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~~ 64 to -~~35~~42
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.

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

[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~~8).
[5] UCAN's attachment V page 2-7 and PG&E's Table 2-4, page 2-8.

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. 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.

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~~6, 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.

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~~5,336 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.

[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.

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 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. 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."[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

[24] DRA, Analysis of SDG&E's AMI Business Case 8/14/20006, page 6-7.
[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, page 3 and Appendix A.