Docket	:	A.06-08-010
Exhibit Number	:	
Commissioner	:	Dian Grueneich
Admin. Law Judge	:	Steven Weissman
DRA Witness	:	Woodruff

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

A.06-08-010

REPORT ON THE SUNRISE POWERLINK

San Diego Gas & Electric Company (SDG&E)

Phase 1 Direct Testimony
Volume 1 of 5

San Francisco, California
May 18, 2007

EXECUTIVE SUMMARY

This Phase 1 Direct Testimony presents the findings and conclusions Woodruff Expert Services (WES) regarding the San Diego Gas & Electric Company's (SDG&E's) proposed Sunrise Powerlink transmission project ("Sunrise" or "Project") has made on behalf of the Division of Ratepayer Advocates (DRA)

SUMMARY OF FINDINGS TO DATE

Sunrise may provide significant benefits to California Independent System Operator (CAISO) ratepayers and SDG&E ratepayers in particular. However, Sunrise is clearly not *needed* to meet any of its stated objectives, including the critical goal of providing reliable service in San Diego. DRA is not convinced that Sunrise is the best alternative for meeting such goals – or even that Sunrise's benefits will exceed its costs.

SAN DIEGO'S LOCAL RELIABILITY NEEDS WILL BE MET THROUGH 2014 WITHOUT SUNRISE

SDG&E has stated that Sunrise offers multiple benefits to CAISO ratepayers. However, DRA believes the most critical need SDG&E faces is meeting the "G-1/N-1" grid reliability criterion in San Diego.[1] Unfortunately, the passage of time has made SDG&E's analysis of Sunrise's value in meeting local reliability needs obsolete.

[1] The CAISO's "G-1/N-1" criterion is discussed in more detail in DRA's Direct Testimony. The terms "local grid reliability needs," and similar terms, are also used herein to refer to the amount of combined generation and transmission resources available to serve peak loads in SDG&E's service territory that is computed using the "G-1/N-1" criterion. The term "San Diego" is used herein to refer to SDG&E's service territory generally, which includes all of San Diego County and a portion of Orange County.

SDG&E claims it faces a 247 MW local reliability "deficiency" in 2010 without Sunrise.[2] However, SDG&E has already taken initiatives to meet this deficit in other proceedings. In Decision (D.) 07-04-043**,** the Commission approved SDG&E's application to install Advanced Metering Infrastructure (AMI), which SDG&E has estimated will reduce San Diego's local reliability need starting in 2009. In addition, SDG&E applied on May 11, 2007 for Commission approval of contracts for 131 MW of new Combustion Turbines (CTs) in San Diego with on-line dates in 2008 (A.07-05-XXX). SDG&E is seeking Commission approval of these contracts in September 2007, that is, before the Commission is scheduled to decide whether to grant a CPCN for Sunrise. SDG&E filed, also on May 11, Advice Letter 1896-E seeking to expand its contract capacity with EnerNOC – an aggregator of demand response and distributed generation resources – to 50 MW effective in 2008.[3] Together, these initiatives should meet San Diego's local reliability needs through 2014, as shown in Table ES-1. Additional initiatives SDG&E is pursuing may meet local needs in additional years as well.

TABLE ES-1
Updated San Diego Local Reliability Capacity Need
Without Sunrise Powerlink
(MW)

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
SDG&E-Asserted Surplus / (Deficiency)	526	(247)	(306)	(346)	(381)	(422)	(472)
SDG&E Initiatives to Meet Need:							
- Advanced Metering Infrastructure	107	161	219	228	238	243	249
- J Power (Pala)	87	87	87	87	87	87	87
- Wellhead Power Maragarita	44	44	44	44	44	44	44
- EnerNOC	50	50	50	50	50	50	50
- Subtotal	288	342	399	409	418	424	429
Surplus / (Deficiency)	**814**	**95**	**93**	**62**	**37**	**1**	**(42)**

2 The term "local reliability deficiency," and similar terms, refers the amount that the combined generation and transmission resources available to serve San Diego loads fall short of the amount computed as necessary to provide reliable service by the "G-1/N-1" criterion. The term "local reliability surplus," and similar terms, means the amount by which such resources exceed the need computed using the "G-1/N-1" standard.

3 The EnerNOC contract currently has a contract capacity of 25 MW. However, SDG&E has not counted this capacity in its computation of local needs per the "G-1/N-1" criterion, so the entire 50 MW of the expanded contract is being considered new capacity in DRA's analysis.

In addition, if necessary, the CAISO has the ability to continue contracting with the existing South Bay Power Plant (SBPP) after 2009 if necessary to meet San Diego's grid reliability needs. Continued operation of the 702 MW SBPP would meet SDG&E's LCR through 2018 even without AMI, the new CTs, or the EnerNOC contract expansion – or without Sunrise.

SUNRISE BENEFITS HIGHLY UNCERTAIN

Two of the three major benefits SDG&E ascribes to Sunrise can be reasonably believed to be sources of significant benefits. These benefits are:

- Reducing San Diego Area Local Reliability Costs: Though Sunrise is not needed to meet San Diego's local needs, it will likely reduce San Diego ratepayers' costs of acquiring the local generating capacity needed to comply with the "G-1/N-1" standard. DRA believes such benefits might be substantial, with a levelized expected value in 2010 dollars of $66 million (MM)/yr and a plausible range of levelized values from $33 MM/yr to $98 MM/yr. The major uncertainties reflected in these estimates are the unknowns surrounding the actual level of San Diego's local need, and the costs of San Diego local capacity and how they compare to the costs of capacity in the rest of the state. Another key uncertainty is whether other aspects of the CAISO's grid reliability criteria might lead to some offsetting increases in other local capacity procurement requirements for San Diego ratepayers.

- Reducing Renewable Resource Procurement Costs: Sunrise is not needed to enable SDG&E and other Load-Serving Entities (LSEs) within the CAISO to meet their Renewable Portfolio Standard (RPS) obligations. However, Sunrise will facilitate – and likely reduce the costs of – LSEs' RPS compliance by reducing the barriers to delivery of Imperial Valley (IV) renewable resources to the CAISO and possibly accelerating incremental investment in IV renewables. DRA believes such benefits might be substantial, with a levelized expected value of $37 MM/yr and a plausible range from levelized values of $0 MM/yr to $137 MM/yr. Major uncertainties regarding these results are the costs of IV renewables, the viability of SDG&E's current contracts for IV renewables, and questions regarding the actions of municipal utilities with interests in IV renewable development.

DRA believes that SDG&E's projected reduction in energy costs will be relatively small, as discussed below:

- Reducing Energy Costs: Sunrise should not be assumed to yield significant reductions in energy costs. Sunrise would expand the connection between the CAISO-controlled electric grid – which delivered power to meet a peak demand of over 50,000 MW last summer – to the Imperial Irrigation District (IID) electric system, which has met a peak demand of less than 1,000 MW. However, Sunrise would not greatly increase CAISO grid access to other resources or markets in the Desert Southwest (DSW) that have historically justified transmission expansions in the region. Instead, the key benefit of enhancing the CAISO's connection to IID is gaining more economical access to IV renewable resources, as described above. DRA believes it critical that these RPS compliance and energy cost benefits be treated separately as much as possible to ensure that each benefit is counted once, but only once. Based on its analysis of various Gridview simulations submitted in this case, WES estimates that energy cost reductions will have a levelized expected value of $25 MM/yr and a plausible range from levelized values of $12 MM/yr to $50 MM/yr. Key uncertainties surrounding these figures are future gas prices and the relative amount of future plant development in the DSW, including coal.

Based on these analyses, and SDG&E's estimate of Sunrise's costs to ratepayers, DRA presents its estimates of Sunrise's total benefits, a reasonable range of such benefits, and resulting Benefit-Cost Ratios (BCRs) to CAISO ratepayers in Table ES-2 below.

TABLE ES-2
Estimated Range of Sunrise Benefits
As Estimated by WES and SDG&E
(levelized $2010 MM)

	DRA Estimates			
	Low	Base	High	SDG&E Reference Case
Benefits				
- Reliability	32.7	66.4	97.8	196.8
- Renewables 1/	0.0	37.0	137.0	N/A
- Energy	12.4	24.9	49.7	163.2
Subtotal	45.2	128.2	284.5	360.0
Costs		156.1		
Net Benefits	(110.9)	(27.9)	128.4	203.9
Benefit-Cost Ratio	0.29	0.82	1.82	2.31

Notes: 1/ Renewable Supply Curve model resulted in negative $25MM levelized benefit in Low scenario; prudent procurement of renewables assumed to limit Low scenario renewables value to zero.

The results in Table ES-2 must be considered with critical caveats in mind. First, as will be developed at length in this Direct Testimony, SDG&E's analysis of Sunrise's benefits is not adequate and should not be relied upon by this Commission.

Second, in measuring Sunrise's benefits, the most appropriate frame of comparison is not the "Gas Turbine (GT) Reference Case" that SDG&E employed to measure the benefits of all alternatives. Rather, Sunrise's BCR should be computed by comparing Sunrise's benefits and costs to those of the best alternative plan that could be developed in the absence of Sunrise. As SDG&E has not performed an analysis sufficiently complete to identify the truly best alternative to Sunrise, the GT Reference Case is likely suboptimal, and Sunrise's relative benefits are thus likely overstated.[4]

Finally, this range of quantified values in Table ES-2 suggests a broad range of uncertainty surrounding Sunrise's value to ratepayers. In Table ES-3 below, DRA presents a list of key outcomes of uncertain variables that will result in Sunrise realizing relatively higher values. Commission approval of a Sunrise CPCN based on SDG&E's current application will imply that the Commission anticipates several of these favorable outcomes occurring.

COMMISSION ACTION IS NEEDED TO ENSURE SAN DIEGO LOCAL NEEDS ARE MET AT LOWEST COST

The Commission should, in this case, ensure that SDG&E takes steps such that San Diego's local reliability needs are met in a least cost manner. DRA perceives that meeting the "G-1/N-1" criterion in San Diego in the coming decade poses significant planning challenges. Though Sunrise would seemingly meet a large amount San Diego's local reliability need, DRA is not convinced it is the option that will meet such needs at the lowest net cost compared to other alternatives. DRA believes there are other options that merit further review that might meet local reliability needs and other goals at lower total cost. These options include:

- Local Capacity Offered in Current Requests for Offers: As noted above, SDG&E has already contracted for 131 MW of new Combustion Turbine capacity pursuant to its "2008 Peaker" Request for Offers (RFO) and exercised its option to expand its EnerNOC contract capacity to 50 MW. SDG&E may also take additional actions in the near-term that would further increase its local reliability surplus in 2010 and later

[4] SDG&E in fact identified an In-Area Combined Cycle Generation scenario as having a higher BCR than the GT Reference Case. But WES does not believe that this scenario can be considered the "optimal" non-Sunrise plan either.

years. SDG&E also received bids on May 17, 2007 in its "2010-2012" RFO, which is seeking new resources with on-line dates from 2010 to 2012, including local Demand Response (DR) and supply resources. SDG&E will also receive bids in its next Renewables RFO on Wednesday, May 30, 2007. Any local resource selected in these RFOs would increase the San Diego local reliability surplus even further. SDG&E will seek Commission approval of any contracts arising from the 2010-2012 RFO in January 2008 – the same month the Commission is scheduled to consider whether to grant a CPCN for Sunrise. SDG&E also has the option of issuing additional RFOs to meet local reliability in the future. Additional DR and local power plants submitted to such RFOs may be able to meet even more of San Diego's local reliability need at a lower net cost than Sunrise.

- Transmission Enhancements: SDG&E reviewed several transmission projects before deciding to propose Sunrise to the Commission and is reviewing several other transmission alternatives at the request of intervenors in this case. DRA believes some of these options may also help meet SDG&E's local reliability need at a lower net cost than Sunrise. DRA offers some analyses of these options in its Direct Testimony.

- Non-Wires and Short-Wires Alternatives: SDG&E has also projected that various "non-wires" and "short-wires" alternatives in San Diego will meet some of its local reliability need. As noted above, the non-wires AMI program will help meet additional local need. Additional penetration of such options may also meet San Diego's local reliability need at lower net cost than Sunrise.

- Continued Operation of Existing San Diego Local Resources: Another key factor in developing the best plan for meeting San Diego's local needs is the best use of existing local generation, particularly the 1,822 MW of divested SDG&E generation that it still operating. This capacity may reasonably be expected to be available in the early years of the next decade – including the 702 MW SBPP – but will likely become increasingly uneconomic and unreliable as the next decade passes.

SUMMARY OF RECOMMENDATIONS

DRA thus recommends the Commission implement a San Diego Grid Reliability Action Plan (SDGRAP) to evaluate and implement the best options for meeting local reliability needs. The Commission can pursue this plan in parallel with its analysis of Sunrise.

IMPLEMENT THE SDGRAP TO ENSURE A TIMELY DECISION

DRA believes the Commission should begin pursuing the SDGRAP analysis immediately in this docket. Though SDG&E has analyzed many possible alternatives already in this case, much of that analysis was deeply flawed.

The SDGRAP should remedy these flaws by first taking a full inventory of all recent initiatives that will meet San Diego's local needs, including the measures listed above. The SDGRAP analysis should then identify all alternatives for meeting San Diego's remaining local need over the next several years and compare these options to one another based on more current and complete information. DRA believes that, in particular, the results of SDG&E's current RFOs will cast considerable light on the best options for meeting San Diego's local needs. The result of the SDGRAP would be a "seven-year plan" that would identify best measures for meeting San Diego's local needs and the best dates for implementing such measures.

However, DRA does recommend the Commission take steps to ensure that Sunrise's most critical purported objective – meeting local grid reliability needs in San Diego – is met in as timely and cost-effective a manner as possible. As discussed below, the Commission has a unique opportunity to take such steps in this docket without unnecessarily delaying a specific decision on Sunrise.

DRA's analysis and recommendations are discussed in more detail below and more fully within the Phase 1 Direct Testimony.

ATTACH CONDITIONS IF A CPCN IS GRANTED

There are some key contingencies that will affect Sunrise's actual value that the Commission can control if it wishes to approve the Project. Three in particular stand out:

- Cost Cap: The role of the cost cap the Commission typically imposes when granting CPCNs for new transmission projects will be particularly important in the case of Sunrise. If the trends in construction costs of recent years continue, the costs of both Sunrise and its major alternatives will exceed the estimates used in the analyses in this case. It is critical the Commission adopt a cost cap under which Sunrise can be expected to be a cost-effective investment for customers as compared to other alternatives and plans. DRA will address the details of the project cost cap issues in Phase 2 when the routing alternatives are more fully developed.

- Rate of Return: SDG&E may seek some incentive returns from the Federal Energy Regulatory Commission (FERC) when it seeks to add Sunrise to its rate base. The Commission should adopt as a condition of any approval that SDG&E will not seek from FERC a rate of return any higher that this Commission's authorized rate of return used for this Commission's ratemaking.

- Confirm IID Transmission Build-Out and Reasonable Cost Recovery: One key uncertainty regarding Sunrise's value is whether the Imperial Irrigation District (IID) will make transmission upgrades on its own system that are necessary to facilitate the projected IV renewable build-out. Without such upgrades, much of Sunrise's value may not be realized. But IID's commitment to supporting the Sunrise project is in considerable doubt. In addition, it is critical SDG&E have some advance assurances as to how IID will recover the costs of its internal upgrades from third parties such as

SDG&E and renewable project developers. The construction of Sunrise without such agreements would give IID the ability to extract much of Sunrise's value for the benefit of its own ratepayers through interconnection and transmission fees.

DRA expects that other important contingencies that should be considered will be introduced during the course of the proceeding.

TABLE ES-3
Key Outcomes that Will Increase Sunrise Powerlink's Realized Value

OUTCOME	WHY OUTCOME INCREASES SUNRISE'S VALUE
RELIABILITY	
o San Diego "G-1/N-1" local needs higher than expected	Higher-then-expected load growth or lower-than-expected resource availability will increase Sunrise's value
o San Diego area capacity costs higher than costs in rest of state	Higher relative capacity costs in San Diego will increase Sunrise's value
o No new, offsetting local San Diego capacity need identified	Emergence of new San Diego local needs due to Sunrise requiring procurement of local capacity would reduce Sunrise's value
RENEWABLE PORTFOLIO STANDARD COMPLIANCE	
o Stirling Energy Systems contract succeeds	Failure of Stirling contract might leave Sunrise largely unused for first several years, reducing its value
o Imperial Valley renewable resource costs compete favorable with other regions'	Sunrise will be more valuable if Imperial Valley renewables are more competitive than other regions'
o IID completes build-out of internal transmission system	Sunrise will be less valuable if IID does not build out its system to enable delivery of more renewables
o IID seeks reasonable recovery of transmission system build-out costs	Value of Sunrise would be transferred to IID ratepayers if IID seeks unreasonable interconnection and wheeling rates
o Green Path North not completed	If LADWP's Green Path North is completed, less renewable power may flow over Sunrise, and only at a higher cost
ENERGY COSTS	
o Gas prices fall	Development of gas-fired generation in San Diego would provide hedge against market prices driven up by higher gas prices, reducing Sunrise's comparative value
o Major new generation built in Desert Southwest, particularly coal	Construction of new projects in Desert Southwest – particularly coal – would provide more inexpensive off-peak power, increase Sunrise's value
PROJECT COSTS	
o SDG&E obtains FERC incentive ratemaking for Sunrise	Transmission ratemaking incentives, if granted by FERC, would transfer portion of Sunrise value to Sempra shareholders

TABLE OF CONTENTS

1. INTRODUCTION

1.1 SDG&E's Request

SDG&E is asking the Commission to grant it a Certificate of Public Convenience and Necessity (CPCN) to build the Sunrise Powerlink ("Sunrise" or "Project").

Sunrise would provide substantial new transmission capacity between the Imperial Valley (IV) service territory of the Imperial Irrigation District (IID) just east of San Diego County and SDG&E's load centers in San Diego and Orange Counties. Sunrise's eastern terminus would be the existing Imperial Valley (IV) Substation near El Centro, California, which would be modified to accommodate termination of one new 500 kilovolt (kV) transmission line. SDG&E interconnects with IID at the IV substation, as well as the 500 kV transmission line between the IV Substation and the North Gila Substation in Arizona. The new 500 kV line would be built from the IV Substation to a new SDG&E-owned Central substation located in east-central San Diego County. SDG&E would also construct a new double-circuit 230 kV line connecting the Central substation to its existing Sycamore Canyon substation to the west and a new single-circuit 230 kV line between the Sycamore Canyon substation and its Peñasquitos substation near the coast.

Sunrise's final route is the subject of Phase 2 of this proceeding, which will be engaged in early August after the Draft Environmental Impact Report / Environmental Impact Statement (EIR/EIS) being prepared jointly by the Commission and the Bureau of Land Management (BLM) is published.

SDG&E has also signed a Memorandum of Agreement (MOA) with IID and Citizens Energy Corporation (Citizens) regarding development, ownership and operational control of related facilities in IID's service territory. In the MOA, the portions of Sunrise located in IID's service territory are labeled the "Green Path Project – Southwest" (GPP-S).

These facilities would include a new 230 kV substation near IID's existing San Felipe substation. This "new San Felipe Substation" would interconnect IID's 230 kV transmission system with the new 500 kV line between the IV and Central Substations. The MOA also provides that the portion of Sunrise within IID's service territory – which will be those portions between the existing IV and Narrows Substations[1] – would be owned by IID. However, IID would transfer the bulk of its GPP-S transfer entitlement to Citizens, which in turn would provide it to the California Independent System Operator (CAISO) by becoming a CAISO Participating Transmission Owner (PTO). Though not explicitly specified in the MOA, IID has also said it will make additional upgrades to its network to support deliveries of additional power to the GPP-S.

SDG&E states, however, that it believes Sunrise is needed with or without the MOA, and will therefore pursue the development of Sunrise whether or not the other parties to the MOA go forward with their commitments.

Under SDG&E's proposed schedule, construction on some portions of Sunrise would begin in April 2008 and the project would enter commercial operation in June 2010. SDG&E estimates Sunrise would cost approximately $1.265 billion, including Allowance for Funds Used During Construction (AFUDC) and would require Operations and Maintenance expenses of approximately $10 million per year in 2010 dollars. If Sunrise is built, such capital and operating costs would be added to the CAISO's Transmission Access Charge (TAC) and paid by customers of all CAISO PTOs. The Federal Energy Regulatory Commission (FERC) would exercise jurisdiction over these rates, including the possible granting of additional incentive returns above and beyond those this Commission typically grants.

1 The Narrows Substation is an existing demarcation point between the SDG&E and IID electric systems.

1.2 Scope of DRA's Review

Woodruff Expert Services (WES) was retained by the CPUC's Division of Ratepayer Advocates (DRA) to perform an analysis of the technical, economic and other policy issues related to Sunrise. In particular, DRA analyzed:

- The "need" for and possible benefits of Sunrise.
- Other alternatives that could achieve some or all of Sunrise's potential benefits, particularly meeting local grid reliability needs within San Diego.
- The relative value of Sunrise and such alternatives at providing various benefits.
- Other policy issues the Commission may wish to consider in this case.

After such review, DRA prepared its findings and recommendations. A summary of these conclusions was presented in the Executive Summary; this Direct Testimony will describe them in more detail. DRA will continue its analysis of Sunrise, including furthering the analyses discussed below, reviewing responses to Data Requests, and considering other parties' Direct and Rebuttal Testimony. DRA may offer additional evidence regarding Sunrise to the Commission in its Rebuttal Testimony and by other means.

1.3 Organization of Report and Sponsoring Witnesses

Mr. Kevin Woodruff, Principal of Woodruff Expert Services, is sponsoring this Volume 1 of DRA's Phase 1 Direct Testimony, including the Executive Summary. Mr. Woodruff's resume is included as Appendix A to this testimony.

Other consultants address specific topics in more detail in their reports, which are being provided as separate Volumes. Mr. Woodruff refers to and relies on these supporting analyses as appropriate. These consultants and the topics they address are:

- Mr. Henry Zaininger, of Zaininger Engineering, Inc., describes Sunrise and its potential transmission alternatives in Volume 2.

- Mr. Daniel Suurkask, of Wild Rose Energy Solutions Inc., addresses several matters related SDG&E's benefit modeling, including the market modeling it performed using Gridview model, SDG&E's analyses of San Diego local reliability costs, the CAISO's renewables supply curve, and related analyses in Volume 3.

- Mr. W. Kent Palmerton, of WK Palmerton Associates, LLC, addresses additional issues related to the economic analysis of transmission projects in Volume 4.

- Dr. Lon W. House, of Water and Energy Consulting, addresses the renewable resource potential of the Imperial Valley – and the viability of the Stirling Energy Systems concentrated solar technology in particular – in Volume 5.

2. SOLUTIONS TO SAN DIEGO'S LOCAL RELIABILITY CHALLENGE

2.1 Maintaining Reliable Service in San Diego is The *Critical Challenge*

SDG&E has stated that Sunrise offers three significant benefits to CAISO ratepayers. However, one of these benefits – maintaining reliable service in SDG&E's electric distribution service territory – is a much more critical issue in this case than the other two. The other two goals – facilitating access to renewable energy and reducing energy costs – can be met on behalf of CAISO ratepayers by a variety of alternatives, many of which do not involve investment in generation or transmission assets that directly serve San Diego.[2]

SDG&E is the only entity with the obligation, motivation and financial wherewithal to take measures needed to maintain reliable service in San Diego. And SDG&E has been taking several such steps in recent years, ostensibly including proposing the Sunrise project. But such efforts to meet its local reliability needs are seemingly proceeding on multiple, uncoordinated fronts. DRA believes that the Commission must, in this docket, carefully assess which among these various proposals best meets San Diego's local reliability needs at lowest net cost and also take steps to implement routine, consistent reviews of other future means of meeting San Diego's local reliability needs.

2.2 "G-1/N-1" Criterion and Computation of Local Reliability Needs

The key measure used to establish San Diego's local reliability needs is commonly known as the "G-1/N-1" criterion. Briefly, this criterion is used to estimate the combined amount of generation in San Diego and transmission serving San Diego that is necessary to meet a forecast "1-in-10" high peak load, that is, the peak load expected to occur only once every ten years. The sum of generation and transmission must equal this peak load *after the capacity of the largest generating unit in San Diego (the "G-1" contingency)*

[2] The term "San Diego" is used herein to refer to SDG&E's electric distribution service territory, which includes all of San Diego County and a portion of Orange County.

and the impact of the loss of the largest individual transmission line serving San Diego (the "N-1" contingency) are subtracted. This criterion has been established by the CAISO's grid planning standards and accepted by the Commission in several prior decisions regarding San Diego-area resource procurement.

A simple summary of SDG&E's computations of San Diego's local reliability needs is shown in Table 2-1 below for 2009.[3]

TABLE 2-1
SDG&E Computation of San Diego Local Reliability Need for 2009
(MW)

	2009	Row ID:	Formula:	Source:
NEED:				
90/10 Peak Load after CSI and Demand Response	4,960	A		1
AVAILABLE CAPACITY:				
Total San Diego Area Generation Capacity	3,547	B		1
Largest ("G-1") Generation Contingency "G-1" (Otay Mesa)	(561)	C		1
Total San Diego Area Generation under "G-1" Conditions	2,986	D	B + C	1
Total Transmission Capacity into San Diego under Normal ("N-0") Conditions	2,850	E		2
Impact of Largest ("N-1") Transmission Contingency (IV-Miguel)	(350)	F		2
Total Transmission Capacity into San Diego under "N-1" Conditions	2,500	G	E + F	2
Total Capacity to Serve San Diego Load Under "N-1/G-1" Conditions	5,486	H	D + G	1
SURPLUS / DEFICIENCY:				
San Diego Area Reliability Surplus / (Deficiency)	526	I	H - A	1

SOURCES:

1. SDG&E, Chapter VII, Supplemental Testimony, January 26, 2007, Table H-1
2. SDG&E, Chapter II, Reliability, August 4, 2006, Pages II-4 to II-5.

[3] In this report, the term "local reliability need," and similar terms, will refer to the amount of generation and transmission capacity established by the "G-1/N-1" methodology as necessary to provide reliable service in San Diego. The term "local reliability deficiency," and similar terms, will be used to describe the amount by which available generation and transmission capacity under "G-1/N-1" conditions falls below the local reliability need. The term "local reliability surplus," and related terms, will describe the amount of which such capacity exceeds the local need.

2.3 Alternatives for Meeting San Diego Local Reliability Need

There are a few basic options for meeting San Diego's local reliability criterion: San Diego-area generation, transmission into San Diego under "N-1" conditions, and load management and smaller San Diego-area generating resources. These basic alternatives are described below.

2.3.1 Generation

Much of San Diego's local reliability need is met – and will continue to be met – by generation that exists in San Diego. Approximately 2,900 MW of generation currently exists in San Diego. The capacities and types of existing generation are summarized in Table 2-2 below. A key assumption in SDG&E's filing is that the current South Bay Power Plant (SBPP) – which has five units with 702 MW of capacity – will retire at the end of 2009, but that all other existing generators will continue to be available through 2020. The major generation owners in San Diego include Dynegy, owner of the SBPP; NRG, owner of the Encina (Cabrillo I) and Cabrillo II power plants; and SDG&E itself. Both the SBPP and Encina plants are under contract to SDG&E through the end of 2009. Many of the smaller units in San Diego are Qualifying Facilities (QFs) or renewable resources are also under long-term contract to SDG&E. In addition, many existing units also have Reliability-Must Run (RMR) contracts, under which the CAISO can direct them to operate to meet grid reliability needs.

In addition, new generation will also help meet San Diego's future local reliability needs. SDG&E has entered several contracts that envision the construction of such new generators. First, Calpine recently executed a contract to complete the 561 MW Otay Mesa power plant in 2009. In addition, SDG&E just filed for Commission approval of contracts for development of three new Combustion Turbines (CTs) with on-line dates in 2008. DRA thinks it highly likely the Commission will approve these contracts later this year. Further, SDG&E also submitted Advice Letter 1896-E on May 11 seeking Commission authority to exercise its option to expand to 50 MW the maximum capacity of its contract with EnerNOC for aggregated electric load curtailments and/or electrical output of small generators. According to AL 1896-E:

> "EnerNOC will attempt to bring resources on as soon as possible and as early as the summer of 2007 and the additional Contract Capacity shall have associated with it an outside commercial operate date of May 31, 2008." (p. 2)

SDG&E has asked this Advice Letter be approved June 10. All these highly likely new units are also shown in Table 2-2.

Other plausible San Diego-area power plants have been publicly discussed. However, none of these projects have been contracted for by SDG&E or another entity and cannot at this point be considered likely additions. However, these proposals have appropriately been considered as alternatives to Sunrise. Among these proposals is a replacement for the existing SBPP. These possible projects are also shown in Table 2-2.

Finally, SDG&E received bids yesterday (May 17, 2007) in response to a "2010-2012" Request for Offers (RFO), which may include some offers to provide Demand Response and local generation resources that would help meet San Diego's grid reliability need. SDG&E will also receive bids in response to its 2007 Renewables RFO on May 30; some of these bids may also offer generation that could help meet local grid reliability needs. As these specific proposals are yet known to DRA, none of these RFO responses were included in Table 2-2.

TABLE 2-2
Existing, Likely and Proposed San Diego-Area Generation Resources

Plant Owner or Type	Plant Names	Capacity (MW)	# of Units	On-Line Date	Comments
EXISTING					
SDG&E	Palomar	541	1		
	Miramar Energy Center	46	1		
NRG	Encina (Cabrillo I)	960	6		
	Cabrillo II	160	11		
Dynegy	South Bay	702	5		SDG&E projects retirement at end of 2009
CalPeak	Border, El Cajon and Escondido	126	3		
MMC	Otay and Escondido	84	2		
Diamond Energy	Border 1 and 2	92	2		
Qualifying Facilities	Various	163	6		
Renewables	Various	34	18		includes Kumeyaay Wind and Rancho Pen.
Subtotal		2,908	55		
LIKELY					
SDCWA	Lake Hodges Pumped Storage	40	2	2008	
J Power	Orange Grove (Pala)	86	1	2008	SDG&E filed application May 11; Commission approval sought in September 2007.
Wellhead	Margarita	47	1	2008	
EnerNOC	Small Generators & Load Cuts	50	numerous	2008	SDG&E filed May 11 seeking approval sought by June 10.
Calpine	Otay Mesa Combined Cycle	561	1	2009	Contract executed May 2007
Renewable	Bull Mose Biomass	20	1	2009	
Subtotal:		804	6		
PROPOSED					
Utility-Owned	Sycamore Canyon	542	1	2010	Case 204
NRG	Encina Combined Cycle	1,083	2	2016	Case 204; envisions retiring existing Encina capacity
Enpex	Enpex Combined Cycle	750	1	2010	Case 209
Dynegy	South Bay Combined Cycle	650	1	2010	Case 210; envisions retiring existing South Bay capacity
Subtotal:		2,483	4		

DRA will comment further on some of the above projects later in this testimony.

2.3.2 Transmission

Much of San Diego's local reliability need is also met by transmission capacity into San Diego, in particular, transmission capacity that is available under "N-1" conditions (that is, when the single largest element is out of service).

There are now three transmission corridors into San Diego:

- Path 44 (aka "South of SONGS"), the five 230 kilovolt (kV) transmission lines that connect the San Onofre Nuclear Generating Station (SONGS) and San Diego,

- SDG&E's Imperial Valley – Miguel (IV-Miguel) 500 kV transmission line, which connects the IV Substation and San Diego, and

- Path 45, which connects San Diego to the electrical grid of Comision Federal de Electricidad (CFE) in Mexico.

Under normal ("N-0") conditions, SDG&E has a Simultaneous Import Limit (SIL) of 2,850 MW through these three corridors. However, under "N-1" conditions – that is, with the IV-Miguel line, its largest transmission element, out of service – SDG&E's import limit falls to 2,500 MW, which is the emergency rating of Path 44. (SDG&E does not consider Path 45 to be a reliable import path in such conditions.)

The individual and combined path and transmission line capacities under "N-0" (no outage) and "N-1" (single largest outage) conditions are summarized in Table 2-3.

Expansion of "N-1" transmission capacity into San Diego is also a feasible means of meeting future local reliability needs. SDG&E states that Sunrise can offer an additional 1,000 MW of such "N-1" capability for just this purpose. SDG&E also states Sunrise would increase San Diego's "N-0" import rating to 1,350 MW. These data are also shown in Table 2-3.

However, SDG&E and other parties have analyzed several other alternatives for increasing SDG&E's "N-0" and "N-1" import capabilities. SDG&E analyzed several such options before deciding to propose Sunrise. The Nevada Hydro Company (TNHC) has also been promoting its Lake Elsinore Advanced Pumped Storage (LEAPS) as a source of new transmission, because it would involve interconnecting the SDG&E and Southern California Edison (SCE) transmission systems. Other parties to this case, notably the Utility Consumers Action Network (UCAN), have proposed several other transmission alternatives. These alternatives, and SDG&E's estimates of their apparent impacts on San Diego's "N-0" and "N-1" import capabilities, are also presented in Table 2-3.

TABLE 2-3
Existing and Proposed Transmission Serving San Diego Area

		Capacity				
Line Owner or Proposer	**Name**	**"N-0" (Normal Conditions)**	**"N-1" (Single Largest Outage)**	**On-Line Date**	**Source 1/**	**Comments**
EXISTING:						
SDG&E	Path 44 ("South of SONGS")		2,500			SDG&E Non-Simultaneous Import Limit equals Path 44 emergency rating.
SDG&E	Imperial Valley - Miguel		0		SDG&E, Chapter II, Reliability, August 4, 2006, Pages II-3 and II-4.	"N-1" capacity equals zero because IV-Miguel is "N-1" contingency.
SDG&E	Path 45	___	0			Path 45 rating apparently not considered in establishing import limits.
	Combined	2,850	2,500			Sum of individual line ratings less than Simultaneous Import Limit (SIL).
PROPOSED:						
SDG&E	Sunrise	1,350	1,000	2010	Tables 6 and H-2 (Case 201)	
	SWPL 2	650	562	2010	Tables 6 and H-8 (Case 212)	SWPL 2 may reduce "G-1" contingency to zero.
The Nevada Hydro Company	LEAPS (inc. transmission)	1,250	795	2008	Tables 6 and H-4 (Case 203)	Estimates of TE-VS import capacity have varied.
Utility Consumers Action Network	"Mexico-Lite"	0	165	2010	Tables 6 and H-13 (Case 211)	
	"SONGS-Lite"	0	0		Table 6	UCAN may have different estimates of these options' impacts.
	"SONGS-Heavy"	0	0		Table 6	

1/ All Table references are to SDG&E, Section VII, Supplemental Testimony, January 26. 2007, unless otherwise noted.

Mr. Henry Zaininger will describe and discuss the proposed transmission projects listed above in Volume 2 of DRA's Phase 1 Direct Testimony.

2.3.3 Non-Wires and Short-Wires Alternatives

The remainder of SDG&E's local reliability need is met by various "non-wires" and "short-wires" alternatives.

SDG&E's analysis included estimates of the impact of energy efficiency and Demand Response (DR) programs, Distributed Generation (DG), and the California Solar Initiative on San Diego local reliability needs.

Recent action on one particular "non-wires" program needs mention. Last month, the Commission issued Decision (D.) 07-04-043 approving SDG&E's Advanced Metering Infrastructure (AMI) program, which is anticipated to further reduce demand in San Diego. SDG&E has projected that AMI will reduce demand by 161 MW in 2010 and grow to 279 MW in 2020. DRA will comment on AMI further below.[4]

[4] Portions of the capacity from the EnerNOC contract might also be reasonably classified as "non-wires" DR or "short-wires" DG resources.

3 DRA SUMMARY AND ANALYSIS OF SDG&E CASE FOR SUNRISE

3.1 SDG&E's Analysis

SDG&E argues that the Sunrise project will provide significant, quantifiable benefits for to CAISO ratepayers. SDG&E classifies these benefits into three separate categories:

- Reliability: SDG&E states that Sunrise will reduce its customers' costs of meeting the San Diego local reliability criterion by reducing the amount and cost of local capacity that would need to be built or maintained.

- Renewables: SDG&E states that Sunrise will also enable it and other CAISO Load-Serving Entities (LSEs) to purchase renewable energy more effectively by providing more transmission capacity into the renewable resource regions of the Imperial Valley (IV).

- Energy: SDG&E states that Sunrise will enable it and other LSEs to purchase electric energy to meet their customers' loads at lower net cost by reducing transmission congestion.

SDG&E estimated each of these benefits for the years of 2010 to 2020, as described further below, extrapolated year 2020 benefits through 2049, converted this stream of benefits to levelized annual figures, and then summed these levelized figures to determine total levelized benefits. SDG&E then compared these levelized benefits to Sunrise's estimated levelized costs; net levelized benefits were determined by subtracting levelized costs from levelized benefits and a Benefit-Cost Ratio (BCR) was computed by dividing levelized benefits by levelized costs.

To estimate Sunrise's benefits, SDG&E first compared reliability, energy and renewable costs in the "Sunrise Powerlink" scenario (Case 201) to an "In-Area Gas Turbine

Reference Case" (Case 201) that assumed that, absent the Sunrise project, SDG&E would build Combustion Turbines (CTs) to meet San Diego's local reliability needs. The computations of net benefits and BCR thus compare SDG&E's estimated benefits and costs of the Sunrise project to the benefits and costs of an alternative build-out consisting entirely of CTs to meet San Diego local reliability needs.

SDG&E also compared other alternatives to the Gas Turbine Reference Case, such as assuming some combined cycles (CC) plants are built in San Diego – such as a combined cycle project to replace the existing SBPP – or some alternative transmission projects are built instead. SDG&E used similar methods to compute each of these alternative's levelized net benefits and BCR compared to the Gas Turbine Reference Case. SDG&E's analysis routinely showed that Sunrise offered the highest benefits among all options studied.

SDG&E's estimates of levelized benefits and costs and BCRs for Sunrise and select alternatives are presented below in Table 3-1. Table 3-1 also displays Sunrise and its alternatives' net benefits and BCRs compared to the best purported alternative to Sunrise, the "In-Area Combined Cycle" scenario (Case 204).

TABLE 3-1
SDG&E Estimates of Levelized Benefits and Costs
and Benefit-Cost Ratios of Sunrise and Selected Alternatives [5]
(levelized over 2010-2049)

		In-Basin Combined Cycles			Transmission	
	Sunrise Powerlink	In-Area Combined Cycles	Enpex Combined Cycle	South Bay Repower	TE/VS - LEAPS	SWPL 2
	(Case 200)	(Case 204)	(Case 209)	(Case 210)	(Case 203)	(Case 212)
Benefits						
Reliability:						
- RMR Savings	100.8	45.2	(7.5)	(3.2)	110.0	11.1
- Avoided Gas Turbine Costs	96.0	96.0	96.0	96.0	96.0	96.0
Subtotal	196.8	141.2	88.5	92.8	206.0	107.1
Energy:	163.2	231.5	113.3	57.6	(55.7)	45.8
Renewables:	n/a	n/a	n/a	n/a	n/a	n/a
Total:	360.0	372.7	201.8	150.4	150.3	152.9
Fixed Costs						
- Sunrise Powerlink	156.1					
- Combined Cycle		219.3	98.1	85.0		
- Gas Turbine			17.2	17.2	2.6	17.2
- Associated Transmission		27.8	20.8	18.9	0.6	7.0
- TE/VE Transmission					76.3	
- LEAPS					126.8	
- LEAPS Transmission					246.4	
- SWPL 2						108.0
Total:	156.1	247.1	136.1	121.1	452.7	132.2
Comparison to Gas Turbine Reference Case (Case 200):						
Benefit/Cost Ratio	2.31	1.51	1.48	1.24	0.33	1.16
Net Benefit	203.9	125.6	65.7	29.3	(302.4)	20.7
Comparison to Best Alternative to Sunrise (Case 204)						
Benefit/Cost Ratio	1.53	1.00	0.98	0.82	0.22	0.77
Net Benefit	78.3	0.0	(59.9)	(96.3)	(428.0)	(104.9)
Source: Tables from May 7 Errata	H-17	H-19	H-25	H-27	H-21	H-29

[5] DRA has reorganized SDG&E's presentation of its benefits to reclassify "RMR Savings" from an "energy" benefit to a "reliability" benefit.

3.1.1 Quantification of Sunrise's Local Reliability Benefits

SDG&E's estimates of Sunrise's reliability benefits consist of three separate elements. The first element is a reduction in RMR contract capacity payments made to existing units the CAISO will need to keep operating to meet the local reliability criterion. SDG&E estimated, for each year from 2010 to 2020, which specific existing plants (except for the SBPP) the CAISO would require to operate pursuant to RMR contracts for this purpose. SDG&E then summed each such plant's estimated capacity payment, which were based on each unit's historical capacity payments. SDG&E also assumed that each plant's payment would vary with the level of "competitiveness" of the local market, such that RMR "Condition 1" contracts that provide recovery of only 30 percent of fixed costs would be awarded in the presence of Sunrise but that RMR "Condition 2" contracts that provide 100 percent recovery of fixed costs would be awarded if no new transmission assets serving San Diego are built. The estimates of Sunrise's reliability benefits thus included both a reduction in the total number RMR contracts and in the cost of each such contract. [6]

The second element of SDG&E's estimated reliability benefits is a reduction in the capacity payments made to any new CTs that SDG&E assumed would be built in San Diego to meet the local reliability criterion when existing capacity was insufficient. SDG&E estimated the amount of new CTs that would need to be built between 2010 and 2020 in San Diego and then determined what the revenue requirements of such CTs, including transmission, would be.

The third element of reliability savings is a reduction in the operational costs the CAISO would incur in operating RMR units that were not captured in SDG&E's energy

[6] The Commission and CAISO both with to phase out RMR contracts in favor of Local Resource Adequacy (LRA) contracts and transfer responsibility for entering such contracts from the CAISO to Load-Serving Entities (LSEs). These shifts in contract form and contracting responsibility may have some impacts of their own on local reliability costs. However, for purposes of this analysis, DRA will assume that for San Diego LRA contracts, the chief options for LSEs to contract will still have largely the same cost structure as existing plants that receive RMR contracts or new CTs.

modeling. SDG&E estimated these latter costs using a spreadsheet model that attempted to mimic how the CAISO would operate such units in response to San Diego area reliability needs and the additional costs that would be incurred as a result

SDG&E estimated these local reliability costs for each case. SDG&E computed "reliability benefits" as the reliability costs incurred in each scenario minus the reliability costs incurred in the Gas Turbine Reference Case. As an illustration of the reduced local capacity needs Sunrise would purportedly cause, Table 3-2 below shows that in the Gas Turbine Reference Case, an additional 839 MW of new combustion turbines are assumed to be built in San Diego by 2020. In the Sunrise Powerlink case, not only are none of these new CTs needed, but the CAISO will purchase much smaller amounts of existing capacity under RMR contracts.

TABLE 3-2
Illustration of Reduced Local Capacity Benefits
of Sunrise or Other Transmission Alternatives
(MW)

	2010	2015	2020	
New CTs *Needed* in Gas Turbine Reference Case	280	513	839	Table H-1
RMR Units *Not Neded* with Sunrise Powerlink	753	527	165	Table H-2
Reduction in Local Capacity Needs with Sunrise	1,031	1,031	1,031	

Source: SDG&E, Chapter VII, Supplemental Testimony, January 26, 2007

After 2020, SDG&E generally assumed that reliability benefits remained at 2020 levels in real terms through 2049. SDG&E then estimated levelized benefits for 2010 to 2049 for inclusion in its benefit summary tables.

3.1.2 SDG&E's Estimates of Energy and Renewables Benefits

SDG&E made a considerable effort to estimate the energy benefits of Sunrise and its alternatives. SDG&E employed the Gridview model to simulate the operation of the entire Western Electricity Coordinating Council (WECC) generation and transmission system assuming each generation or transmission alternative was built. SDG&E then used Gridview outputs to estimate the energy costs in each scenario consistent with CAISO's Transmission Economic Analysis Methodology (TEAM). SDG&E then subtracted the Gas Turbine Reference Case's estimated net energy costs from each other alternative's net energy costs to derive each alternative's energy benefits. SDG&E performed these simulations for the three years of 2010, 2015 and 2020, interpolated the intervening years' energy benefits, and extrapolated energy benefits beyond 2020 by extending estimated 2020 energy benefits through 2049 at zero real escalation.

SDG&E did not separately estimate the renewables benefits of the Sunrise project.

Mr. Daniel Suurkask addresses SDG&E's methodologies in more detail in Volume 3.

3.2 Problems with SDG&E's Case

There are several serious problems with SDG&E's analysis. Some of these issues were present from the start of SDG&E's analysis, but other key flaws have arisen due to SDG&E's continued efforts to meet the local reliability criterion in San Diego. DRA offers its critique of SDG&E's case below and will present its alternative estimates of Sunrise's benefits in Section 4.

3.2.1 Sunrise Reliability Benefits Overstated

3.2.1.1 SDG&E Incorrectly Assumes South Bay Power Plant *Will* Retire

One of SDG&E's key assumptions is that the existing SBPP *will* retire in 2009. SDG&E cites the provisions of the lease that SBPP's owner – the Port of San Diego – has with the plant's operator, now Dynegy. That provision does anticipate that the SBPP will retire after November 2009, when certain Bonds the Port issued to acquire the plant are defeased.

However, the assumption that the SBPP *will* retire or *must* retire is not correct. Rather, the other necessary condition for Dynegy's lease on SBPP to expire is the CAISO's willingness to terminate its RMR agreement for SBPP. The Port's *2005 Annual Report* says of the lease between the Port and Dynegy:

> "The lease terminates three months from the later of the date of full payment of and retirement of the Series 1999 Bonds *or the termination by the ISO of the "must run" obligations imposed on the Plant*." (p. 29, emphasis added)

The CAISO may thus keep SBPP operating if necessary to meet San Diego's local reliability criterion. The cover and relevant page of the Port's *2005 Annual Report* are included as Appendix B.[7]

SDG&E argues that the CAISO "requires" that SBPP be assumed to retire in 2009 in grid planning studies.[8] However, the referenced CAISO document that makes this

---

7 The Port's past *Annual Reports* are also available at http://www.portofsandiego.org/sandiego_about/annualreport.asp.

8 SDG&E, *Chapter II, Reliability*, August 4, 2006, Page II-3, footnote 4.

recommendation suggests that SBPP's lease *will* end – an obvious factual error.[9] This Commission would poorly serve ratepayers by making such a contra-factual assumption in its own analysis of Sunrise or San Diego local reliability issues in general. Rather, this Commission should review all plausible options for meeting San Diego's local reliability criterion at lowest cost. This requires that the assumption that the SBPP will be available to help meet San Diego's local reliability need to be reflected in the Commission's decision-making, and that scenarios assuming continued operation of SBPP should be included in the economic analysis of Sunrise and its alternatives.

3.2.1.2 Sunrise May Cause New Offsetting Local Needs in San Diego

A key to Sunrise's purported reliability benefits is the assumption that Sunrise would reduce San Diego's local reliability need by 1,000 MW. Though DRA has not yet seen a contrary analysis, DRA has seen evidence that Sunrise could lead to some new local requirements that might require SDG&E customers to incur some new costs that would offset Sunrise's reliability benefits.

These potential offsetting local needs were identified in the CAISO's *2009-2011 Local Capacity Technical Analysis, Report and Study Results* (Study), published October 31, 2006.[10] The Study does suggest the need for generation in the San Diego local area would fall by 1,000 MW in the presence of Sunrise, consistent with SDG&E's analysis in this case.

---

9 See *Generation Assumptions for Grid Planning Studies by CAISO/Grid Planning*, Page 5, footnote 1, available at http://www.caiso.com/docs/2001/06/25/20010625134406100.pdf.

10 See pages 2 and 71 to 76 of this CAISO Study, available at http://www.caiso.com/18d8/18d8ce1118390.pdf?ht=2009%202011%20local%20capacity%202009%202011%20local%20capacity%202009%202011%20local%20capacity%202009%202011%20local%20capacity.

However, the Study also identified two additional "Local Reliability Areas" affecting SDG&E customers. The first is the "South Bay Sub-area," which would require contracts with South Bay units to mitigate.[11]

More importantly, the Study also identified a new "Greater Imperial Valley-San Diego" (GIV-SD) area that might require as much as 3,190 MW of local generation be contracted – or exactly 1,000 MW more than the 2,190 MW local generation need for the "San Diego" load pocket alone.

The Study did state that this 3,190 MW need might be reduced by "additional import capability from IID achieved at the new San Felipe substation" (p. 75). Further, 826 MW of additional generation beyond that assumed to exist in San Diego local area would also apparently be eligible to meet this need – specifically, two generators that lie outside the San Diego local area but interconnect directly with the IV Substation.[12] The new GIV-SD area needs might thus at least be met by choosing from a larger pool of generators than can San Diego local area needs.

DRA urges the Commission to get explanations from SDG&E and the CAISO as to the nature of these two new local reliability areas that would apparently arise in San Diego in the presence of Sunrise. In particular, the Commission must know before assessing the benefits of Sunrise and its alternatives whether the analysis is fully counting all of the reliability benefits and costs. And if IID must make additional investments to expand CAISO import capacity at the San Felipe substation to relieve the local generation need in the new GIV-SD area, the Commission must also ensure that IID will follow through with such investments.[13]

---

[11] DRA assumes that such mitigation could be provided by the existing SBPP, a potential new plant at South Bay, or upgrades on SDG&E's transmission system.

[12] These units are Sempra Energy's 601 MW Termoelectrica de Mexicali (TDM) project near Mexicali, Mexico, and 225 MW of the capacity Energia de Baja California's La Rosita plant, also near Mexicali.

[13] DRA will also discuss the importance of gaining assurances from IID about its investment plans in its discussion of the possible renewables benefits of Sunrise.

3.2.1.3 SDG&E Overstates Reliability Need

Even if the SBPP were assumed to retire in 2009, SDG&E's assertions of its local reliability need in 2010 are greatly overstated. This overstatement may be driven largely by the passage of time and SDG&E's continued efforts to meet its customers' various needs. SDG&E has implemented or proposed at least three initiatives that collectively would postpone a local reliability deficit – even without the SBPP – through 2014.

For example, as discussed in Section 2.3.3, the Commission recently approved SDG&E's application to install AMI, which SDG&E has estimated will reduce San Diego's local reliability need starting in 2009. And as discussed in Section 2.3.1, on May 11 SDG&E applied for Commission approval of contracts for 131 MW of new CTs in San Diego by 2008 and an expansion of the capacity of its EnerNOC contract to 50 MW, also by 2008.

The impact of these highly likely San Diego-area resource additions on SDG&E's estimated San Diego local capacity need are summarized in Table 3-3.

TABLE 3-3
Updated San Diego Local Reliability Capacity Need
Without Sunrise Powerlink
(MW)

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
SDG&E-Asserted Surplus / (Deficiency)	526	(247)	(306)	(346)	(381)	(422)	(472)
SDG&E Initiatives to Meet Need:							
- Advanced Metering Infrastructure	107	161	219	228	238	243	249
- J Power (Pala)	87	87	87	87	87	87	87
- Wellhead Power Maragarita	44	44	44	44	44	44	44
- EnerNOC	50	50	50	50	50	50	50
- Subtotal	288	342	399	409	418	424	429
Surplus / (Deficiency)	**814**	**95**	**93**	**62**	**37**	**1**	**(42)**

Any estimate of the potential benefits of Sunrise and its alternatives must reflect "what is" and "what will be" in San Diego regardless of Sunrise. The Commission must thus consider the impact of these resources on Sunrise's benefits in its deliberations.

Further, as also discussed in Section 2.3.1, it is quite possible that SDG&E will soon bring forth additional San Diego-area generation that will help meet local reliability need by 2010 or shortly thereafter, particularly from bids submitted to its 2010-2012 RFO and 2007 Renewables RFO. As with the highly likely projects cited above, the Commission must also take heed of the impacts of any forthcoming SDG&E-proposed local resources on the need for and benefits of Sunrise.

3.2.1.4 SDG&E Assumptions Regarding RMR Contracts Are Unrealistic

One of the major sources of Sunrise's purported reliability cost savings is a reduction in the amount of RMR fixed contract costs San Diego-area customers endure. Such savings would purportedly derive from a reduction in both the quantity of RMR contracts that would be necessary and – due to competitive pressures – the fixed prices of such contracts.

However, SDG&E's analysis of such cost reductions is based on two very unrealistic assumptions. The bulk of the units that are assumed available for RMR contracting are aged and not economically competitive. SDG&E noted:

> "Three of the generating units at the Encina Power Plant are over 58 years old and three of the generating units at the South Bay Power Plant in Chula Vista are more than 42 years old. In fact, the youngest of these San Diego County steam units is 38 years old. These inefficient power plants have heat rates of approximately 10,000 MMBtu/kWh, cannot compete with the new combined cycle plants' heat rate of 7,000 MMBtu/kWh. With the flood of efficient combined cycle units on the horizon, marginal prices in most hours of the year will be determined by combined cycle generation. There will be little room for inefficient boiler-fired generation and it is reasonable to predict many retirement announcements."
> (SDG&E, *Chapter II, Reliability*, August 4, 2006, Page II-14.)

It is not realistic to expect owners of such plants to keep them operating unless they continue to receive contracts that pay them their full costs every year. SDG&E's analysis of RMR contracting costs is flawed in two respects due to its failure to consider these units' lack of competitiveness.

First, SDG&E assumes that all existing generation in San Diego will remain available for RMR contracting through 2020 – even if they are "de-contracted" for multiple years. This assumption is critical to SDG&E's reliability cost computations. But given many existing units' lack of economic value, DRA believes that such de-contracting will lead owners to retire these units, making them unavailable for meeting reliability needs. Instead, a more likely result is that additional new CTs (or other generation or transmission capacity) will be built in San Diego to replace these units' capacity after they have stopped receiving RMR contracts.

Second, SDG&E also assumes that existing units will be economically viable next decade with RMR contracts that provide for less than full cost recovery, that is, under a "Condition 1" rather than a "Condition 2" RMR contract. This assumption is also critical to SDG&E's computation of reliability costs, because it causes the average fixed prices of RMR contracts to fall in the presence of Sunrise. DRA also does not believe this is a realistic assumption. Per the above discussion, DRA believes that existing units will only be financially viable if they receive Condition 2 contracts that provide them full recovery of their costs. DRA does not believe it plausible that these units will commit themselves to the CAISO in exchange for recovery of only 30 percent of their fixed costs until the year 2020.

SDG&E contends that Sunrise will put additional financial pressure on existing units when it said:

> "The Sunrise Powerlink project will augment existing transfer capability between the desert Southwest and California load centers and

> accommodate the retirement of aging and inefficient, gas-fired generation in the San Diego area by providing an increased ability to access capacity sources." (SDG&E, *Chapter IV, Economic Benefits*, August 4, 2006, Page IV-14.)

and

> "While it is impossible to predict the exact year of retirement it is reasonable to believe that the older less efficient power plants will retire within the 10 year planning horizon." (SDG&E, *Chapter II, Reliability*, August 4, 2006, Page II-13.)

SDG&E cannot credibly claim that retirements of existing capacity are imminent – especially if Sunrise is built – but then assume that such units will remain available for RMR contracting through 2020 if Sunrise is built if they are only paid a portion of their fixed costs in some years and/or de-contracted entirely for other years.

Instead, DRA believes it only reasonable to assume that the divested SDG&E units – SBPP, Encina (Cabrillo I), and the Cabrillo II peakers – will only continue to operate if they receive contracts that cover their full costs for each and every year of the decade. But more generally, DRA believes the Commission should anticipate that many of the SDG&E-divested units will retire by the year 2020 – *even if they continue to receive RMR or other contracts*. DRA believes that substantial new investment in San Diego-area resources – including generation and transmission – will be necessary from 2010 to 2020 to replace existing capacity and meet local reliability needs. This long-term assumption should also be built into the local reliability analysis, rather than the assumption that all existing units will be available through 2020. This concern motivates DRA's call to the Commission to pursue the San Diego Grid Reliability Action Plan discussed in Section 4.

3.2.1.5 SDG&E Ignores Offsetting System Resource Adequacy Costs

In computing reliability cost savings, SDG&E also assumes that its customers' benefits equal the full amount by which their payments for local generating capacity are reduced by Sunrise or other alternatives. This assumption is consistent with the computation of local reliability need under the "G-1/N-1" criterion, which does not consider the costs of generation capacity inside or outside a load pocket.

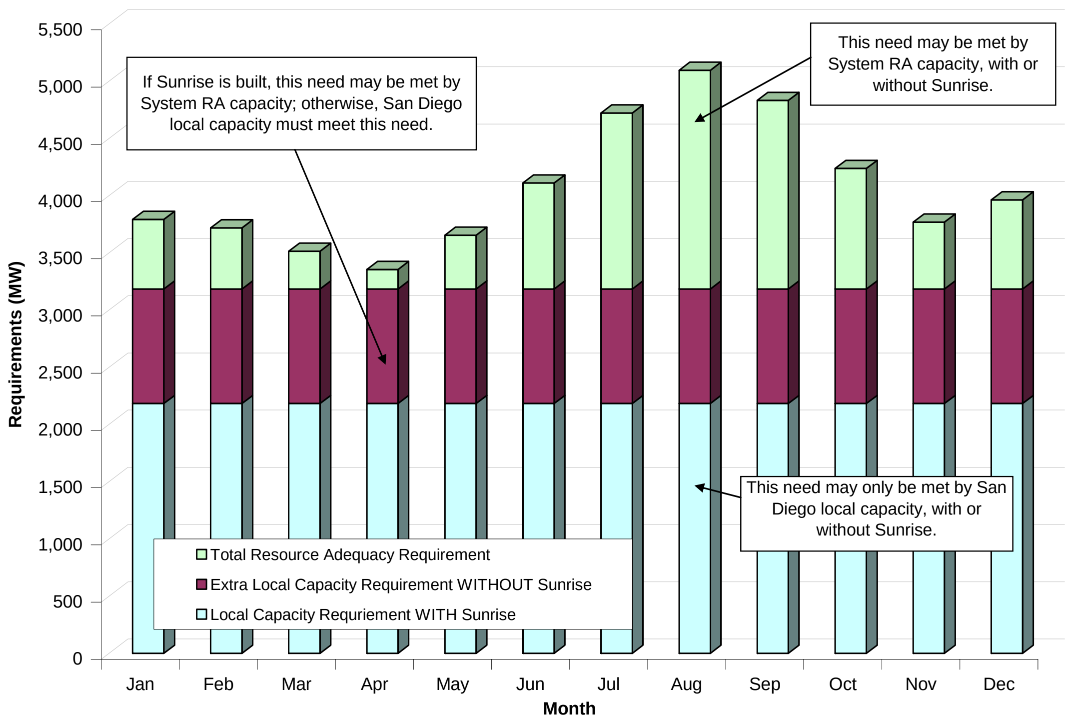
However, SDG&E customers will still be paying for the same amount of generating capacity with or without Sunrise (or any other alternative). The reduction in their obligation to support San Diego area capacity will be replaced – MW for MW – by an obligation to support the same amount of capacity from any source in the CAISO system, or System Resource Adequacy (RA) capacity.

To be specific, Sunrise will not relieve SDG&E customers entirely from paying for an additional 1,000 MW of capacity. It will relieve them of paying for 1,000 MW of San Diego *local* capacity. But SDG&E customers will instead need to pay for an additional 1,000 MW of *System RA* capacity. San Diego customers will still likely benefit from this exchange, as DRA expects the cost of San Diego local capacity to exceed the cost of System RA capacity. The impact of Sunrise on SDG&E customers' obligations to buy San Diego local capacity and System RA capacity is shown in Figure 3-1.[14]

[14] Local capacity procurement requirements are currently a fixed annual quantity, while System RA capacity procurement requirements are computed based on monthly peaks. In months when the monthly peak load, plus the Planning Reserve Margin, is less than the annual local capacity requirement, SDG&E customers will avoid paying for less than 1,000 MW of local capacity requirements.

FIGURE 3-1 [15]

SDG&E Customers' Monthly Local and System Capacity Requirements in 2011



A reasonable estimate of the reliability benefits of Sunrise and its alternatives must consider the offsetting effect of the System RA obligation. DRA addresses this issue in its analysis in Section 4.

3.2.1.6 SDG&E CT Costs Should Reflect 2008 Peaker RFO Results

SDG&E's estimates of the capacity costs of new CTs should also be changed to reflect the bids received in response to its 2008 Peaker RFO. SDG&E provided data regarding these costs in its May 11, 2007, Application for approval of contracts arising from its

[15] Data from *Public Version, San Diego Gas & Electric Company, Exhibits, 2007-2016 Long-Term Procurement Plan*, December 11, 2006 (R.06-02-013).

2008 Peaker RFO (A.07-05-XXX). These data are summarized in Confidential Appendix C.

3.2.2 Energy and Renewable Benefits Modeling Flawed

Despite all the sound and fury surrounding SDG&E's efforts to model the energy benefits of Sunrise (and apparently the renewable benefits as well), DRA thinks such work is of virtually no value. DRA believes the Commission should not rely on SDG&E's modeling results unless significant changes are made to the data set and SDG&E re-runs its simulations.[16]

SDG&E's renewables modeling – which apparently melded such benefits into energy benefits by merely testing the impact of the various alternatives on system energy costs given a static renewables build-out in all cases – is incomplete. Additional transmission into IV should lower the costs of delivered power from IV, which should reduce the delivered costs of currently operating projects and encourage development of additional renewable resources in the IV. But SDG&E assumes that the same level of development of renewables in IV will occur with or without Sunrise or any other new transmission into the IV.

Mr. Daniel Suurkask will provide more details about these major flaws of SDG&E's energy and renewable benefit modeling in Volume 3.

---

[16] However, SDG&E's modeling may be useful in showing the "directional impacts" of alternative assumptions about future electricity systems and markets. For example, their modeling should show whether an increase in gas prices would increase or decrease Sunrise's energy benefits.

4. DRA'S ANALYSIS OF SUNRISE BENEFITS

In this section DRA describes and presents its estimates of Sunrise's net benefits. DRA also identifies some potential benefits and costs that have not been quantified and makes recommendations for further analysis.

4.1 DRA's Estimate of Quantified Benefits

DRA estimated the benefits for Sunrise compared to the GT Reference Case for each of the three categories of benefits SDG&E has identified using SDG&E's local reliability cost template and levelization method. DRA then summed these levelized benefits to determine Sunrise's gross levelized benefits and subtracted Sunrise's estimated levelized costs from this figure to estimate Sunrise's levelized net benefits. DRA also divided Sunrise's estimated gross benefits by Sunrise's estimated costs to determine its Benefit-Cost Ratio (BCR).

4.1.1 Reliability

To estimate the benefits of reduced customer costs for complying with the San Diego local reliability criterion, DRA adapted SDG&E's reliability cost model to develop alternate estimates of the avoided costs of RMR contracts and new CTs. These corrections were introduced in Section 3 and are summarized in Table 4-1 below.

TABLE 4-1
Corrections and Updates Made
to SDG&E Estimates of Sunrise Reliability Benefits

Estimated Need: o Newly-approved or –identified resources reduce needed local generation Costs: o All RMR contracts assumed to be "Condition 2" o RMR units that don't receive contracts retire o System Resource Adequacy costs replace local RMR or new CT costs o CT fixed costs from SDG&E "2008 Peaker RFO" application filed May 11 (A.07-05-XXX)

The specific annual reductions in local reliability need were provided in Table 3-3. DRA adopted the CAISO's estimate of $27/kW-yr (in $2006) as an estimate of the cost of System RA capacity.[17,18] DRA did not change SDG&E's assumption that reliability benefits generally escalate through 2049 from their 2020 values at a "zero real" rate.

DRA also developed estimates of potential high and low values of reliability values. To make these estimates, DRA applied the assumptions shown in Table 4-2 below regarding potential high and low values of San Diego's local need, the additional cost of meeting such local need, and the escalation of such benefits beyond the year 2020.

[17] CAISO, *Initial Testimony…Part 1*, January 26, 2007, Page 31.

[18] SDG&E and the CAISO both assume that the construction of Sunrise will reduce CAISO ratepayers need for an additional 1,000 MW of CTs – that is, that System RA needs would be reduced by 1,000 MW. The CAISO appears to assume that IV renewables will meet San Diego's increased System RA need. However, a more reasonable planning assumption – employed herein by DRA – is that both total CAISO System RA and total CAISO renewables purchases will remain essentially the same *with or without* Sunrise. Sunrise might thus reduce the need for capacity in the San Diego local area by 1,000 MW, but not reduce aggregate CAISO System RA need at all. Similarly, any increased SDG&E purchases of IV renewables would merely offset SDG&E's purchase of renewables from other renewable areas.

TABLE 4-2
Sensitivities Used to Prepare High and Low Scenarios
of Sunrise Reliability Benefits

	High	Low
Need:	Higher local need from SDG&E Long-Term Procurement Plan (R.06-02-013).	Lower local need from SDG&E Long-Term Procurement Plan (R.06-02-013).
Cost:	System RA capacity half the price of San Diego local capacity.	System RA capacity only $5/kW-yr less expensive than San Diego local capacity.
Escalation:	Benefits grow after 2020 at two percent real escalation.	Benefits grow after 2020 at negative two percent real escalation.

DRA computed these annual reliability cost differentials for Sunrise and the GT Reference Case for each year from 2010 to 2020 and escalated benefits in 2020 through all years to 2049. Sunrise's net reliability benefits for the "Sunrise v. Gas Turbine Reference Case" comparison are summarized in Table 4-3 below for these scenarios.

TABLE 4-3
Cumulative Impact of Corrections, Updates and Sensitivities
on SDG&E Estimates of Reliability Benefits
(levelized $MM)

	Sunrise - GT Reference Case			Reduction in Base Values
	Low	Base	High	
SDG&E Assertions:				
- Sunrise - GT Reference Case		196.8		
- Sunrise - GT Reference Case WITH AMI		163.3		33.5
Changes in Need Assumptions:				
- Need Corrected to Reflect Other New Resources		136.0		27.3
Changes in Cost Assumptions:				
- All RMR Contracts are 'Condition 2', Lack of RMR Contract Leads to Retirements and SDG&E 2008 Peaker RFO CT Costs		103.0		33.0
- System RA Costs Replace Local RMR	32.7	66.4	97.8	36.6

The reliability cost reduction benefits of Sunrise are substantially less than SDG&E has estimated. They are still significant. However, there is a substantial range of uncertainty about what these benefit will be, driven by the assumptions outlined in Table 4-2 above.

DRA's analysis does not reflect two of the key deficiencies of SDG&E's showing presented in Section 3: the possibility that the SBPP could continue operating past 2009 to meet local reliability needs and the possibility that Sunrise will create some new local requirements in San Diego that might offset its potential savings. DRA discusses how the Commission can address these matters further below.

4.1.2 Renewables

To estimate the potential for Sunrise to lower customers' costs of complying with the Renewables Portfolio Standard (RPS), DRA used the "Renewables Supply Curve" (RSC) model that the CAISO developed and submitted with its March 1 testimony.[19] In general, DRA found the CAISO's RSC model to be a reasonable tool for isolating the potential "renewables benefits" of Sunrise.

DRA made two modifications to the RSC for its analysis. The first was to exclude from the computation the benefits Sunrise might provide to ratepayers outside the CAISO. Sunrise's costs would be paid by CAISO ratepayers. Consistent with the transmission planning policies of this Commission and the CAISO, only the benefits Sunrise might provide CAISO ratepayers should thus be considered in considering whether Sunrise is a good investment. DRA also treated the costs of transmission related to the Tehachapi region as "sunk," because the Commission has already approved a substantial build-out of transmission to provide greater access to that area's wind resources. These two changes are summarized in Table 4-4.[20]

TABLE 4-4
DRA Enhancements to CAISO Renewable Supply Curve Model

o Count only benefits to CAISO ratepayers
o Treat Tehachapi transmission costs as "sunk."

DRA also tested the impact of key alternative assumptions on Sunrise's value. DRA tested the impact of the risks that IV renewables would be more or less expensive relative

[19] CAISO, *Initial Testimony…Part II*, March 1, 2007, Page 56-66.

[20] DRA also believes that Sunrise's projected renewables benefits should also be adjusted in 2010 because the full build-out of IV renewables is not anticipated to occur by then. However, the structure of the RSC does not readily permit analyzing such a "phase-in" of a region's renewable development.

to other renewable supply sources than the CAISO assumed in the RSC, and that IV renewables would be available in greater or lesser quantities than assumed in the RSC. DRA also tested the impact of changing the CAISO's assumption that renewable benefits would increase at 1.1 percent annually after 2020 by testing escalation rates of minus 1.0 percent per year and 3.2 percent per year. These sensitivities are summarized in Table 4-5 below.

TABLE 4-5
Sensitivities Regarding Imperial Valley Renewables
Used to Prepare High and Low Scenarios of Sunrise Renewables Benefits

	High	Low
IV Renewable Availability:	IV renewable availability increased by 2,500 gWh.	IV renewable availability reduced by 2,500 gWh.
IV Renewables Relative Cost:	IV renewable costs reduced by $10/MWh.	IV renewable costs increased by $10/MWh.
Escalation:	Benefits grow after 2020 at minus 1.0 percent.	Benefits grow after 2020 at 3.2 percent.

The IV renewable cost sensitivity tests assessed the possibility that the cost of IV renewable resources, as compared to other resource areas, is higher or lower than anticipated. But these tests also explored other potential concerns about Sunrise's renewables value. For example, the level of wheeling and interconnection fees that IID will charge to renewables developers is not known yet. The above sensitivity tests help measure the impact on Sunrise's value of the IID seeking higher fees.

The IV availability sensitivity tests explore the impact of IV resources being available in greater or smaller quantities than the CAISO projected. Though substantial new renewable energy resources are commonly assumed to be available in the IV, it is not certain exactly what this amount will be. More importantly for Sunrise's near-term renewables value, it is not certain that IV renewables to be developed under SDG&E's current contracts – notably its contract with Stirling Energy Systems (Stirling) for power from a new concentrated solar technology – will be available in the early years of next decade. Dr. House's testimony in Volume 5 of DRA's Phase 1 Direct Testimony finds that the Stirling project has a reasonable chance of success. Municipal utilities' actions will also affect the amount of renewable power available in the IV. For example, if IID does not build out its internal system as anticipated, less renewable power may be available, also reducing Sunrise's value. Construction of the "Green Path – North" (GPN) project by the Los Angeles Department of Water and Power (LADWP) might also result in excess "renewable transmission capacity" from the IV, possibly diminishing the value of Sunrise.

Finally, DRA also tested the impact of changing the CAISO's assumed escalation of renewables benefits after 2020. The CAISO's RSC escalated year 2020 renewables benefits through the year 2049 at 1.1 percent per year, which approximately equals forecast load growth. DRA used higher and lower escalation rates to test the impact of longer-term uncertainties on Sunrise's renewables value.

DRA then computed these RPS compliance cost differentials for the Sunrise and the Gas Turbine Reference Cases using the enhanced RSC. Sunrise's net renewable benefits as compared to the Gas Turbine Reference Case are summarized in Table 4-6 below.

TABLE 4-6
Impact of Corrections and Sensitivities
on CAISO Estimates of Renewables Benefits
(levelized $MM)

	Sunrise - GT Reference Case		
	Low	Base	High
CAISO RSC Analysis:		56	
DRA Modifications to RSC (Table 4-4):		37	
Sensitivities:			
- Imperial Valley Resource Costs	-40		113
- Imperial Valley Resource Availability	-32		124
- Post-2020 Escalation	-25		137

Sunrise can reasonably be expected to provide some significant additional renewables development benefits as well. But, as with reliability benefits, there is a large band of uncertainty surrounding these benefits, driven by the major uncertainties discussed above.

4.1.3 Energy

As discussed above and by Mr. Suurkask in Volume 3, DRA has little confidence in the estimates of "energy benefits" that SDG&E has produced to date. DRA has somewhat more confidence in the CAISO's modeling.

In particular, DRA agrees with the CAISO that energy benefits are not a key driver of Sunrise's value. This result is entirely intuitive. Sunrise would expand the connection between the CAISO-controlled electric grid – which delivered power to meet a peak demand of over 50,000 MW last summer – to the Imperial Irrigation District (IID) electric system, which has met a peak demand of less than 1,000 MW. However, Sunrise would not greatly increase CAISO grid access to other resources or markets in the Desert

Southwest (DSW) that have historically justified transmission expansions in the region. Energy benefits to CAISO customers from a connection to the IID grid alone should not be expected to be significant, and certainly would not justify the line in and of themselves.

However, energy benefits from Sunrise will exceed zero. To make a provisional estimate of such benefits, DRA used as a starting point the CAISO's levelized estimate of $35 million per year. DRA reduced this levelized figure to $25 million per year to reflect the infirmities that plague the CAISO energy modeling. DRA then assumed that low and high energy benefits will range from 50 percent to 200 percent of this "base" estimate – or from levelized values of $12 million to $50 per year, respectively. These estimates are shown in Table 4-7 below.

TABLE 4-7
DRA Provisional Estimates of Sunrise Energy Benefits
(levelized $MM)

	Sunrise - GT Reference Case		
	Low	Base	High
CAISO Gridview Analysis:		35.5	
DRA Estimates:	12.4	24.9	49.7

To develop more useful estimates of Sunrise's energy benefits and the band of uncertainty surrounding such benefits, however, DRA believes the steps outlined below in Section 4.4.2 are necessary.

4.1.4 Net Benefits and Benefit-Cost Ratios

DRA summed the levelized benefits described above and compared them to Sunrise's estimated levelized costs. These results are summarized in Table 4-8 below.

TABLE 4-8 [21]
Estimated Range of Sunrise Benefits
As Estimated by DRA and SDG&E
(levelized $2006 MM)

	DRA Estimates			SDG&E Reference Case
	Low	Base	High	
Benefits				
- Reliability	32.7	66.4	97.8	196.8
- Renewables 1/	0.0	37.0	137.0	N/A
- Energy	12.4	24.9	49.7	163.2
Subtotal	45.2	128.2	284.5	360.0
Costs		156.1		
Net Benefits	(110.9)	(27.9)	128.4	203.9
Benefit-Cost Ratio	0.29	0.82	1.82	2.31

Notes: 1/ Renewable Supply Curve model resulted in negative $25MM levelized benefit in Low scenario; prudent procurement of renewables assumed to limit Low scenario renewables value to zero.

These results suggest that Sunrise will likely provide non-trivial benefits to CAISO ratepayers – though that such benefits are highly uncertain and will not necessarily exceed Sunrise's costs. Such findings suggest strongly the Commission would be well-served to seek some additional risk or uncertainty analysis before making a decision about granting SDG&E a CPCN for Sunrise.

[21] Same as Table ES-2.

4.2 DRA Analysis of Non-Quantified Benefits and Costs

Not all aspects of Sunrise's benefits and costs are amenable to quantification, at least in practice.[22] DRA addresses two such values in this section, both of which should be favorable factors in the Commission's consideration of Sunrise, particularly compared to the generation alternatives.

4.2.1 Service Reliability

Estimates of Sunrise's "reliability" value have focused on the benefits of reducing customers' costs of meeting the "G-1/N-1" local reliability criterion in San Diego. However, the potential impact on actual service reliability of Sunrise and its alternatives has been barely mentioned.

In brief, DRA believes that Sunrise would likely provide a more reliable means of meeting loads in San Diego than the major generation alternatives – and would especially provide more reliable service than the electric generators that Sunrise would likely force into retirement. Much of the generation that would be at great risk of retirement with Sunrise is, as noted above, aged and experiences outage rates substantially higher than those of a transmission line. DRA thus thinks Sunrise will likely provide more reliable service in the San Diego local area than competing generation alternatives.[23] However, DRA believes Sunrise's "reliability of service" advantage over the major transmission alternatives is either small or non-existent.

---

[22] Studies can of course be conducted to quantify these values, but have not been – and are not likely to be – offered in this case.

[23] However, the apparently higher local reliability "surpluses" with Sunrise shown in SDG&E's various tables – such as Table H-2 of its January 26, 2007 testimony – are deceiving. As discussed in Section 3 above, much of this surplus comes from existing local generation that SDG&E and DRA both believe will likely retire over the next decade. The seeming net local "surplus" with Sunrise is thus likely to be much smaller than shown in such tables.

4.2.2 Option Value

Parties' analyses have also only briefly mentioned another positive aspect of the development of Sunrise compared to generation alternatives: the "option value" of new transmission. For this case, DRA defines option value is the value of the possibility that an asset can be exploited in a beneficial manner not considered by the quantitative analyses or expanded for beneficial use in the future. For example, expanded transmission capacity into San Diego should give SDG&E and other LSEs more procurement options than the purchase of output from a generator in San Diego. In addition, Sunrise might facilitate the construction of beneficial new transmission projects. One such possibility would be another "North Gila-Imperial Valley-Hassayampa" transmission line that would provide additional access to DSW energy, possibly providing significant energy benefits to CAISO ratepayers.[24] DRA believes Sunrise offers such option value that other options – particularly the generation options – do not.[25]

4.3 Uncertainties and Omissions in SDG&E Analysis

There are also several other key factors the Commission should consider in making a decision regarding Sunrise that have not been developed in the record yet. As DRA has prepared its analysis based on these prior submissions, DRA's analysis also does not address these factors. These deficiencies, their importance, and possible means for addressing them in this case are discussed below.

4.3.1 Use of Suboptimal Reference Case

As discussed above, SDG&E estimated the value of Sunrise by comparing customers' "with Sunrise" to customers' costs in a Gas Turbine Reference Case, that is, a scenario in which new 46.6 MW CTs were built in San Diego instead to meet the local reliability

---

[24] However, California policy regarding CO_2 emissions might greatly restrict its customers' ability to purchase power from the DSW, which features a large mix of coal generation.

[25] Mr. Palmerton also discusses option value in Volume 4 of DRA's Phase 1 Direct Testimony.

criterion. The construction of this "reference case" is, at first blush, consistent with traditional electric utility resource planning practice, which typically begins with the assumption that a system is "built out" with CTs to meet reliability margins.

Good resource planning practice then leads to efforts to determine the best alternative set of resources to meet loads reliably. SDG&E partially followed this practice when it tested some other plausible alternatives and compared their costs to the Gas Turbine Reference Case. SDG&E did conclude that one of these alternatives – the In-Area Combined Cycle alternative (Case 204) – was superior to the Gas Turbine Reference Case (though still inferior to Sunrise).

However, SDG&E did not make an effort to find the best set of "No Sunrise" alternatives. For example, the possibility that the SBPP could operate, at least through the early part of next decade, to help meet the local reliability criterion was not included in SDG&E's analysis. It can thus not be concluded that Sunrise is the best of all alternatives for meeting local reliability need, because it is quite possible that a plausible, readily-implementable alternative or set of alternatives could be postulated that would be superior to Sunrise. As SDG&E noted in response to DRA Data Request 3-6g:

> "SDG&E's evaluation of the Sunrise Powerlink benefits was not designed as a resource planning exercise."

SDG&E was apparently focused on assessing the value of a single project against some alternatives. However, the lack of a more complete analysis of SDG&E's options calls SDG&E's conclusion into question.

4.3.2 Failure to Consider Optimal Sunrise Timing

Another key aspect of traditional resource planning is identifying the optimal timing for new resource additions. This issue is particularly critical in this application because some analyses suggest Sunrise's benefits only become significant compared to the alternatives later next decade. For example, the CAISO's analysis found that the Sunrise project does yield a higher levelized value than the South Bay Repower project over the horizon of 2010 to 2049, *but was of lower value in 2015*, as summarized in Table 4-9 below. Such findings suggest that Sunrise may be a valuable asset – but that its construction should be deferred.

TABLE 4-9
CAISO Analysis of Net Benefits of Sunrise and South Bay Repower

	2015 (Nominal $MM)	2020 (Nominal $MM)	2010 – 2049 (Levelized $MM)
Sunrise	(15)	191	84
South Bay Repower	28	32	29
	Table 3.3	Table 3.4	Table 3.5
Source: CAISO, *Second Errata to Initial Testimony…Part II*, April 20, 2007, Pages 39 to 41.			

This limitation of SDG&E's analysis is perhaps a corollary of their failure to conduct a more complete resource planning analysis. Sunrise's advocates' contention that Sunrise should be constructed *to begin service in 2010* is clearly in doubt.

4.3.3 Failure to Consider Uncertainty and Risk

Another critical omission in SDG&E's Sunrise evaluation was any meaningful assessment of risk or uncertainty.[26,27] This omission greatly limits the Commission's ability to assess the conditions under which Sunrise would be a good investment.

The Commission has quite clearly stated it wants transmission project proponents to provide a range of risk analyses.[28] DRA has offered some risk analysis above by providing some plausible ranges for Sunrise's potential benefits compared to the Gas Turbine Reference Case. However, there is substantially more analysis that can and should be done with regard to assessing the risks surrounding energy benefits, as discussed in Section 4.4.2 below.

4.3.4 Failure to Estimate Greenhouse Gas Impact

Another key aspect of resource planning in California that was not considered in SDG&E's analysis is the impact of Sunrise on greenhouse gas emissions. DRA does not believe the Commission should act on SDG&E's application until it knows what Sunrise's likely impact on greenhouse gases is. This question grows in importance with the weight the Commission gives to estimates of Sunrise's prospective energy benefits, as such energy benefits may be driven by an assumed expansion of coal generation in the DSW.

---

[26] SDG&E did perform some "low load" scenarios, but does not appear to have done any assessments of the impacts on the value of Sunrise and its alternatives of the usual uncertain variables, such as gas prices, hydro availability, load volatility, load-resource balance and resource mix.

[27] The CAISO did perform some sensitivity assessments in a report it provided to its Board in July 2006 (included as Appendix I-1 in *Volume 2 – Part 1 (Purpose and Need)* of SDG&E's August 4, 2006 testimony in this docket). However, these sensitivities undoubtedly suffer the same flaws (referenced above) as all the other SDG&E and CASIO Gridview modeling. The list of sensitivities the CAISO considered was also curiously much shorter than the many uncertainties the CAISO considered in its analysis in Application 05-04-015 of the value of the Devers – Palo Verde No. 2 Transmission Line proposed by Southern California Edison.

[28] The Commission's clearest and most detailed expression of this desire was in Decision 06-11-018, particularly at pages 58 to 64 (mimeo). However, this decision was issued after SDG&E filed its original showings in this case.

4.3.5 Uncertainty Regarding Actions of Municipal Utilities

A last key uncertainty in SDG&E's analysis is the impact of the actions of third parties on the ultimate value of Sunrise. Foremost among these concerns are the actions of two municipal utilities – LADWP and IID.

If LADWP completes the GPN as advertised, it is possible that additional competitors for IV renewables will outbid SDG&E and other CAISO LSEs for such energy, driving up the cost of IV renewable energy and/or reducing the use of Sunrise for such purposes. Either outcome could reduce the renewables value of Sunrise.

In addition, IID's actions will play a key role in whether CAISO customers receive any renewables value from Sunrise. The IID must make some internal enhancements to its own system to enable delivery of additional renewable power to Sunrise. However, it is not clear that the IID will make such upgrades, as IID's participation in the GPN and its cooperation with SDG&E are both being reviewed by IID's Board.[29] It is possible that IID will not complete its system upgrades in a manner that will enable the development of IV renewable resources envisioned in SDG&E's analysis, which would reduce the renewables value of Sunrise.

Further, even if IID makes the upgrades necessary to develop fully IV renewable resources, it is not clear how IID will recover the costs of such upgrades. It is possible that IID will seek to extract on behalf of its own ratepayers some of Sunrise's potential renewables value through its interconnection and wheeling fees.

The IID will apparently need to invest in a "new San Felipe Substation" to prevent or mitigate the local capacity requirements of a possible new "Greater Imperial Valley – San Diego" (GIV-SD) local area, as discussed in Section 3. The uncertainty described above about IID's commitment to support the Sunrise project also makes IID's commitment to

---

[29] See Appendix D for a press release issued by IID April 26, 2007 titled "IID Board of Directors responds to Green Path prudency review.

this investment uncertain. A failure by IID to make such upgrades could increase the likelihood that San Diego customers will bear the costs of meeting some new, offsetting local capacity requirements, reducing Sunrise's reliability value.

Though the actions of these municipal utilities are beyond the Commission's direct control, the Commission can have some impact on these matters by setting appropriate conditions in any CPCN it issues to SDG&E.

4.3.6 Uncertainty about Capital Cost Escalation

In addition, capital costs of building both new generation and transmission assets have risen rapidly in recent years. Though rapid recent escalation is no guarantee of rapid future escalation, the Commission should question whether the various capital costs used to compare Sunrise and its alternatives are consistent with each other, that is, were developed at the same time using the same methodology and assumptions. If capital cost assumptions are not consistent, any analysis may be skewed in favor of certain alternatives and against others.

In addition, the Commission should question whether SDG&E's estimated capital costs are still valid over nine months after they were submitted and will still be valid when the Commission takes action on Sunrise, now scheduled for January 2008.

DRA does not offer an opinion on whether SDG&E's transmission and generation capital cost escalation assumptions are consistent and if the transmission capital cost estimates will still be valid when the Commission acts on Sunrise. However, DRA does suggest a means for addressing this latter concern in its discussion below of potential conditions for any CPCN.

4.4 Conclusion

Based on the above analysis, DRA makes the following conclusions regarding Sunrise's economic value relative to other alternatives.

4.4.1 What DRA Can Conclude

Based on the above analysis, particularly the results of Table 4-8, DRA concludes that Sunrise may be a valuable asset to CAISO ratepayers. In addition, some non-quantified factors suggest Sunrise will have other positive benefits for CAISO customers in relation to generation assets.

However, there is a substantial uncertainty surrounding the range of these benefits, which raises significant concerns that Sunrise's actual benefits may not exceed its costs. Further, it is quite possible that some other combination of resources could be identified and developed that would provide higher overall value to CAISO ratepayers. Finally, the analyses also suggest that construction of Sunrise should be delayed until after 2015. And Sunrise is not needed to meet the "G-1/N-1" grid reliability criterion in 2010 or immediately thereafter.

The above analysis suggests that the Commission does not have the evidence yet to approve the CPCN for Sunrise that SDG&E has requested. DRA believes the development of the additional information described below, and the San Diego Grid Reliability Action Plan (SDGRAP) discussed in the next section, will help make the right decision more clear. DRA will also continue its own analysis and review other information parties submit in this case. Based on all this review and analysis, DRA will make a recommendation to the Commission regarding a Sunrise CPCN at the appropriate time.

4.4.2 What Else the Commission Needs to Know

There are several other key unknowns about Sunrise the Commission should insist on knowing before deciding on Sunrise.

First, the Commission should clearly know what impact Sunrise will have on greenhouse gas emissions. This question is answerable by the additional Gridview modeling recommended further below.

The Commission must also be informed about the potential for Sunrise to create some new local reliability obligations that might offset Sunrise's potential reliability benefits.

The Commission could also request from parties other risk analyses that it mentioned in Decision (D.) 06-11-018, such as tipping point analysis. For example, uncertainties surrounding Sunrise's "energy" benefits might best be quantified by modeling using Gridview (or another model) after the critical corrections described by Mr. Suurkask in Volume 3 are made to the database. Such modeling could help test the impact on the value of Sunrise and its alternatives of possible differing future values of gas prices, hydroelectric availability, short-term load variations, load growth, regional load-resource balances and coal plant development.[30] DRA suspects that such tests will reveal that Sunrise has some now-hidden advantages and disadvantages relative to its alternatives with regard to energy benefits.

All the above analyses will help the Commission identify those assumptions or conditions under which Sunrise is likely to be a good investment and those under which Sunrise would not be a good investment.

---

[30] Mr. Palmerton provides an extensive list of potentially significant and uncertain variables in Volume 4 of DRA's Phase 1 Direct Testimony.

4.4.3 What the Commission Will Have to Guess At

Though additional risk analyses should help guide the Commission's actions, no amount of such assessments will entirely resolve the uncertainty about Sunrise's future value. The Commission will fundamentally need to make a decision about a major commitment of CAISO ratepayer funds – with a present value of revenue requirements of over $1.83 billion in 2010 – based on educated judgment.

In addition, other factors that will affect Sunrise's value are not as prone to quantification. Foremost among these is whether LADWP will complete the GPN and whether IID will complete the internal transmission upgrades needed to support Sunrise's reliability and renewables values and to recover upgrade costs in a reasonable manner. However, the Commission can address some of these contingencies in the conditions it attaches to the CPCN, as described below in Section 6.

5. SAN DIEGO GRID RELIABILITY ACTION PLAN

5.1 Need for SDGRAP

Maintaining reliable electric service in San Diego is uniquely challenging. The San Diego area has a relative lack of import capacity – particularly under N-1 contingency conditions – and substantial capacity payments are required to keep much of the region's uncompetitive local generating capacity available. DRA anticipates that SDG&E and other parties will be investing substantial amounts of capital in transmission and/or generation resources to meet San Diego's local reliability needs over the next decade – regardless of how the Commission acts on the Sunrise application. Efforts to meet the local reliability criterion are a regular feature of SDG&E's transmission and procurement filings with the Commission However, SDG&E's various efforts appear to be uncoordinated and quite possibly a suboptimal solution for San Diego ratepayers.

DRA believes the Commission should, just for the specific case of the San Diego local area reliability criterion, implement a "San Diego Grid Reliability Action Plan" (SDGRAP). The goal of the SDGRAP would be to review San Diego's local reliability needs every two years in a routine, integrated manner and identify and implement the likely best means for meeting such needs.

5.2 Long-Term Implementation of SDGRAP

The SDGRAP's regular review of generation, transmission and other non-wires and short-wires options for meeting the San Diego local grid criterion could best be held in SDG&E's regular Long-Term Procurement Plan (LTPP) cases.[31] These LTPP cases currently only consider SDG&E's efforts to meet the needs of its bundled customers, and thus do not fully address local reliability. The Commission should change the scope of the LTPP process so that SDG&E, in a separate portion of its LTPP filing, discusses San

[31] SDG&E's current LTPP was filed December 11, 2006 in Rulemaking (R.) 06-02-013. Workshops and hearings on this LTPP and other issues are scheduled for May and June.

Diego grid reliability issues specifically, various options for meeting the criterion over the planning horizon, and the likely or possible steps that should be taken over the next few years to meet such needs.[32]

In addition to reviewing generation options for serving SDG&E's bundled customers and related issues, SDG&E's LTPP should also review San Diego's grid reliability needs, including any new local needs that emerge; identify options for meeting such needs, including local generation that may be above and beyond bundled customers' needs, new transmission projects, and non-wires and short-wires alternatives; and feature a "seven-year plan" (or something similar) that directs SDG&E to take appropriate steps to meet such needs, which may include procuring generation or proposing additional transmission projects. SDG&E's implementation of SDGRAP should also feature a direct "head-to-head" competition, when possible, between alternative generation, transmission and other solutions to local reliability needs.

A key assumption that SDG&E should include in its SDGRAP has been briefly referenced above – the likelihood that most or all existing SDG&E-divested generation will be retired by 2020. Specifically, DRA recommends that the 1,822 MW of local generation formerly owned by SDG&E should be assumed to start retiring in 182 MW increments starting in 2011 and be retired in its entirety by 2020. Table 5-1 compares this assumption to the retirement assumption underlying SDG&E's case, which envisions the 702 MW SBPP retiring in 2009 but the other 1,120 MW of divested capacity remaining in-service until 2020 – with or without RMR contracts.[33]

---

[32] The other two large Investor-Owned Utilities – the Pacific Gas and Electric Company (PG&E) and the Southern California Edison Company (SCE) – also have Local Reliability Areas (LRAs) that affect their generation and transmission planning. However, meeting the reliability needs of customers in these "load pockets" does not appear nearly as vexing to PG&E and SCE as the San Diego local reliability criterion is to SDG&E. At this time, DRA thus does not recommend changing the scope of these utilities' LTPPs to consider plans for meeting load in their LRAs.

[33] Actual annual retirements will obviously not exactly equal 182 MW per year because unit sizes all differ. Any detailed modeling of energy markets or transmission systems should reflect a specific plan for unit retirements. But the 182 MW per year retirement assumption is reasonable for basic grid planning purposes using the "G-1/N-1" rubric.

TABLE 5-1
Recommended Planning Assumptions Regarding SDG&E-Divested Capacity (MW)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SDG&E Assumptions:												
- Retirement	0	702	0	0	0	0	0	0	0	0	0	0
- Remaining	1,822	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120
Recommended SDGRAP Assumptions:												
- Retirement	0	0	182	182	182	182	182	182	182	182	182	184
- Remaining	1,822	1,822	1,640	1,458	1,276	1,094	912	730	548	366	184	0

The assumption displayed in Table 5-1 should be combined with the recent additions to SDG&E's expected capacity described in Table 3-3 and other changes that will occur as time passes to develop realistic estimates of San Diego's long-term local reliability need. Table 5-2 below shows the local reliability need DRA recommends SDG&E be directed to start planning for in its SDGRAP. This need is much lower than projected by SDG&E in 2010 – because the SBPP is correctly assumed to be available to meet local needs – but substantially higher than assumed by SDG&E in 2020, after all SDG&E-divested capacity is assumed retired.[34]

[34] DRA did not compute the reliability benefits of Sunrise or its alternatives based on the need presented in Table 5-2, but would take that step if the Commission wishes to pursue implementation of the SDGRAP or similar program.

TABLE 5-2
Recommended SDGRAP Planning Assumptions
Regarding San Diego Grid Reliability Needs
(MW)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
San Diego Reliability Surplus / (Deficiency)	814	95	93	62	37	1	(42)	(107)	(172)	(239)	(305)	(373)
- Restore SBPP Capacity in 2010	0	702	702	702	702	702	702	702	702	702	702	702
- Assume Retirements from 2011 to 2020	0	0	(182)	(364)	(546)	(728)	(910)	(1,092)	(1,274)	(1,456)	(1,638)	(1,822)
Adjusted Surplus / (Deficiency) for SDGRAP	814	797	613	400	193	(25)	(250)	(497)	(744)	(993)	(1,241)	(1,493)

DRA believes such integrated planning to meet the San Diego local reliability criterion, plus a more realistic look at San Diego's local generation fleet, is in the best interests of SDG&E's ratepayers in particular and CAISO ratepayers in general. The SDGRAP should result in a more orderly and efficient investment in the capital needed to meet San Diego's local needs over the next decade.

5.3 Initiation of SDGRAP in this Docket

The Commission should take steps in this docket to implement the SDGRAP. First, the Commission should keep this case's record open as long as reasonably possible to reflect in a final assessment of Sunrise's value the impact of any additional resource proposals SDG&E makes or receives over the next several months. For example, yesterday SDG&E received bids in response to its 2010-2012 RFO. Information about local generation alternatives that may have been bid into that RFO should be considered in this case. The Commission may even wish to consider revising the scope of the 2010-2012 RFO to consider such local resources more explicitly as means of meeting San Diego local reliability needs. SDG&E may make other proposals to the Commission this year for new San Diego area resources that should also be reflected in this case's final analysis.

In addition, the Commission should direct SDG&E to consider additional transmission alternatives in its transmission planning process, regardless of its actions on Sunrise. For example, SWPL 2 is a potentially interesting option that SDG&E could implement largely on its own. The Nevada Hydro Company's LEAPS project, plus its associated transmission, should also be encouraged to offer their capacity to SDG&E's and other utilities' competitive RFOs. Several other transmission alternatives proposed by intervenors also merit further consideration. Given the inter-utility coordination involved in developing transmission projects, however, it is not clear some of these alternatives could be implemented as quickly as new generation projects.

Finally, as discussed elsewhere, the questions raised in Section 4 about the potential for Sunrise to lead to new and offsetting local needs should also be answered in this docket – *before the Commission takes any action on Sunrise*.

6. CONDITIONS FOR CPCN

Should the Commission decide to approve a CPCN for Sunrise, several conditions should be attached thereto to protect ratepayers' interests from some major uncertainties. These conditions are described below.

6.1 Costs

6.1.1 Capital Cost Cap

The Commission traditionally imposes "cost caps" on the capital costs of new projects that receive CPCNs. The Commission should do so in this case too. However, in this case, there is an additional reason to impose such a cap – the recent rapid escalation in costs of building new generation and transmission assets adds an additional layer of uncertainty to the analysis itself, and also suggests that completing Sunrise on budget may be a major challenge to SDG&E. DRA above recommended the Commission to ensure it uses consistent capital costs in its analysis. DRA here recommends the Commission also impose a cost cap on Sunrise that will hold SDG&E to the cost estimates it has used in justifying Sunrise's value.

6.1.2 Limits on Rate Recovery Requested from FERC

The Commission no longer sets the transmission revenue requirements paid by California retail customers. That responsibility is instead exercised by the Federal Energy Regulatory Commission (FERC). In July 2006, FERC issued Order No. 679 which allows transmission owners the ability to seek higher returns on equity on their transmission assets and other financial incentives.

However, SDG&E conducted its analysis of Sunrise's economics on the assumption that it would receive its standard California-authorized returns. Clearly, if SDG&E seeks higher returns from FERC, some of Sunrise's benefits presented to the Commission would instead be transferred to Sempra shareholders and the federal Treasury in the form of higher returns and taxes on such returns.

To avoid this unfavorable outcome, the Commission should condition its CPCN on SDG&E accepting rates of return and other ratemaking provisions authorized by this Commission.

6.2 IID Uncertainties

As discussed above, several key uncertainties regarding Sunrise's value arise from the uncertainty about the future actions of the IID. CPCN conditions to address these concerns are discussed below.

6.2.1 Renewable Resource Access

As discussed, IID has signed a MOA with SDG&E and Citizens to participate in the development of Sunrise. IID is also working with LADWP to support the development of GPN. According to SDG&E:

> "…upgrades of IID's internal transmission system are needed to accommodate a large expansion of geothermal generating capacity in the Imperial Valley." (SDG&E, *Chapter VII, Supplemental Testimony*, January 26, 2007, p. 66)

However, the IID Board is currently investigating whether IID should be involved in such activities. If the IID board changes IID's direction, it is possible that IID will not make the upgrades necessary to provide access to the full array of IV-area renewables reflected in SDG&E's analyses. If not, the renewables value of Sunrise might be greatly diminished.

6.2.2 New San Felipe Substation

In addition, IID's commitment described above to develop the new San Felipe Substation may also be critical to Sunrise's potential reliability value. As noted in Section 4, import capacity at San Felipe may be critical to reducing one of the new local area requirements that Sunrise might cause. The IID Board's ongoing review of IID's participation in Sunrise is thus an obvious issue for the project's reliability benefits too.

6.2.3 Cost Recovery of New Construction

Even if IID proceeds with the above construction projects, the Commission must also address an additional uncertainty that may affect the realization of Sunrise's potential value. IID will be in a position to charge various interconnection and wheeling fees to renewable project developers, and possibly to SDG&E itself, in exchange for access to renewable power and firm import capability that the CAISO will count on in an emergency. These fees, if not specified in advance, may diminish the value of Sunrise, perhaps greatly.

To address these three concerns, the Commission should include in any CPCN a condition that SDG&E, before proceeding with major financial commitments, must negotiate an agreement with IID guaranteeing that IID will make the upgrades necessary to access fully IV-area renewable resources and provide firm emergency import capacity at the new San Felipe substation. As another condition, SDG&E should also be directed to reach agreement with IID on cost recovery terms for itself and renewable resource developers that will not impinge on the potential value of the Sunrise project.

6.3 Green Path North Construction

A final contingency the Commission should consider would offer some protection from the possibility that Sunrise's value would be diminished by LADWP's successful construction of the GPN. The Commission should consider having SDG&E approach

LADWP to explore the potential for joint development of a project before providing a final CPCN to SDG&E. Such a development might help both utilities by limiting their initial investment and minimizing potential they will have “stranded” transmission capacity. Alternately, the Commission could condition the CPCN on LADWP’s abandonment of the GPN.

7. FURTHER ANALYSES DRA WILL PERFORM

DRA will continue its analysis of Sunrise and its alternative as this case progresses. DRA anticipates providing the following analyses.

7.1 Issues Raised by Other Parties

DRA will review issues raised by other parties in response to discovery, Direct and Rebuttal Testimony, and other possible avenues. DRA will respond as appropriate to such information, likely including filing Rebuttal Testimony on June 15. DRA will also seek other appropriate avenues to introduce relevant information into the record.

7.2 Phase 2 Impacts on Sunrise Costs

When the Draft EIR/EIS is issued in August, DRA will assess the impact of the EIR/EIS's recommendations on Sunrise's cost, and will update and submit its analysis into Phase 2 of this docket.

7.3 Uncertainty Analysis

DRA will continue refining the uncertainty analysis it provided above and will provide such updated analyses at appropriate times. DRA will also help the Commission and other parties specify additional uncertainty and risk analyses that the Commission requests.

7.4 As Directed by Commission

DRA will also participate in any Commission-directed efforts to perform further analysis on Sunrise and its alternatives. As discussed above, DRA believes the Commission should require SDG&E to update its key assumptions regarding need and its modeling assumptions and perform some additional simulations, including some detailed risk analysis.

8. CONCLUSIONS

In brief, DRA summarizes its findings below.

8.1 No Recommendation Yet Regarding Sunrise CPCN

DRA does not believe the Commission has sufficient evidence yet to approve a CPCN for Sunrise. Sunrise is not needed to meet the "G-1/N-1" grid reliability criterion in San Diego in 2010 or immediately thereafter. Sunrise will yield some value to CASIO ratepayers, some of which has not been quantified in this record yet. However, there is substantial uncertainty about the level of these benefits and whether they will exceed Sunrise's costs to ratepayers. The Commission can address some of these uncertainties through including certain conditions in any grant it might make of a CPCN. But many of these other uncertainties are beyond the reach of the Commission. Unfortunately, the record to date has been sadly deficient in providing any reasonable risk analysis for the Commission's benefit.

8.2 DRA Will Weigh Results of SDGRAP and Related Analyses

DRA will review other parties' responses to Data Requests, Direct and Rebuttal Testimony, and statements at hearings, continue its own analysis of the value of Sunrise, and may provide more formal recommendations at a later date. DRA will consider in particular how well Sunrise appears to meet SDG&E's local grid reliability needs in comparison to practical alternatives based on current data regarding such needs. DRA will also consider how well the apparent uncertainty surrounding the level of Sunrise's benefits can be quantified to allow better decision-making or mitigation of risks to CAISO ratepayers.

APPENDIX A

Kevin Woodruff Qualifications

RESUME

Kevin Woodruff

Principal, Woodruff Expert Services

EXPERIENCE

WOODRUFF EXPERT SERVICES 1100 K Street, Suite 204 Sacramento, California 95814 916-442-4877 (voice) 916-442-2029 (fax) kdw@woodruff-expert-services.com November 2002 –	**PRINCIPAL** Analyze complex policy and business issues faced by electric utilities, generators, customers, and other industry players. Communicate to clients analytic findings and corollary recommendations for action. Help clients communicate findings and recommendations to other parties, including preparing expert testimony for and supporting litigation efforts.
HENWOOD ENERGY SERVICES, INC. **(now Global Energy Decisions)** April 1988 – November 2002	**PRINCIPAL CONSULTANT (as of July 1992)** Helped manage Henwood's transition into leading supplier of electric power system and market analytic software by managing complex software development and implementation projects and managing the development, marketing, and sales of software products. Helped develop Henwood's power market analysis consulting practice into national leader by managing individual projects, managing and developing other staff to provide such services, identifying and developing new and enhanced services, and marketing and selling services to new and existing clients. Provided variety of consulting services to clients with interests in energy utility industry, including preparing expert testimony and supporting litigation efforts, analyzing, modeling, and forecasting operations of power systems, power markets, and individual generating units, forecasting utility and project revenues, costs, and rates, and analyzing and consummating business transactions.
CALIFORNIA STATE UNIV, SACRAMENTO September 1994 – May 1995 (part-time)	**LECTURER IN MANAGEMENT** Taught upper division courses in Finance.
SIERRA ENERGY AND RISK ASSESSMENT May 1986 – April 1988 November 1985 – May 1986 (part-time)	**STAFF CONSULTANT** Provided clients analysis of gas and electricity project economics and utility revenues, costs, and rates.
PRIOR EXPERIENCE	Five years with private legislative reporting firm; California state economic development, regulatory, and tax agencies and Legislature; and labor organization.

EDUCATION

A.B., Economics, University of California, Berkeley, 1976
M.B.A, California State University, Sacramento, 1990

10/05

ADDENDUM 1

to Resume of Kevin Woodruff

EXPERIENCE WITH WOODRUFF EXPERT SERVICES

CLIENT	PROJECTS
THE UTILITY REFORM NETWORK 711 Van Ness Avenue, Suite 350 San Francisco, CA 94102 415-929-8876 Mr. Robert Finkelstein, Executive Director Mr. Mike Florio, Senior Staff Attorney Mr. Matt Freedman, Staff Attorney	**ANALYZE IOUs' PROPOSALS TO DEVELOP OR ACQUIRE NEW POWER PLANTS. Sep 03 – present.** Review, analyze, comment, and testify on California Investor-Owned Utilities' (IOUs') various plans to acquire or purchase output from specific new power plants. **MONITOR CALIFORNIA IOUs' SHORT- AND MID-TERM ELECTRIC PROCUREMENT. Aug 03 – present.** Review, analyze, and comment on California IOUs' short- and mid-term electric power procurement and related activities by participating in their confidential Procurement Review Groups. **ANALYZE ELECTRIC RESOURCE PLANNING AND ADEQUACY POLICIES. May 03 – present.** Review, analyze, comment and testify on California electric resource planning issues, including the Resource Adequacy Requirement and the development of new power plants. **MONITOR INITIATIVES TO CHANGE CALIFORNIA TRANSMISSION PLANNING PROCESSES. Feb 04 – Aug 05.** Reviewed, analyzed, and commented as appropriate on California state agencies' various initiatives to change transmission planning and evaluation processes.
DIVISION OF RATEPAYER ADVOCATES of the CALIFORNIA PUBLIC UTILITIES COMMISSION 505 Van Ness Avenue San Francisco, CA 94102 415-703-1418 Mr. W. Scott Cauchois, Senior Manager Mr. Scott Logan, Regulatory Analyst	**ANALYZE COST-EFFECTIVNESS OF PROPOSED TRANSMISSION LINE.** **Dec 06 – present** Leading team of consultants analyzing cost-effectiveness of San Diego Gas & Electric Company's proposed Sunrise Powerlink. **Aug 05 – Jan 07.** Led team of consultants analyzing cost-effectiveness of Southern California Edison's proposed Devers–Palo Verde No. 2 Transmission Line Project (DPV2).
NEVADA OFFICE OF THE ATTORNEY GENERAL, BUREAU OF CONSUMER PROTECTION 100 N. Carson Street Carson City, NV 89701 (775) 684-1180 555 E. Washington Avenue, Suite 3900 Las Vegas, NV 89101 (702) 486-3129 Mr. Eric Witkoski, Chief Deputy Attorney General	**ANALYZE COST-EFFECTIVNESS OF PROPOSED GENERATION AND TRANSMISSION RESOURCES. Jun 06 – Nov 06.** Led team of consultants analyzing proposals to build significant new generation and transmission resources made by the Nevada Power Company and Sierra Pacific Power Company in their 2006 Integrated Resource Plan filings.

CLIENT	PROJECTS
TEXAS OFFICE OF PUBLIC UTILITY COUNSEL 1701 N. Congress Ave., Suite 9-180 Austin, TX 78701- 512-936-7500 Mr. Clarence L. Johnson, Dir., Regulatory Analysis	**ANALYZED REASONABLENESS OF EL PASO ELECTRIC COMPANY'S POWER PURCHASES. Feb 05 – Mar 06.** Reviewed and filed testimony regarding reasonableness of three contracts signed by El Paso Electric Company in 2001 for delivery of power in 2002.
UTILITY CONSUMERS' ACTION NETWORK 3100 5th Ave., Suite B San Diego, CA 92103 619-696-6966 Mr. Michael Shames, Executive Director	**ANALYZE SAN DIEGO GAS & ELECTRIC PROPOSAL TO DEVELOP NEW POWER PLANTS. Sep 03 – Sep 06.** Review, analyze, and testify on SDG&E's plan to purchase Palomar power plant, contract for power from Otay Mesa power plant, and make other transactions. (*Joint effort with TURN.*)
PASADENA WATER AND POWER 150 S. Los Robles Ave., Suite 200 Pasadena, CA 91101 Contact Woodruff for reference.	**ESTIMATED HISTORIC GAS COSTS. Apr – May 03.** Reviewed, analyzed, and provided testimony to Federal Energy Regulatory Commission regarding the gas costs facing Pasadena Water and Power during the period from October 2000 to June 2001.
NORTHERN CALIFRONIA POWER AGENCY 180 Cirby Way Roseville, CA 95678 916-781-3636 Mr. Don Dame, Assistant GM, Power Management Mr. Thomas S.W. Lee, Mgr, Portfolio Planning	**CONFIDENTIAL PROJECT. Feb – Apr 03.**

3/07

ADDENDUM 2

to Resume of Kevin Woodruff

EXPERIENCE RELATED TO ELECTRIC RESOURCE PLANNING

Woodruff Expert Services
Sacramento, California
November 2002 to present

- Leading effort to assess value of San Diego Gas & Electric Company's proposed Sunrise Powerlink on behalf of Commission's Office of Ratepayer Advocates (ORA).
- Led effort to assess value of Southern California Edison's proposed Devers-Palo Verde No. 2 Transmission Line Project (DPV2) on behalf of ORA.
- Analyze and provide expert testimony regarding cost-effectiveness of California Investor-Owned Utilities' (IOUs') specific proposals to contract for output of or acquire electric generating projects.
- Analyze and provide analysis, including expert testimony, regarding California's electric Resource Adequacy Requirement and electric IOUs' long-term electric resource plans and short-term procurement and risk mitigation plans.
- Analyze and provide comments procurement and risk mitigation strategies as part of each IOU's Procurement Review Group.
- Led analysis of proposals to build significant new generation and transmission resources made by the Nevada Power Company and Sierra Pacific Power Company in their 2006 Resource Plan filings.
- Analyzed and provided analysis regarding California state agencies' initiatives to develop consistent process for planning for and evaluating new transmission projects.
- Monitor development of estimates of renewable transmission and other integration costs and "green tag" trading system.

Henwood Energy Services, Inc.
Sacramento, California
April 1988 to November 2002

- Modeled and analyzed long-term resource planning issues of California electric IOUs
- Modeled and analyzed short-term operations of California electric IOUs
- Prepared resource plan for municipal utility
- Managed and assisted public power entity's power supply Request for Proposal (RFP) processes
- Helped generation plant owners respond to California IOU and other RFPs for electric power
- Sold, conducted, and/or managed forecasts of power market operations and prices and related valuations of generating assets
- Prepared analyses of IOU and municipal utility revenue requirements, stranded costs, and rate design
- Managed projects to develop and implement software for electric plant and system operations, electric system forecasting and planning, risk quantification, and asset valuation
- Sold and managed projects to develop and implement maintenance planning software for vertically-integrated utilities
- Helped electric generators buy gas commodity and pipeline capacity rights
- Prepared and defended expert testimony on behalf of applicants and interveners in Commission proceedings in California and Montana

Sierra Energy and Risk Assessment
Sacramento / Roseville, California
May 1986 to April 1988 (full-time)
November 1985 to May 1986 (part-time)

- Assisted analysis for CPUC advocacy staff regarding SCE's proposed Devers-Palo Verde 2 transmission line.

APPENDIX B

Excerpt from Port of San Diego *2005 Annual Report*

Unified Port of San Diego

2005 Annual Report

A Port for the Region

The District's required debt service payments for long term debt for fiscal years ending June 30 is as follows:

	Principal	Interest	Total debt service
2006	$1,917,847	5,677,660	7,595,507
2007	2,468,411	5,109,235	7,577,646
2008	2,578,475	4,997,421	7,575,896
2009	2,701,878	4,874,031	7,575,909
2010	2,832,582	4,745,014	7,577,596
2011-2015	15,355,009	21,468,786	36,823,795
2016-2020	18,495,547	17,256,391	35,751,938
2021-2025	23,488,299	11,760,379	35,248,678
2026-2030	30,531,626	4,712,687	35,244,313
2031	1,812,784	29,478	1,842,262
Total	$102,182,458	80,631,082	182,813,540

(4) San Diego Convention Center

In 1985, the District entered into an agreement, which was subsequently amended four times, (collectively, the Original Agreement) with the City of San Diego (the City) for the management of the San Diego Convention Center (the Convention Center). The Original Agreement provides that the City will manage, operate, maintain, and promote the Convention Center, and the District will manage, operate, and maintain the parking facility of the Convention Center.

In consideration of the District's investment in constructing the Convention Center and managing, operating, and maintaining the parking facility, the City paid the District $20 ($1 per year). The City operates and maintains the Convention Center and receives all income from, and bears all expenses of, the Convention Center. The District receives all income from, and bears all expenses of, the operations and maintenance of the parking facility.

During fiscal year 1994, the District entered into a Memorandum of Understanding (MOU) with the City regarding a proposed expansion of the Convention Center (the Expansion Project). The MOU provides that the District will assist the City in the annual payment of any debt obligation created to finance the Expansion Project by contributing up to $4,500,000 per year for 20 years, not to exceed total payments of $90,000,000.

The MOU also provides that the District will reimburse the City for the cost of the program manager contract and other consultants and contractors associated with the planning, design, and construction of the Expansion Project, not to exceed $4,500,000 per year as part of the annual obligation described above. During fiscal year 1997, the District incurred expenses of $9,349,413, including a payment to the City of $9,000,000 toward the planning and design costs for the Expansion Project and $349,413 of District costs for the Expansion Project. The District does not anticipate incurring additional planning and design costs for the Expansion Project. The MOU provides that the $9,000,000 payment to the City would be applied toward the 19th and the 20th annual payments required.

During August 1998, the District entered into a series of additional agreements with the City. These agreements include (a) a Support Agreement that supersedes the 1994 MOU, (b) a 1998 Convention Center Management Agreement (the 1998 Agreement) that supersedes the Original Agreement, and (c) a Purchase Option and Lease Agreement.

The Support Agreement provides for a payment of $9,000,000 to the City, in lieu of the 17th and 18th annual payments required under the MOU upon the sale of bonds to finance the construction of the Expansion Project, and an annual payment of $4,500,000 for 16 years beginning on June 30, 1999. On September 17, 1998, the lease revenue bonds were issued to finance the construction of the Expansion Project. The debt obligation for the bonds was structured as the City's sole legal responsibility. On September 21, 1998, $9,000,000, less the costs incurred by the District for the Expansion Project in the amount of $349,413, totaling $8,650,587, was paid to the City in accordance with the terms of the Support Agreement. On June 30, 1999, the District accrued $4,500,000 representing the first annual payment, which was subsequently paid on July 1, 1999. Each year thereafter, beginning with fiscal year 2000, an annual payment of $4,500,000 has been made by the District in accordance with the terms of the Support Agreement. As of June 30, 2005, $49,500,000 has been paid to the City of San Diego under this agreement.

The 1998 Agreement contains modifications that take into account the debt financing on the Expansion Project as well as the authorization for the City to operate the expanded Convention Center. Other terms contained in the Original Agreement remain unchanged in the 1998 Agreement.

Under the Purchase Option and Lease Agreement, beginning on the closing of the bond issuance for the Expansion Project and extending through July 30, 2012, the District is required to maintain reserves in the amount of $5,500,000, which may be drawn upon by the City if the Transient Occupancy Tax (TOT) fails to increase for two consecutive years. If the TOT fails to increase for two consecutive years, the City may request the District to advance monies from the reserves in exchange for a property, which is acceptable to the District with an appraised value of at least $5,500,000. As of June 30, 2005, the District had restricted equity of $5,500,000 for the Expansion Project.

(5) South Bay Cities

In June 1995, the Board of Port Commissioners approved a Memorandum of Understanding (MOU) for each of the District's South Bay cities of Coronado, Chula Vista, National City, and Imperial Beach (collectively South Bay MOU). The MOU provides that the District shall annually set aside as restricted reserves, $9,000,000 for each of the seven years beginning July 1, 1994, to be expended for certain District projects, as shown in the Tidelands Capital Development Program adopted by the Board of Port Commissioners on April 26, 1994. The total unawarded contract cost is periodically adjusted for inflation using the Building Cost Index (BCI). As of June 30, 2005, the District had either set aside, expended, or committed to expend a total amount of $89,355,798 under the MOU. This includes the initial cost of $63,280,000, BCI escalation of $12,227,727, and $13,848,071 of additional funding from the Capital Development Program (CDP). Of this total, $22,407,729 remains to be expended at June 30, 2005.

(6) South Bay Power Plant

Pursuant to the Asset Sales Agreement between the District and the San Diego Gas & Electric Company (SDG&E), the District acquired the South Bay Power Plant (Plant) in April 1999. The District recognized that it would be in the baywide region's best interest to acquire the Plant as the means to accelerate the closure, decommission, and/or relocation of the Plant. The Plant is currently classified by the California Independent System Operator (ISO) as a "must run" plant; meaning that the Plant must remain in operation until a replacement plant is constructed or ISO removes the "must-run" designation.

The California Maritime Infrastructure Authority (Authority) issued $115,000,000 of Taxable Lease Revenue Bonds, San Diego Unified Port District South Bay Plant Acquisition Series 1999 (Series 1999 Bonds) on April 22, 1999 to assist the District with financing the acquisition of the Plant. The Series 1999 Bonds that are due

November 1, 2009 are payable solely from and secured by a pledge of rent payments sufficient to pay principal of, and interest on, the Series 1999 Bonds pursuant to a Lease Agreement between the District and Duke Energy South Bay, LLC (Duke South Bay). Duke South Bay's obligation to make such rent payments have been unconditionally guaranteed by Duke Capital Corporation, the parent company of Duke South Bay.

The Series 1999 Bonds are limited obligations of the Authority and do not constitute a debt, liability, or obligation of the Authority, the District, or the State of California. The District is not liable and the credit or taxing power of the District is not pledged for the payment of the Series 1999 Bonds or their interest, and accordingly, the Series 1999 Bonds are not reported in the basic financial statements.

The California State Legislature appropriated $15,000,000 to assist the District in acquiring the Plant to mitigate environmental and community issues. The District deposited $15,000,000 into the Property Escrow Account that has been established by the District and Duke South Bay. The escrowed funds together with their earnings are to be retained in the Property Escrow Account until such time as the funds are needed to decommission or dismantle the Plant or for the environmental remediation of the Plant site. At June 30, 2005, the balance in the property escrow account is $17,227,742, after drawdowns and income on investments. All such costs in excess of amounts available in the escrow account are the responsibility of Duke South Bay, so long as the approval to decommission and dismantle the plant is obtained and a replacement generating plant is constructed during the term of the lease, or of future operators in the event that the lease with Duke South Bay expires or is terminated. SDG&E remains responsible for the cost and performance of the environmental remediation of the Plant. The lease terminates three months from the later of the date of full payment of and retirement of the Series 1999 Bonds or the termination by the ISO of the "must run" obligations imposed on the Plant. At the termination of the Lease Agreement, Duke South Bay is required to decommission, dismantle, and remove the Plant and return the Plant site free and clear of all structures and improvements.

In fiscal year 1999, pursuant to the Real Property Contribution Agreement that was entered into between the District and SDG&E, SDG&E donated approximately 165 acres of land located beneath and adjacent to the Plant with a fair market value of $24,900,000. The land transaction was recorded as contributed capital and is included in capital assets in the basic financial statements.

The District intends to use the site for the highest and best use for the public benefit after it is returned by Duke South Bay at the termination of the Lease Agreement.

At June 30, 2005, $64,248,803.55 of the Series 1999 Bonds was outstanding.

(7) Defined Benefit Plan

(a) Plan Description

The District's defined benefit pension plan, administered by the City of San Diego's City Employees' Retirement System (SDCERS), provides retirement and disability benefits, annual cost of living adjustments, and death benefits to plan members and beneficiaries. SDCERS is an agent multiple employer public employee retirement system that acts as a common investment and administrative agent for the City of San Diego, the District, and the SDCRAA, administered by the Retirement Board of Administration (Board). San Diego City Charter, Section 144 and San Diego Municipal Code Sections 24.0100 et seq. assigns the authority to establish and amend the benefit provisions of the plans that participate in SDCERS to the Board. The plan is integrated with the Federal Social Security Program.

The Board issues a publicly available financial report that includes financial statements and required supplementary information for SDCERS. The financial report may be obtained by writing to the San Diego City Employees' Retirement System, 401 B Street, Suite 400, San Diego, California 92101, or by calling (619) 525-3650.

(b) Funding Policy

The City's Municipal Code requires member contributions to be actuarially determined to provide a specific level of benefit. Member contribution rates, as a percentage of salary, vary according to age at entry, benefit tier level, and certain negotiated contracts, which provide for the District to pay a portion of the employees' contributions. Member contribution rates (weighted average) expressed as a percentage of salary were 10.24% for general members and 13.04% for safety members. The District contributes at an actuarially determined rate; the rates for fiscal year 2005, expressed as a percentage of covered payrolls, were 19.52% for general members and 23.32% for safety members. The contribution requirements of plan members and the District are established and may be amended by the Board.

(c) Annual Pension Cost

For fiscal year 2005, the annual pension cost of $10,056,395 for the SDCERS pension plan was equal to the District's required and actual contributions. The required contribution was determined as part of the June 30, 2003 actuarial valuation using the entry age actuarial cost method. The actuarial assumptions included (a) an 8% investment rate of return, (b) projected salary increases of 4.75%, and (c) the assumption that benefits for certain members will increase after retirement. Both (a) and (b) included an inflation component of 4.25%. The actuarial value of assets was determined using techniques that smooth the effects of short term volatility in the market value of investments over a 5 year period. Any unfunded actuarially accrued liability would be funded as a level percentage of projected payrolls over a closed 30-year period.

Schedule of funding progress for SDCERS (in thousands) – (unaudited):

Actuarial valuation date	Actuarial value of asset	Actuarial accrued liability (AAL)	Unfunded AAL (UAAL)	Funded ratio	Covered payroll	UAAL as a percentage of covered payroll
June 30, 2002	$140,613	140,197	—	100.3%	$39,063	— %
December 31, 2002	125,619	137,824	(12,205)	91.1	33,995	35.9
June 30, 2003	123,884	154,300	(30,416)	80.3	34,164	89.0
June 30, 2004	141,375	175,366	(33,991)	80.6	34,916	97.4

The funding for fiscal years ended June 30, 2003 and 2004 reflects benefit increases for the District's general members. The fiscal year 2003 decrease in the funded ratio to 80.3% was a result of investment performance below the 8% assumed rate, the benefit enhancements for general members, and the one-year contribution lag policy. The funded ratio for fiscal year 2004 increased slightly to 80.6%, and the unfunded accrued actuarial liability will be amortized over the next 17 years.

APPENDIX C

CONFIDENTIAL – PROVIDED UNDER SEPARATE COVER

APPENDIX D

Imperial Irrigation District Press Release
Regarding “Green Path Prudency Review”

IMPERIAL IRRIGATION DISTRICT

FOR IMMEDIATE RELEASE: April 26, 2007
CONTACT: Kevin Kelley (760) 427-1593

NEWS RELEASE

IID Board of Directors responds to Green Path prudency review

The Imperial Irrigation District Board of Directors met in closed session Wednesday to discuss the confidential findings of the Green Path prudency review performed by D&G Energy Advisors. The IID board met with D&G consultants Geeta Oberoi Tholan and Jack Allen, who provided directors with an assessment of the district's transmission system, a regulatory, cost and technical analysis of the deal points and an evolution of the terms and conditions associated with negotiations between IID, San Diego Gas & Electric and Citizens Energy on the proposed Green Path Southwest project.

"We met with the authors of the prudency review and other IID consultants who have worked on the Green Path project," said Board President Stella Mendoza. "As a result of those candid and wide-ranging discussions, the board has identified several areas of concern that merit further attention."

Negotiations had been put on hold until the board received the final report from D&G Energy. Those negotiations will remain on hold, Mendoza said, until an updated business case can be developed for the Green Path Southwest project. The lack of a business case that IID negotiators – and the board – could rely on was cited in the report as a process weakness by the prudency review team. Other processes found to be inadequate include communication, cost/budget management and accountability.

"The board is currently defining the parameters of future negotiations," said Mendoza, "and we have asked D&G Energy to assist the board in providing independent oversight and guidance to the negotiators on a going-forward basis."

IID Energy remains committed to being constructively engaged in the development of the geothermal resource in Imperial County, Mendoza said. "The IID board requested this impartial review of the Green Path project to ensure that our ratepayers' best interests would continue to be served," she said. "That remains our goal as we prepare to resume negotiations."

# # #