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

CHAPTER 22

Prepared Rebuttal Testimony

of

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SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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I. Introduction

The purpose of my rebuttal testimony is to refute the erroneous conclusions of DRA and UCAN as they pertain to the derivation of the value of AMI enabled demand response and avoided generation capacity. DRA and UCAN address the net capacity value of a gas combustion turbine (CT) in their AMI capacity valuations. The net capacity value of a CT is generally accepted as the annual fixed costs of a CT minus the market energy benefits the CT could earn. My review of UCAN and DRA net CT value leads to the following conclusions:

- UCAN's net CT values are much larger once UCAN's energy benefits of a CT are corrected to a real 2006 value and adjusted for Southern California market conditions.
- DRA inflates the net market energy benefits for CTs based on a faulty assessment of SDG&E's methodology and inappropriately escalates SDG&E's value using an unjustified price ratio.

This traditional capacity valuation fails to address the Additional Value of AMI Enabled Demand Response.

An important element of SDG&E's capacity valuation is the Additional Value of AMI Enabled Demand Response. Just as the market energy benefit of a CT must be considered, the additional value of AMI enabled demand response must also be considered. This additional value is above and beyond the traditional net capacity value of a CT. The Additional Value of AMI Enabled Demand Response includes:

- Reduced Demand Volatility and Planning Reserves;
- Increase Rate Design Flexibility;
- Additional Reliability Value; and
- Other unique benefits of AMI.

These benefits are fully discussed in my July 14 testimony. Both DRA and UCAN identify additional AMI benefits in their August 14 testimony. DRA describes the value of Information Feedback Systems.[1] UCAN lists several benefits including a Consumer Portal.[2]

My review of UCAN and DRA testimony leads to the following conclusions:

- All parties agree that the fixed capacity cost of a CT is at least $85/kW-year in levelized nominal dollars.
- UCAN does not address or dispute the additional values proposed by SDG&E; and
- DRA discounts SDG&E's additional values based on faulty logic and without fully considering the potential benefits.

Once the issues regarding the additional value of AMI enabled demand response and net CT value are considered, SDG&E's valuation is appropriate.

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[1] DRA, Analysis of SDG&E's AMI Business Case, 8/14/06, Ted Geilan, Chapter 10.
[2] UCAN, Summary of UCAN Testimony and Selected Issues Relating to Expenditures for SDG&E's 2006 AMI application, 8/14/06, pages 8 to 13.

Table JCM-1 below summarizes the position of SDG&E, DRA, and UCAN based on direct testimony to date. SDG&E recommends a real 2006 value of $60/kW-Year (equitant to a nominal levelized $85/kW-Year). DRA recommends a $52/kW-Year value. UCAN proposes a real 2006 value range of $52/kW-Year or $20/kW-Year.

Table JCM-1

Capacity Value of SDG&E's AMI Enabled Demand Response
Comparison of Parties Values
(Summarized from Direct Testimony of Parties)

	($/kW-Year)		
	SDG&E	**DRA**	**UCAN**
Capacity Components:			
1. Avoided Fixed Generation Capacity	60.00	85.00	82 to 71
2. Gas CT Market Energy	-22.89	-35.37	-52 to -35
Net CT Cost	37.11	49.63	52 to 7
Additional Value of AMI enabled Demand Response:			
3. Resource Availability		-14.89	
4. Reduced Demd. Vol. & Planning Reserves	1.51	0.00	
5. Increased Rate Design Flexibility	13.79	7.50	
6. Additional Reliability Value (range)	0.021 to 0.53	0.021 to 0.53	
Calculated Sum	52.94	42.29 to 42.61	
7. Additional Unique Benefits	7.06	8.39 to 9.07	
Recommended Value	60	52	52 to 20

The following discussion points out various issues regarding each party's values.

1. Avoided Fixed Generation Capacity:
    - SDG&E's $85/kW-Year nominal levelized value is equivalent to a $60/kW-Year real escalating value as presented in table JCM-1.
    - DRA accepts SDG&E's nominal $85/kW-Year value but includes real escalating Additional Values in their analysis. DRA should not mix real and nominal values.
    - UCAN calculates real escalating values for fixed (gross) generation capacity, but subtracts nominal levelized Market energy benefits. UCAN should not mix real and nominal values.
2. Gas CT Market Energy:
    - SDG&E calculates a $22.89/kW-year real escalating value based on data used for SDG&E's 2004 Long Term Resource Plan filing.
    - DRA adjusts SDG&E's real value to $35.37 based on a flawed interpretation of SDG&E's methodology. Furthermore the adjustment ratio used by DRA is also flawed.
    - UCAN presents a range of nominal CT market energy benefits which are subtracted from their real capacity costs, resulting in a mismatch of real and nominal values.

3. Resource Availability:
   - SDG&E does not adjust AMI enabled demand Response for resource availability.
   - DRA reduces the resource availability based on faulty assumptions regarding CT reliability run hours and LOLP allocations assuming restricted operational parameters for Demand Response.
   - UCAN does not include a value but makes similar arguments as DRA using assumptions of restricted operations of Demand Response.
4. Reduced Demand Volatility & Planning Reserves:
   - SDG&E calculates a real $1.51/kW-year based on the ability of AMI enabled demand response to reduce the level of planning reserves by 1%.
   - DRA does not recognize this benefit.
   - UCAN does not address SDG&E's proposed values.
5. Increased Rate Design Flexibility:
   - SDG&E calculates a real $13.79/kW-Year value based on the additional value Real-Time pricing could provide above and beyond SDG&E's AMI proposal of CPP and PTR.
   - DRA recommends a real $7.50/kW-Year value by discounting SDG&E's value based on incorrect assumed market conditions, and the current long term generation contracts.
   - UCAN does not address SDG&E's proposed values.
6. Additional Reliability Value:
   - SDG&E proposes a range of value based on the ability of Programmable Communicating Thermostats (PCT)s avoiding un-planned outages.
   - DRA does not contest SDG&E's value.
   - UCAN does not address SDG&E's proposed values.
7. Additional Unique Benefits:
   - SDG&E does not quantify the additional unique benefits of AMI such as peak fuel diversity, reduction on market power of generators, smart home integration, and other demand side management innovations. The real 2006 value of $7.06 in Table 1 is calculated based on the difference in benefits proposed by SDG&E and SDG&E recommended real 2006 value of $60/kW-Year.
   - DRA does not quantify the additional unique benefits of AMI. The value in Table 1 is but based on the difference in benefits proposed by DRA and DRA recommended value of $52/kW-Year.
   - UCAN does not address SDG&E's unique benefits, but introduces several values from their Smart Grid proposals, such as a Consumer Portal.

II. SDG&E's Capacity Valuation of Demand Response Captures the Benefits Unique to AMI and is the Best Methodology for Purposes of Analyzing AMI Business Case

A. UCAN fails to the "do careful analysis that does not mix real and nominal dollars"[3] they recommend the Commission must do.

UCAN fails to perform its own careful analysis and mixes real and nominal dollars, exactly what they caution against in Table 13 of their August 14, 2006 AMI analysis (page 116). Table 13 calculates a range of net CT costs two different ways; as a nominal levelized cost, and as a real economic carrying charge which escalates for inflation. Unfortunately, UCAN uses the same nominal CT Market Earnings values to calculate both values. By doing so, UCAN creates a fundamental mismatch with the energy costs.

The market energy values provided by UCAN are from a PG&E's filing,[4] and from a UCAN CT dispatch analysis. The PG&E value is a nominal levelized cost for 2008 through 2013.[5] The UCAN value is a nominal 2011 value using data from their E3 avoided cost model. UCAN subtracts these nominal values from their real CT fixed costs to incorrectly represent their real net CT costs. In other words, UCAN has mismatched real escalating values (fixed CT costs) with nominal levelized values (CT energy profits).

B. UCAN over-estimates the real 2006 CT market earnings, by using nominal values, thus UCAN under-estimates the real net CT cost.

Three nominal estimates of CT market energy sales are provided by UCAN in their Figure 8 (page 113). Figure 8 shows nominal values ranging from a low of \$51.90/kW-year, sourced from PG&E, to a high of \$63.96/kW-year using 2011 nominal results from their E3 model modified for seasonal gas pricing. These nominal values overestimate the real 2006 value. A real 2006 value is the most appropriate comparison.

[3] UCAN, Analysis of SDG&E's AMI Application, 8/14/06, page 109.
[4] UCAN, Analysis of SDG&E's AMI Application 8/14/06 (Attachment V: Attachment 4A - PG&E Phase 2 Testimony, Table 2-4, page 2-2).
[5] UCAN's attachment V page 2-7 and PG&E's Table 2-4, page 2-8.

UCAN overestimated the real 2006 PG&E market energy benefits of a CT by $5.24/kW-year. I convert the nominal PG&E value of $51.90/kW-year to a real 2006 value of $46.66/kW-year using the NPV method illustrated in Table JCM-2. The PG&E nominal value is a levelized six year value from 2008 through 2013. My real 2006 $46.66/kW-year value escalating at 2.5% per year yields the same six year NPV (2008 through 2013) as PG&E's nominal value over the same six years. (51.90 – 46.66 = 5.24).

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Table JCM-2

Comparison of PG&E's CT Gross Profit Nominal vs. Real Values			
		CT Gross Profit ($/kW-Yr)	
Line No.	Year	PG&E's Nominal Levelized Cost*	Calculated Real Escalating Cost**
1	2006		**46.66**
2	2007		47.83
3	2008	51.90	49.03
4	2009	51.90	50.25
5	2010	51.90	51.51
6	2011	51.90	52.80
7	2012	51.90	54.12
8	2013	51.90	55.47
9	2008 NPV***	238.26	238.26

* Source:UCAN, Analysis of SDG&E's AMI Application 8/14/06 (Attachment V: Attachment 4A - PG&E Phase 2 Testimony, Table 2-4, page 2-2) and (Figure 8: PG&E 2007 TY GRC Phase 2 Market Model, page 113).
** Annual escalation rate is 2.5%

*** Net Present Value in 2008 dollars for cost from 2008 to 2013, discounting at 8.23%.

Likewise UCAN overestimated the real 2006 E3 value of a CT by $15.10/kW-year. Using an E3 model similar to UCAN's model, I calculate the nominal 2011 UCAN value of $63.96 is equivalent to a real 2006 value of $51.70/kW-year. I expand the model to include all of E3's data from 2006 through 2030. Both UCAN's and my models produce similar nominal results for 2011. UCAN reports their E3 model results as $63.96/kW-year of CT profits in 2011 from running 1,600.[6] My E3 model results in a $66.80/kW-year of CT profits in 2011 from running 1,601 hours, or a real 2006 value of $51.70 when considering the more complete E3 data set.[7] My real 2006 value escalated at 2.5% annually, yields the same 2006 NPV as the nominal annual E3 results over the same time period (2006 through 2030). The lower real 2006 market energy benefits result in higher net CT costs.

[6] UCAN, Analysis of SDG&E's AMI Application, 8/14/06, page 112 and 113.
[7] Using the same operating parameters as detailed in footnote 100 on page 112 of UCAN Analysis of SDG&E's AMI Application 8/14/06. SDG&E uses city gate monthly varying gas prices, while UCAN uses Henry Hub TX based monthly varying gas prices.

C. The E3 data shows that the CT market energy benefits are at least 5% less in Southern California than Northern California.

UCAN incorrectly argues that the similarity of its results and PG&E's option model results makes a nominal $52/kW-year CT profit a "more robust" and "independently confirmed" result.[8] On the contrary, the E3 data illustrates that market differences exist between Northern and Southern California. UCAN's E3 model used Southern California data; where as, the PG&E option model uses Northern California (NP15) data.[9] The similarity of UCAN and PG&E results illustrate the random convergence of two different methodologies using different data from different regions.

My calculations using the E3 Southern California market data shows 5% lower CT market profits than the same model using market data from Northern California. Table JCM-3 shows results from my E3 Northern and Southern California models. The Northern CT runs more hours and produces more energy benefits than the Southern CT. These results from the E3 model indicate that a Southern California CT would earn about 5% less than a Northern California CT. Results with SCE data indicate that the Southern California market benefits may be even lower.[10]

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[8] UCAN, Analysis of SDG&E's AMI Application, 8/14/06, page 113, including footnote 101.
[9] UCAN, Analysis of SDG&E's AMI Application 8/14/06 (Attachment V: Attachment 4A - PG&E Phase 2 Testimony, Table 2-4, page 2-7).
[10] See $8.76/kW-year CT gross market energy benefits in TURN, Electric Marginal Cost and Revenue Allocation of Southern California Edison Company, 1/20/06, page 34.

Table JCM-3

Comparison of CT Market Earnings Southern and Northern California Using E3 Market Data 2006 - 2030*	Year 2011 Run Hours	Nominal 2011 ($/kW-yr)	Real 2006 ($/kW-yr)
Southern California	1,601	$66.80	$51.70
Northern California	1,723	$70.30	$54.17
% South less than North	7%	5%	5%

*E3's March 20, 2006 update, and 6/01/06 gas update for monthly gas factors.

D. The Commission should view the high values for market energy benefits developed by UCAN from the E3 model with a healthy skepticism.

The calculation of market energy benefits depends on a number of assumptions including the southern California load profile, the resulting hourly price profile over the year, and the marginal costs of operating a CT. The analysis by Mr. Marcus in the Edison General Rate Case, Phase 2, was based on the hourly price profile developed by SCE in a similar manner to the SDG&E hourly price profile, based on its resource plan and expected future southern California market conditions. In that proceeding, Mr. Marcus calculated a value for market energy benefits of $8.76 per kW-year based on that data for the Southern California market.[11] Based on SDG&E's resource plan data specific to future southern California conditions, I have calculated a value of $22.89 per kW-year. In contrast, the E3 data on hourly price profiles is based on data from the now defunct PX market in 1998-2000 and may not adequately reflect long-term future conditions.

But even estimates based on the E3 hourly price data have produced much lower values. SDG&E has used modified versions of the E3 data for transparency purposes in short-term avoided cost applications both in its Rate Design Window (A.05-02-019) and Phase 2 of the Avoided Cost Proceeding, R.04-04-025. In the Rate Design Window, UCAN estimated market energy benefits based on that data

[11] See $8.76/kW-year CT gross market energy benefits in TURN, Electric Marginal Cost and Revenue Allocation of Southern California Edison Company, 1/20/06, page 34.

to be $29.72 for 2006, a value much less than used in this proceeding.[12] In the Avoided Cost proceeding, SDG&E calculated market energy benefits produced by a CT based on modified E3 data to be $16.78 per kW-year.[13]

The experience of the last several years also raises doubt about the high values for market energy benefits. The CEC has estimated that a new CT can expect to operate a little over 800 hours per year,[14] and it has been reported that some new CTs have been operating at less than 400 hours per year in contrast to UCAN's assumption of 1600 hours per year.[15] Going forward in the long-run, when old and inefficient CTs are replaced by new CTs, not all the new CTs would have high operating hours given the shape of the load profile, some will be relegated to operating substantially less to provide reliability in the top 100 hours.

E. <u>SDG&E and UCAN would have similar net CT capacity costs, once UCAN's data is corrected to real 2006 values and the minimally adjusted for Southern California market conditions</u>.

While SDG&E does not calculate the net CT capacity cost in direct testimony, SDG&E does calculate the required components (fixed CT costs and market energy benefits). Table JCM-5 compares SDG&E's and UCAN's net CT capacity costs after corrections (Comparable to UCAN's Table 13).[16] My comparison shows that the SDG&E's net CT capacity cost is in the same range as the corrected UCAN values.

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[12] UCAN, Electric Marginal Cost, Revenue Allocation, and Rate Design for SDG&E, A. 05-02-019, June 24, 2005, pages 16 and 17.
[13] SDG&E, Prepared Testimony of David T. Barker, August 31, 2005, R.04-04-025, Exhibit 85, page 16.
[14] CEC, Comparative Cost of California Central Station Electric Generation Technologies, Section E-3, Table D-5, August, 2003.
[15] California Cogeneration Council Rebuttal Testimony, October 28, 2005, R.04-04-025, Exhibit 103, page 59.
[16] UCAN, Analysis of SDG&E's AMI Application, 8/14/06, page 116

Table JCM-5

Comparison of SDG&E and UCAN Net CT Costs
Real 2006 Values ($/kW-Year)

Case	Gross CT Cost	Market Earnings	Net CT Cost
SDG&E	60.00	22.89	**37.11**
Corrected UCAN*:			
Upper Bound case			52.00
High case	82.12	35.47	46.65
Mid-High case	82.12	44.33	37.79
Recommended case	71.28	44.33	26.95
Low case	71.28	51.70	19.58

* Corrected CT market earnings for real 2006 values and for lower Southern California market earnings.

Table JCM-5 makes the following corrections to UCAN's Table 13:

- SDG&E case subtracts the real 2006 $22.89/kW-year market energy benefit,[17] which UCAN failed to include.
- UCAN High, Mid-High, and Recommended cases corrects PG&E's nominal 2011 CT market earnings, to a real 2006 values (from $51.90 to $46.66), and adjusts the Northern California CT market earnings to reflect that a Southern California CT earns 5% less than a Northern California CT ($46.66 * .95 = 44.33.[18].
- UCAN's Low case is adjusted to convert their E3 nominal 2011 value to a real 2006 value (from $63.96 to $51.70).

With the correction above, SDG&E and UCAN results are not nearly as far apart as the UCAN testimony would make it appear. The net CT cost for SDG&E is $37.11/kW-Year. On balance both SDG&E and UCAN analyses have similar results except that UCAN ignores the Additional Value of SDG&E's AMI enabled Demand Response.

[17] SDG&E, AMI Application 7/14/2006, page JCM-13.
[18] UCAN's High case uses 80% of PG&E's energy savings as Market Earnings.

F. DRA incorrectly asserts that SDG&E has calculated its CT market energy benefit by utilizing a "straight average of energy prices across 21 years"[19].

SDG&E estimated a CT market energy benefit using forecasted hourly prices for 20 years (2006 through 2025), not a "straight average of energy prices across 21 years". SDG&E used forecasted hourly energy prices and associated forecasted monthly gas prices to evaluate a gas CT's market energy profitability each hour to arrive at a $22.89/kW-year value. An analysis of the underlying data translates to over 1,600 hours of CT operations that provide at least some profit to the CT operator. The 1,600 hours of operations is a very liberal estimate of annual operating hours, far exceeding the typical annual 800-1,000 hours that are used for CT profitability analysis. DRA ramps up SDG&E's value by using a ratio of "straight average of energy prices across 21 years" and an average energy prices for "CPP-like" times.

DRA's ratio arbitrarily doubles SDG&E's estimate of CT market energy benefits and does not produce a reasonable result. Using DRA's logic, if the projected price of energy during CPP-periods was four times higher than the average price, then AMI enabled demand response would have zero value. One would expect the avoided capacity cost of AMI to increase as CPP-period prices increase.

Alternatively, by doubling the value of CT energy profits, DRA may be implying that a CT will run almost 3,200 hours a year. That is, on average, DRA may be implying that a CT would operate for over 36% of the total annual hours. This level of long term operation is essentially unprecedented and impractical for a CT unit designed for peaking generation.

G. The AMI valuation must include the additional benefits of AMI enabled demand response (beyond net CT costs).

Just as the CT energy benefits must be included in an AMI capacity valuation, so must the additional value attributed of SDG&E's AMI enabled demand

[19] DRA, Analysis of SDG&E's AMI Business Case page 6-4.

response. UCAN does not dispute these additional benefits, and both UCAN and DRA identify additional benefits of this type.

H. <u>UCAN incorrectly characterizes AMI enabled demand response as merely "a demand response program with only 100 hours or less of operation per year"[20]</u>.

SDG&E's AMI enabled demand response is more that a (Critical Peak Pricing) CPP rate with limited dispatch. SDG&E's business case includes rates and programs described in Dr. George's & Mr. Gaines' testimony. These rates and programs include **CPP** with limited dispatch, Peak Time Rebate (**PTR)** with flexible dispatch, Time-Of-Use (**TOU)** rates, and a Programmable, Controllable Thermostat (**PCT**) program. These rates and programs provide a greater capacity benefit than proposed by UCAN.

Additional unique benefits are provided by AMI enable demand response that a CT can not provide. These unique benefits are described in my prepared direct testimony and later in this rebuttal. These unique benefits include rate design flexibility which allows for Real Time Pricing (RTP), a variety of dynamic rates, interruptible programs and enhanced energy management tools (per DRA witness Mr.Geilen). These unique benefits make SDG&E's AMI-enabled demand response as valuable as a combustion turbine.

I. <u>UCAN acknowledges the planning reserves benefit of AMI enabled Demand Response, as well as the Additional Value of AMI Enabled Demand Response</u>.

UCAN does not dispute including a 15% reserve margin benefit for demand response. They simply continue to question whether or not demand response is real. UCAN sees the planning reserves "as a contingent benefit" – which will only be received by ratepayers if the demand response program is successful for several years. SDG&E agrees with this assessment. That is why SDG&E's AMI proposal includes demand response programs with wide participation across all

[20] UCAN, Analysis of SDG&E's AMI Application, 8/14/06, page 109.

customer classes, has a PCT program, and includes rate design flexibility to assure the success of long term demand response.

J. UCAN neither addresses nor disputes the Additional Value of AMI Enabled Demand Response.

Nowhere in their testimony does UCAN dispute the value of Reduced Demand Volatility and Planning Reserves, or dispute the value of Increase Rate Design Flexibility, or dispute the Additional Reliability Value of PCTs. In fact UCAN identifies several Additional Unique Benefits of AMI, including a Consumer Portal.[21]

K. DRA unjustifiably argues that the resource availability of AMI Enabled Demand Response is less than a CT.

DRA asserts that a CT operates 822 hours a year,[22] presumably for reliability purposes. This is based on the CEC's Comparative Cost study of generation technologies.[23] The CEC's study does not differentiate between reliability and economic operation. If the DRA assertion is to be believed, Solar Photovoltaics provide 2,086 hours a year of reliability, a wind farm provides 6,132 hours a year of reliability, and a Combined Cycle-Baseload plant provides 8,024 hours a year of reliability. The CEC's operating hours should be viewed as a combination of both reliability and economic dispatch. SDG&E includes the CT market energy benefit to reflect the fact that a CT operates many hours for economic purposes.

L. DRA use of a LOLP allocation to reduce the capacity value of AMI enabled demand response but ignores the rate design flexibility enabled by AMI.

DRA asserts that "a valuation of demand response should also be lowered due to limitations of the program".[24] DRA's argues that since SDG&E's CPP and PTR is limited to only day-ahead dispatch for on-peak operation during summer

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[21]UCAN, Summary of UCAN Testimony and Selected Issues Relating to Expenditures for SDG&E's 2006 AMI application, 8/14/06, page 8.
[22]DRA, Analysis of SDG&E's AMI Business Case 8/14/20006, page 6-6.
[23]CEC, Comparative Cost of California Central Station Electricity Generation Technologies. (100-03-001), August 2003. Tables M-6, R-6, & C-6.
[24] DRA, Analysis of SDG&E's AMI Business Case 8/14/20006, page 6-7.

months and limited to 91 hours per year, it can not provide capacity that may be needed at other times. SDG&E's PTR proposal does not limit the number of dispatch hours, thereby, allowing for unlimited dispatch in any season, including day-of dispatch if necessary. In addition SDG&E's proposal includes over 50,000 PCTs which can provide reliability dispatch comparable to a CT. The rate design flexibility of AMI enabled demand response allows for implementation of additional interruptible and curtailable rates that can provide unlimited dispatch possibilities. AMI enabled demand response provides for real-time pricing which can reduce the overall loss of load probabilities because it can help reduce the short term variations in load due to weather,[25] as well as reduce other demand factors affecting the hourly LOLP probabilities. DRA chooses to ignore these facts when discounting AMI enabled demand response for LOLP periods.

M. <u>DRA discounts the "potential of AMI to allow the Commission to more accurately allocate costs and fairly reflect the true cost of service in energy rates to all customers</u>."[26]

DRA asserts that RTP "is a rate design and pricing strategy which neither SDG&E nor DRA would propose, especially for all residential customers."[27] DRA has not reflected the Commission's direction as shown in the following passage from the favorable PG&E AMI decision. "In subsequent proceedings, with adequate time and an appropriate record, AMI opens the door to true real-time pricing which accurately reflects the cost of energy." SDG&E includes the RTP functionality in its AMI proposal, not only to comply with prior ALJ rulings,[28] but because of the additional benefits RTP can provide. Mr. Fong and Mr. Hansen discuss both the direction of the Commission as it pertains to demand response rates and SDGE's rate strategy looking forward over the next several years.

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[25] SCE, Phase 2 of 2006 GRC Marginal Cost and Sales Forecast Proposals (A.05-05-023), 9/6/2005, page 29.
[26] CPUC, Final Opinion Authorizing Pacific Gas and Electric Company to Deploy Advanced Metering Infrastructure. (D.06-07-027), 7/24/06, page 11.
[27] DRA, Analysis of SDG&E's AMI Business Case, 8/14/06, page 6-11.
[28] CPUC, ALJ Ruling (02-06-001), 2/19/04

N. DRA inappropriately adjusts SDG&E's Rate Design Flexibility.

DRA reduces SDG&E's benefits which are based on Dr. Borenstein's 2005 study titled The Long-Run Efficiency of Real-Time Electricity Pricing. DRA asserts that "the reality of California's generation supply does not reflect the paper's theoretical assumptions."[29] In fact, the current generation mix only increases the benefits described in Dr. Borenstein's paper. The paper evaluates an optimal generation portfolio under flat rates vs. an optimal generation portifolio under RTP rates. The paper shows that RTP results in a lower cost generation portfolio compared to the optimal flat rates portfolio. Today's mix of generation is likely not as "optimal" as modeled by Dr. Borenstein, therefore, moving to an optimal generation mix under RTP will likely result in even greater benefits than stated in the paper, all else being equal.

O. DRA incorrectly argues that long term contracts will prevent SDG&E from achieving the benefit of Rate Design Flexibility.

DRA states that the "bulk of SDG&E's power procurement over the next 20 years will be tied-up in long-term and nuclear contracts."[30] Therefore, DRA argues that the generation mix can not change to achieve these benefits. Their prospective does not recognize the flexibility of wholesale markets. It is true that SDG&E will have generation tied up in long term contracts, but much of the current DWR allocations (43% in DRA testimony) are eliminated by 2011. Thus, as these contracts expire, new opportunities to optimize SDG&E's supply portfolio will arise. Even with a fixed physical generation portfolio, SDG&E will buy and sell excess capacity in the wholesale market as it does today. Under RTP, there will be less wholesale purchases in high price periods and less wholesale sales in low price periods, thus providing the benefits of Rate Design Flexibility. Regardless of SDG&E's current contracts for generation, Rate Design Flexibility creates opportunities to create a lower cost generation portfolio.

[29] DRA, Analysis of SDG&E's AMI Business Case, 8/14/06, page 6-11.
[30] DRA, Analysis of SDG&E's AMI Business Case, 8/14/06, page 6-12.

P. <u>DRA testimony by Ted Geilen on Information Feedback illustrates the existence of even more unique benefits of AMI</u>.

Mr. Geilen identifies energy conservation benefits associated with customers increased understanding of the cost of energy use. This benefit valuation has not been evaluated by this witness, however the value appears considerable, at $29.6 million, based on Mr. Geilen's testimony.

In conclusion, UCAN calculates an equivalent CT value as SDG&E when the market energy benefits are correctly calculated. The Additional Value of AMI enabled demand response is not contested by UCAN. DRA's analysis is highly flawed. DRA uses flawed reasoning to increase CT market energy benefits estimated by SDG&E. DRA also discounts SDG&E's additional values based on faulty logic and without fully considering their potential benefit. The appropriate value of capacity for evaluation of AMI enabled Demand Response should include fixed CT costs, CT market energy benefits, and the additional value of the AMI system. When all these factors are considered, SDG&E's valuation is appropriate.

This concludes my prepared rebuttal testimony.