCE's cases, SCE modeled the EOR power flow to unreasonably high levels, while having very low flows on all other parallel paths into Southern California. At the December 2, 2003 joint study meeting between SCE and SDG&E, SDG&E strongly opposed unreasonable path flow schedules on the East-of-the-River (EOR) path.[4] Such artificial stressing of one path among many paths in parallel is generally modeled only in a "non-simultaneous path rating study". To help understand the extremity of such dispatches, SDG&E collected data for Heavy Summer cases developed in past two years from both the California Independent System Operator Corporation ("CAISO") and WECC for the years 2004 through 2014. The average flows of paths into

[4] SDG&E also challenged SCE on various assumptions at that December 2 meeting, but apparently SCE pursued studies irrespective of SDG&E's attempted corrections to those assumptions.

Southern California are listed next to two of SCE cases for comparison. These values are representative of those seen in SCE's cases.

Table 1: Major Path Flow Compared to Average of Available Peak Summer Cases

Path Name	Path Rating	SCE "SONGS On" Case	SCE "SONGS Off with No New SDG&E 500 kV Line" Cases	Typical number in WECC operating cases
Midway-Vincent *	3400[5]	1210	1759	2546
IPPDC *	1920	1536	1536	1726
North of Lugo *	1200	1461	1462	North of Lugo flow is not generally one of the paths monitored in most WECC cases
West of River *	10118	8689	9402	5893
PDCI *	3100	1054	1053	2196
SCIT	NS: 18886 S: 15200	13908	15153	13561
East of River[6]	7550	7550	8263	4475
SCIT+EOR		21458	23413	18036

* The sum of the power flows on these five paths is considered in the Southern California Import Transmission (SCIT) nomogram.

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[5] The 3400 MW Midway-Vincent rating is the present rating, but may be increased in the future depending on the schedule of future upgrades.

[6] The EOR Path Rating Increase from 7055 MW to 8055 MW, based on short-term upgrades, is currently in Phase II of the WECC Study Process. An additional increase to 9000 MW, following addition of the proposed Palo Verde – Devers #2 500 kV Line, is also currently in the Phase II Review Process.

It is very clear from Table 1 that for the summer peak conditions studied, SCE's cases had modeled the East-of-the-River ("EOR") and West-of-the-River ("WOR") flows at very extreme levels. Such flow assumptions are inappropriate for a study that was purportedly designed to seek reasonable means of maintaining reliability and of serving load if SONGS Units 2 & 3 are shut down, rather than for the purpose of determining a maximum rating of a particular transmission path.

SCE also assumed the Midway - Vincent power flow from Northern California, the Pacific DC Intertie ("PDCI") power flow from the Northwest and the Intermountain Power Project DC ("IPPDC") power flow from State of Utah area were much lower than average heavy summer cases. Such unreasonable dispatches once again demonstrates that SCE's study is not credible and its conclusions and remedial proposals cannot be trusted.

In response to SCE's unrealistic path flow assumptions, SDG&E took SCE's "SONGS Off with No New SDG&E 500 kV Line" case, reduced 1000 MW of flow off the EOR system (and therefore a similar amount off the WOR system) and increased the PDCI flow by 1000 MW. SDG&E made no other changes to this SCE case. SDG&E's simulation resulted in an EOR flow at 7370 MW, WOR flow at 8472 MW, and PDCI flow at 1931 MW. Though reduced, the EOR and WOR flows are still at relatively high levels of the typical operating range and PDCI is at the low end of the typical operating range.

In contrast to SCE, this single re-dispatch assumption to replicate reasonable system path flows made very significant changes in the results and substantially lowered the cost of mitigating the problems seen in the "SONGS Off with No New SDG&E 500 kV Line" case. The needed SVC for the 500 kV system could be reduced by 600 MVAR. Another 700 MVAR of proposed SVC could be moved to 230 kV level. However, SCE and SDG&E did not undertake reactive resource optimization (as should be performed in a more detailed study). Had this optimization been undertaken, the SVC requirements would be further reduced. Significantly, all of the NERC, WECC and CAISO planning standards were met in SDG&E's studies, yet SDG&E's studies show far lower SVC requirements than SCE's studies.

Unlike SCE, SDG&E further made another reasonable assumption concerning the path flow for SCE's Imperial Valley - Ramona 500kV Line case (the "ivrma" case). Similar to SCE's representation of the second Palo Verde – Devers 500 kV Line as being in-service, it is appropriate to model the Imperial Valley – Ramona 500 kV Line (or other alternative 500 kV Line) as being in service as needed for the SDG&E system regardless whether SONGS Units 2 & 3 continue to operate or are shut down. The use of the previously-discussed assumptions that reflects a typical operating range of major path flows, as well as modeling a new 500 kV Line to SDG&E, significantly reduced the need for SVCs. For the "ivrma" case, SDG&E undertook a study in which the EOR flow was reduced by 1200 MW and, therefore, the WOR flow was reduced a like amount. SDG&E also assumed that the PDCI flow was increased by 1200 MW. As a result, the "ivrma" case had an EOR flow at 7077 MW, WOR flow at 8250 MW and PDCI flow at 2242 MW. Once again, EOR and WOR flows are still at relatively high levels of the typical operating range and PDCI is at the low end of the typical operating range.

Unlike SCE, this re-dispatch to reasonable system path flow levels made very significant changes in the results and substantially lowered the cost of mitigating the case results. The study results reflect that from the 1374 MVAR of proposed SVC requirement, the needed SVC for the 500 kV system could be reduced by 776 MVAR. The remaining of 598 MVAR of needed SVC installation can be installed at the 230 kV level. However, SCE and SDG&E did not undertake reactive resource optimization for this case, like the previous case described above. Again, had this optimization been undertaken (as should be done in a more detailed study), the SVC requirements would be further reduced. Significantly, all of the NERC, WECC and CAISO planning standards were met in SDG&E's studies, yet SDG&E's studies show far lower SVC requirements than SCE's studies.

G. SDG&E's Validation Analysis Finds Flaws in SCE's Recommended Mitigation Proposals

SDG&E's validation analysis took all of SCE's cases "as is" and conducted necessary thermal screening, post transient analysis and transient stability analysis.[7] The results of this further study reflect that with all of the transmission mitigation proposed by SCE, there are still various Post Transient overloads. Thus, this indicates that SCE's studies are not complete and further study, or further mitigation, may be needed beyond what has been presented by SCE.

SCE proposed to remedy the Barre - Ellis 230 kV line overloading in its "No New SDG&E 500 kV Line" case. However, in the same case, SCE's Lugo - Serrano 500 kV and Vista - San Bernardino 230 kV Lines were also overloaded, and there seemed to be no mitigation proposed by SCE in its studies. SCE appears to be "cherry-picking" its study results. Regardless, this further undermines the credibility of SCE's study

[7] Note that SCE uses the term "Dynamic Stability" to describe studies of system oscillations from 0 to 10 seconds after a system disturbance, whereas SDG&E generally uses the term "Transient Stability" to describe such studies.

conclusions. Specifically, by SCE's effort to perform and analyze studies in a manner that seems to minimize facilities required by SCE for the "absence of SONGS" scenario, while maximizing facilities required by SDG&E, the resultant cost-sharing ratio is erroneously tilted in SCE's favor.

It is well known under the reliability criteria that generator tripping and load dropping are permissible for N-2 contingencies (such as the WECC Category C outage criteria), which would include the double-line outage of the Palo Verde – Devers 500 kV Lines. Such remedial actions were simulated by SCE under the SCE "SONGS Off with No New SDG&E 500 kV Line" case. For that case, tripping 908 MW of generation and 780 MW of load, along with other Remedial Action Scheme (RAS) elements, did not mitigate post transient voltage drop violations in the Devers area. Furthermore, the Hassayampa – North Gila and North Gila – Imperial Valley segments of the SWPL were seen to be loading in the study results over the newly-proposed 2200 Ampere rating that is planned by the Path 49 (EOR) short-term upgrade. Maintaining the tripping of 908 MW of generation while increasing the amount of load dropping from 780 MW to 1219 MW, eliminated the post transient voltage drop violations. That change slightly reduced, but did not eliminate, the SWPL overload. In addition, transient voltage dip criteria violation existed in all of SCE's cases with proposed mitigations. Again, this further impeaches the credibility of the study and conclusions drawn from it.

IV. SYSTEM SEPARATION IS NOT AN ACCEPTABLE ALTERNATIVE TO ALLOCATE MITIGATION COST

SDG&E does not agree that system separation is an adequate alternative to deal with transmission contingencies or for the purpose of allocating cost responsibility. Such a scenario assumes that the SCE and SDG&E systems are interconnected under normal operation before contingency. At the moment of contingency, all five 230 kV lines connecting SDG&E to SCE system through SONGS are assumed to be tripped or opened.

Tripping off the five lines is not part of any valid Remedial Action Scheme ("RAS"), as it is against NERC interconnection principles and would worsen the system performance under an emergency situation.

SDG&E studied the two contingencies listed below.

- Double Palo Verde – Devers 500 kV Line outage
- Imperial Valley - Miguel 500 kV Line outage

Along with the tripping of the five 230 kV lines, both contingencies become WECC/NERC Category D contingencies. This means that these contingencies would constitute an "[e]xtreme event resulting in two or more (multiple) elements removed or cascading out of service." Accepted WECC study practices recognize that this "[m]ay involve substantial loss of customer demand and generation in a widespread area or areas" and "[e]valuation of these events may require joint studies with neighboring systems."[8] For these reasons, SDG&E does not support such a severe and unilateral approach by SCE in using such a scenario as its rationale for cost sharing.

Using a system separation scenario to justify and allocate cost responsibility may be unique, but it ignores NERC fundamental principles of system interconnection. However, since SCE pursued this course of study, SDG&E performed a sensitivity analysis of such a system separation to verify how correction of the system assumptions, as I have earlier described, changes the study results significantly.

With both a new SDG&E 500 kV Line and a second Devers - Palo Verde 500 kV Line assumed for 2010, and after making the above-mentioned assumption corrections,

[8] April 2004 Western Electricity Coordinating Council "Reliability Criteria", page 25.

the following table summarizes SDG&E's analysis results. These results do not acknowledge any legitimacy of assuming that a theoretical system separation is a valid rationale for cost allocation. They are merely presented to show that even if pursuing SCE's rationale, the quantitative results are very different from SCE's results when using corrected study assumptions.

Table 2: Corrected MVAR Requirements for System Separation Scenario

Contingency	IV-ML + South of SONGS	2 DPV + South of SONGS
SCE load drop	None	2764 MW
SCE additional SVC required	300MVAR@500kV 400MVAR@230kV	300MVAR@500kV 400MVAR@230kV
SDG&E load drop	333MW	None
SDG&E additional SVC required	200MVAR@230kV	200MVAR@230kV

The following study assumptions were used in creating Table 2;

- A 388/-300 MVAR SVC at Devers 500 kV and a 388/-300 MVAR SVC at Valley 500 kV are part of the second Palo Verde – Devers 500 kV Line project.
- A 200/-100 SVC at Imperial Valley 230 kV and a 100/-100 SVC at Ramona 230 kV are part of the Imperial Valley - Ramona 500 kV line project.
- The Talega 138 kV bus has an existing 100/-100 MVAR STATCOM (a new- generation type of SVC)
- SVCs reported in the above table are mitigation needed in addition to the above- mentioned assumed projects (the second Palo Verde – Devers 500 kV Line and the Imperial Valley – Ramona 500 kV Line projects).

Based on the above assessment, the ratio of SVCs required for the SCE system as compared to the SDG&E system is in a 700:200 ratio (3.50:1), not a 600:2520 (0.24:1) ratio as shown in SCE's Filing.

V. SCE'S "WALK AWAY AND PAY NOTHING" THEORY DOES NOT HAVE TECHNICAL MERIT

SDG&E's position was characterized by SCE at the April 15, 2004 Prehearing Conference (page 54 of the transcript) as "… their plan is they walk away, pay nothing and still get substantial voltage support … from the project." SCE's claim is utterly without merit, as shown by technical studies that demonstrate that SDG&E is not getting any implied "free ride" from SONGS or from SCE. To the contrary, study results indicate that it is SCE and not SDG&E that benefits from SONGS voltage support more than its Ownership Share. For example, examination of SCE's own "SONGS On" base case power flow indicates that of the 323 MVAR output from the SONGS units (reflecting reactive power which provides voltage support), 308 MVAR flow to SCE and 15 MVAR flow to SDG&E: a 95.4% / 4.6% ratio. Thus, SCE's own case shows that SDG&E receives far less voltage support (MVARs) than their ownership share would represent.

For the "SONGS Off" cases, I cannot examine such MVAR splitting, since the SONGS units are modeled as being absent. For those cases, I examined the MVAR flow occurring at the SONGS 230 kV bus interconnection between SCE and SDG&E. Depending on which SCE case we examine, I see the range of 204 MVAR flowing from SDG&E to SCE for the SONGS Off base case (no mitigation) to 277 MVAR flowing from SDG&E to SCE for the SONGS Off base case in which SCE assumed that no new 500 kV line would be built to the SDG&E system and all mitigation was in the form of voltage support measures. In SDG&E's "SONGS Off" case that reflects the modeling corrections described above and a new 500 kV line being added to SDG&E's system that is part of SDG&E's transmission plan regardless of the presence or absence of SONGS

Units 2 & 3, there exist 130 MVAR that flow from SDG&E to SCE at the SONGS interconnection.

All of these case scenarios undertaken by SCE and SDG&E indicate that SDG&E's system is providing voltage support to the SCE system. Thus, it is SCE that benefits from voltage support from SDG&E, with or without the presence of the SONGS units, not the other way around as SCE incorrectly would lead us to believe.

These conclusions are confirmed by examining historical real-time data recordings as opposed to study results of future scenarios. For example, both SONGS Units 2 and 3 were recently off-line in the November 19 to November 23, 2004 period. At that time, Unit 3 was down for refueling and other repairs, when Unit 2 tripped off-line. Real-time data of the MVAR flow from SDG&E's five 230 kV lines to the SONGS 230 kV bus during that period indicate that an average of 73 MVAR were flowing from SDG&E's system to SCE's system, again illustrating the voltage support that SDG&E was providing to SCE (via the SONGS 230 kV bus) during that period. In yet another example, the hourly recorded data was examined for the second half of the previous year, 2003. In that data, I see an average of 77.7 MVAR flowing from the SDG&E system to the SONGS 230 kV bus (the SONGS interconnection with SCE). At the same time, the recorded data shows that the average MVAR output of Unit 2 was 16.1 MVAR and the MVAR output of Unit 3 was 16.7 MVAR, a total of 32.8 MVAR. Therefore, I conclude that on average for that data period, 100% of the MVAR output of the SONGS units flowed to the SCE system (to support the SCE system voltage). While on average SDG&E received none of those SONGS-produced MVARs to support its own system voltage, the SDG&E system actually sent an additional 44.9 MVARs of voltage support to SCE's system to create the average total 77.7 MVAR flow seen in that historic data. Again, these data show that it is SCE that receives voltage support from SONGS and from SDG&E, not the other way around.[9]

VI. SUMMARY

Regrettably, SCE chose to pursue a "parallel path" study process -- performing a joint study with SDG&E and at the same time pursuing studies unknown to SDG&E. In reviewing SCE's study results, I find many flaws in the study assumptions and the resulting conclusions. Therefore, SCE's transmission study should not be relied on as accurately portraying the transmission grid facilities required for the scenarios presented by SCE and its study results should be discarded.

The attached summary indicates the differences between the five SCE cases, and shows one SDG&E case for comparison. SDG&E's case includes, for comparison purposes, the Imperial Valley – Ramona 500 kV Line, regardless of the presence or absence of SONGS Units 2 and 3. SDG&E's case includes the many study corrections discussed herein. Accordingly, the net amount of SVCs required because of the absence of SONGS are reduced from SCE's figure of 1374 MVAR down to a corrected level of 598 MVAR, representing a significant cost savings for SCE and SDG&E ratepayers as compared to SCE's study conclusions.

SCE's cost-sharing methodology for transmission grid mitigations, based on a system separation scenario that would not withstand scrutiny under established reliability standards, should also be rejected as being without foundation or precedent. However,

[9] SDG&E's historical data referenced here does have some data points that represent bad data or no data for a given hour. Most of the data recorded in the first half of 2003, at least until May 2, was recorded as 0. For that reason, the data given here is only for the second half of 2003. Although the data for the second half of 2003 still has some occasional 0 data for certain hours, these should have no significant impact on the concepts presented here.

even if that methodology were to be accepted over SDG&E's objection, SDG&E's study results to date indicate that the SCE / SDG&E cost-sharing ratio for SVC costs (voltage support mitigation) should be corrected from the 0.24:1 ratio proposed by SCE to a corrected 3.50:1 ratio. This corrected ratio could change based on future updated and optimized studies, and any such studies should be jointly performed and agreed-to by SCE and SDG&E. Any possible suggestion that SDG&E is benefiting, or may possibly benefit in the future, from a "pay nothing and receive free voltage support" philosophy should be soundly rejected based on the technical study results of both SCE and SDG&E, which indicate that the opposite is true for all the study scenarios examined.

To conclude, I am drawn to page 35 of SCE's Exhibit SCE-5, where it claims that "SDG&E ratepayers receive more benefits from SONGS 2 & 3 continued operation based on the cost responsibility for transmission upgrades required to mitigate SONGS 2 & 3 shutdown. These transmission upgrades required to mitigate SONGS 2 & 3 shutdown benefit SDG&E ratepayers more than SCE ratepayers because SDG&E is a relatively higher beneficiary from the availability of SONGS 2 & 3 to the electrical grid." These are words that do not remotely resemble any words I have ever seen or heard in previous "absence of SONGS" studies that have withstood the scrutiny of the collaborative process. In my professional opinion, based on the facts I have demonstrated in this testimony, SCE's statements are completely without merit and appear to be merely an attempt to show mitigation costs for the absence of SONGS scenario that are far too high, then shift cost responsibility unjustifiably to SDG&E ratepayers.

It is simply inappropriate to rely on studies that SCE has peformed independently in this matter. Such studies are of such great importance, and of significance to many parties, that they should be performed on a joint, collaborative process as in the past. Thus, SCE's studies should be discarded, and, if needed, SCE should be directed to perform updated studies collaboratively with at least SDG&E, and preferably with the CAISO and Interested Stakeholders, to the extent that such study results are needed to be relied on by the Commission in making a decision in this matter.

VII. QUALIFICATIONS

My name is Richard A. Sheaffer. My business address is San Diego Gas & Electric Company, 8316 Century Park Court, CP52A, San Diego, CA 92123. I am presently employed by San Diego Gas & Electric Company (SDG&E) as Principal Engineer in the Electric Transmission Planning Section.

I graduated with a Bachelor of Science degree in Electrical Engineering (BSEE) from The Pennsylvania State University (Penn State) in 1972. I later received a Master of Science degree in Electrical Engineering (MSEE) from the University of Southern California (USC) in 1975. I further received a Master of Business Administration (MBA) degree, with a management focus, from Pepperdine University in 1996. I am also a registered Professional Engineer (in the Electrical Branch) in the State of California (No. E8877) and in the State of Florida (No. PE-0030014).

With respect to my professional experience, I worked for Southern California Edison Company (SCE) during the period from 1973 to 1979, and again from 1980 to 1990. For approximately one year, between 1979 and 1980, I was employed by Harris Corporation (Controls Division), located in Melbourne, Florida. I began working for SDG&E in 1990, and continue to do so.

I have held a number of positions throughout my career involving electric utilities, the majority of which have involved electric transmission planning and grid operations. Such positions have involved modeling of the transmission grid for both California and the interconnected system of the Western Systems Coordinating Council (WSCC). I have also served as a representative on the WSCC Technical Studies Subcommittee, Pacific and Southwest Transfer Subcommittee, and Rating Methods Task Force. WSCC is now known as the Western Electricity Coordinating Council (WECC). In addition, I have also served as SDG&E's representative to the San Onofre Nuclear Generating Station (SONGS) in regard to decommissioning Unit 1.

Having worked for both SDG&E and SCE, I am familiar with their transmission systems and the systems to which they interconnect. In the past, I led the SDG&E effort in a joint study with SCE to determine grid mitigations for the "absence of SONGS" scenario.. This study was entitled "SCE and SDG&E Joint Study: Transmission System Performance Absent the San Onofre Nuclear Generating Station," issued in 1999. That study was a precursor to the "Phase 2" study later undertaken by the California Independent System Operator (CAISO), SCE, SDG&E and Interested Stakeholders, later issued in 2000. Although those studies are now outdated, the study methodologies were similar to today's studies.

I have been familiar with the evolution of the system referred to as the "Arizona-California" transmission system, also called the "East of the River" (EOR) system or "Path 49," and its impact on studies of transmission grid reliability, since I began working in SCE's transmission planning area in 1976. The "River", for this purpose, refers to the Colorado River, which has made a convenient dividing line for defining major East-West transmission. While working in SDG&E's transmission planning area, I was responsible for leading the effort to increase the EOR rating, under the then-existing WSCC rating procedures, from the then-existing rating of 7365 MW up to the present rating of 7550 MW. Such ratings define the maximum permissible flow while maintaining adequate reliability under the various reliability criteria.

Similar to my knowledge of the EOR system, my knowledge of the "West of the River" (WOR) system, and its impact on studies of transmission grid reliability, started in 1976 when I was working in SCE's transmission planning area. While later working in SCE's grid operations area, around 1984, I performed studies and developed a methodology for rating the WOR system for the first time on a real-time basis while maintaining adequate grid reliability. That methodology, based on a WOR nomogram that I developed, was later replaced by a new methodology using a Southern California Import Transmission (SCIT) nomogram, which now considers the dynamic system rating based on the EOR flow and five interdependent paths, one of which is the WOR system.

I have not previously testified before this Commission.

This concludes my prepared direct testimony.

MITIGATION COMPARISON

		<------------ SCE Filing Cases				------------>	SDG&E Final Case
SVC	Comment	SONGS On Base	SONGS Off Base	SONGS Off no 500 kV (ie. SONGS Off 230 kV)	SONGS Off with Valley - Rainbow	SONGS Off with Imperial Valley - Ramona *	SONGS Off with Imperial Valley - Ramona **
		Max	Max	Max	Max	Max	Max
SVC@Devers 500	388/-300 for DPV2	388	388	867	800	600	387
SVC @ Valley 500	388/-300 for DPV2	388	388	667	600	500	387
SVC @ Serrano 500 (have "-300")		0	0	1200	200	300	0
SVC @ Santiago 230							150
SVC @ Viejosc 230							250
SVC @ Chino 230							
SVC @ Talega 138 (have "-100)		100	100	300	200	150	100
SVC @ Sycamore 230		0	0	0	0	0	
SVC @ IV 500		0	0	360	0	500	
SVC @ IV 230	200/-100 for IV-Ramona						300
SVC @ Ramona 500		0	0	0	0	200	
SVC @ Ramona 230	100/-100 for IV-Ramona						
SVC @ Rainbow 230		0	0	0	593	0	
SVC @ Mission 230		0	0	0	200	0	200
SVC as part of new lines proposed and as existing SVC		876	876	876	1669	876	1176
Total		876	876	3394	2593	2250	1774
Net SVC Due to SONGs Off		**N/A**	**N/A**	**2518**	**924**	**1374**	**598**

* SCE failed to count SVCs that are part of the IV - Ramona 500 kV Line project

** SDG&E shows 200MVAR @ IV 230 kV and 100 MVAR @ Ramona 230 kV as part of the IV - Ramona 500 kV Line project

Application of Southern California Edison Company (U 338-E) for Authorization: (1) to replace San Onofre Nuclear (SONGS 2 & 3) steam generators; (2) establish ratemaking for cost recovery; and (3) address other related steam generator replacement issues.	))))))))

Application No. 04-02-026
Exhibit No.: (SDG&E-[redacted]
Witness: Michael M. Schneider

PREPARED DIRECT TESTIMONY

OF MICHAEL M. SCHNEIDER

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

DECEMBER 13, 2004

TABLE OF CONTENTS

PREPARED DIRECT TESTIMONY
OF MICHAEL M. SCHNEIDER
ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

I. INTRODUCTION

The purpose of my testimony is to describe SDG&E's economic analysis that supports SDG&E's position that participation in the SGRP is cost effective to San Diego customers only if SDG&E's ownership share of SONGS falls below a particular threshold based upon the terms of the San Onofre Operating Agreement (Agreement). If SDG&E's ownership remains above that threshold, then given the projected SGRP costs, SDG&E customers are better off with SDG&E not participating in the SGRP. In other words, as long as SDG&E retains more than the threshold ownership percentage of SONGS without participating in the SGRP, then SDG&E's customers are better off not participating in the SGRP.

That threshold ownership share depends on the costs associated with the type of replacement generation resource assumed in the analysis. If the replacement generation resource is assumed to be a gas-fired Combustion Turbine Combined Cycle (CTCC) power plant the threshold ownership share is 0%, which means SDG&E's customers are better off not participating in the SGRP regardless of the level of SDG&E's resulting ownership share. If the replacement generation resource is assumed to be a geothermal power purchase agreement (PPA), the threshold ownership share is 15%, which means SDG&E's customers are better off not participating in the SGRP only if SDG&E's resulting ownership share remains above 15% from a cost-effectiveness basis only. Later in my testimony I address certain other benefits flowing from this type of renewable resource that can reduce this threshhold. Any potential increase in costs related to the SGRP beyond the level currently projected in SCE's cost estimates would reduce these threshold ownership percentages, thereby making participation in SGRP uneconomical for SDG&E's customers over a wider range of ownership share outcomes.

Below is an explanation of the economic analysis supporting the comparison of various SGRP alternatives related to SDG&E's ownership share of SONGS.

II. SDG&E EVALUATES 3 ALTERNATIVES

A. Alternative 1: SDG&E Participates in SGRP

Alternative 1 is based on the assumption that the SGRP is implemented in 2009-10 as proposed by SCE. SDG&E would fully participate in the project by paying its 20% share. SDG&E would retain its current 20% ownership of SONGS 2&3, and its current entitlement to 20% of the Units' net energy production through 2022. This alternative evaluates the total cost to SDG&E customers of producing energy from SONGS 2&3 over years 2004-2022.

B. Alternative 2: SDG&E Ownership Reduction

Alternative 2 is based on the assumption that the SGRP is implemented in 2009-10 as proposed by SCE, but SDG&E would not participate in the project. SDG&E would not pay its 20% share of the cost of the SGRP, but instead would forfeit a portion of its SONGS 2&3 ownership in 2009-10 when the SGRP is completed on each Unit. This alternative is possible because SCE has declared the steam generator problem to be an Operating Impairment under the terms of the Agreement. Because the amount of

SDG&E's ownership reduction is still unknown, this alternative was evaluated at the following levels of ownership: 20%, 15%, 10%, 5%, and 0%. This alternative evaluates the total cost to SDG&E customers of producing the same amount of energy as Alternative 1 over the period 2004-2022. That energy would be provided in part by SONGS 2&3, and in part by either a new CTCC power plant, or a new Geothermal PPA. The Geothermal option is discussed further in Section VI as a sensitivity analysis.

C. Alternative 3: SDG&E Ownership Transfer with PPA

Alternative 3 is based on the assumption that the SGRP is implemented in 2009-10 as proposed by SCE, but SDG&E would not participate in the project. Instead, SDG&E would transfer its entire 20% SONGS ownership share to SCE in 2004. This alternative evaluates the total cost to SDG&E customers of producing a fixed amount of energy over the period 2004-2022. That energy would be provided through a PPA with SCE. In this alternative the actual amount of energy provided would be somewhat higher than in Alternative 1, because the PPA is assumed to be based on a more optimistic SONGS capacity factor than is reflected in Alternative 1, which is based on SCE's projection. The value of this increased energy is incorporated into the analysis of this alternative. Alternative 3 is discussed further in Section VI as a sensitivity analysis.

III. ECONOMIC ANALYSIS METHODOLOGY

The comparative analysis of Alternatives 1 and 2 consists of determining all relevant costs by year for years 2004 through 2022 and discounting the sum of these costs back to year 2004 dollars on an NPV basis. All relevant costs for this analysis are assumed to be incremental, and generally include fuel, fixed and variable O&M, nuclear decommissioning trust (NDT) contributions, and routine (non-SGRP) capital costs for both alternatives. These costs and all other related costs are explained in more detail in Sections IV and V of this testimony. All costs included in Alternatives 1 and 2 are adjusted for the specifics of each alternative.

Analysis for Alternative 1 includes all costs noted above, and the incremental revenue requirement associated with SDG&E's 20% share of SGRP capital costs. All costs individually presented as Alternative 1 have been escalated and discounted at SDG&E's authorized rate of return of 8.18% for years 2004 through 2022. The total sum of all costs associated with Alternative 1 in 2004 NPV dollars and 2004 $/MWh are shown in Attachments 1 and 2 of this testimony.

Analysis for Alternative 2 conducted in two phases includes all costs noted above, and in addition, the revenue requirement associated with replacing the reduction of SDG&E's 20% share of SONGS output with either a 30-year CTCC power plant (provided in Section IV-B) or a Geothermal PPA (provided in Section VI as a sensitivity analysis). Analysis for Alternative 2 excludes any revenue requirement associated with transmission mitigation facilities. Transmission mitigation is not needed in this alternative because it is assumed SONGS continues to operate until 2022. In addition, the analysis adjusts all costs to reflect SDG&E's SONGS ownership share ranging from its current 20% down to 0%, in increments of 5%. As noted in Section II-B above, Alternative 2 assumes that the SGRP goes forward, but SDG&E's ownership share is reduced to some level, which is unknown at this time. The analysis also incorporates end-effects assumptions related to the CTCC power plant at the end of 2022. This is necessary because the revenue requirement for the CTCC facility is calculated over thirty years (2010-2039), which is greater than the time period covered in this analysis (2004-2022). Therefore this analysis provides for the value of the CTCC facility to be credited back at replacement cost new less depreciation less remaining book value at the end of year 2022. All costs other than the revenue requirement associated with CTCC facility presented as Alternative 2 have been escalated and discounted at SDG&E's authorized rate of return of 8.18% for years 2004 through 2022. The revenue requirement associated with the CTCC facility presented in Alternative 2 have been escalated and discounted at SDG&E's filed (but not yet approved) rate of return of 8.78% for years 2004 through 2022. The total sum of all costs associated with Alternative 2 in 2004 NPV dollars and 2004 $ per MWh, are shown in Attachments 1 and 2 of this testimony.

IV. REPLACEMENT GENERATION REQUIREMENTS USING COMBINED CYCLE

A. Alternative 1 Requirements

Under Alternative 1 no replacement generation is needed, because it is assumed SONGS will replace its steam generators in 2009-2010, and will continue operating until 2022. It is further assumed that SDG&E would fully participate in the project by paying its 20% share of SGR capital costs and SDG&E would retain its current 20% ownership of SONGS 2&3, and its current entitlement to 20% of the Units' net energy production through 2022. SDG&E's portion of incremental SONGS routine (non-SGRP) capital costs used in the analysis for years 2004-2022 was based on SCE's 2006 GRC application. In Alternative 1, SDG&E's portion of incremental fixed and variable

O&M costs and nuclear fuel costs for years 2004-2022 were obtained from SCE's SGRP workpapers.

B. Alternative 2 Requirements

Alternative 2 assumes that SONGS will continue to operate but SDG&E will reduce its share of ownership. Since SDG&E's ownership reduction is still unknown, the analysis for Alternative 2 was evaluated at the following levels of ownership: 20%, 15%, 10%, 5%, and 0%. Alternative 2 assumes that energy would be provided in part by SONGS 2&3, and in part by a new CTCC power plant.

Alternative 2 assumes a 506 MW turn-key CTCC power plant owned by SDG&E will replace the reduction in SDG&E's share of SONGS energy beginning in year 2010. The estimated capital costs associated with the CTCC facility are assumed to be $473.0 million. These estimates were arrived at using SDG&E's future rate based investment in its Palomar facility recently filed in October 2004 with the Commission as a proxy. However, only the portion of the CTCC power plant needed to replace SDG&E's share of SONGS in years 2010-2022 is relevant to this alternative. Thus, as SDG&E's current 20% ownership in SONGS is reduced in this analysis in 5% increments, the capital costs associated with the CTCC power plant increase accordingly. Conversely, as SDG&E's current 20% ownership in SONGS is reduced in this analysis in 5% increments, SONGS routine (non-SGRP) capital costs for years 2010-2022 reduce accordingly. SDG&E's portion of SONGS routine (non-SGRP) capital costs used in the analysis for years 2010-2022 was based on SCE's 2006 GRC application. As SDG&E's current 20% ownership in SONGS is reduced in this analysis in 5% increments, SDG&E's incremental fixed and variable O&M expenses decrease, beginning in year

2010. As more SONGS energy is replaced with CTCC power plant energy, fixed and variable O&M expenses decrease due to the lower costs associated with operating a new power plant. The consulting group of Sargent and Lundy provided information related to fixed and variable O&M expenses. As SDG&E's current 20% ownership in SONGS is reduced in this analysis in 5% increments, incremental fuel costs associated with operating the CTCC power plant in years 2010-2022 increase accordingly. As more SONGS energy is replaced with CTCC power plant energy, fuel expenses increase due to the higher gas costs associated with operating a new gas-fired CTCC power plant. Fuel cost data were based on gas forecasts obtained from SDG&E's Long Term Resource Plan. Costs associated SDG&E's NDT contributions for years 2004-2013 also decrease as SDG&E's current 20% ownership in SONGS is reduced in this analysis in 5% increments. Alternative 2 requirements were also determined based on an alternative assumption that replacement generation would be provided by a Geothermal PPA, instead of a CTCC power plant. That analysis appears in Section VI. D.

V. TRANSMISSION MITIGATION REQUIREMENTS

For purposes of this analysis, two overarching key assumptions have been adopted in regard to transmission mitigation. It is assumed that SDG&E will add a 500kV interconnection to its existing electric transmission infrastructure by year 2010, but for reasons unrelated to SGRP. In addition, it is also assumed that a second Devers-Palo Verde 500kV line will be added to SCE's existing electric transmission infrastructure by year 2010, but for reasons unrelated to SGRP.

Under each of the alternatives evaluated by SDG&E, no transmission mitigation is needed, because it is assumed SONGS will replace its steam generators in 2009-2010, and will continue operating until 2022.

VI. SENSITIVITY ANALYSES

A. SONGS O&M and Capital Increases

A sensitivity study was conducted for Alternative 1, assuming that SDG&E's portion of SONGS routine (non-SGRP) capital and O&M expenses provided by SCE were to increase by 20%. This sensitivity results in a 2004 NPV of $1,884 million and $30.45 per MWh, which is significantly higher than the $1,636 million and $26.44 per MWh for Alternative 1 shown in Attachments 1 and 2. This analysis illustrates that in the event future SONGS capital and O&M costs are higher than SCE's current projections, the threshold ownership percentages discussed in Alternative 2 would be reduced, thereby making participation in SGRP uneconomical for SDG&E's customers over a wider range of ownership share outcomes. In that event SDG&E's customers would be further advantaged if SDG&E does not participate in SGRP, and reduces its ownership in SONGS as described in Alternative 2, and even more so if SDG&E transfers its entire 20% ownership share to SCE described in Alternative 3.

B. Alternative 3: SDG&E Ownership transfer with PPA

Alternative 3 is based on the assumption that SDG&E would transfer its entire 20% ownership share in SONGS to SCE in 2004. In return, SCE would accept responsibility for all future capital, O&M, and fuel costs associated with SDG&E's current 20% ownership share. SDG&E would also transfer the balance in its NDT to

SCE in 2004, and SCE would accept responsibility for all future decommissioning costs associated with SDG&E's current 20% ownership share. Finally, SDG&E would enter into a PPA with SCE in 2004 to provide SDG&E's customers a fixed amount of energy each year through 2022.

Analysis for Alternative 3 includes all costs identified under Alternative 1, including SDG&E's 20% share of SONGS O&M and fuel, as well as SDG&E's projected SONGS depreciation, return, and NDT contributions. However under Alternative 3 these costs would be paid by SCE and recovered from SDG&E through the PPA. Therefore the cost of the PPA expressed in 2004 present value dollars, is equal to the 2004 present value of all costs associated with Alternative 1.

Under the PPA, SCE would provide to SDG&E a fixed amount of energy equivalent to SDG&E's current 430 MW entitlement in SONGS at a capacity factor of 91.8%. That capacity factor was chosen because it is equal to the historic average of SONGS 2&3 capacity factors over the past 5 years (1999-2003). Since this capacity factor is greater than the capacity factor projected by SCE in their cost-effectiveness study (88%), Alternative 3 would result in somewhat more energy being delivered to SDG&E than Alternative 1. Therefore, while the total 2004$ cost of the PPA would equal the total 2004$ cost of Alternative 1, the total 2004$ cost of Alternative 3 is somewhat less than the total 2004$ cost of Alternative 1 because it includes the value of this increased energy. As shown in Attachment 1 the value of this increased energy is estimated to be $63.5 million (2004$).

C. Potential Income Tax Resulting from Ownership Share Reduction

SDG&E has provided additional analysis regarding a potential adverse tax consequence that could arise if SDG&E were to reduce its ownership share in SONGS as contemplated under Alternative 2. The details surrounding this tax consequence are discussed in the direct testimony of SDG&E witness Marina Vengrin. SDG&E would most likely recognize a taxable gain if it were to reduce its SONGS ownership share in year 2010 resulting in a tax payment to the IRS of up to $32.0 million. This taxable gain would result if the tax basis of the portion of SONGS that is transferred to SCE were less than the Fair Market Value (FMV) of SDG&E's ownership share in the new steam generators. This additional cost was evaluated as sensitivity to Alternative 2 only. As SDG&E in its analysis of Alternative 2 reduces its SONGS ownership share from its current 20% to 0% in 5% increments, each progressive reduction in ownership share would result in a decrease in the $32.0 million tax liability.

If SDG&E's ownership reduction is ultimately approved and this tax consequence were to occur, SDG&E would seek cost recovery of these potential tax costs in future rates.

SCE will experience a similar adverse tax consequence related to the SDG&E's SONGS ownership reduction. However, the adverse impact of this tax consequence on SDG&E's and SCE's customers can be mitigated if the utilities enter into a tax partnership designed specifically for this purpose.

D. Replacement Generation Requirements Using Geothermal

This section of my testimony addresses the replacement generation requirements associated with Alternative 2, assuming that the reduction of SDG&E's

share of SONGS energy is replaced by a Geothermal PPA instead of by a new CTCC power plant. As addressed in the testimony of Mr. Avery (Section III.C.2), a Geothermal PPA has additional renewable and fuel diversity benefits, which would not be realized if SDG&E replaced its ownership reduction with a new CTCC power plant.

Alternative 2 assumes that SONGS will continue to operate but SDG&E will reduce its share of ownership. Since SDG&E's ownership reduction is still unknown, the sensitivity analysis for Alternative 2 was evaluated at the following levels of ownership: 20%, 15%, 10%, 5%, and 0%. This sensitivity analysis for Alternative 2 assumes that energy would be provided in part by SONGS 2&3, and in part by a Geothermal PPA. This sensitivity analysis assumes the reduction of SDG&E's portion of SONGS energy is replaced by a Geothermal PPA at a levelized cost of $93.56 per MWh. This analysis assumes the Geothermal PPA could be structured to match the reduction of SDG&E's share of SONGS in years 2010-2022. In this analysis, as SDG&E's current 20% ownership in SONGS is reduced in 5% increments, the costs associated with a Geothermal PPA would increase accordingly. Routine (non-SGRP) capital and NDT costs for this analysis are identical to those used in Section IV-B of this testimony. Incremental SONGS O&M and fuel costs are identical to those used in Section IV-B for years 2004-2009 since ownership reductions are not assumed until year 2010. In this sensitivity analysis, SONGS O&M and fuel costs decrease and Geothermal PPA costs increase as SDG&E's ownership in SONGS decreases in 5% increments, since more of SONGS energy is replaced with energy from a Geothermal PPA beginning in year 2010.

VII. ECONOMIC ANALYSIS RESULTS

This section of my testimony summarizes the results of the economic analysis of Alternatives 1, 2, and 3, and ranks these alternatives in order of preference for SDG&E's customers. The costs associated with each alternative are graphically displayed in Figures 1 and 2 below, and further detailed in Attachments 1 and 2.

Alternative 3 is SDG&E's first preference for two distinct reasons. Under Alternative 3 SDG&E would transfer its 20% ownership to SCE in 2004, and would enter into a PPA with SCE for a fixed amount of energy each year through 2022. First, Alternative 3 provides a lower cost than Alternative 1 due to the value of the additional energy that SDG&E would receive under the assumptions incorporated into this analysis. Second, Alternative 3 provides SCE with an incentive to manage its costs related to SDG&E's purchase power entitlement of SONGS and provides SDG&E with cost certainty to its customers no higher than the amounts currently forecasted by SCE.

Alternative 2 is SDG&E's second preference. Under Alternative 2, SDG&E would take an ownership reduction in SONGS in 2010 in lieu of participating in the SGRP. SDG&E would replace its lost SONGS energy with energy from a new CCTC power plant. As noted in Figure 1 below, Alternative 2 provides a lower cost than Alternative 1 regardless of the level of SDG&E's resulting ownership share. Alternative 2 is also less costly than Alternative 3 if SDG&E's ownership share remains high, but since SDG&E's resulting ownership share is uncertain and Alternative 2 does not provide for cost certainty and incentive benefits like Alternative 3, Alternative 2 is considered to be less preferable than Alternative 3. As presented in this testimony, SDG&E could replace its lost SONGS energy with energy from a Geothermal PPA instead of a CTCC power plant. However, as indicated from the sensitivity analysis conducted in Section VI-D and Figure 2 below, the Geothermal PPA would be cost-effective only if SDG&E's ownership share of SONGS remains above 15%. The Geothermal PPA option has added benefits of providing continued fuel diversity to SDG&E's generation portfolio as well as supporting the State's energy policy of requiring higher levels of renewable resources for future energy and capacity supply. These benefits should be considered in addition to the cost-effective analysis and provide a premium such that even if SDG&E's ownership in SONGS falls below 15%, a Geothermal PPA would be preferred over participation in the SGRP.

Alternative 1 is SDG&E's third preference. Under Alternative 1, SDG&E would continue to keep its 20% ownership percentage in SONGS, while SCE goes forward with the SGRP.

FIGURE 1
TOTAL COST OF SDG&E ALTERNATIVES (2004$, MILLIONS)
BASED ON CTCC REPLACEMENT GENERATION

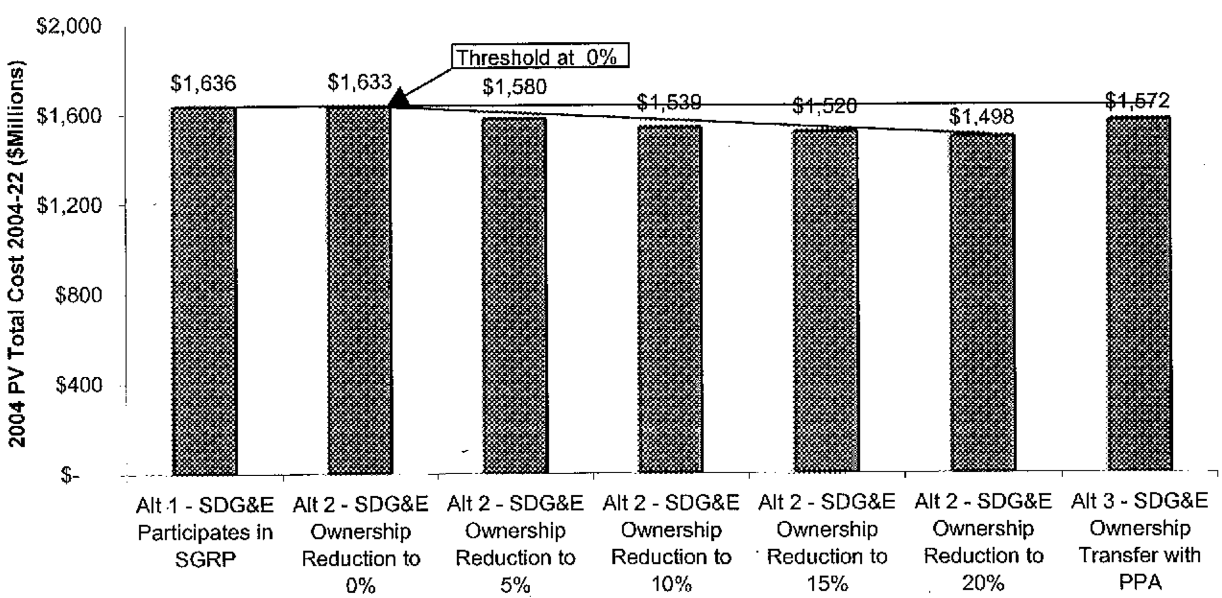
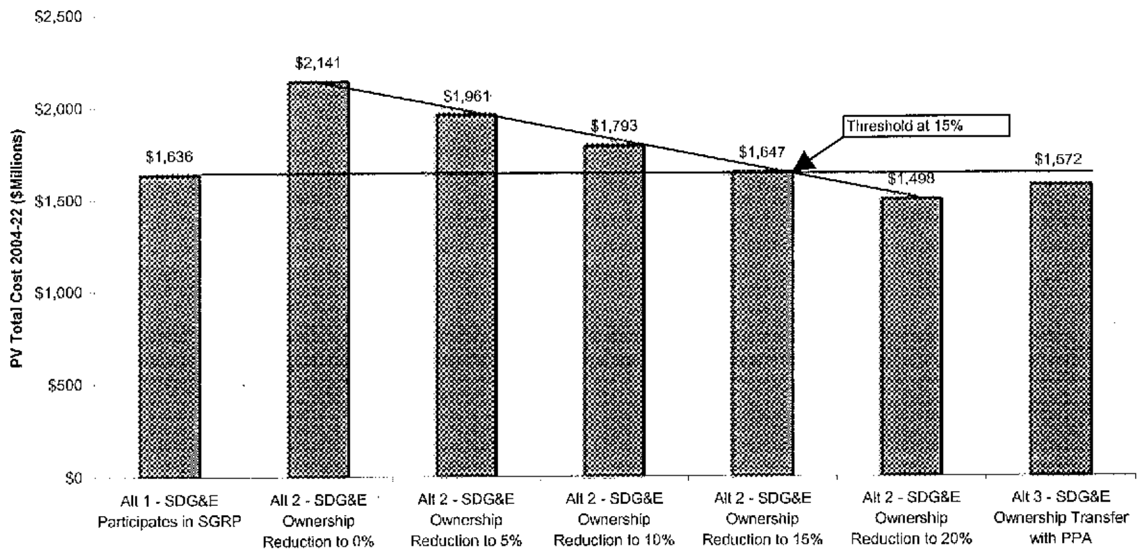


FIGURE 2
TOTAL COST OF SDG&E ALTERNATIVES (2004$, MILLIONS)
BASED ON GEOTHERMAL REPLACEMENT GENERATION



VIII. DIFFERENCES BETWEEN SCE'S AND SDG&E'S ANALYSES

This section compares SDG&E's Economic Analysis to SCE's Cost-Effectiveness Study (SCE-4) by highlighting the key differences between the two studies in terms of purpose, methodology, assumptions, and results.

The purpose of SDG&E's analysis is not to determine if the SGRP is cost-effective, but whether it is cost-effective for SDG&E to participate in the SGRP. SDG&E's study is based on an assumption that the SGRP will go forward. The purpose of SCE's study on the other hand is to establish that the SGRP is cost-effective overall, and cost-effective to SCE's and SDG&E's customer groups individually.

SDG&E evaluated the following three alternatives:

- Alternative 1: "SDG&E Participates in SGRP"
- Alternative 2: "SDG&E Ownership Reduction"
- Alternative 3: "SDG&E Ownership Transfer with PPA"

SDG&E estimated the total cost of providing power to its customers under each of these alternatives over the period 2004-2022. SDG&E in its final analysis did not evaluate the alternative whereby the SGRP does not go forward and as a result SONGS permanently shuts down in 2010.

SCE evaluated the following two alternatives:

- SGRP goes forward
- SGRP does not go forward

SCE calculated a benefit/cost ratio for the SGRP by estimating the cost and benefit associated with the project. In this context, the "cost" is the cost associated with the SGRP itself. The "benefit" is essentially the cost of not doing the SGRP; that is, the difference in cost between SONGS shutting down in 2010 and 2022. In other words, SCE's "benefit" amount is equal to a) costs that would be incurred if SONGS shuts down in 2010 minus b) costs that would be incurred if SONGS shuts down in 2022. It should be noted at this point that SCE appears to have erred by omitting from item b) above, the cost of the SGRP itself. This error overstates the "benefits" of SGRP, and thus overstates the benefit/cost ratio.

Whereas SDG&E evaluated the ownership reduction alternative, SCE initially did not do so because SCE had not at that time declared the steam generator problem to be an Operating Impairment under the terms of the Agreement. However, in its Augmented Testimony SCE expanded its analysis to include the full range of possible ownership share outcomes.

Whereas SDG&E evaluated its alternatives relative to its 20% ownership share of SONGS, SCE evaluated the SGRP at the 100% level, then "allocated" the benefit/cost ratio between SDG&E's and SCE's customers.

One significant difference is that SCE includes in its "benefits" the deferral of major transmission improvements, whereas SDG&E assumed that SCE and SDG&E will construct major transmission lines by 2010 whether SGRP goes forward or not. Specifically, SCE will build Palo Verde – Devers #2 by 2010 and the new 500kV interconnection in SDG&E's resource plan will be in place by 2010. With these assumptions, and since all of SDG&E's alternatives are based on SONGS remaining in service until 2022, no transmission mitigation was necessary in SDG&E's analysis.

SDG&E and SCE both assumed that SONGS generating capacity would be replaced by new gas-fired CTCC generating capacity. However, where SCE assumed the capital cost of the CTCC plants would be $625/kW, SDG&E assumed the cost would be $935/kW.

SDG&E included its share of currently forecasted Nuclear Decommissioning Trust fund contributions in its estimates of SONGS costs. SCE did not.

SDG&E's portion of SONGS routine (non-SGRP) capital costs used in the analysis was based on SCE's 2006 GRC application. This forecast is larger and more current than the forecast used in SCE's cost-effectiveness study.

The results of SCE's study appear in SCE-4 (Figure V-10 on page 57), which shows a Benefit/Cost ratio of 2.16. In other words, SCE indicates that the cost of not doing the SGRP would be 2.16 times greater than the cost of doing the SGRP. This result differs significantly from the results of SDG&E's analysis. SDG&E's Alternative 2 estimated the cost to SDG&E's customers of producing the same amount of energy as Alternative 1 over the 2004-2022 period. That energy would be provided in part by SONGS 2&3, and in part by a new CTCC power plant. SDG&E evaluated five levels of SONGS ownership ranging from its current 20% to 0%. The analysis showed that as SDG&E's ownership share is reduced, the cost-effectiveness of this alternative is reduced accordingly. However, even in the case where SDG&E's ownership share is reduced to zero, SDG&E's customers still benefit by not participating in the SGRP. In other words, SDG&E's study indicates that any level of reduction in SONGS output could be economically replaced by a new CTCC power plant. Under the Geothermal PPA, the cost-benefit calculation needs to include the continued benefits of fuel diversity and desire for higher levels of renewable energy for the future supply.

IX. QUALIFICATIONS OF MICHAEL M. SCHNEIDER

My name is Michael M. Schneider. I am employed by San Diego Gas & Electric Company as the Director of Business Planning and Budgets for SDG&E and Southern California Gas Company. My business address is 8330 Century Park Court, San Diego, California 92123-1530.

I received a Bachelor of Economics degree from the University of Arizona in 1987. I received a Masters of Business Administration from George Mason University with an emphasis in finance and accounting in 1990. I have been employed by SDG&E since 1992. I have held various positions during my tenure with SDG&E, including pricing analyst, regulatory case manager, Manager of Pricing, and Director of Business Analysis.

In my current capacity as Director for Business Planning and Budgets, I am responsible for the utilities' 5-year financial plan, monthly financial plan review, financial and economic analysis, budgeting, and cash flow forecasting. I have previously testified before both the Federal Energy Regulatory Commission and California Public Utilities Commission.

This concludes my prepared direct testimony.

ATTACHMENT 1

Attachment - 1

Total Cost of SDG&E Alternatives (2004$, Thousands)
Based on CTCC Replacement Generation

	Alternative 1	Alternative 2					Alternative 3
	SDG&E Participates	SDG&E Ownership Reduction to:					SDG&E Ownership
Description	in SGRP	0%	5%	10%	15%	20%	Transfer with PPA
Fuel Costs	$ 180,602	$ 708,147	$ 576,261	$ 444,375	$ 312,489	$ 180,602	$ 180,602
Operating & Maintenance	$ 1,002,422	$ 510,775	$ 633,687	$ 756,598	$ 879,510	$ 1,002,422	$ 1,002,422
NDT Contributions	$ 76,763	$ -	$ -	$ 12,439	$ 45,636	$ 76,763	$ 76,763
Capital - Routine (non-SGRP)	$ 238,035	$ 127,975	$ 155,490	$ 183,005	$ 210,520	$ 238,035	$ 238,035
Capital - SGRP	$ 137,796	$ -	$ -	$ -	$ -	$ -	$ 137,796
Capital - CTCC Power Plant	$ -	$ 286,014	$ 214,510	$ 143,007	$ 71,503	$ -	$ -
Capital - Transmission Mitigation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Value of Additional Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ (63,493)
Total 2004 NPV $	$ 1,635,618	$ 1,632,911	$ 1,579,948	$ 1,539,424	$1,519,658	$ 1,497,822	$ 1,572,125

Total Cost of SDG&E Alternatives (2004$, Thousands)
Based on Geothermal Replacement Generation

	Alternative 1	Alternative 2					Alternative 3
	SDG&E Participates	SDG&E Ownership Reduction to:					SDG&E Ownership
Description	in SGRP	0%	5%	10%	15%	20%	Transfer with PPA
Fuel Costs	$ 180,602	$ 77,246	$ 103,085	$ 128,924	$ 154,763	$ 180,602	$ 180,602
Operating & Maintenance	$ 1,002,422	$ 413,942	$ 561,062	$ 708,182	$ 855,302	$ 1,002,422	$ 1,002,422
NDT Contributions	$ 76,763	$ -	$ -	$ 12,439	$ 45,636	$ 76,763	$ 76,763
Capital - Routine (non-SGRP)	$ 238,035	$ 127,975	$ 155,490	$ 183,005	$ 210,520	$ 238,035	$ 238,035
Capital - SGRP	$ 137,796	$ -	$ -	$ -	$ -	$ -	$ 137,796
Geothermal PPA	$ -	$ 1,521,380	$ 1,141,035	$ 760,690	$ 380,345	$ -	$ -
Capital - Transmission Mitigation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Value of Additional Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ (63,493)
Total 2004 NPV $	$ 1,635,618	$ 2,140,544	$ 1,960,673	$ 1,793,240	$1,646,566	$ 1,497,822	$ 1,572,125

ATTACHMENT 2

Attachment - 2

Total Cost of SDG&E Alternatives (2004$/MWh)
Based on CTCC Replacement Generation

Description	Alternative 1 SDG&E Participates in SGRP	Alternative 2 SDG&E Ownership Reduction to: 0%	5%	10%	15%	20%	Alternative 3 SDG&E Ownership Transfer with PPA
Fuel Costs	$ 2.92	$ 11.45	$ 9.32	$ 7.18	$ 5.05	$ 2.92	$ 2.92
Operating & Maintenance	$ 16.20	$ 8.26	$ 10.24	$ 12.23	$ 14.22	$ 16.20	$ 16.20
NDT Contributions	$ 1.24	$ -	$ -	$ 0.20	$ 0.74	$ 1.24	$ 1.24
Capital - Routine (non-SGRP)	$ 3.85	$ 2.07	$ 2.51	$ 2.96	$ 3.40	$ 3.85	$ 3.85
Capital - SGRP	$ 2.23	$ -	$ -	$ -	$ -	$ -	$ 2.23
Capital - CTCC Power Plant	$ -	$ 4.62	$ 3.47	$ 2.31	$ 1.16	$ -	$ -
Capital - Transmission Mitigation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Value of Additional Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ (1.03)
Total NPV $/MWh	$ 26.44	$ 26.40	$ 25.54	$ 24.89	$ 24.57	$ 24.21	$ 25.41

Total Cost of SDG&E Alternatives (2004$/MWh)
Based on Geothermal Replacement Generation

Description	Alternative 1 SDG&E Participates in SGRP	Alternative 2 SDG&E Ownership Reduction to: 0%	5%	10%	15%	20%	Alternative 3 SDG&E Ownership Transfer with PPA
Fuel Costs	$ 2.92	$ 1.25	$ 1.67	$ 2.08	$ 2.50	$ 2.92	$ 2.92
Operating & Maintenance	$ 16.20	$ 6.69	$ 9.07	$ 11.45	$ 13.83	$ 16.20	$ 16.20
NDT Contributions	$ 1.24	$ -	$ -	$ 0.20	$ 0.74	$ 1.24	$ 1.24
Capital - Routine (non-SGRP)	$ 3.85	$ 2.07	$ 2.51	$ 2.96	$ 3.40	$ 3.85	$ 3.85
Capital - SGRP	$ 2.23	$ -	$ -	$ -	$ -	$ -	$ 2.23
Geothermal PPA	$ -	$ 24.59	$ 18.45	$ 12.30	$ 6.15	$ -	$ -
Capital - Transmission Mitigation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Value of Additional Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ (1.03)
Total NPV $/MWh	$ 26.44	$ 34.60	$ 31.70	$ 28.99	$ 26.62	$ 24.21	$ 25.41

Application of Southern California Edison Company (U 338-E) for Authorization: (1) to replace San Onofre Nuclear (SONGS 2 & 3) steam generators; (2) establish ratemaking for cost recovery; and (3) address other related steam generator replacement issues.)

Application No. 04-02-026
Exhibit No. __ (SDG&E-[redacted])
Witness: Marina Vengrin

PREPARED DIRECT TESTIMONY
OF MARINA VENGRIN
ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

DECEMBER 13, 2004

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PREPARED DIRECT TESTIMONY
OF MARINA VENGRIN
ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

I. INTRODUCTION

Southern California Edison ("SCE"), San Diego Gas & Electric Company ("SDG&E"), the City of Anaheim, California, and the City of Riverside, California (each an "Owner", collectively the "Owners") jointly own the San Onofre Nuclear Generating Station ("SONGS"). Under the Second Amended San Onofre Operating Agreement ("Operating Agreement"), SCE is the operator of SONGS. SCE intends to fund substantial capital improvements called the Steam Generator Replacement Project ("SGRP"). By comparison, SDG&E does not intend to participate in the funding of this capital improvement, as is its right under the Operating Agreement. As a result, pursuant to the Operating Agreement, SCE will become entitled to a greater percentage interest in SONGS and its output, and SDG&E's interest in SONGS and its output will decrease.

The purpose of my testimony is to discuss the costs that would be incurred by and the distortions that may be imposed on SDG&E and SCE as co-owners of SONGS Units 2 & 3, from a Federal income tax perspective, as a result of the funding by SCE of the improvements to SONGS. It also addresses how these costs and distortions can be largely eliminated by either 1) having SONGS be taxed as a partnership for Federal income tax purposes or 2) having the Internal Revenue Service agree in a ruling that the ownership changes qualify for non-recognition treatment. If unchecked, these costs and distortions would cause the economic arrangement between the Owners as prescribed in the Operating Agreement to be altered.

II. PARTNERSHIP ISSUES

A. <u>Election out of Treatment as a Tax Partnership</u>

The Owners own fractional undivided interests in SONGS as tenants in common. Section 25.1 of the Operating Agreement evidences the Owners' intent that the joint ownership of SONGS not be construed as, among other things, a partnership. Under Section 25.2 of the

Operating Agreement, the Owners have made an election under section 761 of the Internal Revenue Code of 1986, as amended (the "Code"), such that the arrangement between the Owners for the joint ownership and operation of SONGS will not be subject to the partnership provisions of Subchapter K of the Code (the "761 Election"). Accordingly, SONGS has not been subject to the Federal income tax rules for partnerships, and each of the Owners is treated for Federal income tax purposes as directly owning an undivided interest in each of the assets that comprise SONGS. The Owners have shared in the output produced and in the expenses associated with the operation of SONGS in accordance with their ownership interests as provided for in the Operating Agreement.

B. Costs and Distortions that may Result under the Status Quo from the Investment in SONGS by SCE

As a result of the 761 Election, the funding of the improvements for SONGS by SCE will result in a deemed taxable exchange (the "Deemed Exchange") between the Owners. That is, the unilateral decision by SCE to fund the improvements will cause SDG&E to be treated, for Federal income tax purposes, as if it exchanged a portion of the assets of SONGS that SDG&E is treated as owning directly for a portion of the improvements of equivalent value. Because SDG&E would have a tax basis in the transferred assets that is significantly less than their fair market value, SDG&E may realize a substantial gain for Federal income tax purposes.[1] Estimates put this realized gain between $120 and $150 million.[2] Although a portion of this gain may be entitled to nonrecognition treatment as a "like kind exchange" pursuant to Code section 1031, as discussed in Part II C below, it is possible that SDG&E will be forced to recognize a significant amount of this realized gain.

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[1] Although SCE would likewise be treated as engaging in a taxable exchange, the gain realized by SCE would likely be minimal because it should have a tax basis in the improvements approximately equal to fair market value.

[2] As a result of this taxable event, SDG&E will receive a fair market value tax basis in the assets which it will depreciate over the tax lives of the assets. That is, SDG&E will receive increased depreciation deductions going forward.

Moreover, the Deemed Exchange would distort the economic arrangement of the Owners on a going forward basis by realigning the benefits and burdens associated with SONGS in a manner inconsistent with the intention of the Operating Agreement. Specifically, as a result of the Deemed Exchange, (i) SDG&E would own in fee a share of the improvements funded by SCE and would thus have to be allocated all of the tax items associated with these improvements, and (ii) SCE would own in fee a share of the historic assets of SONGS previously owned by SDG&E and would thus have to be allocated all of the tax items associated with these historic assets. This would not comport with the expectations of the Owners, which are that SCE would be allocated the tax items associated with all of the improvements that it funded, while SDG&E would continue to be allocated the tax items associated with the assets that it currently owns. It is probable that this would cause SCE economic harm as the historic assets would likely have longer recovery periods for depreciation purposes than the improvements.

C. Potential Application of Code Section 1031 to Mitigate Costs

As mentioned above, the Deemed Exchange of a portion of the SONGS assets by SDG&E for a share of the improvements funded by SCE may be eligible for nonrecognition as a "like kind exchange" under Code section 1031. An exchange generally qualifies as a like kind exchange to the extent that the property transferred in the exchange (the relinquished property) is of like kind to the property received in the exchange (the replacement property). Section 1.1031(a)-2T(b) of the Income Tax Regulations (the "Regulations") provides a safe harbor pursuant to which the relinquished and the replacement property will be considered like kind if they are properly classified within a single code that is provided under Sectors 31-33 of the North American Industry Classification System (NAICS). Property that is not considered like kind under the safe harbor must satisfy the much more stringent test for like kind provided under common law, with the result that the property may not be afforded the protection of Code section 1031.

Based upon our estimates, which rely heavily on several simplifying assumptions, it is possible that a significant portion of the SONGS assets that SDG&E is treated as transferring to SCE may not be within the same NAICS code as the improvements that SDG&E is treated as receiving from SCE. As a result, a significant portion of the property exchanged may not be like kind pursuant to the safe harbor or otherwise, and SDG&E may be required to recognize a substantial portion of the gain realized. Although estimates are difficult to make at this time due to the inability to gauge how much the simplifying assumptions made for purposes of these estimates will differ from the actual situation that will exist at the time of the exchange, an attempt has nevertheless been made in this regard. Although realized gain is estimated to be in the range of $120 to $150 million, the amount recognized after the application of section 1031 is estimated at $60 and $80 million. As a result, tax liability of approximately $32 million could be incurred by SDG&E at the estimated combined state and federal corporate tax rate of 40%.

While Code section 1031 will defer some of the gain recognition, the application of Code section 1031 may not alleviate the distortions in the economic arrangement between the Owners described in Part II B above. It may be possible to request a ruling from the Internal Revenue Service in order to try to confirm the extent to which 1031 will apply to the actions contemplated by the parties but certain risks will remain such as law changes or factual changes during the pendency of the contemplated work.

D. Elimination of Costs and Distortions through the Revocation of the 761 Election

The potential adverse tax consequences resulting from the Deemed Exchange could be mitigated if SONGS were owned, for Federal income tax purposes, by a partnership among the Owners. If the 761 Election were revoked, the Owners would be treated, solely for Federal income tax purposes, as if they transferred their undivided interests in the assets of SONGS to a newly formed tax partnership in exchange for interests in the tax partnership in a tax-free exchange, and would become subject to the partnership rules of Subchapter K of the Code.

Assuming that this revocation were made prior to the funding of significant improvements by SCE, the Deemed Exchange described above could be eliminated and the economic arrangement of the Owners could be preserved on a going forward basis. Specifically, any improvements made by SCE would be treated as capital contributions to the tax partnership, upon which SCE would receive or would be entitled to receive from the tax partnership an additional interest in SONGS. The additional interest issued to SCE would be determined under the current Operating Agreement or as otherwise agreed to by the Owners. At the time the additional interest is issued to SCE, the other Owners' interests in SONGS would automatically be reduced. As a result, the Deemed Exchange would not occur because the tax partnership would be treated as owning SONGS both before and after the improvements for Federal income tax purposes, with the capital contributions made by SCE being treated as a "transaction" between SCE, as a partner, and the tax partnership.

In addition, tax provisions could be drafted to allocate the tax items arising from SONGS in a manner that would not distort the current economic arrangement among the Owners. Specifically, all of the tax items generated by the improvements could be allocated to SCE, and all of the tax items generated by the other assets of SONGS could be shared in accordance with the Owners' current interests in SONGS. In this way, the Owners can be assured that they will receive the benefits and burdens associated with their ownership in SONGS in accordance with their expectations. The Operating Agreement could continue to control (without change) all matters among the owners, including the managerial, operational, and economic relationships between the Owners.

E. <u>Revocation of 761 Election has no Effect for Non-Tax Purposes</u>

The revocation of the 761 Election would have no effect for any purpose other than Federal income tax purposes. Thus, this deemed transaction would not result in a change in the legal structure of SONGS, and none of the legal or economic relationships would be affected. For all purposes other than Federal income tax purposes, the Owners would continue to be treated as owning SONGS as tenants in common, and no transfer taxes would be applicable. In addition, financial statements and property taxes would continue to be prepared and determined in the same manner.

III. DECOMMISSIONING TAX ISSUES

A. <u>Tax Consequences under the Status Quo (761 Election not Revoked)</u>

Under the formula required to be used under Section 22 of the Operating Agreement to determine each Owner's respective share of the decommissioning liability (the "DCS Formula"), SDG&E will remain liable for the portion of the decommissioning liability related to its original ownership interest in SONGS for the period during which such original ownership interest was in effect. This is because the DCS Formula calculates each Owner's share of the decommissioning liability based on a weighted average (*i.e.*, the average of the Owner's interests in the plant multiplied by the time for which each interest was in effect). Thus, for the purposes of satisfying its liability as determined by the DCS Formula, SDG&E must maintain the decommissioning funds collected as of the date of the exchange. Accordingly, there should be no transfer of Qualified Fund assets from SDG&E to SCE as a result of the reduction in SDG&E's interest in SONGS occurring as a result of SCE's funding of the SGRP (the "Share Reduction").

As explained below, based on the policy behind Code section 468A and the Regulations thereunder, there should be no Federal income tax consequences to the Qualified Fund as a result of the Share Reduction. Although this conclusion is more certain with respect to a diminution of SDG&E's interest in SONGS as opposed to a complete termination of SDG&E's interest in SONGS, the result in either case should be the same – no portion of SDG&E's Qualified Fund will be disqualified under Code section 468A as a result of the Share Reduction. However, because the Internal Revenue Service (the "Service") has never directly addressed the consequences of a disposition of an interest in a nuclear power plant that is not accompanied by a transfer of Qualified Fund assets, this result must be confirmed by requesting a private letter ruling from the Service.

1. <u>The Impact of Share Reduction on Qualified Decommissioning Funds under Code Section 468A</u>

Regulations section 1.468A-6 describes the Federal income tax consequences of a transfer of the assets of a Qualified Fund in connection with the sale, exchange, or other disposition by a taxpayer of all or a portion of its qualifying interest in a nuclear power plant. However, neither the Regulations under Code section 468A, nor any other authority, address the tax consequences (if any) to the Qualified Fund of the sale, exchange, or other disposition of a portion of the taxpayer's qualifying interest in a nuclear power plant that is not accompanied by a transfer of Qualified Fund assets.

Only an "eligible taxpayer" is entitled to establish a Qualified Fund.[3] For this purpose, an eligible taxpayer is defined as "any taxpayer that possesses a qualifying interest in a nuclear power plant ..."[4] A "qualifying interest" is defined to include, among other things, a direct ownership interest, and a "direct interest" includes an interest in a nuclear power plant as a tenant in common.[5]

Regulations section 1.468A-5(c) provides that a taxpayer's Qualified Fund will be disqualified if, at any time during the Qualified Fund's taxable year, either (i) the Qualified Fund does not satisfy the requirements of Regulations section 1.468A-5(a); or (ii) the Qualified Fund and a disqualified person engage in an act of self dealing within the meaning of Regulations section 1.468A-5(b)(2).[6] If a Qualified Fund is disqualified, the assets in the Qualified Fund are deemed to be distributed to the electing taxpayer, with the fair market value (with certain adjustments) of these assets being included in the taxpayer's gross income for the taxable year.[7]

After the Share Reduction, SDG&E will continue to be an "eligible taxpayer" within the meaning of Regulations section 1.468A-1(b)(1), and will continue to directly own a "qualifying interest" in a nuclear power plant within the meaning of Regulations section 1.468A-1(b)(2). Moreover, no disqualifying event will have occurred as SDG&E's Qualified Fund will continue to satisfy the requirements of Regulations section 1.468A-5(a), and no act of self dealing within the meaning of Regulations section 1.468A-5(b)(2) will have occurred.

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[3] Code section 468A, Regulations section 1.468A-1(a)(1).
[4] Regulations section 1.468A-1(b)(1).
[5] Regulations section 1.468A-1(b)(2).
[6] Regulations section 1.468A-6(c)(1).
[7] Regulations sections 1.468A-5(c)(1)(i) and 1.468A-5(c)(3).

In short, there is nothing in Code section 468A or the Regulations thereunder that will either (a) cause the Qualified Fund to be disqualified as a result of the Share Reduction; or (b) result in any other Federal income tax consequences as a result of the Share Reduction.

However, while the Regulations under Code section 468A, by their terms, do not address the transfer of an interest in a nuclear power plant without the concomitant transfer of Qualified Fund assets, the Regulations under Code section 468A can be read to "expect" that a transfer of an ownership interest in a plant will be accompanied by a transfer of Qualified Fund assets. SDG&E will request a private letter ruling from the Service to confirm that there will be no Federal income tax consequences to SDG&E's Qualified Fund as a result of the Share Reduction and the Deemed Exchange.

2. The Impact of a Complete Termination of SDG&E's Interest in SONGS on the Qualified Funds under Code Section 468A

SCE has asserted that SDG&E's ownership interest in SONGS should be reduced to zero as a result of SCE's funding of the SGRP. As stated, SDG&E disputes this result. Even if SDG&E's interest in SONGS is reduced to zero, under the DCS Formula, SDG&E will still be liable for a portion of the decommissioning liability. Accordingly, SDG&E will be required to maintain an external decommissioning trust fund and should maintain its Qualified Fund even if it is deemed to no longer have an interest in SONGS.

If SDG&E's interest in SONGS is reduced to zero, SDG&E will no longer own a "qualifying interest" in a nuclear power plant within the meaning of Regulations section 1.468A-1(b)(2), and will therefore no longer be an "eligible taxpayer" within the meaning of Regulations section 1.468A-1(b)(1). There is nothing in Code section 468A or the Regulations thereunder, however, that would result in the disqualification of SDG&E's Qualified Fund if SDG&E's interest in SONGS is reduced to zero.[8] While it is true that only an eligible taxpayer may make a

[8] If a Qualified Fund is disqualified, the assets in the Qualified Fund are deemed to be distributed to the electing taxpayer, with the fair market value (with certain adjustments) of these assets being included in the taxpayer's gross income for the taxable year. Regulations sections 1.468A-5(c)(1)(i) and -5(c)(3).

deductible contribution to a Qualified Fund (Regulations section 1.468A-1(a)(1)), there is nothing in the Regulations the prohibits the maintenance of a Qualified Fund by a taxpayer that is no longer an eligible taxpayer.

As stated above, however, the Regulations under Code section 468A "expect" that the transfer of an ownership interest in a plant will be accompanied by a transfer of Qualified Fund assets – specifically, along with the disposition of the taxpayer's entire interest in a plant, the taxpayer will have also transferred its entire Qualified Fund. Thus, in the event that SDG&E's interest in SONGS is deemed to completely terminate as a result of SCE's Funding of the SGRP, SDG&E will request a private letter ruling from the Service to confirm that SDG&E may still hold a Qualified Fund.

3. **Schedule of Ruling Amounts after the Deemed Exchange**

As a result of the Share Reduction, the Owners will want to seek a new schedule of ruling amounts from the Service.[9] Further, if the CPUC (as expected) reduces the amount of decommissioning costs to be included in SDG&E's cost of service for the taxable year that includes the Share Reduction or for any subsequent taxable year, SDG&E is required by the Regulations under Code section 468A to seek a revised schedule of ruling amounts.[10] Deductions for contributions made during the taxable year to a taxpayer's Qualified Fund are limited by, among other things, the ruling amount for the taxable year that is provided in the schedule of ruling amounts.[11]

A schedule of ruling amounts is a private letter ruling from the Service specifying the annual payments (*i.e.*, the "ruling amounts") that over the taxable years remaining in a plant's funding period, will result in a projected balance, on the last day of the funding period, equal to the "amount of decommissioning costs allocable to the fund."[12] The "amount of decommissioning costs allocable to the fund" is determined with respect to, among other things,

[9] See Regulations section 1.468A-3(h)(i)(2), providing for elective review of a schedule of ruling amounts.
[10] Regulations section. 1.468A-3(h)(i)(1)(iii)(A)(3).
[11] Regulations section 1.468A-2(b).
[12] Regulations section 1.468A-3(a)(1).

the "taxpayer's share of the total estimated cost of decommissioning the nuclear power plant to which the fund relates."[13] The taxpayer's share of the total estimated cost of decommissioning the nuclear power plant equals the "total estimated cost of decommissioning the plant multiplied by the percentage of such nuclear power plant that the qualifying interest of the taxpayer represents."[14]

As required by the DCS formula, after the Share Reduction, in order to properly fund each decommissioning fund, the Owners should collect decommissioning costs in accordance with their post-exchange interests in SONGS. This is consistent with Regulations section 1.468A-3's definition of "ruling amount" which, at any given time, must be calculated in accordance with the taxpayer's current interest in a nuclear power plant.

B. <u>Tax Consequences if the 761 Election is Revoked</u>

If the 761 Election is revoked, as described above, SDG&E and SCE would be deemed to form a partnership for Federal income tax purposes, and the newly-formed tax partnership would be deemed to be the owner of SONGS for these purposes. As discussed in further detail below, the consequences of this transaction would be as follows:

1. For purposes of Code section 468A and the Regulations thereunder (and indeed for all Federal income tax purposes), the tax partnership would be considered to be the direct owner of SONGS.
2. Because the tax partnership would be deemed to be the owner of SONGS for Federal income tax purposes, the election under Code section 468A would have to be made by the tax partnership and not by the Owners.
3. This would necessitate the transfer of the assets of the Owners' Qualified Funds to a single Qualified Fund that would be established and held by the tax partnership. However, this could likely be accomplished in a manner that would allow each Owner to maintain separately the assets transferred from its Qualified Fund to satisfy its share of the decommissioning liability, and that

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[13] Regulations section 1.468A-3(d)(1).
[14] Regulations section 1.468A-3(d)(3).

would not require the Owners to share the risks associated with decommissioning.

As is the case with regard to the decommissioning tax consequences discussed in Part III A above that would result from the Share Reduction, the impact of a revocation of a 761 Election on the Qualified Funds is an issue of first impression. Thus, in order to confirm the tax consequences in this situation, a private letter ruling would be requested from the Service allowing SDG&E and SCE to maintain separately the assets transferred from their Qualified Funds to satisfy their respective liability for decommissioning.

1. **The Tax Partnership Would be the "Eligible Taxpayer"**

The revocation of the 761 Election would necessitate the transfer, for Federal income tax purposes, of each Owner's Qualified Fund assets to the new tax partnership. This is because a taxpayer is permitted to make deductible contributions to a Qualified Fund only if the taxpayer possesses a "qualifying interest" in a nuclear power plant.[15] For this purpose, a qualifying interest includes a direct ownership interest in a plant, but does not include the ownership of stock in a corporation or an interest in a partnership that, in turn, owns a nuclear power plant. Accordingly, in the case of a tax partnership that owns a nuclear power plant, the election under Code section 468A must be made by the tax partnership and not by its partners. This necessitates that the tax partnership hold the Qualified Funds directly.[16]

2. **Requirement of a Single Qualified Fund**

Generally, under Code section 468A, each electing taxpayer is required to maintain a separate Qualified Fund (and only one such Fund) for each nuclear power plant in which the taxpayer has a qualifying interest.[17] Further, Regulations section 1.468A-5(a)(1)(iii)

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[15] Regulations section 1.468A-1.

[16] Regulations section 1.468A-1 specifically states that, in the case of an unincorporated organization that has elected out of Subchapter K, each co-owner of the nuclear power plant is eligible to make a separate election under Code section 468A.

[17] Code section 468A(e)(1); Regulations section 1.468A-5(a)(1)(ii).

requires an electing taxpayer to maintain only one Qualified Fund for each nuclear power plant. However, the Regulations provide that this requirement may be waived in certain circumstances. Specifically, in the case where a nuclear power plant is subject to the ratemaking jurisdiction of more than one public utility commission, and any such commission requires a separate Qualified Fund to be maintained for the benefit of ratepayers whose rates are established by that public utility commission, the Regulations permit the taxpayer to maintain separate funds comprising a single Qualified Fund (whether or not maintained under a single trust agreement).

This exception appears to reflect a policy decision to permit segregated funds where a regulatory body that has jurisdiction over the Qualified Fund requires the monies collected and set aside for decommissioning to not be commingled with other monies. The Regulations provide that the Service will issue a single schedule of ruling amounts for the Qualified Fund, and that the Qualified Fund must file a single income tax return, even where the taxpayer maintains separate Qualified Funds treated as a single Qualified Fund pursuant to the exception.[18]

In this case, for Federal income tax purposes, each of the Owners will be deemed to have transferred, for Federal income tax purposes, its Qualified Fund assets to a single Qualified Fund established by the tax partnership. However, the separate funds of each of the Owners will be segregated into separate funds for all purposes other than for purposes of Code section 468A. Permitting the maintenance of two trust accounts with respect to the Qualified Funds held by the tax partnership under these circumstances appears to be consistent with the policies under Code section 468A.

3. <u>Tax Consequences of Transfer of Qualified Funds</u>

As stated, the revocation of the 761 Election will result in the formation of a tax partnership and will necessitate the transfer of each Owner's Qualified Fund assets to a single Qualified Fund established by the tax partnership. The Federal income tax consequences of the

[18] Regulations section 1.468A-5(a)(1)(iii). Additionally, if such Qualified Fund is disqualified by the Service, the assets of each of the separate funds are treated as distributed on the date of disqualification. *Id. See also* Private Letter Ruling 200238046 (September 20, 2002).

transfer of the assets of a Qualified Fund in connection with a sale, exchange or other disposition of a qualifying interest in a nuclear power plant to another taxpayer (transferee) are described in Regulations section 1.468A-6. In this instance, it appears that the Service would treat the Qualified Funds as being transferred to the new tax partnership since it is the new electing taxpayer. Regulations section 1.468A-6(c)(2) provides that if the requirements of Regulations section 1.468A-6(b) are satisfied, neither the transferee, the transferor, nor the Qualified Fund will recognize gain or loss or otherwise take any income or deduction into account by reason of the transfer of the assets of the transferor's Qualified Fund to the transferee's Qualified Fund.

Moreover, under Regulations section 468A-6(g), the Service may treat any disposition of an interest in a nuclear power plant occurring after December 27, 1994, as satisfying the requirements of Regulations section 1.468A-6 if the "Service determines that this treatment is necessary or appropriate to carry out the purposes of [Code] section 468A and the [R]egulations thereunder." The purpose of Code section 468A is to facilitate the accumulation of funds to decommission nuclear power plants at the end of their useful lives. The legislative history of Code section 468A provides: "[T]he Congress believed that the establishment of segregated reserve funds for paying future nuclear decommissioning costs was of sufficient national importance that a tax deduction, subject to limitations, should be provided for amounts contributed to qualified funds." Staff of Joint Comm. on Taxation, 98th Cong., 2d Sess., *General Explanation of the Revenue Provisions of the Deficit Reduction Act of 1984* 270 (Comm. Print 1984). *See also* S. Rep. No. 98-169, at 277 (1984). Further, the Statement of the Managers provides: "The conferees recognize the importance of ensuring that utilities comply with nuclear power plant decommissioning requirements." H.R. Conf. Rep. No. 98-861, at 878 (1984), *reprinted in* 1984 U.S.C.C.A.N. 1445.

The requirements set forth in Regulations section 1.468A-6(b) mandate that each of the following is true: (1) the transferor maintained a Qualified Fund immediately prior to the transfer, (2) immediately after the transfer the transferee maintains a Qualified Fund, (3) the interest acquired is a qualifying interest of the transferee, (4) either a proportionate amount or the entire Qualified Fund is transferred to the transferee, and (5) the transferee continues to meet the requirements of Regulations section 1.468A-5(a)(iii) to maintain only one Qualified Fund for each nuclear power plant.

Under these facts, both the transfer of SDG&E's Qualified Fund and the transfer of SCE's Qualified Fund to the tax partnership should satisfy the requirements of Regulations section 1.468A-6(b). First, with respect to the acquired interest, both SDG&E and SCE have maintained a Qualified Fund. Second, immediately after the deemed transfer to the tax partnership, the tax partnership will maintain a Qualified Fund with respect to its interest in SONGS. Third, the tax partnership will have a qualifying interest in SONGS. Fourth, SDG&E and SCE will be deemed to transfer the entire Qualified Fund to the tax partnership in accordance with Regulations section 1.468A-5. Finally, although SDG&E and SCE will continue to maintain their Qualified Fund assets pursuant to the existing agreement and will not commingle the assets or agree to share the portion of the decommissioning liability that they will assume, the Service should treat the arrangement as one Qualified Fund for purposes of the mechanics of Code section 468A.[19]

Accordingly, pursuant to Regulations section 1.468A-6(c)(2), neither the tax partnership nor its Qualified Fund should recognize gain or loss upon the receipt of a proportionate amount of the assets of the Qualified Funds of SDG&E or SCE. Similarly, neither SDG&E, SCE, nor their Qualified Funds should recognize any gain or loss upon the transfer of a proportionate amount of the assets of their Qualified Funds to the Qualified Fund of the tax partnership.

Regulations section 1.468A-6(c)(3) provides that the transfer of assets of a Qualified Fund to which Regulations section 1.468A-6 applies does not affect the basis of these assets. Thus, under Regulations section 1.468A-6(c)(3), the tax partnership's Qualified Fund will have a basis in the assets received that is the same as the basis of those assets in the Qualified Funds of SDG&E and SCE immediately before the transfer.

[19] In cases where the Service believes that the transfer of a Qualified Fund does not meet the requirements of Regulations section 1.468A-6(b), the Service has exercised its discretion to allow the Qualified Fund to be transferred tax-free.

4. <u>Nonqualified Funds</u>

No transfer need occur with respect to SDG&E's or SCE's nonqualified nuclear decommissioning trust funds ("Nonqualified Funds"), because there is no requirement that the tax partnership hold the Nonqualified Funds directly.[20]

IV. QUALIFICATIONS

My name is Marina Vengrin. My business address is 101 Ash Street, San Diego, California, 92101. I am employed by San Diego Gas & Electric Company (SDG&E) as Director – Corporate Taxes. I oversee the company's income tax research, compliance and IRS audits. I attended Loyola University (Chicago) School of Law, graduating with a Juris Doctorate Degree in 1995. Prior to that, I attained a Bachelor of Science Degree in Accounting from DePaul University (Chicago), graduating in 1988. I am a Certified Public Accountant (CPA) on inactive status and a member of State Bar in Illinois. Prior to joining SDG&E in 1999, I was a Federal Tax Manager with USG Corporation (Chicago), a manufacturer of building products. Prior to that, I functioned as the Tax Advisor for Ernst & Young, a CPA firm.

I have not previously testified before this Commission.

This concludes my prepared direct testimony.

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[20] Nonqualified Funds are nuclear decommissioning funds that do not qualify under Code section 468A. Neither the Code nor the applicable regulatory rules would require the Nonqualified Funds to be held directly by the owner of a nuclear generating facility. Even if the Nonqualified Funds were treated as transferred to the tax partnership, however, no adverse tax consequences should result from this transfer.

CERTIFICATE OF SERVICE

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a true copy of the foregoing **PREPARED DIRECT TESTIMONY OF SAN DIEGO GAS & ELECTRIC COMPANY** on each party named in the official service list for proceeding R.04-02-026 by mailing a properly addressed copy by first-class mail with postage prepaid.

Executed on December 13, 2004 at San Diego, California.

Cathy Johnston

Cathy Johnston

CALIFORNIA PUBLIC UTILITIES COMMISSION
Service Lists

Proceeding: A0402026 - EDISON - TO REPLACE
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