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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

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| Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design. | Application 05-03-015 (Filed March 15, 2005) |

**COMMENTS OF SAN DIEGO GAS & ELECTRIC COMPANY
TO THE RULING OF ADMINISTRATIVE LAW JUDGE GAMSON**

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January 16, 2007

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**OF THE STATE OF CALIFORNIA**

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**TO THE RULING OF ADMINISTRATIVE LAW JUDGE GAMSON**

San Diego Gas & Electric Company (SDG&E) provides these comments[1] concerning its January 4th submission, in accordance with the December 15, 2006 Ruling of Administrative Law Judge Gamson (Ruling)[2] As SDG&E's January 4th analysis reveals, partial AMI deployment is not cost effective when evaluated using the Ruling's assumptions and, under any analysis, would be unfair to half of our residential customers. Conversely, the January 4th analysis clearly demonstrates that SDG&E's as-filed business case for full AMI deployment is reasonable even when analyzed using a 17-year life, and is cost effective when evaluated using the lowest avoided capacity values put forth in this proceeding, assuming rational demand response benefits.[3]

The central issue in this proceeding, however, is not which scenario—full or partial deployment-- is the least expensive. Rather, the question is whether or not full deployment of AMI is cost effective. As is clearly articulated in the Energy Action Plan

[1] ALJ Gamson granted SDG&E a two day extension via e-mail dated January 9, 2007.
[2] Administrative Law Judge's Ruling Reopening the Record and Requesting Further Information Regarding San Diego Gas & Electric Company's Advanced Metering Infrastructure Proposal. Via email dated January 9, 2007, ALJ Gamson granted the UCAN/DRA request for an extension of the deadline for comments, from January 11th to January 16, 2007.
[3] A partial deployment analysis that assumes the same demand response benefits assumptions would also be positive although negligibly different than full deployment.

and Commission decisions,[4] deploying AMI statewide for all customers is State policy. <u>If a reasonable business case demonstrates that full deployment is economically sound (break even or better) then partial deployment should be eliminated from consideration</u>.

The assumptions presented in SDG&E's as-filed case are correct, result in a net benefit to ratepayers of approximately $60 million, and should be adopted. SDG&E wishes to make it abundantly clear that the multiple scenarios being discussed herein are one in the same, i.e., AMI deployment consisting of the same deployment costs and types of benefits, viewed under different financial modeling assumptions. SDG&E has not changed its initial request for rate recovery reflecting a total project cost of $503.6 million[5] (until operations and associated costs related to AMI are incorporated into the next GRC (2012)).

SDG&E's business case is at least as cost effective as the PG&E AMI project the Commission recently approved and is similar in almost every respect to SCE's AMI proposal, which is supported by DRA[6]. To give further assurance that SDG&E will deploy the most cost effective AMI technology possible, however, SDG&E recommends that the final decision include a symmetrical risk sharing mechanism that will effectively give ratepayers a share of any under spending and include a certain level of shareholder risk should the project experience cost overruns.

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[4] See, for example, Joint ACR & ALJ Ruling, dated February 19, 2004, Section 3, p. 5 which states, '[w]e clarify that the Commission anticipates that full scale implementation of AMI will provide **all** customers in **all** rate classes with the option to choose dynamic and static rate structures.

[5] See SDG&E's AMI Opening Brief of 10/27/2006, p. 72 for a further breakdown of the $503.6 million project cost figure.

[6] See *ex parte* notice from DRA, calendared Dec. 18, 2006.

## I. DISCUSSION

As directed by the ALJ Ruling, SDG&E submitted a cost-effectiveness analysis of a partial advanced metering infrastructure (AMI) deployment scenario. The ALJ Ruling directed SDG&E to assume a limited deployment option whereby all Commercial and Industrial (C&I) customers would be AMI-equipped but only residential customers in the Inland Climate Zone 3 would receive AMI equipment (Ruling, p. 1).

Additionally, the ALJ Ruling directed SDG&E to perform this analysis using a set of extreme, worst case financial and demand response assumptions that are at the lowest end of the assumptions presented by parties. As could be expected, the results of this analysis demonstrated that neither full nor partial AMI deployment in the SDG&E service territory is cost effective if, one assumes, as the Ruling requires 1) a residential demand response participation level of 50%, 2) avoided capacity costs of $52/KW-year and $60/KW-year (nominal), 3) a limited business case analysis period of 17 years, and 4) the exclusion of certain demonstrable and real ratepayer benefits.

In Scenarios 6 and 7, SDG&E provided two additional full deployment scenarios to more closely mimic PG&E's financial modeling assumptions which, while not as compelling as SDG&E's preferred business case (Scenario 1), are financially viable. In addition, on January 8, 2007, the Energy Division propounded a data request that seeks analysis of another full deployment scenario -- Scenario 8 --, which eliminates from Scenario 6 the impact of residential Critical Peak Pricing (CPP) rates and assumes a 17 year analysis period (Attachment 1). In order to reflect SDG&E's response to the Energy Division request, SDG&E has revised Table 1 included in its January 4th comments, to include Scenario 8 and it is attached herein and labeled Table 1 Revised.

**Table 1 REVISED 01/16/07**

**A.05-03-015 / SDG&E's Comparative AMI Business Case Deployment Scenarios**

*Revenue Requirement – Present Value*

*Loaded, Escalated and Discounted $2006*

*($millions)*

| Scenario: | 1 | 2 | 3 | 4 | 5 | | 6 | 7 | 8 |
|---|---|---|---|---|---|---|---|---|---|
| **Assumptions:** | **Full Deployment (As Filed)** | **Partial Deployment (Per ALJ)** | **Full Deployment** | **Partial Deployment (Per ALJ)** | **Full Deployment** | **Notes:** | **SDG&E Alternative Scenario Full Deployment** | **SDG&E Alternative Scenario Full Deployment** | **Energy Div Alternative Scenario Full Deployment** |
| **Avoided Capacity Value** | $85 kW-Yr | $52kW-Yr | $52 kW-Yr | $60 kW-Yr | $60 kW-Yr | | $52 kW-Yr | $85 kW-Yr | $52 kW-Yr |
| **Analysis Period** | 2007- 2038 34 Years | 2007-2026 17 Years | 2007-2026 17 Years | 2007-2026 17 Years | 2007-2026 17 Years | | 2007-2029 20 Years | 2007-2029 20 Yrs | 2007-2026 17 Years |
| **Terminal Value** | Remaining Net Book Value | Trailing Benefits | Trailing Benefits | Trailing Benefits | Trailing Benefits | | None | None | Trailing Benefits |
| **Residential:** | | | | | | | | | |
| Deployment | Zones 2, 3, & 4 | Zone 3 only | Zones 2, 3, & 4 | Zone 3 only | Zones 2, 3, & 4 | | Zones 2, 3, & 4 | | |
| Participation | 70% | 50% | | | | | PTR-50% CPP-80% | | 70% |
| Peak Time Rebate (PTR) Rate | 65 cents | 50 cents | | | | | 50 cents | | 65 cents |
| Critcal Peak Pricing (CPP) Rate | 0 | | | | | | 80 cents | | 0 |
| Other | | | | | | | includes T-24 PCT impacts and PTR thru 2013, then default CPP | | includes T-24 PCT impacts |
| **C&I:** | | | | | | | | | |
| Participation Small Commercial | 33% | | | | | | 33% | | |
| Participation Med and Lg C&I | 100% | | | | | | 100% | | |
| Peak Time Rebate (Small C&I) | 65 cents | | | | | | 65 cents | | |
| CPP rate | 90 cents | | | | | | 90 cents | | |
| **Costs:** | | | | | | | | | |
| **Capital** | | | | | | | | | |
| Electric Meters | $210 | $96 | $171 | $96 | $171 | | $175 | $175 | $171 |
| Gas Meters | $2 | $1 | $2 | $1 | $2 | | $2 | $2 | $2 |
| Gas Modules | $86 | $37 | $69 | $37 | $69 | | $71 | $71 | $69 |
| MDMS | $13 | $10 | $12 | $10 | $12 | A | $12 | $12 | $12 |
| Other IT System Costs (ex. Head End Software) | $5 | $5 | $5 | $5 | $5 | B | $5 | $5 | $5 |
| AMI Communication System | $25 | $21 | $21 | $21 | $21 | | $23 | $23 | $21 |
| Capitalized Labor | $122 | $69 | $100 | $69 | $100 | | $100 | $100 | $100 |
| Capital Contingency | $44 | $17 | $21 | $17 | $21 | C | $26 | $26 | $21 |
| All Other | $22 | $15 | $19 | $15 | $19 | | $21 | $21 | $19 |
| **Total Capital Costs** | **$530** | **$271** | **$419** | **$271** | **$419** | | **$434** | **$434** | **$419** |
| **O&M** | | | | | | | | | |
| O&M Contingency | $9 | $4 | $9 | $4 | $9 | C | $5 | $5 | $9 |
| All other O&M Costs | $203 | $131 | $155 | $131 | $155 | | $169 | $169 | $155 |
| **Total O&M Costs** | **$212** | **$135** | **$164** | **$135** | **$164** | | **$174** | **$174** | **$164** |
| **Total Costs** | **$741** | **$406** | **$583** | **$406** | **$583** | | **$608** | **$608** | **$583** |
| **Benefits:** | | | | | | | | | |
| **Operational** | | | | | | | | | |
| O&M Operational Benefits | $304 | $105 | $211 | $105 | $211 | | $240 | $240 | $211 |
| Capital Operational Benefits | $57 | $31 | $46 | $31 | $46 | | $52 | $52 | $46 |
| Theft, OBR, Meter Calibration | $69 | $24 | $49 | $24 | $49 | | $55 | $55 | $49 |
| Transmission Deferral | $11 | $8 | $13 | $8 | $13 | | $12 | $12 | $13 |
| **Demand Response** | | | | | | | | | |
| Information Feedback | $0 | $19 | $19 | $19 | $19 | D | $19 | $19 | $19 |
| **Avoided Capacity & Energy:** | | | | | | | | | |
| Residential | $123 | $26 | $40 | $29 | $45 | | $80 | $126 | $69 |
| Title 24 PCTs -residential | $0 | $0 | $0 | $0 | $0 | E | $16 | $25 | $13 |
| C&I, < 20kW | $14 | $7 | $7 | $8 | $8 | | $7 | $11 | $6.8 |
| C&I, 20-200kW | $63 | $30 | $30 | $35 | $35 | | $30 | $49 | $30.2 |
| C&I, > 200kW | $62 | $31 | $31 | $36 | $36 | | $36 | $58 | $31.1 |
| **Other** | | | | | | | | | |
| Avoided DRP | $98 | $40 | $40 | $40 | $40 | F | $81 | $81 | $73 |
| Residual Book Value | $10 | | | | | G | | | |
| Terminal value, net O&M benefits | | $8 | $16 | $8 | $16 | | $0 | $0 | $16 |
| Terminal value, DR benefits | | $7 | $6 | $8 | $7 | | $0 | $0 | $9 |
| **Total Benefits** | **$801** | **$336** | **$508** | **$351** | **$524** | | **$626** | **$725** | **$587** |
| | | | | | | | | | |
| **Net benefits (costs)** | **$60** | **($70)** | **($75)** | **($55)** | **($59)** | | **$18** | **$117** | **$3** |

**Notes and Comments:**

**A**: Full implementation costs

**B**: All IT system costs are listed in Table 4 in SDG&E's January 4 comments and an estimate of the appropriate scalable factor. The IT infrastructure is not scalable, except for the data storage system which can be scaled by the number of meters deployed.

**C**: Assumed $583.5 million for total costs, before adjusting for the limited residential roll-out (equaling DRA's 17-year cost estimate of $607 million minus a $23.5 million adjustment for risk-sharing). Scenarios 6 & 7 contingency is derived in the same way as Scenarios 2 & 4 (calculated at 7.4% of the total costs for the '07-'11 period and therefore SDG&E assumes a symmetrical cost/reward sharing mechanism. In this case, if cost overruns occur, SDG&E is responsible for a share of the cost overruns above and beyond the reduced contingency amount of $33.8 million. Similarly, SDG&E is provided an incentive to reduce or minimize AMI project costs because expenditures below the $469.8 million will be shared between customers and SDG&E.

**D**: DRA testimony of Ted Geilen, page 10-1.

**E**: Assumes expected adoption of Title 24 standards that would require PCTs in all new residential construction and remodels beginning in 2008.

**F**: Reduced per DRA's Table 5-2 for Scenarios 2,3,4 and 5 only.

**G**: All costs are shown net of book value. As a result, residual book value benefits are shown for informational purposes only; they are not included in total benefits (only applicable to Scenario 1).

## A. As long as the full deployment business case is positive the Commission should not consider partial deployment

The Commission is considering, through the deployment of AMI, a complete departure from how the utilities currently measure energy consumption, deliver that data back to the customer and facilitate newer and better ways of achieving demand response from its customers. Partial deployment creates a hybrid utility operation that neither improves the customers' experience nor achieves new business efficiencies; rather, it creates two operating systems and bifurcates the residential customers into "have" and "have nots." If full AMI deployment is shown to be cost effective as measured by the full range of ratepayer and societal benefits that it will provide, then the Commission should authorize full AMI deployment so that all ratepayers have equal access to AMI's benefits. Such is the case here. SDG&E has demonstrated that its assumptions are reasonable and that its full deployment business case is cost effective, even when a range of assumptions are considered at their lowest level, as in Scenario 8.

Further, the list of reasons why partial deployment is operationally impractical and unsound from a customer prospective is lengthy, but notable among them are the following:

1) Operational benefits, such as meter reading, outage detection and restoration are reduced, without a commensurate reduction in costs.
2) Operating costs are not reduced by a significant amount largely because, in addition to the MDMS system, the IT communication system must be installed throughout the service territory.
3) Additional costs of parallel operating systems, operating processes, policies procedures and practices (electronic and manual meter reading).

4) Inequity among ratepayers – all ratepayers share in the costs but only the commercial and inland residential customers have the opportunity to benefit from demand response, even a higher-level of customer service, etc. Half of the residential customers would not have the opportunity to earn a PTR credit or to access their detailed energy usage information.
5) The difference in the net benefit/cost ratio between full and partial deployment is negligible.
6) Customer education would be complicated.
7) Smart Grid benefits require AMI data from all meters.

**B. Full deployment scenarios that are based on reasonable assumptions are cost effective, and in fact SDG&E's business case remains positive even when considered using very conservative assumptions, i.e. the analysis period is shortened and demand response benefits valued at $52kW Year**

In its January 4th comments, SDG&E provided two additional full deployment scenarios, Scenarios 6 and 7 which are also cost effective. Scenario 8, a full deployment scenario that assumes even more conservative analysis assumptions, is also positive (approximately break-even).

SDG&E ran full deployment Scenarios 6 and 7 to mimic closely the modeling assumptions used in PG&E's' approved business case and to demonstrate that, within the range of demand response valuations being presented in this proceeding, the SDG&E business case remains cost effective. Subsequent to filing this data, Energy Division requested that SDG&E further "strain the model" and reduce the analysis period to17 years, use $52 kWYr avoided capacity value and eliminate any residential CPP rate benefits; once again, the business case holds up and is positive (Scenario 8).

The variables used in all eight scenarios and the soundness of SDG&E's assumptions have been proven in testimony and in briefs. They are detailed and summarized below:

1. Avoided Capacity Value: Parties have based their analyses on a nominal fixed levelized value of either $52, $60 or $85 per kW year. These values represent the worth of demand response and avoided marginal generation capacity, and bracket the low and high values of the parties' positions. At the low end, the nominal $52 per kW year value is essentially a real $43 per kW year value in today's dollars. In simple terms, a value of $43 per kW year for the net value (net of energy profits) of avoided generation equates to what it would cost to purchase Combustion Turbine (CT) generation capacity at peak demand and sign such a contract over a 20 year period. This low end valuation is unreasonable. If CT generation was available at that price, the Commission should dismiss all of the utilities' AMI applications and direct them to build incremental peaking CTs. In reality, the cost of building new capacity is far higher. Even if one were to net out the expected energy profits that the incremental CT would generate, a $43 per kW-year is absurdly low. No existing 15 or 20 year contract is available just to purchase peaking capacity at $43 per kW-year from a third party. Nonetheless, even at this bargain basement valuation of demand response benefits, SDG&E's Scenarios 6 and 8 are positive.

2. Analysis Period: SDG&E stands by its business case which assumes a 34 year lifecycle. This lifecycle coincides with the longest-lived component of the AMI infrastructure as well as the approximate useful life of the peaker plants that

would otherwise be needed to provide the peaking capacity avoided by AMI-related peak demand reduction. SDG&E used the 20 year term in the scenario 6 and 7 analyses because it is comparable to the term of analysis that PG&E used in its case and is identical to the SCE December 21st 2006 AMI Preliminary Cost Benefit Analysis period. Scenario 8 used a 17 year lifecycle at Energy Division's direction. Regardless of the analysis period used, SDG&E's business case is positive using all three analysis methodologies.

3. Terminal Value: SDG&E considered multiple modeling approaches to find the one that would best capture the trailing value of the remaining assets at the end of the analysis period. SDG&E believes that the two lifecycle approach is the most accurate means of capturing this value. PG&E chose a different modeling approach, which was simulated in Scenarios 6 and 7. This analysis captures the value of the remaining useful life of any equipment at the end of the period and more or less assumes that all AMI-related equipment becomes inoperable and worthless suddenly on January 1, 2027. In Scenario 8, SDG&E includes the terminal value of the still operable AMI equipment. In all three scenarios the business case is positive.

4. Participation/Awareness Rates: For its residential Peak Time Rebate (PTR) program, SDG&E assumed a 70% awareness rate and demand response

participation comparable to the Statewide Pricing Pilot[7], (as reflected in Scenarios 1 and 8). The ALJ Ruling, however, directs SDG&E to assume a residential demand response participation level of 50%[8], (as reflected in Scenarios 2, 3, 4, 5, 6 and 7).

A 50% participation level is unreasonably low, especially in light of the Commission's decision approving the PG&E AMI proposal. That decision adopts a 40% participation level assumption for PG&E's strictly <u>voluntary</u> opt-in CPP rate for residential customers, requiring explicit customer enrollment. It is intuitive that a default incentive rate will generate substantially higher participation than a voluntary tariff. Given that all residential customers will be enrolled in SDG&E's PTR program, common sense would lead one to conclude that SDG&E's default PTR incentive program would have a significantly greater participation rate than PG&E's voluntary residential CPP program.

Listed below are other significant features of SDG&E's PTR program that set it apart from (and should make it more appealing to customers than) PG&E's voluntary CPP rate. Under the PTR program,

- Customers are not penalized if they do not change their usage patterns during peak times, but are rewarded if they do. The PTR incentive rate provides all residential customers the opportunity to reduce their bills by responding during critical peak periods;

[7] Transcript page 200 lines 6-16. Question by Mr. Shames, Answerer by Mr. Gaines:
"Q. Okay. So you're saying that 70 percent of your customers, your residential customers are going to hear about the program, and therefore 70 percent of your customers are going to participate in the program and be entitled to and actually get a rebate?
A. No. 70 percent will be aware of it. And then as Dr. George testifies, that number is utilized to evaluate the actual demand response from the customers that hear about the message, not that all of them would respond. Some will respond a lot. Some will respond less. Some will respond not at all."
[8] DRA-Exhibit 101, DRA's proposed residential PTR participation rate, Table 5-2, p. 5-8.

- The PTR has similar DR attributes to a CPP type rate, yet no impediments to participation such as penalties for non-participation or complicated enrollment;
- All residential customers will participate because their monthly bills will be either on their otherwise applicable tiered rate or have a PTR credit if the customer is able to reduce energy usage during the critical peak periods.
- Incentive Preserving Rebates also reframe scarcity "events" as opportunities to get rebates rather than as periods of extremely high prices.[9]

For these reasons, SDG&E's assumed awareness rate of 70% is far more supportable than DRA's 50% participation assumption.

5. Residential CPP Rate: In Scenarios 6 and 7, SDG&E has assumed that an eventual residential CPP rate will be rolled out concurrent with the expiration of the various DWR contracts. Through the EAP and other recent Commission decisions[10] the Commission has reaffirmed the State's focus on demand response and the importance of demand response rates *for all customers*. The AB1X roll-off after 2013 and a default CPP rate (or equivalent demand response) for residential customers reflect the reasonable assumption that at DWR energy contract obligations and associated AB1X rate caps will end and that the

[9] CSEM WP 162, Applying Psychology to Economic Policy Design: Using Incentive Preserving Rebates to Increase Acceptance of Critical Peak Electricity Pricing, Robert Letzler, December 2006.
[10] See D.06-03-024, Decision Adopting Settlement (demand response programs and budgets for 2006-2008), March 15, 2006 and D.06-11-049, Order adopting changes to 2007 Utility Demand Response Programs. Nov. 30, 2006.

Commission will be free to implement dynamic rates for residential customers. PG&E has been ordered to consider this scenario in its next General Rate Case (GRC) and to offer a proposed roll off strategy. SCE's December 21st 2006 AMI filing assumes that AB 1X rate requirements expire when SCE's DWR contracts expire 12/31/2011. Therefore, it is reasonable to assume that a residential CPP rate will be an option in the foreseeable future.

6. Title 24 PCT: The CEC is currently considering Title 24 energy code requirements that will mandate Programmable Communicating Thermostats (CPTs) for all new construction and remodeled dwellings with central air-conditioning, effective 2009 at the latest. PCTs are thermostats that receive a price-based or system reliability-based load curtailment signal will automatically reduce energy consumption by moving up the air conditioning set point. SDG&E's July 14th business case includes a retrofit program that would replace 56,000 Small and Medium C&I thermostats with PCTs.[11] SDG&E considered the residential benefits from Title 24 PCTs to be too uncertain to be considered as part of the original business case. With the passage of time, however, SDG&E now believes strongly that the revised Title 24 will be adopted and that these benefits will be realized; therefore, SDG&E's Scenarios 6, 7 and 8 assume that residential new construction will have PCTs installed pursuant to the Title 24 energy code revisions. SCE's December 21st 2006 AMI analysis also assumes that Title 24-compliant PCTs will be available and installed in new homes, as well as in HVAC retrofits requiring permits, beginning in 2009.

[11] SDG&E's business case (scenario 1) does not include any residential PCT.

7. Avoided Demand Response Program Savings: SDG&E has demonstrated that AMI-enabled demand response will reduce spending on existing and future DR programs. These programs will continue until AMI meters are deployed, but will be ramped down during the installation process, and end when AMI meter deployment is completed. Without AMI, traditional DR program costs must grow to reach the State's DR goals. This is especially true given that large C&I day-ahead programs are the only existing priced-based DR programs. Accordingly without AMI, SDG&E will need to continue and greatly increase the spending for C&I and residential day-ahead pricing programs. AMI avoids these program expenses along with their otherwise inevitable increases in real costs. Thus, these tangible program savings should be reflected as a benefit attributable to SDG&E's deployment of AMI.
8. Out of Scope Benefits: The ALJ Ruling directs SDG&E to ignore $14.5 million in operational benefits[12] in seeming concurrence with UCAN's assertion that these benefits should not be "counted" since they were not specifically called-out in the Scoping Memo. The "out of scope" benefits that UCAN wants disallowed are real avoided capital and O&M costs that represent benefits derived from reduced metering costs for load research and dynamic load profiling, which are a direct benefit of implementing AMI. It is important to note that UCAN did not attempt to prove that these benefits were invalid other than to call them out as

[12] UCAN-Exhibit 201, p. 53, Table 4, Out of Scope Benefits ($000): Possible Reprogram (productivity enhancement) SB5, $3,932 total; Title 20 (CB 10—Load Surves), $453; Special Projects (CB 10), $1,315; Load Research (CB 10), $1,810; Future DR and AC Cycling M&E (BC 10), $1,449; Avoided annual-communication cost (CB 10), 2,986; DLP Smaple (CB 10), $2,579.

being out of scope, nor did it stop UCAN from introducing Smart Grid benefits which were never contemplated in the Scoping Memo. If we are to follow this same line of logic, then the Information Feedback benefit[13] should not be included, although the ALJ Ruling presumes that it is. What seems obvious to SDG&E is that the scoping memo was not meant to provide an inclusive list of all possible AMI benefits but was, rather, intended to be a starting point for discussion. Certainly, there is no justification for excluding real benefits that have been identified by SDG&E and are funded in SDG&E'S GRC rates. These activities would be reduced or eliminated with full deployment of AMI. To exclude these tangible, quantifiable benefits because they were not "initially" identified in the original business case scoping document is simply UCAN's attempt to constrain the analysis in order to reach a preordained outcome.

**C. The Societal Benefits that will accrue from AMI, although hard to quantify, should be considered in a prudent evaluation of the business case.**[14]

SDG&E has described in testimony and in briefs many of the difficult to quantify and, sometimes, intangible benefits AMI will bring to our customers. There are many other benefits that have yet to be identified by any party but will accrue to all customers. These benefits were not included in SDG&E's financial analysis (Scenario 1) in order to provide conservative assumptions on which the Commission could make an informed decision. The total value of these societal benefits is estimated to be between $90 and $387 million net present value (NPV).

[13] The ALJ Ruling specifically directs SDG&E to include $19 million of demand response benefits as identified by DRA in Ted Geilen's errata testimony 10-1.
[14] SDG&E Briefs, page 51-53, Section 8.1 AMI delivers real, but difficult to quantify benefits.

Some of these benefits are, in fact, included in several of the analytical scenarios in Table 1 Revised above. DRA helped quantify the Information Feedback benefit, which SDG&E included in Scenarios 2, 3, 4, 5, 6, 7 and 8. SDG&E quantified the benefit derived from the implementation of time differentiated rates (TDR) and included this benefit in scenarios 6 and 7, but explicitly excluded it from Scenario 8. The individual benefit ranges are listed in Table 2 below and a discussion of each benefit item follows.

**Table 2**

| **SDG&E AMI Reply Brief Benefit Items:** | **Benefit Range ($ Millions NPV) Low** | **High** |
|---|---|---|
| Implementation of TDR Rates | $0 | $26 |
| Improved Public Safety | $11 | $15 |
| Improved Customer Service & Satisfaction | $0.18 | $0.22 |
| Environmental Benefits | $8 | $54 |
| Optimized Deployment Sequence | tbd | tbd |
| Information Feedback | $19 | $207 |
| Enabling Technologies Advancements/Developments | $24 | $48 |
| Smart Grid Benefits | $28 | $36 |
| Reading Water Meters | $0.2 | $0.5 |
| **Total** | **$90** | **$387** |

**1. Implementation of TDR Rates. $0 to $26.1 million NPV.**

Moving residential and small C&I customers from the Peak Time Rebate (PTR) to CPP when AB1X expires, could increase Demand Response (DR) benefits by $26 Million NPV. SDG&E's June 16th Supplemental testimony examined the benefits of scenarios where the PTR program is implemented when the AB1X rate cap is in effect.[15] For purposes of analysis the program is then terminated in favor of placing customers on default CPP tariffs with the ability to opt-out to an alternative rate.[16] Although not a

[15] Ex. 36 E, filed pursuant to the May 19, 2006 Ruling.
[16] Ex. 36, E June 16th 2006, Prepared Supplemental Testimony of SDG&E, at page 22.

certainty with respect to the timing, AB1X rate cap will sunset and the utilities are now considering various dynamic rates that can be implemented at that time. Therefore, it is reasonable to assume that a residential CPP rate will be an option in the foreseeable future and, as such, the demand response benefits from such a rate should be evaluated accordingly.

Moving Residential and Small C&I customers from the Peak Time Rebate (PTR) to CPP when AB1X expires, could increase Demand Response (DR) benefits by $26 million NPV. The Demand Response benefits are detailed in Table 12 on page 20 of the June 16th Supplemental testimony. SDG&E's identified $189.9 million (PV 2006 $) DR benefit in its March 28th AMI filing. The scenario titled SDG&E Recommended (AB1X ends 2013) has $216.0 million benefits. The difference is a $26.1 million increase in DR benefits for moving customers from PTR to CPP in 2013.

**2. <u>Improved Public Safety $11.5 to $15.0 million NPV</u>.**

This safety-related benefit has not been added to any of the Scenarios. It is attributable to three items:

a. Increased security & tolerance to attacks/natural disasters – taken from the EPIC 'San Diego Smart Grid Study Final Report' of Oct 2006. The EPIC "San Diego Smart Grid Study Final Report" is referenced in UCAN testimony and in SDG&E rebuttal testimony.[17]

b. Detecting customer's electrical back-feed into SDG&E's electrical system from unmapped photovoltaic (PV) or distributed generation (DG) sources.[18] A conservative estimate of the benefit resulting elimination of one safety incident

[17] UCAN Ex. 202, p. 4-14. and SDG&E Ex. 34, p. EF-6.
[18] Tr. P. 533, lines 21-25, Reguly, SDG&E 52.

every five years is included. As PV and DG develops over time this safety issue will become more relevant.

c. Quicker detection of gas leaks; quicker outage detection (and in some cases, therefore, repair of downed 'hot' wires, as well as quicker restoration of traffic signals).[19] This is a general safety related benefit resulting from AMI implementation, which can save lives. This is very difficult to quantify, but for sake of this analysis we assume a conservative value, and that one life is saved every five years.

**3. Improved Customer Service and Satisfaction. $0.18 to $0.22 million NPV.**

Customer satisfaction is another difficult to quantify benefit. The performance based ratemaking (PBR) mechanism can be used as a proxy for the value customers place on improvements in utility service and satisfaction.[20] This benefit was not added into any of the scenarios. The PBR benefit is $10,000K per tenth of a point above dead-band levels. There is a direct impact, since elimination of meter reading errors and associated erroneous bills will result in greater customer satisfaction. The maximum reward is $500,000 per year at the 89.4% very satisfied range (equates to a $110,000 per year reward). A conservative increase estimate in this area might be $20 k per year.

**4. Environmental Benefits. $8 to $54 million NPV.**

SDG&E has not included any environmental benefits in any of its analytical scenarios. The conservation effect of information-feedback can provide an additional $8

[19] Ex. 22, Ch. 2, pl EF-13, lines 4-6 Fong, SDG&E.
[20] D.05-03-023, Decision On Southern California Gas Company And San Diego Gas & Electric Company's Phase 2 Post-Test Year 2004 Ratemaking, Earnings Sharing, Incentive Proposals, And 2004 Incentive Proposals, March 17, 2005.

million NPV in $CO_2$ emission, reductions or more, as described below. DRA quoted academic literature showing real-time information-feedback allowed ratepayers to reduce whole-house electricity consumption between 6.5% and 12.9%.[21] The Business Case Assessment for Energy Service Portal by the Consortium for Electric Infrastructure to Support a Digital Society (CEIDS)[22] Steering Committee, states that a 1% decrease in California's annual electricity usage translates to almost 10 million tons of $CO_2$ reductions.[23] SDG&E's residential customers represent approximate 50% of SDG&E's energy usage and SDG&E represents over 8% of California's UDC load (4,467 SDG&E peak load / 50,270 ISO peak load). Using the low end of DRA's consumption reduction, the annual emission could be reduce by 2.6 million tons per year (50% of SDG&E's load X 8% of the States load X 10 million tons per 1% reduction X 6.5 DRA's reduction estimate). Over 17 years starting in 2013 at SDG&E's 8.23% discount rate this saving represents $8 million NPV savings when valued at $0.40 per ton of $CO_2$[24]. It should be noted that D.04-12-048 adopted a range of $8 to $25 per ton of $CO_2$ (for above, SDG&E's assumed $0.40) to explicitly account for the financial risk associated with Green House Gases (GHG) emissions in the evaluation of fossil generation bids.

AMI Demand Response can provide $46 Million NPV of reduced NOx and SOx emissions during critical peak periods and from use of distributed generation. The Smart Grid Study identified over $2.4 million a year of environmental benefits gained by

[21] DRA-Exhibit 107E (Chapter 10 Ted Geilen), p. 10-5, lines 8-10.
[22] CEIDS is a partnership between the Electric Power Research Institute and the Electricity Innovation Institute, including the Department of Energy.
[23] March 2004, Business Case Assessment for Energy Service Portal, CEIDS, page 44.
[24] Id. p. 44, $.4/ton credit (it should be noted that D.04-12-048 adopted a range of values to explicitly account for the financial risk associated with GHG emissions of $8 to $25 per ton of CO2, to be used in the evaluation of fossil generation bids.

increased asset utilization.[25] This $2.4 million a year benefit is equivalent to $46 million NPV ($2.4M / $71.8M annual system benefits * $1,433M NPV 20 year System Benefits)[26]. This benefit is further described in sections 12.6 on page 177 and sections 12.4.4 on page 174 of the Smart Grid Study.

**5. <u>Information Feedback. $19 to $207 million NPV.</u>**

Information Feedback or a Customer Portal can add as little as $19 million and potentially up to $207 million NPV to SDG&E's business case, or more. A significant element of SDG&E's AMI case is the ability to drive timely interval data to the customer and show them how their usage relates to their bill via SDG&E's Customer Portal.[27] SDG&E included this feedback portal in its requirements and costs, but does not assign a direct customer benefit. DRA valued Information Feedback at $19 million over 17 years.[28] EPIC's Smart Grid final report values the Customer Portal at $10.4 million annually.[29] The Smart Grid's $10.4 million annual benefit is equivalent to $207 million NPV ($10.4 M annual portal benefits /$141.5 M total annual benefits * $2,829 M 20-year NPV total system and societal benefits).

The CEIDS' Business Case Assessment for Energy Service Portal estimates a $15 billion NPV California value for the Energy Service Portal.[30] With SDG&E customers representing about 8% of the State's load and usage, the CEIDS value would translate to $1.2 billion NPV for SDG&E. CEIDS used a 20 year analysis time frame and a 15% discount rate.

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[25] October 2006, San Diego Smart Grid Study Final Report, Table 18, Page 56.
[26] Id. Table 18 and Table 17.
[27] SDG&E-Exhibit 30. (Chapter 10 – Rick Caruso – IT). p. RC-7, lines 7-12.
[28] DRA-Exhibit 101, Table 1-1, p.1-1, and Ch. 10.
[29] See Smart Grid Report Table 21 item 5 – Portal, page 60.
[30] March 2004, Business Case Assessment for Energy Service Portal, CEIDS, page 5.

## 6. Enabling Technologies Advancements. $24 to $48 million NPV.

SDG&E's business case includes approximately 57,000 PCTs for commercial customers,[31] but did not include the impacts for residential Title 24 PCTs. Since passage of revised Title 24 is more certain, SDG&E believes that it is entirely appropriate to include these benefits in its analysis. These benefits were included in Scenarios 6,7, and 8 ($13 to $25 million NPV). By including the benefits derived from Title-24 Programmable Communicating Thermostats (PCT) for residential customers SDG&E's AMI case can provide benefits between $24 million to $48 million NPV. The PIER Draft PCT report indicates a potential of $44.16 million annual benefit from Title -24 PCTs for California's residential customers.[32] This translates to a 10 year savings of $440 million NPV ($44.16 M annual residential savings/ $61.16 M total annual savings X $610 M NPV 10-year savings).[33] With SDG&E representing about 8% of the State's load, the Report value would translate to $35 million NPV for SDG&E. To account for PCT costs, Table 16 on page 31of the report shows a residential Benefit/Cost Ratio of 3.4 for Title 24 Climate Zone 7[34], therefore the costs would be approximately $11 million NPV ($35 M / 3.4 bc ratio). Thus the low end benefit is calculated at $24 million NPV ($35 M benefits - $11 M costs). A high end benefit is assumed to be double ($48 million NPV), based on the reports statement that benefit "values could be approximately doubled if the

[31] SDG&E Ex. 31, p PP-4, line 11.
[32] February 14, 2006, Draft Report-Demand Responsive Control of Air Conditioning via Programmable Communicating Thermostats (PCTs), PIER. table 3, page 9.
[33] Id.
[34] Not to be confused with the SPP climate zones 1-4. In the PIER report, San Diego County is Forecast Zone 7 and mapped to Title 24 California Climate Zone 13, (see Figure 15, p. 83 and Table 37, p. 84).

requirements for PCTs also applied to buildings and homes where the air conditioner is being replaced or undergoing major repairs".[35]

The Draft PCT report uses simulation results that assume various participation rates for Critical Peak Pricing (CPP). Thus it relies on AMI implementation to achieve these PCT benefits.

**7. Smart Grid Benefits. $28 to $36 million NPV.**

The San Diego Smart Grid Study Final Report shows a range of 20 year net benefits from $403 to $508 million NPV.[36] Some of these Smart Grid benefits are included elsewhere in SDG&E's business case (scenario 1-8), others are estimated here in Section C. The benefits included in scenarios 1 through 8 are Reduced Blackout Probability, Reduction in Peak Demand. The information feedback benefits of the Customer Portal benefits are included in (scenario 2-8) and discussed in section 5 above. The Environmental benefits gained by increased asset utilization, as well as increased security & tolerance to attacks/natural disasters are discussed in sections 2 & 4 above.

To eliminate any double counting, SDG&E removed these previously mentioned benefits, reducing overall Smart Grid benefits by about 30% [($1.5 M + $25.6 M + $2.4 M + 10.4 M +1.2 M annual benefits)/$141.5 M total annual benefits].[37] Lowering the Smart Grid 20 year NPV net benefits (see above) by 30% would result in $282 million to $355 million NPV net benefits. The resulting benefit range is $28 to $36 million after the value of Smart Grid benefits included elsewhere are subtracted from the total.

[35] Id.
[36] October 2006, San Diego Smart Grid Study – Final Report, EPIC, Table 20, page 59.
[37] Id. Table 18, page 56 and Table 21 page 60.

Since AMI is a key assumption used to quantify the Smart Grid Benefits,[38] a conservative 10% attribution is used in this assessment. The resulting benefit range is $28 to $36 million NPV. The San Diego Smart Grid Study analysis assumes that SDG&E will have completed AMI deployment by the end of 2010.

### 8. Reading Water Meters. $0.2 to $0.5 million NPV.

The SDG&E AMI business case mentions it will provide the *capability* to read water meters[39] but not the benefit. Reading water meters can help offset some of the fixed costs associated with the AMI communications and meter data management system. Assuming one million water meters, SDG&E charging a fee between $0.30 and $0.70 per monthly read, and assuming a 8.23% return from the miscellaneous revenues generated by these fees, the 17 year NPV is $0.2 million and the 34 year NPV is $0.5 million.

In addition, many of SDG&E's operational benefits will accrue to water utility customers. These benefits include reduced meter reading costs, earlier detection of water leaks and potential conservation benefits from water information feedback. This assessment does not quantify these water-related operational benefits.

## D. A symmetrical risk sharing mechanism is prudent to insure that ratepayers achieve cost effective deployment of AMI

In its AMI project budget, SDG&E has included a risk contingency cost element that is based on 15% of the total estimated capital cost of the project over the first 5 years (2007 -2011) to account for any unforeseen elements of cost within the project scope[40].

[38] Smart Grid Study, page 11, section 2.1.1. Key Assumptions and initial Conditions.
[39] Transcript p. 617 line 23 and p. 621 line 27.
[40] See A.05-03-015, Chapter 9, p. PC-10 - PC-11, and Transcript P. 318, lines 17-28.

Neither the prudence of including the risk contingency nor the amount included has been challenged by any party. Rather, DRA has recommended a risk allowance that is split between ratepayers and shareholders[41], identical in methodology to the risk sharing mechanism approved in PG&E's AMI proceeding. SDG&E agrees that a risk sharing mechanism is a useful means of providing added assurance that costs will stay below the stated cap. If costs exceed the cap, ratepayers and shareholders would share in the consequences. However, like PG&E, SDG&E should be allowed to recover costs that occur due to events beyond SDG&E's control[42]. In addition SDG&E believes that there is both precedent[43] and a strong logical basis for the Commission to recommend a symmetrical sharing of costs and benefits that not only punishes the utility for cost overruns, but rewards both SDG&E ratepayers and shareholders for completing the AMI project under budget. This "symmetrical" sharing method is analogous to the risk and benefit sharing mechanism adopted by the Commission in performance based ratemaking (PBR). A chief component of PBR is its revenue-sharing mechanism which allows shareholders and ratepayers to benefit when the utility's financial performance results in earnings in excess of the authorized rate of return. In the PBR context, the Commission found that "an incentive mechanism, based only on a penalty, is not an incentive[44]". SDG&E believes that symmetrical risk sharing between ratepayers and shareholders is appropriate for a capital project of this size and magnitude.

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[41] Louis Irwin testimony, pp 3-1 to 3-2

[42] SDG&E Opening Brief, pp 73 – Events outside of SDG&E's control, such as changes in the scope of the AMI Project due to governmental or regulatory actions, issuance of any order, judgment, award or decree which affects the AMI project; significant delays before or during project deployment caused by regulatory or governmental action or inaction, including delays cause by cities and local governments or permit delays; project approval beyond March 1, 2007; force majeure events that materially affect SDG&E's ability to implement the project as planned.

[43] SDG&E OB, pp. 74

[44] D. 05-03-023, FOF No. 66.

The highlights of the symmetrical risk sharing mechanism can be summarized as follows:

- Project costs, estimated to be $503.6 million over the 2007-2011 period[45], would be recovered in rates without any after-the-fact reasonableness review.

- If the Commission adopts a different total project cost for SDG&E's AMI project, the ratemaking treatment for cost overruns would be implemented for overruns above the Commission adopted project cost.

- 90% of up to the first $50 million of project costs beyond the total project cost of $503.6 million in this application would be recovered in rates without any after-the fact reasonableness review.

- 10% of up to the first $50 million of project costs beyond the total project cost of $503.6 million in this application would be borne by shareholders and not be included in AMI Project-related revenue requirements.

- Project costs in excess of $50 million over the total project cost of $503.6 million would be recoverable in rates to the extent approved by the Commission following a reasonableness review of the excess amounts.

- If total project costs fall below $503.6 million, SDG&E shareholders will share in the cost savings with ratepayers as follows: 90% to ratepayers, 10% to SDG&E shareholders[46].

**E. SDG&E business case compares favorably and is consistent with PG&E and SCE's business cases**

The state of California is leading the nation in pioneering a wide-scale deployment of AMI in its three regulated utilities' service territories. There is no existing body of data the Commission can use to compare the results of SDG&E's business case, so it is logical that the Commission and other parties would choose to compare SDG&E's

[45] The $503.6 million represents total deployment costs (that is, total costs over the 2007-2011 period) of $390.2 million in capital and $79.6 million in O&M costs in addition to the $33.8 million in contingency costs discussed herein (made up of $26.9 million in capital contingency and $6.9 million in O&M contingency).

[46] Rewards due to shareholders as a result of the sharing mechanism will be recorded and recovered in SDG&E's Reward and Penalties Balancing Account

business case to PG&E's[47] and SCE's[48]. However, the three utilities business cases are not easily comparable as many differences exist in the utilities' service territories, their operational characteristics and in the financial methodologies each used. The three utilities are cooperating and are in constant communication regarding their findings as they move forward with their respective business cases.

DRA has recommended that SDG&E withdraw its application and wait to apply the findings that SCE will propose in its application and has further suggested that SDG&E could benefit from the added functionality that SCE's proposed technology will provide. This would simply be a waste of time and an unnecessary delay in the deployment of AMI. SCE and SDG&E are on similar deployment schedules, although the regulatory schedules are different. Except for the inclusion of an electric remote disconnect (SCE is considering) both utilities are considering similar technologies with the same functionality.

The aforementioned notwithstanding, SDG&E has made an effort to create an apples-to- apples comparison of the SCE and PG&E business case as presented in Table 3 below. Comparison of the relative costs and benefits is further complicated by the differences in the size of the three utilities. SDG&E, has a far more efficient meter reading operation, making it difficult to achieve a resounding and proportionally larger share of operational benefit. On the other hand, the fixed costs that are more or less the same for all three utilities, must be disbursed among SDG&E's smaller customer meter population. Therefore, SDG&E's costs are higher on a per meter basis.

[47] PG&E's AMI application was adopted in D.06-07-027approving revenue requirement of $1.7 billion
[48] SCE filed its predeployment application, A.06-12-026 on December 21, 2006 seeking $67 million in predeployment activities.

When looking at like analysis assumptions and durations (20 yrs), SDG&E's per meter cost (Scenarios 6 and 7) are within 10% of the other utilities', and the Benefit to Cost Ratios are comparable.  As the results of this comparison demonstrate, SDG&E's business case compares favorably to the other utilities filed business cases.

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**Table 3**

**SDG&E / PG&E / SCE**
**AMI Business Case Comparison**
($s in millions except per meter numbers)

| | **SDG&E Scenario 1** as filed 7/14/06 | **SDG&E Scenario 6** | **SDG&E Scenario 7** | **SDG&E Scenario 8** | **PG&E** as filed 10/13/05 & adjudicated in D.06-07-027 | **SCE** as filed 12/21/06 |
|---|---|---|---|---|---|---|
| Avoided Capacity Value | $85 kW Year | $52 kW Year | $85 kW Year | $52 kW Year | $52 kW Year | $56 - CPP / $92 - TOU / $49 - PCTs |
| Analysis Period | 34 Years | 20 years | 20 Years | 17 Years | 20 Years | 20 Years |
| Rate Assumptions | | | | | | |
| Proposed Rollout Scope | Full Deployment (throughout territory / all customer classes) | | | | | |
| Total Costs (PVRR) | $741 | $608 | $608 | $583 | $2,258 | $1,197 |
| *Total Cost per meter* | *$322* | *$264* | *$264* | *$253* | *$251* | *$239* |
| Operational Benefits (PVRR) | $442 | $358 | $358 | $319 | $2,024 | $678 |
| *Op benefits per meter* | *$192* | *$156* | *$156* | *$139* | *$225* | *$136* |
| Op Benefit 'cost coverage' ratio | 59.6% | 58.9% | 58.9% | 54.7% | 89.6% | 56.6% |
| DR Benefit 'Gap' (dif between Costs and Op Benefits) | $299 | $250 | $250 | $264 | $234 | $519 |
| *DR Gap as a % of overall costs* | 40.4% | 41.1% | 41.1% | *45.3%* | 10.4% | 43.4% |
| DR Benefits (PVRR) | $262 | $188 | $287 | $169 | $270 | $626 |
| *DR benefits per meter* | *$114* | *$82* | *$125* | *$74* | *$30* | *$125* |
| Avoided DRP & Terminal value Benefit | $108 | $81 | $81 | $98 | $0 | $0 |
| Total Benefits (PVRR) | $801 | $626 | $725 | $586 | $2,294 | $1,304 |
| *Total benefits per meter* | *$348* | *$272* | *$315* | $255 | *$255* | *$261* |
| Overall PVRR | $60 | $18 | $117 | $3 | $36 | $107 |
| Benefit/Cost Ratios | 1.081:1 | 1.03:1 | 1.192:1 | 1.005:1 | 1.016:1 | 1.089:1 |
| | | | | | | |

- Cost per meter for all three Utilities AMI cases are within 10% of each other, utilizing comparable methodology
- AMI can be made cost effective for SDG&E even at $52 (Scenario 6 & 8)
- SDG&E's Benefit to Cost ratio is comparable to both PG&E and SCE

## II. CONCLUSION

SDG&E has presented for Commission approval a proposal to immediately and fully deploy AMI. As shown throughout this proceeding, SDG&E's AMI business case is cost effective, well reasoned and its benefits to customers are considerable. In its response to the December 15, 2006 Ruling reopening the record in this proceeding, SDG&E has been able to thoroughly test the soundness of its business case by applying three additional financial analysis models to its costs and benefits.

Even when modeled using nearly all of the intervenors' overly pessimistic assumptions, SDG&E's case is still cost-effective from a revenue requirement perspective. With the inclusion of significant but uncounted, Societal Benefits, and the overwhelming state policy support for AMI and DR, the Commission should have no hesitation approving this application and directing SDG&E to begin deploying AMI to all of its customers.

Respectfully submitted,

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Senior Counsel for:
SAN DIEGO GAS & ELECTRIC
COMPANY

# ATTACHMENT 1

**ENERGY DIVISION DATA REQUEST NUMBER 2**
**REVISED 01/09/2007**
**SDG&E AMI A.05-03-015**
**SDG7E RESPONSE DATED: 01/11/07**

**SDG&E AMI Technical Requirements:**

**Question 1:**

Please isolate the value of PCTs on deployment scenario 6 by assuming a 17 year analysis period and no residential default CPP impacts.

**SDG&E Response 1:**

In order to capture the effects of the PCT's on the AMI business case with a 17 year analysis and no default CPP, SDG&E is providing Scenario 8. Scenario 8 includes 13 million in incremental PCT benefits for the residential class, uses a 17 year analysis period and assumes a 65 cent PTR rebate with 70% awareness for the residential class.

The residential Title 24 PCT benefits for this scenario were calculated as follows:

- The elasticities for the customers with PCTs were drawn from the Track C CPP-V section of the SPP experiment. All of the customers in this section of the experiment were single family homes with air-conditioning.
- SDG&E estimated the percentage of new construction that is single family with air-conditioning as follows.
    - According the 2003 RASS study, 64% of single family homes built between 2001 and 2003 have air-conditioning.
    - Removing multi-family customer's results in an estimate of 56% of new construction which is single family with air-conditioning. Therefore, the PCT elasticities were applied to 56% of customers whose homes are built after 2008.
- The average load shape for air-conditioning customers from the SDG&E June 16th filing was used for the average load for these customers. These customers provide roughly 26 million in demand response benefits, about 50% of which is attributable to the thermostat, resulting in an incremental PCT estimate of 13 million dollars.

All 8 scenarios are in the attached excel spreadsheet.

ALJ Summary
Table.xls

**SDG&E Response 1-Continued:**

SDG&E has extracted Scenario 1, 6 and 8 in the following:

| **Scenario #** | ***1*** | ***6*** | ***8*** | ***Notes:*** |
|---|---|---|---|---|
| **Assumptions:** | **SDG&E As Filed Full Deployment** | **SDG&E Alternative Scenario Full Deployment** | **Energy Division Alternative Scenario Full Deployment** | |
| **Avoided Capacity Value** | $85 kW-Yr | $52 kW-Yr | $52 kW-Yr | |
| **Analysis Period** | 2007- 2038<br>34 Years | 2007-2029<br>20 Years | 2007-2026<br>17 Years | |
| **Terminal Value** | Remaining Net Book Value | None | Trailing Benefits | |
| **Residential:** | | | | |
| Deployment | Zones 2, 3, & 4 | | | |
| Participation | 70% | PTR-50%<br>CPP-80% | 70% | |
| Peak Time Rebate (PTR) Rate | 65 cents | 50 cents | 65 cents | |
| Critical Peak Pricing (CPP) Rate | 0 | 80 cents | 0 | |
| Other | | includes T-24 PCT impacts and PTR thru 2013, then default CPP | includes T-24 PCT impacts | |
| **C&I:** | | | | |
| Participation Small Commercial | 33% | | | |
| Participation Med and Lg C&I | 100% | | | |
| Peak Time Rebate (Small C&I) | 65 cents | | | |
| CPP rate | 90 cents | | | |
| **Costs:** | | | | |

**SDG&E Response 1-Continued:**

| **Capital** | | | | |
|---|---|---|---|---|
| | | | | |
| Electric Meters | $210 | $175 | $171 | |
| Gas Meters | $2 | $2 | $2 | |
| Gas Modules | $86 | $71 | $69 | A |
| MDMS | $13 | $12 | $12 | B |
| Other IT System Costs (ex. Head End Software) | $5 | $5 | $5 | |
| AMI Communication System | $25 | $23 | $21 | |
| Capitalized Labor | $122 | $100 | $100 | C |
| Capital Contingency | $44 | $26 | $21 | |
| All Other | $22 | $21 | $19 | |
| **Total Capital Costs** | **$530** | **$434** | **$419** | |
| **O&M** | | | | C |
| O&M Contingency | $9 | $5 | $9 | |
| All other O&M Costs | $203 | $169 | $155 | |
| **Total O&M Costs** | **$212** | **$174** | **$164** | |
| **Total Costs** | **$741** | **$608** | **$583** | |
| **Benefits:** | | | | |
| **Operational** | | | | |
| O&M Operational Benefits | $304 | $240 | $211 | |
| Capital Operational Benefits | $57 | $52 | $46 | |
| Theft, OBR, Meter Calibration | $69 | $55 | $49 | |
| Transmission Deferral | $11 | $12 | $13 | |
| **Demand Response** | | | | |
| Information Feedback | $0 | $19 | $19 | D |
| Avoided Capacity & Energy: | | | | |
| Residential | $123 | $80 | $69 | |
| Title 24 PCTs –residential | $0 | $16 | $13 | E |
| C&I, < 20kW | $14 | $7 | $6.8 | |
| C&I, 20-200kW | $63 | $30 | $30.2 | |
| C&I, > 200kW | $62 | $36 | $31.1 | |
| **Other** | | | | |
| Avoided DRP | $98 | $81 | $73 | F |
| Residual Book Value | $10 | | | G |
| Terminal value, net O&M benefits | | $0 | $16 | |
| Terminal value, DR benefits | | $0 | $9 | |
| **Total Benefits** | **$801** | **$626** | **$587** | |
| **Net benefits (costs)** | **$60** | **$18** | **$3** | |

**SDG&E Response 1-Continued:**

| **Notes and Comments:** |
|---|
| **A**:  Full implementation costs |
| **B**:  All IT system costs are listed in Table 4 in SDG&E's January 4 comments and an estimate of the appropriate scalable factor.  The IT infrastructure is not scalable, except for the data storage system which can be scaled by the number of meters deployed. |
| **C**:  Assumed $583.5 million for total costs, before adjusting for the limited residential roll-out (equaling DRA's 17-year cost estimate of $607 million minus a $23.5 million adjustment for risk-sharing).  Scenarios 6 & 7 contingency is derived in the same way as Scenarios 2 & 4 (calculated at 7.4% of the total costs for the '07-'11 period and therefore SDG&E assumes a symmetrical cost/reward sharing mechanism.  In this case, if cost overruns occur, SDG&E is responsible for a share of the cost overruns above and beyond the reduced contingency amount of $33.8 million.  Similarly, SDG&E is provided an incentive to reduce or minimize AMI project costs because expenditures below the $469.8  million will be shared between customers and SDG&E. |
| **D**:  DRA testimony of Ted Geilen, page 10-1. |
| **E**:  Assumes expected adoption of Title 24 standards that would require PCTs in all new residential construction and remodels beginning in 2008. |
| **F:**  Reduced per DRA's Table 5-2 for Scenarios 2,3,4 and 5 only. |
| **G:**  All costs are shown net of book value.  As a result, residual book value benefits are shown for informational purposes only; they are not included in total benefits (only applicable to Scenario 1). |

## CERTIFICATE OF SERVICE

I hereby certify that pursuant to Commission's Rules of Practice and Procedure, I have this day served a true and correct copy of **COMMENTS OF SAN DIEGO GAS & ELECTRIC COMPANY TO THE RULING OF ADMINISTRATIVE LAW JUDGE GAMSON** to each party of record on the service list in A.05-03-015 via electronic mail. Those parties without an email address were served by placing copies in properly addressed and sealed envelopes and depositing such envelopes in the United States Mail with first-class postage prepaid.

Executed this 16th day of January, 2007 at San Diego, California

/S/ DEANNA M. PORTER

___________________________

Deanna M. Porter

# CALIFORNIA PUBLIC UTILITIES COMMISSION
## Service Lists

**Proceeding: A0503015 - SDG&E - FOR ADOPTION**
**Filer: SAN DIEGO GAS & ELECTRIC COMPANY**
**List Name: LIST**
**Last changed: January 10, 2007**

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# Appearance

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