Application of SAN DIEGO GAS & ELECTRIC COMPANY For Authority to Update Marginal Costs, Cost Allocation, And Electric Rate Design (U 902-E))

Application No. 07-01-__
Exhibit No.: (SDGE-02) ________

PREPARED DIRECT TESTIMONY

OF ROBERT W. HANSEN

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

JANUARY 31, 2007

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PREPARED DIRECT TESTIMONY

OF

ROBERT W. HANSEN

CHAPTER 2

I. OVERVIEW AND PURPOSE

This General Rate Case (GRC) Phase 2 Application presents San Diego Gas & Electric's (SDG&E) electric revenue allocation and rate design proposals for implementing the GRC Phase 1 electric revenue requirement changes. SDG&E's GRC Phase 1 Application (A.) 06-12-009 was filed on December 8, 2006. The GRC Phase 1 Application proposed increases to SDG&E's distribution and generation/commodity revenue requirements based on forecast test-year 2008 sales. Revenue allocation proposals, rate design proposals, and customer bill impacts presented in this filing are compared against rates effective January 1, 2007, and the proposed revenues and rate levels are revenue-neutral with SDG&E's GRC Phase 1 increase proposals. Allocations and rate designs in this proceeding may need to be updated to reflect the final outcome of SDG&E's GRC Phase 1 proceeding. Adoption of pending rate proposals such as those in SDG&E's Energy Resource Revenue Allocation (ERRA) proceeding, or in SDG&E's Advice Letter 1865-E addressing California Solar Initiative (CSI) cost recovery, will also cause variations in the rate and customer bill impacts presented in this filing. SDG&E proposes that changes approved in this proceeding be implemented on January 1, 2008 consistent with SDG&E's GRC Phase 1 implementation proposal.

The purpose of my testimony is to: (1) summarize the policies and guiding principles, sponsored by SDG&E witness Jeff Hartman in Chapter 1, that were followed in developing revenue allocation and rate proposals; (2) describe how policies were considered in developing more “cost-based” rate designs for Distribution and Generation/Commodity components; (3) present SDG&E’s proposal for continuation of the “2006 Rate Design Settlement Component” “RDSC” which SDG&E proposes to rename the “Total Rate Adjustment Component” “TRAC”; and (4) present a methodology and example for the phase-out of residential rate caps and subsidies related to Assembly Bill (AB) 1X.

As previously mentioned, allocation and rate proposals in this proceeding are designed to recover SDG&E’s GRC Phase 1 increases to distribution and commodity revenue requirements. Rate proposal impacts as presented in Chapter 6 by SDG&E witness Susan M. Claffey are measured against rates effective January 1, 2007. SDG&E uses test-year 2008 sales, sponsored by SDG&E witness Gregory Katsapis in Chapter 3, in developing its allocation and rate proposals. As presented by SDG&E witness James S. Parsons in Chapter 5, SDG&E’s electric distribution revenues will increase $138.8 million, or 16.31%, and commodity revenues will increase $11.8 million, or 0.86%. Fixed Transition Amount (FTA) bond revenues are shown as a revenue reduction due to the scheduled elimination of the rate component by 2008.

In the development of allocation and rate proposals, SDG&E has conformed to the overarching policies described by SDG&E witness Hartman. Allocation and rate proposals presented by myself and SDG&E witnesses Parsons, Claffey, David A. Borden, and Cynthia S. Fang are independent of SDG&E’s Advanced Metering Infrastructure (AMI) enabled dynamic rate proposals described by SDG&E witnesses Edward Fong and James R. Magill.

In this filing SDG&E proposes revisions to the categories of distribution, commodity (or generation), and a minor change to Ongoing Competition Transition Charges (CTC). No changes are proposed for transmission or reliability service (RS) rates that are subject to Federal Energy Regulatory Commission (FERC) jurisdiction. Also, no changes are proposed to the categories of Public Purpose Program (PPP), or nuclear decommissioning (ND) charges.

II. REVENUE ALLOCATION PRINCIPLES

SDG&E proposes revisions to revenue allocation for the categories of distribution and generation/commodity in this proceeding. The allocation proposals are based on an Equal Percent of Marginal Cost (EPMC) methodology. The proposed EPMC revenue allocations reflect the use of updated marginal cost of service studies for distribution and generation/commodity, and test-year 2008 sales. SDG&E proposes that revenue allocations be uncapped and therefore reflect SDG&E's estimate of "cost-based" allocations.

Methodological details and results of SDG&E's revenue allocation proposals are described in the testimony of SDG&E witness Parsons in Chapter 5. With the variations as described by SDG&E witness Parsons, the revenue allocation methodology for distribution is consistent with the methodology proposed by SDG&E in its most recent Rate Design Window (RDW) proceeding (A.05-02-019) which was implemented with RDW Decision (D.) 05-12-003.

The revenue allocation methodology for generation/commodity is similar to the methodology proposed by SDG&E in its most recent RDW proceeding (A.05-02-019).

SDG&E again proposes an EPMC methodology for total costs including Utility Retained Generation (URG) costs and California Department of Water Resources (DWR) costs. Generation/Commodity marginal capacity costs are based on capacity costs of a Combustion Turbine (CT) peaking unit. As more fully described by SDG&E witness Parsons in Chapter 4, SDG&E proposes a value of $76.40 per kW based on a real economic carrying charge (RECC) approach. This RECC approach is consistent with past marginal cost-of-service studies of SDG&E and complies with the California Public Utilities Commission's (Commission or CPUC) decision in SDG&E's prior RDW proceeding (D.05-12-003, Ordering Paragraph 4). SDG&E proposes that generation capacity costs be allocated to customer classes based on the top-100 hours of system load, using the results for 3 years of load data.

The proposed generation/commodity revenue allocation methodology significantly differs from SDG&E's currently-adopted methodology that was approved in SDG&E's most recent RDW proceeding in D.05-12-003. The current allocation methodology was the result of a negotiated settlement in the RDW proceedings. The RDW settlement methodology treated DWR above-market costs differently than other costs because a portion of residential usage was excluded in the allocation process.

The adopted RDW settlement methodology allocated DWR above-market costs on an equal-cent per kWh basis to all non-exempt bundled customer usage. DWR above-market costs used in the settlement allocation methodology were based on an estimate provided by Southern California Edison Company (SCE) in the DWR cost allocation proceeding that was ongoing in 2005. DWR permanent allocation methods were subsequently adopted by the Commission in D.05-06-060. Identification of DWR above-market costs and SCE's proposed methodology for allocation of DWR above-market costs are no longer relevant. SDG&E believes that DWR above-market costs (if any such costs are quantified in other Commission proceedings) should be allocated in the same manner as other commodity revenue requirements using an EPMC methodology.

III. RATE DESIGN PRINCIPLES

SDG&E proposes rate design changes to the categories of distribution, generation/commodity, and CTCs. SDG&E's intent is to balance the objective of moving toward cost-based rates with the often conflicting objectives of rate simplicity, rate change continuity, increased customer understanding of rates, and legislative or Commission-directed mandates. In addition, SDG&E has taken into consideration adverse customer bill impacts that could result from more cost-based rates. In developing SDG&E's "traditional" rate proposals SDG&E proposes no major structure changes requiring new metering prior to AMI implementation. Therefore, rate proposals described in this chapter, and those sponsored by SDG&E witnesses Claffey and Borden in Chapters 6 and 7, respectively, are not dependent on AMI deployment. Whereas, the proposals related to dynamic pricing sponsored by SDG&E witness Magill in Chapter 10 are dependent on AMI deployment.

Distribution rates for the various customer classes have been designed to recover the allocated class revenue requirements. To the extent possible, SDG&E proposes that distribution rates be set at marginal costs of providing service. For example, SDG&E proposes to adjust Basic Service Fees to more closely reflect marginal customer costs, but SDG&E proposes to mitigate customer bill impacts by increasing Basic Service Fees by no more than 20 percent. Consistent with the Commission's interpretation of AB1X rate cap requirements, SDG&E does not propose a Basic Service Fee for residential customers.

A. Residential Rates

SDG&E proposes a new residential rate option that would be applicable to customers with photovoltaic (PV) systems. Proposed Schedule DR-SES (Solar Energy System) would provide a more cost-based Time-of-Use (TOU) rate structure as compared to current Schedule DR. Consistent with requirements in Senate Bill (SB) 1, proposed Schedule DR-SES would not be limited by AB1X rate capping or baseline rate discounts. Proposed Schedule DR-SES is designed without baseline credit provisions and it will therefore provide increased rate incentives for installation of PV systems for smaller usage residential customers. The PV installation incentives are significantly increased for most residential customers as compared to incentives provided under Schedule DR-TOU, which incorporates a baseline tier structure and AB1X rate caps.

Other notable residential rate proposal structure changes include: (1) reduction in the number of usage tiers from five usage tiers to four tiers, and (2) modification of rates applicable to low-income customers taking service under the California Alternate Rates for Energy (CARE) program.

SDG&E contends that the current five-tier residential rate structure is unnecessarily complex, and is not based on the costs of providing service. To make a relatively minor movement towards cost-based rates with SDG&E's primary residential rate schedules, SDG&E proposes that all usage in excess of 200 percent of baseline usage be priced at the same rate. The current structure of applying slightly higher rates for usage in excess of 300 percent of baseline allowances (tier 5) would be eliminated.

SDG&E proposes that rates for CARE customers be modified to bring discounts for large-use CARE customers in-line with discounts for low-use CARE customers. To accomplish this, SDG&E proposes that the tier structure applicable to CARE customers be the same as for non-CARE customers, i.e. a four-tier rate structure. Net discounts would be reduced for large-use CARE customers with the incorporation of a four-tier inverted rate structure (as described previously for Schedule DR). CARE customers would continue to receive the legislated 20 percent line-item discount on their bills, as well as: exemption from the CARE surcharge, exemption from CSI charges, and exemption from the DWR bond charge. Residential rate and customer impacts are sponsored by SDG&E witness Claffey in Chapter 6.

SDG&E proposes no changes to baseline allowances in this proceeding. SDG&E witness Magill in Chapter 10 presents a study of current baseline allowances for each climate zone and residential customer type. As described by SDG&E witness Magill, the present baseline quantities appear to still closely match the target usage identified with the implementation of D.02-04-026, which addressed baseline allowances in the context of AB1X.

B. Commercial & Industrial (C&I) Rates

For medium and large C&I customers, SDG&E proposes that distribution revenue requirements in excess of Basic Service Fee revenue continue to be recovered primarily through non-coincident demand charges.

SDG&E proposes a new kWh-based charge applicable to the C&I customer class to recover allocated revenue requirements associated with: CSI program, Self-Generation Incentive Program (SGIP), hazardous substance cleanup costs, AMI Infrastructure costs, and the Advanced Metering and Demand Response Program costs. These cost categories are currently recovered in distribution rates of large C&I customers by means of demand charges. SDG&E's distribution demand charge structure is applicable only to C&I customers served at Primary and Secondary service voltages. The new kWh-based distribution rate would enable recovery from all retail C&I customers including customers at transmission and substation service voltages.

Transmission-level customers, as well as customers serviced under the Substation options, are currently bypassing costs being assessed through distribution rates. SDG&E therefore proposes a more equitable approach to eliminate the current intra-class C&I subsidies. SDG&E proposes that, similar to the method of PPP cost recovery, costs associated with the programs and cost categories described above be recovered through an equal-cent-per-kWh rate structure added to the large customer C&I tariffs. Details of the approach are described in the testimony of SDG&E witness Borden in Chapter 7.

Distribution facilities are designed to serve a circuit or customer maximum demand, no matter when the maximum demand may occur. Therefore, distribution cost recovery by means of a non-coincident demand charge is more appropriate than recovery through on-peak demand charges or through energy-based charges. Medium and Large C&I rate designs are sponsored by SDG&E witness Borden in Chapter 7.

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C. Commodity Rates

Generation/commodity rates have also been designed to more closely reflect SDG&E's marginal cost of providing service. Seasonal commodity rate differences are proposed to be incorporated in Schedule EECC (Electric Energy Commodity Cost) for several rate schedules that are currently non-seasonal. SDG&E proposes that current seasonal period definitions being used for distribution rate design also be applied to generation/commodity rate design.

SDG&E proposes that Schedule EECC TOU rates be updated to more closely reflect marginal energy cost estimates, with adjustments to reflect the class' allocated revenue requirement and to mitigate adverse bill impacts. Rates are proposed to be differentiated by service voltage to account for variations in energy losses. Uncapped generation/commodity rates based on the marginal cost study are sponsored by SDG&E witness Parsons. These unit marginal costs are then translated into rates as described for the various "traditional" rate scheduled by SDG&E witnesses Claffey and Borden, in Chapters 6 and 7, respectively.

SDG&E's current Schedule EECC generation/commodity rates are entirely energy based. SDG&E proposes that a generation demand charge be incorporated in Schedule EECC rates applicable to Medium and Large C&I rate schedules to more closely reflect costs of providing generation capacity. The demand charge should be phased-in over the next several rate design proceedings and should be designed to recover marginal generation capacity costs of $76.40 per kW based on a RECC approach. SDG&E proposes to mitigate customer bill impacts related to the new generation on-peak demand charge structure by setting the rate level at 50 percent of the cost-based level.

Since marginal generation-related capacity costs are primarily related to serving SDG&E's system peak load, the demand charge would be highly seasonal. To avoid system and meter programming changes the season definitions for the demand change would be unchanged from the currently defined summer definitions. The summer season for the C&I rate schedules would continue to be May through September.

To increase customer understanding of the new demand charge the structure of the generation demand charge should be dependent on and consistent with the existing demand rate structure of each C&I tariff. For Schedules AL-TOU, AY-TOU and PA-T-1 the demand charge would be based on monthly summer on-peak demand, with no ratchet provision. For Schedule AD, which does not currently have an on-peak demand structure, the generation demand charge would be based on the customer's monthly maximum demand during each billing period. For Schedule A6-TOU the demand charge would be based on the monthly system peak demand charge during the summer season. As described in the testimony of SDG&E witness Borden, the generation demand charges are based on results of the generation marginal cost study sponsored by SDG&E witness Parsons, multiplied by a phase-in factor of 50 percent.

IV. METHODOLOGY FOR APPLYING AB1X RATE CAP AND COST RECOVERY SURCHARGES

A. Background

In response to the energy crisis that began in the summer of 2000, AB1X was signed into law on February 1, 2001, adding Water Code §80110 that authorized DWR to procure power for California retail customers that the three investor owned utilities could not provide from their own resources. To protect residential customers from further rate increases resulting from the energy crisis, AB1X capped electric rates of 130 percent of baseline residential usage at February 1, 2001 rate levels (AB1X rate cap).

The AB1X rate cap was first implemented for SDG&E in D.01-09-059 when the Commission exempted 130 percent of baseline usage from the commodity rate increase adopted to recover higher DWR costs. The revenue shortfall resulting from the AB1X rate cap were recovered from all customer usage not protected under the rate cap through a surcharge implemented on commodity rates. Since approximately 70 percent of residential usage was protected under the AB1X rate cap provision[1], the majority of the revenue shortfall resulting from the rate cap was being allocated and recovered from non-residential customers. This allocation policy resulted in significant cross-subsidies in the rates of non-residential customers and a distortion of commodity rates of all customers.

[1] D.02-04-026 increased the residential baseline allowance in June and July 2002 which resulted in a higher percentage of residential usage being under 130 percent of baseline (increased the percentage from approximately 60 percent to 70 percent) and thus, more residential usage is under the AB1X rate cap.

The distortion of commodity rates due to these AB1X rate cap subsidies was exacerbated by the Commission's subsequent ruling in D.04-02-057 that the AB1X rate cap applies to total electric rates and not just commodity rates. For this reason, any rate increase implemented by SDG&E required residual adjustments to 130 percent of baseline commodity rates to ensure total rates do not exceed AB1X rate cap levels. This resulted in commodity rates of 130 percent of baseline usage being set well below costs while the commodity rates of all other usage needed to be set above costs to fully recover costs.

In SDG&E's 2006 RDW proceeding (A.05-02-019), SDG&E proposed the adoption of non-bypassable rate component called the TRAC to implement the AB1X rate cap and recover the revenue shortfall resulting from the rate cap. Under SDG&E's proposed (and currently-adopted) methodology commodity rates can be set at cost-based levels while the subsidies resulting from the AB1X rate cap are passed-through and fully recovered within the TRAC rate component. SDG&E stated that the benefits of this proposal are as follows: (a) commodity rate distortion is removed which will hopefully lead to more efficient energy use; (b) adopting a separate, non-bypassable charge (or credit) will ensure that the cost of providing such subsidies cannot be avoided and shifted to bundled customers by electing Community Choice Aggregation (CCA) or Direct Access (DA) service; and (c) consolidating the AB1X subsidies into the TRAC rate component will provide better information and clarity about the magnitude of AB1X subsides and their impact on the rates of various customer classes. In addition, SDG&E intent under its AB1X allocation proposal was to minimize and eventually eliminate AB1X cross-subsidies by allocating and recovering as much of the AB1X revenue shortfall within the residential class, but only to the extent that total residential revenues are kept within capped increase levels.

In D.05-12-003 the Commission adopted the all-party settlement for SDG&E's 2006 RDW Application with the exception of the TRAC terminology. Instead of approving the "TRAC" term the Commission changed the name of the mechanism from TRAC to 2006 RDSC and approved its use for allocating and recovering AB1X subsidies during the 2006 RDW term. The Commission changed the name of the rate component to 2006 RDSC to make it clear that this component is being approved for the current RDW term and that its approval does not set a precedent for approval of a similar non-bypassable rate component in SDG&E's next rate design proceeding.

B. Continuation of Non-Bypassable AB1X Rate Cap Component

If the Commission were to be considering the 2006 RDSC concept as an experimental approach to dealing with AB1X subsidies and cost recovery, then SDG&E would contend the approach has been highly successful since its implementation on February 1, 2006. SDG&E therefore proposes continuation of the RDSC non-bypassable credit/rate concept, currently being used to implement the AB1X rate cap and recover the revenue shortfall resulting from the rate cap, until the AB1X rate cap is eliminated. SDG&E proposes that the name of the rate component be changed to the Total Rate Adjustment Component (TRAC) and remain in effect until the AB1X rate cap is eliminated. The TRAC rate component should apply to all residential customers, including existing DA customers currently exempt from paying 2006 RDSC charges.[2] The rate component should continue to be included in SDG&E's electric rate schedules and the charges or credits should continue to be shown as a line-item on customer bills. Also, like the 2006 RDSC the TRAC component should allocate and recover all AB1X subsidies within the residential class to avoid any cross-subsidies.

The reasons for continuing the use of the non-bypassable rate component to implement the AB1X rate cap and recover the resulting revenue shortfall are as follows: (1) prevents commodity rate distortion that would occur if instead commodity rates were used to implement AB1X rate capping; (2) ensures that the cost of providing the AB1X subsidies cannot be avoided and shifted to bundled service customers by electing CCA or DA service; and (3) clearly identifies the level of AB1X subsidies being provided and the cost of providing such subsidies.

(1) Avoid Commodity Rate Distortion

Prior to using the 2006 RDSC to implement the AB1X rate cap, commodity rates were used to accomplish this task which resulted in distorted commodity rates. First, to maintain AB1X rate cap levels any residential rate change implemented required an offsetting adjustment to 130 percent of baseline commodity rates. Second, the revenue shortfall resulting from the AB1X rate cap were recovered by way of a commodity rate surcharge paid by usage not protected under the rate cap. The adjustments to residential commodity rates to maintain the AB1X rate cap requirement and recover the revenue

[2] Under the settlement reached in the 2006 RDW proceeding that was approved in D.05-12-003, customers that were eligible for DA under laws and regulations existing as of July 26, 2005 were provided 2006 RDSC credits but were exempt from paying 2006 RDSC charges.

shortfall from the rate cap through a commodity rate surcharge resulted in distorted commodity rates which could lead to inefficient energy use decisions.

Under the proposed approach for handling the AB1X rate cap, commodity rates can be set at cost-based levels, without price variations by usage tier, since the non-bypassable rate component handles AB1X rate capping. This allows customers to get the correct price signal regarding the cost of SDG&E providing commodity service. Since utility commodity rates are a prime consideration of customers in making peak-period energy use decisions and in evaluating options such as energy efficiency investment, customer generation investments (such as PV or other forms of self-generation), CCA or DA service, it is important that commodity rates not be distorted by AB1X subsidies. Like the 2006 RDSC, the TRAC component will ensure that such distortion does not occur in commodity rates in the future.

(2) Ensure AB1X Cost Responsibility Can Not be Avoided

Another benefit of implementing the AB1X rate cap and recovering the resulting revenue shortfall through a non-bypassable rate component is that it ensures that customers can not avoid their responsibly for paying AB1X costs. Under the TRAC mechanism, the benefits and costs of the AB1X rate cap protection will be applicable to all customers, including CCA and DA customers.

The non-bypassable treatment of the AB1X rate cap protection is appropriate for two reasons. First, it is imperative that customers not be allowed to avoid the cost of providing AB1X subsidies by switching to CCA or DA service since this would put upward pressure on the rates of remaining bundled service customers. Second, the AB1X rate cap protection applies to all utility rate components, not just commodity rates, and thus, it's appropriate to apply the AB1X rate cap benefits and costs to all customers.

(3) Clearly Identify AB1X Subsidies and Resulting Rate Impacts

As mentioned earlier, prior to the adoption of the 2006 RDSC to implement the AB1X rate cap, SDG&E's commodity rates were structured to address AB1X rate caps and to recover subsidy costs. This not only resulted in distorted commodity rates as discussed above but also hid the amount of AB1X subsidies being provided. SDG&E believes that not having this information, especially given the amount of the subsidy, can result in uneconomic energy use decisions on behalf of customers.

By using a separate rate component to implement the AB1X rate cap and to recover the resulting AB1X revenue shortfall both customers and the Commission will have better information and clarity about the magnitude of AB1X subsidies and their impact on the rates of various customer classes. Customers will have the information necessary to make efficient energy decisions and will know the price level and rate structure of the AB1X subsidies to which they are subject. In addition, using the non-bypassable component to identify the AB1X rate cap subsidies will also allow SDG&E to more easily adjust and phase-out the AB1X rate capping, as discussed in the next section.

V. PHASE-OUT OF AB1X RATE CAP

SDG&E proposes to phase-out the AB1X rate cap requirement, and associated rate subsidies, over the period that the DWR contracts expire. SDG&E's assigned contracts terminate by 2014. The duration of contracts assigned to SCE and Pacific Gas & Electric Company (PG&E) also vary and discontinue in their entirety by 2016.

Concurrent with the proposed January 1, 2008 implementation date of its GRC, SDG&E is proposing that the AB1X rate cap phase-out period begin on January 1, 2008 and be completed on January 1, 2016 when the last DWR contract assigned to any utility expires. Levelizing the phasing out of the AB1X rate cap over an eight year period will help mitigate the bill impact of eliminating the rate cap and subsidies.

SDG&E's proposal ties phase-out of the AB1X rate cap requirements with straight-line reductions each year until all of the DWR contracts have expired. AB1X rate subsidies would be phased-out by 11.1 percent per year, for 9 years, with AB1X capping and subsidies phase-out entirely by January 1, 2016.

Under SDG&E's proposal, the TRAC component consolidates all AB1X subsidies and surcharges. Therefore, AB1X capping and subsidies can be easily phased out by applying annual adjustment factors to the TRAC credits and surcharges. TRAC rates would continue to be designed to apply AB1X rate caps and subsidies, and would then be adjusted by a single annual adjustment effective January 1 of each year. SDG&E proposes the first factor of 0.89 be implemented on January 1, 2008. AB1X credits, surcharges and subsidies would be scaled to a reduced level by applying this single factor to all TRAC rates.

An alternative would be a utility-specific AB1X phase-out methodology. SDG&E could calculate an AB1X phase-out factor by multiplying the DWR contract MWs for the current year by the DWR contract MWs for the benchmark year. The benchmark year would be established as the current year of 2007, so the "TRAC Adjustment Factor" would be 100 percent, which would equate to no change. In 2008 the adjustment factor would be 64 percent, so TRAC rates could be multiplied by a single factor of 0.64 effective January 1, 2008. The TRAC Adjustment Factor could be multiplied by the current year's unadjusted TRAC rates to determine the Adjusted TRAC charges/credits for the current year.

Attachments RWH-1, RWH-2 and RWH-3 provide an illustrative calculation of TRAC rates and resulting total rates.

Attachment RWH-1 shows total of the DWR contracts (in MWs) for each utility by year based on information in Revised DWR Revenue Requirement Report, filed October 12, 2006. If a utility-specific phase-out methodology were applied, SDG&E's TRAC adjustment factors could be based on the forecasted yearly DWR contract MWs as made publicly available in the DWR's annual revenue requirement filings.

Attachment RWH-1 also shows annual AB1X phase-out factors if based on aggregate state-wide DWR contract MW levels by year, and SDG&E's proposed factors based on applying annual straight-line reductions. SDG&E proposal is that a straight-line AB1X phase-out factor be applied to TRAC credits and surcharges through 2015.

Attachment RWH-2 shows the proposed straight-line phase-out factor and SDG&E's current unbundled rates for Schedule DR. Column "(J)" shows the TRAC credits and surcharges which would be adjusted by the AB1X phase-out factor.

Attachment RWH-3 shows how TRAC rates would be adjusted annually by applying the AB1X phase-out factor. For clarity of illustrating the AB1X roll-off concept, all rate components other than the TRAC are held constant. The example shows how a phase-out of TRAC will ultimately, by 2016, allow AB1X capping and subsidies to be fully eliminated.

SDG&E currently redesigns TRAC (aka RDSC) rates with each and every retail rate change. Under SDG&E's proposal, the TRAC rates would continue to be redesigned with periodic retail rate changes. The TRAC adjustment factor would be modified only once per year. Applying the same TRAC adjustment factor to all TRAC rates ensures that AB1X credits (applicable to usage up to 130 percent of baseline) and AB1X surcharges are kept in sync. That is, when a single AB1X phase-out factor is applied to all TRAC credits and surcharges the forecast AB1X credit revenues will continue to equal the AB1X subsidy revenues that are collected.

VI. SUMMARY AND RECOMMENDATIONS

This chapter summarizes policies and "traditional" rate proposals related to recovery of the GRC Phase 1 revenue requirement requests. This chapter also describes several residential rate design proposals as well as SDG&E proposal for a TRAC component and phase-out proposal related to AB1X rate capping and subsidies.

Recommendations are as follows:

1. Revenue allocations to the classes should be uncapped. That is, class allocations should be set at cost-based levels.
2. Distribution rates should be set at cost-based levels, with no changes to distribution rate structures in this proceeding.
3. Basic Service Fees, where they currently exist, should be updated to more closely reflect SDG&E's updated estimates of marginal customer costs, but increases in Basic Service Fees should be capped at 20 percent.

4. New Schedule DR-SES should be adopted as the default Time-of-Use service option for residential customers installing new PV systems.
5. Discounts to CARE customers should be designed to pass through the legislated 20 percent bill discount. In addition, CARE customers would continue to be exempt from: DWR Bond charges, CSI costs, and the CARE surcharge.
6. Generation/commodity charges applicable to customers with demand metering should incorporate demand charges. The demand charges should be phased-in at 50 percent of the marginal cost-based level in 2008.
7. To allow cost recovery from all large C&I customers, including transmission and substation level customers, a kWh-based distribution charge should be implemented. The component would recover authorized revenue requirements associated with CSI, SGIP, DRP, hazardous substance cleanup costs, and AMI.
8. The current 2006 Rate Design Settlement component used to identify AB1X subsidies and surcharges should be renamed the Total Rate Adjustment Component (TRAC) and should continue for the duration of AB1X rate capping.
9. AB1X rate capping and associated subsidies should be rolled off in their entirety by January 1, 2016 though annual straight-line adjustments to TRAC rates.

This concludes my prepared testimony.

VII. QUALIFICATIONS OF ROBERT W. HANSEN

My name is Robert W. Hansen. My business address is 8330 Century Park Court, San Diego, California, 92123. I am Electric Rate Design Manager in the Regulatory Strategy Department for San Diego Gas & Electric Company (SDG&E). My primary responsibilities include the development of cost-of-service studies, determination of revenue allocation and electric rate design methods, analysis of ratemaking theories, and preparation of various regulatory filings.

I received a Bachelor of Science degree in Mining Engineering from South Dakota School of Mines & Technology in 1981. I received a Master of Science degree in Policy Economics from the University of Illinois in 1987, where my areas of specialization were natural resource and environmental economics. I am a Registered Professional Engineer in the State of Indiana.

From 1991 to 1998, I was employed by SDG&E as a Pricing Design Analyst and Senior Pricing Analyst. From 1998 to July 2000, I was employed by Sempra Energy as a Regulatory Policy Analyst in the Regulatory Affairs Division. From July 2000 to December 2001, I was employed by Enron Energy Services as Director – Utility Risk Management, and Director – Product Management. I have been employed in my current position since April 2002.

I have testified before the FERC and the CPUC in other proceedings.

ATTACHMENT

RWH -1

Attachment RWH-1
SAN DIEGO GAS & ELECTRIC COMPANY - ELECTRIC DEPARTMENT
GRC Phase 2 (A.07-01-___)
AB1X ROLL-OFF PROPOSAL
DWR CONTRACTS BY YEAR, BY UTILITY AND AGGREGATE

Line #		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Line #
				SDG&E								
1	Total Contract MWs	1,806	1,156	1,156	1,156	831	680	108	0	0	0	1
2	% of 2007 MW	100%	64%	64%	64%	46%	38%	6%	0%	0%	0%	2
				SCE								
3	Total Contract MWs	4,862	4,432	4,432	4,432	2,507	0	0	0	0	0	3
4	% of 2007 MW	100%	91%	91%	91%	52%	0%	0%	0%	0%	0%	4
				PG&E								
5	Total Contract MWs	4,354	4,534	4,534	2,634	2,234	1,028	277	277	277	0	5
6	% of 2007 MW	100%	104%	104%	60%	51%	24%	6%	6%	6%	0%	6
				Total								
7	State-wide Total MWs by Year	11,021	10,121	10,121	8,221	5,571	1,708	385	277	277	0	7
8	Aggregate Roll-off Factor	100%	92%	92%	75%	51%	15%	3%	3%	3%	0%	8
9	Straight-Line Roll-off Factor (Proposal)	**100.0%**	**88.9%**	**77.8%**	**66.7%**	**55.6%**	**44.4%**	**33.3%**	**22.2%**	**11.1%**	**0.0%**	9

Source: Revised DWR Revenue Requirement Report filed October 12, 2006

Attachment RWH-1

ATTACHMENT

RWH -2

Attachment RWH-2

ATTACHMENT RWH-2
SAN DIEGO GAS & ELECTRIC COMPANY - ELECTRIC DEPARTMENT
GRC Phase 2 (A.07-01-___)
PROPOSED AB1X PHASE OUT FACTORS BY YEAR, AND CURRENT RDSC (TRAC) RATES

DWR CONTRACT SCHEDULE

LINE NO.	DESCRIPTION	UNITS	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	LINE NO.
1	TOTAL of DWR Contracts	MW	11,021	11,021	10,121	10,121	8,221	5,571	1,708	385	277	277	1
2	**PHASE OUT FACTOR (Levelized)**		**100.0%**	**88.9%**	**77.8%**	**66.7%**	**55.6%**	**44.4%**	**33.3%**	**22.2%**	**11.1%**	**0.0%**	2

RESIDENTIAL SCHEDULE DR -- CURRENT UNBUNDLED UNIT CHARGES (EFFECTIVE 1-1-07)

LINE NO.	DESCRIPTION (A)	UNITS (B)	TRANSMISSION RATE (C)	DISTRIBUTION RATE (D)	PPP RATE (E)	ND RATE (F)	FTA BOND PAYMENT RATE (G)	CTC RATE (H)	RS RATE (I)	RDS (TRAC) RATE (J)	TOTAL UDC RATE (K)	EECC RATE (L)	DWR BOND RATE (M)	TOTAL RATE (N)	LINE NO.
3	Summer														3
4	Baseline Energy	$/kWh	0.00869	0.05754	0.00615	0.00046	0.00513	0.00140	0.00602	**(0.04749)**	0.03790	0.08608	0.00469	**0.12867**	4
5	101% to 130% of Baseline	$/kWh	0.00869	0.07068	0.00615	0.00046	0.00513	0.00140	0.00602	**(0.04046)**	0.05807	0.08608	0.00469	**0.14884**	5
6	131% to 200% of Baseline	$/kWh	0.00869	0.07068	0.00615	0.00046	0.00513	0.00140	0.00602	**0.05475**	0.15328	0.08608	0.00469	**0.24405**	6
7	201% to 300% of Baseline	$/kWh	0.00869	0.07068	0.00615	0.00046	0.00513	0.00140	0.00602	**0.06382**	0.16235	0.08608	0.00469	**0.25312**	7
8	Above 300% of Baseline	$/kWh	0.00869	0.07068	0.00615	0.00046	0.00513	0.00140	0.00602	**0.07965**	0.17818	0.08608	0.00469	**0.26895**	8
9	Winter														9
10	Baseline Energy	$/kWh	0.00869	0.05754	0.00615	0.00046	0.00513	0.00140	0.00602	**(0.02052)**	0.06487	0.05911	0.00469	**0.12867**	10
11	101% to 130% of Baseline	$/kWh	0.00869	0.06295	0.00615	0.00046	0.00513	0.00140	0.00602	**(0.00576)**	0.08504	0.05911	0.00469	**0.14884**	11
12	131% to 200% of Baseline	$/kWh	0.00869	0.06295	0.00615	0.00046	0.00513	0.00140	0.00602	**0.07383**	0.16463	0.05911	0.00469	**0.22843**	12
13	201% to 300% of Baseline	$/kWh	0.00869	0.06295	0.00615	0.00046	0.00513	0.00140	0.00602	**0.08265**	0.17345	0.05911	0.00469	**0.23725**	13
14	Above 300% of Baseline	$/kWh	0.00869	0.06295	0.00615	0.00046	0.00513	0.00140	0.00602	**0.10073**	0.19153	0.05911	0.00469	**0.25533**	14

ATTACHMENT

RWH -3

Attachment RWH-3

ATTACHMENT RWH-3
SAN DIEGO GAS & ELECTRIC COMPANY - ELECTRIC DEPARTMENT
GRC Phase 2 (A.07-01-___)
ILLUSTRATION OF RATES BY TIER, BY YEAR, WITH PHASE-OUT OF TRAC

RESIDENTIAL SCHEDULE DR -- TRAC RATES BY YEAR

LINE NO.	DESCRIPTION	UNITS	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	LINE NO.
												TRAC	
1	Summer		CURRENT									PHASED OUT	1
2	Baseline Energy	$/kWh	(0.04749)	(0.04221)	(0.03694)	(0.03166)	(0.02638)	(0.02111)	(0.01583)	(0.01055)	(0.00528)	0.00000	2
3	101% to 130% of Baseline	$/kWh	(0.04046)	(0.03596)	(0.03147)	(0.02697)	(0.02248)	(0.01798)	(0.01349)	(0.00899)	(0.00450)	0.00000	3
4	131% to 200% of Baseline	$/kWh	0.05475	0.04867	0.04258	0.03650	0.03042	0.02433	0.01825	0.01217	0.00608	(0.00000)	4
5	201% to 300% of Baseline	$/kWh	0.06382	0.05673	0.04964	0.04255	0.03546	0.02836	0.02127	0.01418	0.00709	(0.00000)	5
6	Above 300% of Baseline	$/kWh	0.07965	0.07080	0.06195	0.05310	0.04425	0.03540	0.02655	0.01770	0.00885	(0.00000)	6
7	Winter												7
8	Baseline Energy	$/kWh	(0.02052)	(0.01824)	(0.01596)	(0.01368)	(0.01140)	(0.00912)	(0.00684)	(0.00456)	(0.00228)	0.00000	8
9	101% to 130% of Baseline	$/kWh	(0.00576)	(0.00512)	(0.00448)	(0.00384)	(0.00320)	(0.00256)	(0.00192)	(0.00128)	(0.00064)	0.00000	9
10	131% to 200% of Baseline	$/kWh	0.07383	0.06563	0.05742	0.04922	0.04102	0.03281	0.02461	0.01641	0.00820	(0.00000)	10
11	201% to 300% of Baseline	$/kWh	0.08265	0.07347	0.06428	0.05510	0.04592	0.03673	0.02755	0.01837	0.00918	(0.00000)	11
12	Above 300% of Baseline	$/kWh	0.10073	0.08954	0.07835	0.06715	0.05596	0.04477	0.03358	0.02238	0.01119	(0.00000)	12

RESIDENTIAL SCHEDULE DR -- TOTAL RATES BY YEAR (WITH PHASE-OUT OF TRAC)

LINE NO.	DESCRIPTION	UNITS	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	LINE NO.
												AB1X	
13	Summer		CURRENT									PHASED OUT	13
14	Baseline Energy	$/kWh	0.12867	0.13395	0.13922	0.14450	0.14978	0.15505	0.16033	0.16561	0.17088	0.17616	14
15	101% to 130% of Baseline	$/kWh	0.14884	0.15334	0.15783	0.16233	0.16682	0.17132	0.17581	0.18031	0.18480	0.18930	15
16	131% to 200% of Baseline	$/kWh	0.24405	0.23797	0.23188	0.22580	0.21972	0.21363	0.20755	0.20147	0.19538	0.18930	16
17	201% to 300% of Baseline	$/kWh	0.25312	0.24603	0.23894	0.23185	0.22476	0.21766	0.21057	0.20348	0.19639	0.18930	17
18	Above 300% of Baseline	$/kWh	0.26895	0.26010	0.25125	0.24240	0.23355	0.22470	0.21585	0.20700	0.19815	0.18930	18
19	Winter												19
20	Baseline Energy	$/kWh	0.12867	0.13095	0.13323	0.13551	0.13779	0.14007	0.14235	0.14463	0.14691	0.14919	20
21	101% to 130% of Baseline	$/kWh	0.14884	0.14948	0.15012	0.15076	0.15140	0.15204	0.15268	0.15332	0.15396	0.15460	21
22	131% to 200% of Baseline	$/kWh	0.22843	0.22023	0.21202	0.20382	0.19562	0.18741	0.17921	0.17101	0.16280	0.15460	22
23	201% to 300% of Baseline	$/kWh	0.23725	0.22807	0.21888	0.20970	0.20052	0.19133	0.18215	0.17297	0.16378	0.15460	23
24	Above 300% of Baseline	$/kWh	0.25533	0.24414	0.23295	0.22175	0.21056	0.19937	0.18818	0.17698	0.16579	0.15460	24