PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ENERGY DIVISION **RESOLUTION E-4020**
October 19, 2006

R E S O L U T I O N

Resolution E-4020. Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) are authorized to implement the Capacity Bidding Program (CBP) to replace the California Power Authority Demand Reserves Partnership.

By Advice Letter (AL) 2839-E Filed on June 1, 2006 by PG&E, AL 2010-E Filed on June 2, 2006 by SCE, and AL 1799-E Filed on June 1, 2006 by SDG&E.

SUMMARY

This Resolution approves SDG&E, PG&E, and SCE's proposal to implement the Capacity Bidding Program (CBP) to replace the California Power Authority Demand Reserves Partnership. The CBP will add much-needed demand response capability in California at a time when additional capacity is necessary in the face of increasing demand for electricity and the possibility of future heat storms.

The CBP as proposed by SDG&E, PG&E, and SCE does not sufficiently facilitate the participations of third-party demand response providers, known as aggregators. The Resolution modifies the capacity incentive payment so that aggregators receive the full amount of the capacity payment while directly-enrolled customers receive 80%.

The proposed CBP should be modified to provide more incentives for customers to participate. The Resolution modifies the proposed CBP to reward customers for partial demand reductions, include a day-of component of the program, and fix the capacity incentive payment rates for two years.

The CBP has not been evaluated for cost-effectiveness, as that issue is beyond the scope of this Resolution. Several intervenors opposed the CBP, citing an apparent lack of cost-effectiveness. The Resolution notes that the Commission should defer the issue of cost-effectiveness to a more appropriate forum.

The budgets proposed by SDG&E, PG&E, and SCE are not consistent with program needs. The Resolution modifies those budgets, as described below.

Several other issues raised by intervenors have been addressed with recommendations for additional program modifications, while several additional arguments advanced by intervenors were found to be without merit.

BACKGROUND

The Demand Reserves Partnership (DRP) program is a demand response (DR) program developed by the California Power Authority (CPA) and the California Department of Water Resources (DWR). The program is based on a five-year contract (starting in 2002) between the CPA and DWR in which DWR secures power from the CPA through reductions in demand, rather than from generation.

The program relies on aggregators who "nominate" amounts of capacity to be reduced when a DRP event is called. Aggregators inform the CPA, prior to the beginning of each month, of the amount of load they are nominating. The CPA in turn informs the DWR of the amount of load that can be called. DWR triggers the program for economic or reliability purposes, based on recommendations from PG&E, SDG&E, and SCE (the Utilities). The aggregators receive a monthly capacity payment, based on the number of MWs nominated and the number of hours that those MWs will be reduced, even if a DRP event is not called. The aggregators also receive an energy payment, based on the number of kWhs saved during any events called that month. During months when one or more events are called, an aggregator receives its full capacity payment if at least 95% of the nominated load is provided. Aggregators receive a penalty, based on their kWh shortfall, if less than 95% of the nominated load is provided.

The largest participant in the program is the California State Water Project (SWP), who contributes approximately 200 MWs of demand response per month. SWP participates directly in the program, meaning that it does not rely on an aggregator to submit its monthly nomination to the CPA.

The DRP program is one of a spectrum of demand response programs, which together are designed to offer customers a wide choice of compensation, commitment, and risk levels. It is one of a handful of day-ahead demand response programs available in California[1].

While each of the demand response programs has different requirements and incentives, the DRP program differs from all other demand response programs in two ways:

1. As noted above, the DRP program has as its foundation a 5 year contract between DWR and CPA. The program is managed by DWR and CPA, who have contracted with the firm APX to manage the program. The Utilities may recommend dispatch of the program for economic purposes[2], but other than that, DWR, CPA, and APX are responsible for the management and administration of the program. All other demand response programs are managed by the Utilities.

2. The DRP program is the only DR program that involves Demand Reserve Providers, or aggregators, to market the program, recruit customers, and then aggregate and bid the customers' demand reduction capabilities.

The DRP program will not continue when the CPA contract expires in May 2007. D.06-03-024 approved the Utilities' 2006-2008 demand response programs and associated budgets, based on a settlement agreement between the Utilities, DRA, TURN, Aglet, and others. D.06-03-024 states in it discussion of the DRP program that, by the terms of the settlement, "the utilities would continue these programs until they expire in May 2007 and, no later than June 1, 2006, they

[1] Other programs currently offered by the Utilities are Critical Peak Pricing, Demand Bidding and C&I 20/20.

[2] In D.03-06-032 the Commission directed the Utilities to coordinate with DWR so that DWR could dispatch the program when it was economic to do so. The Utilities proceeded to recommend program dispatch when the forecast price of energy was greater than $80/MWh, which is equal to the program's energy payment. Commission Resolution E-4009 has since directed the Utilities to advise DWR to dispatch the program using an assigned heat rate of 15,000 BTU/kWh, as described below.

would file advice letters or applications proposing new programs and budgets, following consultation with intervenors."

Hence, SDG&E, SCE, and PG&E have proposed the creation of the Capacity Bidding Program (CBP) to replace DRP beginning in May 2007. The proposed CBP is designed only for retail customers. PG&E will negotiate a separate demand response contract with wholesale customers such as the SWP. PG&E proposes to file that contract as an addendum to this advice letter (or as a new advice letter should this one be resolved before the contract is finalized). In addition, PG&E may contract for demand response with other wholesale customers.

The CBP, as proposed by the Utilities, has the following features:

- The CBP, as stated above, will be available to retail **commercial, industrial and agricultural** customers[3]. This includes Direct Access (DA) customers and any future Community Choice Aggregators (CCA), although SDG&E's DA and CCA customers must participate through an aggregator.

- Customers (other than DA or CCAs located in SDG&E's service territory) can choose to enroll in CBP **through an aggregator or directly with the utility**. Customers choosing to enroll through an aggregator will receive smaller payments from the aggregators than they would from the Utilities, but will also be exposed to less risk, as aggregators can manage their accounts as a group to achieve requisite levels of demand reduction.

- The Utilities are providing participants[4] with three different "**products**" to choose from, which allow participants to choose the most appropriate range for the minimum and maximum number of hours that could occur for each

[3] The three utilities phrase the customer eligibility for CBP slightly differently:
SCE – all general service and agricultural bundled service customers with advanced meters
SDG&E – commercial, industrial and agricultural customers over 20 kW
PG&E – all commercial, industrial and agricultural customers with advanced meters

[4] "Participants" includes both directly-enrolled retail customers and aggregators, since both may participate in CBP.

event. Those products are a 1-4 hour call option, a 2-6 hour call option, and a 4-8 hour call option. In addition, SDG&E has a day-of option.

- Participants will receive **capacity payments**, based on the amount of capacity nominated each month. The exact amount differs for each utility, month, and product chosen, as shown in Table 1. In addition, SDG&E offers higher capacity payments for its day-of program than for its day-ahead program.

Table 1

PG&E Capacity Price ($/kW-Month)

Product	May	June	July	August	September	October
1-4 Hour	0.00	3.71	15.60	21.57	13.30	0.00
2-6 Hour	0.00	3.71	15.60	21.57	13.30	0.00
4-8 Hour	0.00	3.71	15.60	21.57	13.30	0.00

SCE Capacity Price ($/kW-Month)

Product	May	June	July	August	September	October
1-4 Hour	4.05	6.30	14.85	17.10	9.45	2.25
2-6 Hour	4.95	7.70	18.15	20.90	11.55	11.00
4-8 Hour	4.95	7.70	18.15	20.90	11.55	11.00

SDG&E Day-Ahead Capacity Price ($/kW-Month)

Product	May	June	July	August	September	October
1-4 Hour	5.37	7.35	13.54	15.11	9.77	4.71
2-6 Hour	5.51	7.54	14.07	15.63	10.06	4.81
4-8 Hour	5.65	7.76	14.71	16.23	10.49	4.94

SDG&E Day-Of Capacity Price ($/kW-Month)

Product	May	June	July	August	September	October
1-4 Hour	6.44	8.82	16.25	18.13	11.72	5.65
2-6 Hour	6.64	9.04	16.89	18.75	12.07	5.78
4-8 Hour	6.79	9.31	17.66	19.48	12.59	5.93

- If the program is not called during a given month, the participant receives the full capacity payment. If one or more events are called, participants receive the full capacity payment if they succeed in reducing their demand to the nominated amount. The participant will receive a capacity payment proportional to the demand reduction if that reduction is between 90 and 100% of the nominated amount, but will receive no capacity payment if the reduction is between 50 and 90% of the nominated amount, as shown in Table 2. This calculation is made separately for each event hour.

Table 2

Actual reduction	Capacity Payment
100%	100%
90%-100%	90%-100% (proportional)
50%-90%	0
< 50	participant pays penalty

- If a participant does not reduce demand by at least 50% of the amount nominated during a called event, the participant incurs a **penalty** proportional to the actual reduction**.** The penalty is equivalent to 50% minus the percentage of the actual reduction, multiplied by the full capacity payment. For example, if the participant reduces demand by only 10% of the nominated amount, the penalty which accrues is equal to 50% – 10%, or 40% of the full capacity payment.

- Participants will also receive **energy payments**, based on their reduction in energy consumption in kWh, when an event is called. The energy payment will be equal the product of each utility's city gate natural gas price and the trigger heat rate of 15,000 BTU/kWh. Participants receive this payment for up to 150% of their nominated demand reduction. However, if a participant does not reduce demand by the amount nominated during a called event, the participant will incur a shortfall and their energy payment will be reduced proportionally.

- The program will be operational all **weekdays** except for utility holidays, from **11 a.m. to 7 p.m.** SCE and SDG&E offer capacity payments from May until October, while PG&E currently offers a capacity payment only from June until September. All three utilities offer energy payments from May until October.

- The CBP will be triggered by a 15,000 BTU heat rate. In other words, the program will be triggered when the day-ahead market anticipates the use of generation resources that are the equivalent of a gas-fired power plant that takes 15,000 BTUs of natural gas to generate one kWh of electricity.

- The program can be called for a **maximum of 24 hours** per month.

- CBP will include both day-ahead and day-of (SDG&E only) options. The day-ahead notification will be given by 3 p.m. the previous business day, and the day-of 1 hour in advance of an event (SDG&E only).

- Customers must **nominate** the amount of demand reduction they can provide in any given month at least 5 days before the beginning of that month. SDG&E participants can nominate both day-ahead and additional day-of amounts.

- The Utilities will continue to contract with APX to manage the program.

- **<u>Utilities' Proposed Budgets</u>**

Each utility has requested additional budget to cover the costs associated with this program. The amounts differ considerably between the three Utilities, as shown in Table 3:

Table 3

<table>
<tr><th>UTILITY:
Estimated Cost (000)</th><th colspan="2">PG&E</th><th colspan="2">SDG&E</th><th colspan="2">SCE</th></tr>
<tr><th></th><th>2007</th><th>2008</th><th>2007</th><th>2008</th><th>2007</th><th>2008</th></tr>
<tr><td>APX charges</td><td>$500</td><td>$500</td><td rowspan="3">$801</td><td rowspan="3">$652</td><td rowspan="2">$750</td><td rowspan="2">$700</td></tr>
<tr><td>Administration</td><td>$400</td><td>$300</td></tr>
<tr><td>Marketing</td><td>$160</td><td>$20</td><td>$200</td><td>$100</td></tr>
<tr><td>M&E</td><td>$200</td><td>$200</td><td>$103</td><td>$103</td><td>$50</td><td>$100</td></tr>
<tr><td>Program Costs</td><td>$1,260</td><td>$1,020</td><td>$904</td><td>$755</td><td>$1,000</td><td>$900</td></tr>
<tr><td>Capacity Incentives</td><td>$1,596</td><td>$2128</td><td rowspan="2">$516</td><td rowspan="2">$816</td><td>$3000</td><td>$3600</td></tr>
<tr><td>Energy Incentives</td><td>$326</td><td>$434</td><td>$528</td><td>$594</td></tr>
<tr><td>TOTAL</td><td>$3,182</td><td>$3,582</td><td>$1,419</td><td>$1,571</td><td>$4,528</td><td>$5,094</td></tr>
<tr><td>Size of Program:</td><td>30 MW</td><td>40 MW</td><td>5 MW</td><td>? MW</td><td>50 MW</td><td>60 MW</td></tr>
<tr><td>Program Cost/MW*</td><td>$42,000</td><td>$25,500</td><td>$180,800</td><td>$151,000</td><td>$20,000</td><td>$15,000</td></tr>
<tr><td>Total Cost/MW*</td><td>$10,667</td><td>$89,550</td><td>$283,800</td><td>$314,200</td><td>$90,560</td><td>$84,900</td></tr>
<tr><td>Program Cost as % of Total Cost</td><td>40%</td><td>28%</td><td>64%</td><td>48%</td><td>22%</td><td>18%</td></tr>
</table>

*in **actual** $/MW (not 1000s)

<u>NOTICE</u>

Notice of AL 2839-E was made by publication in the Commission's Daily Calendar. PG&E states that a copy of the Advice Letter was mailed and distributed in accordance with Section III-G of General Order 96-A. Notice of AL 2010-E was made by publication in the Commission's Daily Calendar. SCE states that a copy of the Advice Letter was mailed and distributed in accordance with Section III-G of General Order 96-A. Notice of AL 1799-E was made by publication in the Commission's Daily Calendar. SDG&E states that a copy of the Advice Letter was mailed and distributed in accordance with Section III-G of General Order 96-A. The Utilities also notified the service list of A.05-06-006 et al. by email.

PROTESTS

PG&E 's Advice Letter 2839-E was protested by The Utility Reform Network (TURN), the Aglet Consumer Alliance (Aglet), the Division of Ratepayer Advocates (DRA), and the Demand Reserves Partnership (which represents the groups generally referred to as the "Aggregators"), on June 21, 2006.

PG&E responded to the protests of all four parties on June 28, 2006.

SCE 's Advice Letter 2010-E was protested by The Utility Reform Network (TURN), the Division of Ratepayer Advocates (DRA), and the Demand Reserves Partnership on June 21, 2006. The Aglet Consumer Alliance (Aglet) also filed a protest on June 22, 2006.

SCE responded to the protests of all four parties on June 29, 2006.

SDG&E 's Advice Letter 1799-E was protested by The Utility Reform Network (TURN), Utility Consumers Action Network (UCAN), the Division of Ratepayer Advocates (DRA), and the Demand Reserves Partnership, on June 21, 2006.

SDG&E responded to the protests of all four parties on June 28, 2006.

DISCUSSION

TURN, UCAN, Aglet and DRA argue that the Capacity Bidding Program, as proposed by the Utilities, is not cost-effective. However, the issue of cost-effectiveness is outside the scope of this Resolution.

TURN recommends that "the Commission reject all three advice letters, as the utilities themselves have demonstrated that these programs are not cost effective." UCAN argues that "the program is not competitively priced when compared with market prices for supply side resources."

DRA points out "[T]he primary reason why the proposed CBP program is not cost effective is because almost all of [the Utilities'] estimated avoided costs will be paid out to the participants in the program in the form of capacity and energy payments. DRA believes this incentive payment structure is likely to keep the CBP program from ever becoming cost effective." DRA explains that, based on the Program Administrator Cost (PAC) test, a program which pays participants incentives which are equal to the program's avoided costs will necessarily have a benefit/cost ratio of less than 1, as the PAC test considers the costs of the program to be the sum of the incentives and the program administrative costs. DRA further states that "If one includes the considerable administrative costs of the program the ratepayer benefits are actually substantially negative."

PG&E points out that the proposed CBP is "in the range of cost-effectiveness of other demand response programs approved by the Commission in D. 06-03024," while SDG&E states that "the analysis it performed can best be characterized as nothing more than a proxy for a cost-effectiveness evaluation of the proposed program" because "there is, at present, no Commission-adopted cost-effectiveness protocol applicable to demand response." In addition, SCE argues that "Based on the Total Resource Cost (TRC) test, the CBP is shown to provide net benefits to ratepayers….Under the Standard Practice Manual, the TRC test should be the primary tool for evaluating the cost-effectiveness of demand response."

The issue of cost-effectiveness is usually a relevant one as the Energy Action Plan favors demand response programs that are cost-effective. However, this Resolution is not the proper forum for parties to debate the cost-effectiveness of the Capacity Bidding Program for the following reasons:

- D.06-03-024 approved the Utilities' three-year ('06-'08) demand response budget. That Decision defers the question of cost-effectiveness for the demand response programs that it approved to a process outlined in D.05-11-009.[5] That process has been initiated, and therefore should be the

[5] See discussion under "Cost Benefit Issues" in D.06-03-024. The process initiated by D.05-11-009 includes a cost-effectiveness scoping workshop (held in March 2006) and the release of a draft set of load impact protocols for public comment (distributed in April 2006). Energy Division staff (along with staff

Footnote continued on next page

proper forum to determine a cost-effectiveness method for demand response programs.

- The issue of measuring cost-effectiveness of demand response programs is a complex undertaking and deserves an evaluation much more comprehensive than what can be provided via these advice letters. DRA's concern that this program will never be cost-effective because the Utilities have structured it so that the incentives paid to participants are based on each utility's avoided costs for capacity and energy is significant, and merits further examination. However, demand response programs provide additional benefits to ratepayers, particularly in increased reliability of the system, that were not taken into account by the Utilities in their cost-effectiveness calculations of this program. It is clear that there are costs and benefits of demand response programs that are omitted by the rudimentary analyses that can take place within the context of these advice letters.

- The Utilities' analysis of CBP cost-effectiveness consists mainly of applying the TRC and PAC tests, two tests from the Standard Practice Manual (SPM) which is used by the CPUC to determine the cost-effectiveness of energy efficiency programs. It has not yet been established which of the SPM tests, if any, should be used to determine the cost-effectiveness of demand response programs. It is therefore unclear how accurate or relevant the Utilities' analysis is, although it is likely that these two tests provide a reasonable starting point for determining demand response program cost-effectiveness[6].

Given the number of outstanding questions in relation to determining the cost-effectiveness of this program, Energy Division believes it is more important for the Commission to focus on whether the CBP can increase, or at least maintain,

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from the California Energy Commission) has prepared a next step recommendation which is under consideration by the Commission.

[6] . While previous Commission decisions have stated that the TRC test is the *primary* test of cost-effectiveness for energy efficiency programs, the Commission has always considered both the TRC and PAC tests to determine cost-effectiveness.

the level of demand response achieved by the DRP program. Energy Division concludes that the incentive levels proposed by the Utilities for the CBP should remain in effect at the current time.

In its comments on the draft resolution, TURN argues that the proposed capacity payments should be reduced to $40 per kW-year on the basis that the Commission recently adopted $40 per kW-year as a trigger for granting Local RAR waivers, meaning that load serving entities could be relieved of their resource adequacy capacity requirements if they could not obtain a reasonable contract for capacity at $40 per kW-year. TURN argues that because the CPB will likely be called only a few hours per year, its only benefit is capacity (its energy benefit would be negligible).

SCE and PG&E oppose TURN's recommendation, arguing the $40 per kW-year capacity value was not adopted as a price cap by the Commission, is a conservative proxy based on a lower heat rate than the CBP's, and does not capture all of the benefits provided by the CBP such as allowing the utility to avoid the 15% capacity reserve margin it would have been acquired to procure. SCE also comments that the footnote 6 mischaracterizes its argument about cost-effectiveness tests and should be eliminated.

Energy Division agrees with the arguments put forth by SCE and PG&E and recommends that the capacity payments as proposed in the resolution remain unchanged. Energy Division also corrects footnote 6.

Energy Division is concerned with the administrative costs of the program, as presented in the utility's requested budgets as shown in Table 3, above. Energy Division believes that the interests of the ratepayers and the needs of the Utilities would both be sufficiently served by a budget for program costs shown in Table 4.

Table 4

UTILITY: Estimated Cost (000)	PG&E 2007	PG&E 2008	SDG&E 2007	SDG&E 2008	SCE 2007	SCE 2008
APX charges	$500	$500	$350	$450	$625[7]	$700
Administration	$100	$100	$70		$125	
Marketing	$160	$20	$50	$25	$200	$100
M&E	$80	$80	$40	$40	$80	$80
Total Program Costs	**$840**	**$700**	**$510**	**$515**	**$1,030**	**$880**

DRA points out that the administrative costs of the proposed program are considerable. In particular, SDG&E proposes a budget which is as large or larger than that of SCE or PG&E, even though the other utilities' programs are considerably larger.

The Utilities' proposed budgets for Measurement and Evaluation (M&E) of the CBP are inconsistent with previous and current budgets for DR program M&E. Energy Division does not find PG&E's claim that M&E costs will increase because of the need to evaluate both the CBP program and their wholesale contracts to be credible. Based on those budgets, a reasonable estimate for the M&E of the CBP is $200,000 per year, distributed among the three utilities in roughly the same proportions as M&E costs have been divided in previous and current DR programs.

Energy Division also questions the Utilities' proposed estimates for program administration. If most of the program administration will be performed by APX, then most of the administration budget will go towards paying those fees and the Utilities should not require much in the way of additional funds. Consequently, a total program administration budget of approximately 120% of the estimated APX charges is a reasonable estimate. Based on PG&E's estimate of $500,000 in APX charges for 2007, and the relative size of the programs, Energy Division staff have estimated the likely APX charges to SDG&E and SCE as $350,000 and $625,000, respectively. Hence, Energy Division recommends that

[7] SCE is in the process of negotiating an agreement with APX for CBP services. The line item in this table is not a requirement that SCE pay a specific amount of its budget to APX. The total combined administration and APX costs for SCE shall not exceed $750 million for 2007.

the Commission approve budget amounts for program administration as shown in Table 4.

In addition, Energy Division recommends that given the small size of SDG&E's program that the Commission authorize only a proportional amount of money for marketing.

In their comments on the draft resolution, PG&E and SCE oppose the budget changes as reflected in Table 4. SCE states that it does not have an agreement with APX at this time, and thus a line item for APX charges should be removed, and that SCE's original budget request should be approved. PG&E objects to the reductions made to its administrative budget, claiming that there are several transitional tasks that must be done with APX. PG&E also objects to the reductions made to its M&E budget stating that the extra funds were needed to evaluate the utility enrollment option.

TURN argues that no incremental funding is necessary for the CPB because APX will continue to manage the program as it did with the DRP. TURN also points out that the Utilities have underspent their administrative budgets for demand response programs for 2006-2008, and thus there is no need to provide the funding requested.

Energy Division declines to restore the original budgets requested by PG&E and SCE. Furthermore, TURN's recommendation to eliminate all incremental funding for the program is also rejected. While APX is expected to administer the program, there are transitional administrative tasks that will need to be completed by the Utilities. Energy Division is not convinced that the funds authorized in this resolution are inadequate to accomplish those tasks. The M&E budget as proposed in the resolution is reasonable based on previous M&E studies, and should additional funds be necessary, the Utilities have the ability to shift funds within their demand response '06-'08 budgets as provided in D.06-03-024. Energy Division declines to remove the APX line item for SCE, but has added a footnote to the table that clarifies that the APX line item is not requirement that APX shall be paid the amount reflected.

UCAN and Aglet also protest one of the cost-effectiveness calculations. Energy Division agrees with SCE that the UCAN/Aglet protest seems to be based on a misunderstanding. UCAN and Aglet argue that the capacity benchmark of $85,000/MW-year used to calculate SCE's avoided costs, when spread out over an entire year, is equivalent to $85,000/8760 hours or about $10/MWh. They state that "this compares unfavorably with a DR product which can only be called 24 hours per month and is predicted to cost $10,000 or more per MW-month."

SCE responds that UCAN and Aglet are confusing capacity and energy payments, so that it is inaccurate to say that $85,000/MW-year is equivalent to $10/MWh, because this calculation "fails to recognize the time-differentiated value of firm capacity inherent in forward market prices."

Energy Division agrees with SCE that demand response programs should be compared with peaking capacity, not with plants which operate 8760 hours per year.

DRA also comments that the cost-effectiveness inputs used by the three utilities are inconsistent. However, these cost-effectiveness issues are outside the scope of this advice letter.

DRA asks that the Commission direct the three utilities redo the cost-effectiveness analyses using consistent inputs so that the Commission can make a meaningful comparison of their programs. DRA's point is well-taken. However, for reasons as stated above, cost-effectiveness issues are outside the scope of this advice letter.

Aggregators ask that customers who enroll in CBP directly with the Utilities receive 70% of the proposed capacity payments, while aggregators would receive the full capacity incentive. Energy Division agrees that aggregators should be compensated for the value they add to this program, but recommends that directly-enrolled customers receive 80% of the proposed capacity incentive payment and aggregators receive the full capacity incentive.

The Demand Reserves Partnership, which represents the groups generally referred to as the "Aggregators," have requested a number of changes in the proposed CBP which would make the program more attractive to aggregator participation.

The Aggregators argue that the Utilities' proposal to pay the same incentives to both aggregators and directly-enrolled customers means that few customers are likely to enroll in CBP through an aggregator, and that this will "drive many if not all aggregators out of the demand response market in California."

SDG&E responds that "establishing a capacity price differential would tilt the playing field in favor of the aggregators," and SCE argues that "aggregator services should not warrant a subsidy," while PG&E believes that because "Aggregators have the ability to offer their customers options to mitigate risk that are not available to customers enrolling directly with the utility" the incentive payments to aggregators and directly-enrolled customers should be the same.

While aggregators offer customers an opportunity to participate in demand response with less risk than a directly-enrolled customer, that alone is unlikely to attract enough customers to compensate aggregators for the services they provide. Aggregators are small, competitive energy service providers who can provide a wide array of energy management services with a level of customer service that is difficult for a large company to provide. They provide an opportunity for customers to participate in demand response programs with less risk than they would if they were directly enrolled with the utility, by taking on a large portion of that risk themselves. However, aggregators can only provide these services if they are justly compensated.

While the history of the DRP program does not provide a clear indicator of aggregators' abilities, the experience of other states does seem to indicate that aggregators provide a great deal of value to DR programs and have the potential to greatly increase customer participation[8].

Energy Division believes that it is likely that Aggregators can play a significant role in increasing the amount of demand response in California, and should be given the opportunity they require to do so. Energy Division agrees with the Aggregators that the CBP program should be modified so that there is a payment

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[8] N.Y. State and the ISO-New England region have very successful DR programs in which aggregators provide all (N.Y. State) or a sizable percentage of the demand response. Recent DR studies also indicate the value added by aggregators to DR programs. For example, FERC (*Assessment of Demand Response and Advanced Metering*, August 2006) states that the emergence of aggregators is a "key development" in demand response that "provide a valuable service to customers, because many large customers have limited expertise or experience with aggregating or managing demand response" (p. 77).

differential between the capacity incentive payments that directly-enrolled customers and aggregators receive. However, Energy Division believes that having directly-enrolled customers receive 80% of the proposed capacity incentive payment should be sufficient to provide aggregators with just compensation for the value they add to this program.

In their comments on the draft resolution, the Utilities oppose the 20% payment differential. The Utilities argue that a payment differential is inequitable since the capacity provided by a directly enrolled customer has the same value as the capacity provided by an aggregator. They also argue that the differential is unnecessary because aggregators have a portfolio to balance the risk, and the differential will also reduce customer interest in the program.

The Aggregators argue that the payment differential should be 30% as they originally proposed in their protest. They also repeat their earlier assertions that having no payment differential, as proposed by the Utilities, will likely result in the most competent and well-informed customers opting to directly enroll with the utility because the aggregators cannot pass on the entire payment to these customers as the utility can. This leaves the high risk, less competent customers to enroll with the aggregators. The aggregators' portfolio strategy of pooling risk is unlikely to work if it cannot attract competent customers to balance its high-risk customers.

Energy Division realizes that a payment differential could deter some customers from participating. Energy Division also acknowledges that the capacity delivered by a customer has the same value as the capacity delivered by an aggregator. On the other hand, Energy Division maintains its belief that aggregators can play a significant role in building up demand response resources in this state, and that their portfolio approach is dependent on attracting customers who can perform. Energy Division is convinced that the payment differential is necessary for the aggregators to attract competent customers which would then enable aggregators to also add high-risk customers (who would naturally be reluctant to sign up) to their pools. The concept of aggregating loads and risk carries the potential benefit of expanding demand response participation to higher levels than they are today, and therefore enabling aggregators to be active participants outweighs the arguments raised by the Utilities.

Energy Division is not convinced by the Aggregators' comments that the payment differential should be increased to 30%, and thus it should remain at 20%.

Aggregators request a customer size threshold of one MW for direct enrollment. Energy Division recommends that the CBP proposal should not be modified to allow only customers over one MW[9] to directly enroll in CBP.

The result of this requirement is that smaller customers would only be eligible to participate in CBP through an aggregator. Aggregators argue that they have the expertise needed to manage small customers. The Utilities respond that this would limit customer choice.

Smaller commercial, industrial and agricultural customers may not have sufficient staff or expertise to manage their energy usage, and are therefore less likely to participate in demand response programs such as CBP which have substantial penalties for under-performance. Aggregation for such customers may be useful, but other customers may decline to enroll if their only option is through an aggregator.

In their comments on the draft resolution, the Utilities are opposed to the one MW requirement for direct enrollment, stating that it restricts customer options and forces <1 MW customers to negotiate entirely with aggregators to be in the program. PG&E and SCE also state that the one MW requirement will be difficult to administer. EnergyConnect states that customers should be free to enroll with whomever they prefer, utility or aggregator.

The Aggregators urge that the threshold be maintained, stating that it represents a compromise from their original request that customers who can curtail one MW (rather than a demand of one MW) be able to directly enroll.

Energy Division is persuaded by the comments submitted by the Utilities and EnergyConnect on this issue. Customer choice is important, and in this instance allowing such choice for customers below one MW does not create undue

[9] A "customer over one MW" means any customer whose total accounts are over one MW. (e.g., a customer with three accounts, each at 400 kW, would be considered a "customer over one MW."

disadvantages for aggregators. Given the differential in capacity payment rates as discussed above, Aggregators should be able to attract a fair share of customers below one MW. The one MW requirement is not necessary and thus Energy Division has revised the resolution by removing the requirement.

Aggregators propose two specific changes in the capacity payment structure proposed by the Utilities (shown in Table 2 above), **so as to reward customers who achieve partial demand reductions. Energy Division recommends that one of those changes be adopted so as to modify the capacity payment schedule as shown in Table 6 below.**

The Aggregators recommend that customers achieving between 90% and 100% of their nominated demand reduction receive their full capacity payment of 100%, and that customers achieving between 75% and 90% receive 50% of their capacity payment, as shown in Table 5. The Aggregators are not opposed to the imposition of penalties for performance below 50%.

Table 5

Actual reduction	Capacity Payment
100%	100%
90%-100%	**100**%
75%-90%	**50%**
50%-75%	0
< 50	participant pays penalty

The Utilities argue against addition of the 90%-100% tier, as it would send the wrong signal to customers if they were paid the full capacity payment for less than the full reduction. However, PG&E says that addition of the 75%-90% tier is "a creative way to reward partial performance." SDG&E does not think any modifications to the capacity payment structure are necessary, but says that if the CPUC is inclined to modify the payment schedule that adopting the 50% payment for the 75%-90% group, would be a reasonable change. SCE does not think any changes to the capacity payment structure are necessary.

Energy Division agrees that it does not make sense to pay customers the full capacity payment when the demand reduction is less than 100%. However, adding an incentive for partial payment could result in a considerable increase in demand response. Therefore, Energy Division recommends that the capacity payment schedule be modified as shown in Table 6.

Table 6

Actual reduction	Capacity Payment
100%	100%
90%-100%	90%-100% (proportional)
75%-89.99%	50%
50%-74.99%	0
< 50	participant pays penalty

In their comments on the draft resolution, TURN and SCE oppose paying participants 50% of the capacity payment for a 75% to 90% reduction stating that such a structure rewards participants for under-performance, and thus serves to decrease the amount of demand response delivered. TURN also believes that the penalty payment for below 50% is overly lenient, and is only appropriate if there is no payment for the 75%-90% performance level.

The Aggregators assert that participants may over-perform and deliver more than is expected, but will still be compensated for a 100% performance. Thus, allowing for 100% payment for a 90-100% performance essentially balances the slightly underperformers (90%) with the over-performers (+100%). The Aggregators defend the 50% payment for 75-90% performance as a reasonable compromise between the need to provide strong incentives for performance and the need to encourage participation. Adoption of the utilities' original structure (no payment for 50%-90% performance) would be too severe for customers to sign up. ECS recommends a sliding scale structure as opposed to the ramp-down structure as proposed in the draft resolution.

Energy Division concludes that the payment structure as proposed in the draft resolution is a reasonable compromise that balances the Commission's objectives to get a high level of performance while also encouraging participation. Energy Division has made a slight revision to Table 6 to eliminate the overlap between the reduction categories.

Aggregators ask that SCE and PG&E add a day-of option to their CBP. Energy Division recommends that the Commission direct SCE and PG&E to include a day-of option for their CPB programs, and that all three utilities include a clear description of how the day-of option will be triggered.

SDG&E includes both day-ahead and day-off options for their CBP programs, while SCE and PG&E do not. SCE states that while the CBP is "designed to accommodate products with day-of notification," they are only offering day-ahead products at this time. PG&E is offering only a day-ahead option and says that they "already offer day-of interruptible programs." Energy Division believes that the addition of a day-of component to the CBP offers participants the opportunity to easily add additional MWs the day of an event without having to sign up for another demand response program, and is likely to result in increased demand reduction when an event is called. Energy Division recognizes that the Utilities' reluctance to add a day-of component to the CBP is likely due to the fact that day-of programs were determined in D.05-01-056 to be reliability-based, and therefore do not count towards established goals for price-based demand response. However, Energy Division believes that the need for increased demand response should take precedence at this time[10], especially considering that both these goals and the distinction between day-ahead and day-of programs are under review.

It is not clear from SDG&E's advice letter how the day-of program will be triggered. Energy Division recommends that the Commission direct all three utilities to clearly indicate how the Day-of option will be triggered.

In its comments on the draft resolution, PG&E states that it supports a Day-of option for the CBP and includes a matrix that proposes various features for it. PG&E emphasizes though that customers cannot participate in both the Day-ahead option and the Day-of option for double-counting and double-payment reasons. SCE argues that it not be required to implement a Day-of option as it already has other demand response programs that can be triggered on a day-of basis.

The Aggregators agree with the resolution that the Day-of option trigger needs additional detail and provides general suggestions on how it should be designed. In response to PG&E's proposed features of a Day-of option, the Aggregators

[10] Since the issuance of D.06-03-024, which adopted 2006-2008 budgets for the demand response programs, the State of California experienced an unusually intense heat storm which strained the state's electrical system. Accordingly, the commission issued an Assigned Commissioner's Ruling on August 9, 2006, which reopened that proceeding and directed three Utilities to propose program augmentations and improvements designed to increase the amount of demand response by the summer of 2007.

note that PG&E proposes to pay participants the same capacity payment as its Day-ahead option which it argues does not reflect the incremental value of being called on short notice. The Aggregators urge that SDG&E's proposed capacity payments in its Day-of proposal be followed by the other utilities. The Aggregators rebut SCE's position that a CBP Day-of option is duplicative of its existing I-6 and BIP programs because of differences in design.

DRA states that the draft resolution does not provide any guidance on what additional capacity payments are appropriate for a Day-of option. Furthermore DRA points out that it (and other parties) will have no opportunity to comment on the level of additional payments proposed by the Utilities unless there is another round of comments allowed.

Energy Division agrees with PG&E that it would not be advisable to allow customers to participate in both a Day-ahead and Day-of option for the CBP. We also agree with the Aggregators that a Day-of option provides an incremental value because of its ability to be called on short-notice and thus higher capacity payments for it are reasonable. PG&E's proposed Day-of option should be re-submitted with this in mind. Energy Division also agrees with the Aggregators that a Day-of option could have an appeal that SCE's I-6 and BIP programs do not, and therefore SCE should be directed to propose a Day-of option. Energy Division agrees with DRA that a round of comments are necessary for the Day-of option and hereby recommends that each utility be directed to file a separate advice letter for its Day-of option. Each utility, including SDG&E, should clarify in its separate filing its Day-of triggering conditions.

The Aggregators ask that the CBP capacity incentive payment rates be fixed for two years. Energy Division agrees that the capacity payment rates to participants, as proposed by the Utilities (shown in Table 1) **remain fixed for 2007 and 2008.**

The Utilities have indicated that the monthly capacity payment rates may need to be revised periodically to reflect changing energy prices. Aggregators recognize that these payment rates may have to be adjusted over the long term, but ask that they be fixed for two years so that any confusion and uncertainty due to possible changes in those payments not impact the ability of the CBP to attract and retain market participants.

PG&E and SDG&E state that although they have no intention of changing the capacity payment, their obligation to make DR more cost-effective means that they need to have the option to make changes. SCE says it would not make changes without filing an Advice Letter which would allow for discussion of this issue.

Because it is likely that frequent program changes do contribute to customer confusion and inhibit participation, Energy Division agrees that fixing the capacity payment rates for two years will improve customer stability for the CBP.

In its comments on the draft resolution, DRA argues that the Commission should not fix the capacity incentive rates for two years given the Commission's intent to measure cost-effectiveness for all demand response programs and to make necessary adjustments to the programs to ensure they are cost-effective. DRA recommends that the program capacity payments be fixed for two years only upon a showing that the program is cost-effective.

SCE and SDG&E oppose DRA's recommendation, stating that the issue of cost-effectiveness is outside the scope of the resolution. PG&E and SCE also note that the capacity incentive rate, not the capacity incentive, should be fixed for two years.

Energy Division declines to add the text suggested by DRA as it commits the Commission to an outcome that has yet to be developed. Cost-effectiveness of demand response programs will be addressed in a formal proceeding, but the details of how that proceeding will proceed are still to be determined.

DRA and TURN argue that the 3-day baseline currently used for customer settlement over-estimates customers' demand reductions and "grossly overcompensates participants," and asks that it be replaced by a more accurate baseline. While it is likely that the 3-day baseline is less accurate than desired, Energy Division recommends that the baseline for CBP remain as proposed by the Utilities at this time.

DRA proposes replacing the 3-day baseline with a 10-day baseline, while TURN states that a 10-day baseline or a regression analysis-based methodology are more accurate indicators of actual load reductions.

None of the Utilities dispute that there are more accurate baselines than the 3-day baseline currently used, but all three argue that the issue of which baseline to use is being considered in other proceedings, and that for the sake of consistency across DR programs it would not make sense to use one baseline for the CBP program and another baseline for other programs.

Energy Division concurs that the 10-day baseline is a better estimate of most customers' actual demand than the 3-day baseline. However, there are several reasons why changing baselines at this point in time is inadvisable. It is by no means certain that the 10-day baseline is the *best* available baseline. Therefore, changing to a 10-day baseline at this point would possibly be a temporary measure, which would have the additional drawback of adding confusion and inconsistency to the CBP.

In addition, changing to a 10-day baseline for CBP would have several other disadvantages. It would make it difficult to compare the effectiveness of CBP to the other DR programs, which currently use the 3-day baseline. It is also likely to result in substantially lower customer enrollment and program participation than predicted because it would decrease the amount of most customer's incentives.

Determination of the most appropriate and accurate baseline to use for customer settlement for demand response programs is a load impact protocol issue that would be better addressed in a formal proceeding.

In its comments on the draft resolution, TURN repeats its opposition to the 3-day baseline, arguing that it overstates the amount of actual load reductions. TURN argues that there is no reason to delay fixing a major technical flaw with the program.

The Utilities respond that the issue of appropriate baselines for all demand response programs needs to be developed in a broader context, such as a formal proceeding, and not in the advice letter process.

Energy Division concludes that the baseline should not be modified for the reasons outlined in the resolution.

DRA expresses concern about the wholesale contract between PG&E and DWR, and points out that "(a)ny substantial departure from the features of the

retail program will make the future DWR replacement program an entirely different program from the CBP." Energy Division recommends that the Commission direct PG&E submit its proposal for the wholesale contract within 30 days of the effective date of this Resolution.

PG&E states that the terms of the wholesale contract will be similar to those of the proposed CBP. Energy Division believes that PG&E should submit the terms of this contract as soon as possible so that the issues discussed here do not have to be revisited long after these Advice Letters are resolved.

DRA believes that the proposed 15,000 BTU/kWh heat rate trigger be used as a guidepost but not as the determining factor to trigger a CBP event. Energy Division believes that the trigger should remain as proposed, so that a CBP event is called when a 15,000 BTU/kWh heat rate is required.

PG&E responds that they are amenable to discussion of adding flexibility to the trigger. SDG&E says that they have already included "a discussion of the representative conditions that might trigger a program event" but that "because the program is designed to function as a supply side resource, it is indeed the occurrence of the 15,000 BTU/kWh heat rate that would ultimately trigger a program event, save for some other SDG&E operational emergency or CAISO alert." SCE also states that the heat rate trigger is appropriate for this program, and that they have other programs which are designed to respond to reliability concerns.

Energy Division believes that the 15,000 BTU/kWh heat rate is an appropriate trigger and that it is important that participants understand exactly what conditions will trigger an event. Energy Division believes that DRA's protest stems from problems associated with the previous trigger of $80/MW used in the DRP program. This trigger sometimes resulted in the DRP being called even when the system was not experiencing economic or reliability constraints. By assigning the CBP a heat rate equivalent to a peaking power plant, the CBP program would only be called in place of a peaking plant.

In its comments on the draft resolution, DRA re-submits its arguments that the program trigger be flexible so that it could be called in an emergency situation. DRA acknowledges that it would be rare for an emergency condition to exist while the utilities' resource stack had not reached the 15,000 BTU/kwh heat rate.

DRA also argues that the utilities should have the flexibility to not trigger the program if the resources are not needed.

SDG&E responds that DRA's recommendations are not necessary because SDG&E is offering a Day-Of option which is designed to address emergency situations. SCE is opposed to DRA's recommendation because the program is intended to be price-responsive. Inserting an emergency trigger would run counter to the objective of the program as well as the Commission's objective in developing more price-responsive programs. SCE states that it already has sufficient reliability programs that could be called in emergency situations. SCE is also opposed to DRA's recommendation for a flexible trigger because a firm trigger provides certainty for customers which is necessary for a program with capacity payments and penalties for non-performance.

Energy Division agrees with SCE that the trigger for the CBP should be firm because its participants must have certainty on when they are expected to perform. Energy Division also agrees with SCE that inserting an emergency triggering condition into the Day-ahead option for the program is not appropriate. Energy Division believes that directing the utilities to also offer a Day-Of option will address DRA's concern.

The Aggregators are concerned about the length of time required for settlement and ask that both aggregators and directly enrolled customers receive payment within 30 days. Energy Division recommends modifying the proposed CBP to require that the Utilities strive to pay both directly enrolled customers and aggregators by 30 days after the end of the operating month, but not more than 60 days after the end of the operating month.

In their advice letters, the Utilities propose payment within either 60 (PG&E) or 90 (SDG&E) days for aggregators. The Aggregators also point out that SCE is not clear in its Advice Letter whether they will pay aggregators in 30 or 60 days. In addition, they ask that any charges incurred by aggregators be netted against payments due to that aggregator, and if no payments are due then charges are payable within 30 days rather than the 15 proposed by the Utilities.

SCE and SDG&E propose to change the language of their proposal so that all participants receive payments within the same time period (60 days for SCE and 90 days for SDG&E). PG&E argues that technical considerations require 60 days to determine billing data for aggregated customers. SDG&E also state that they already provide for payments incurred by aggregators to be netted against payments due, but that its standard bill and payment terms, as approved by CPUC, require that bills be payable within 15 days.

Aggregators require timely payments to retain solvency, but the Utilities require sufficient time to calculate settlements. Energy Division recognizes that quick settlement may be difficult, depending on the point in the billing cycle at which an event occurs. Energy Division therefore recommends modifying the proposed CBP to require that the Utilities strive to pay both directly enrolled customers and aggregators by 30 days after the end of the operating month and not more than 60 days after the end of the operating month.

The Aggregators also point out that that the meaning of the Utilities' requirement that bills be payable "within 15 days" is unclear. The Aggregators indicate that there is some confusion as to whether the Utilities mean "within 15 days of a CBP event" or "within 15 days after receiving their bill" (i.e., with 15 days after the 30 to 60 day period). Energy Division believes that the intent of the Utilities was to say that any aggregators or directly enrolled customers who incur penalties or other charges during an event will have a period of 15 days after receiving their bill to pay those charges.

In their comments on the draft resolution, the Utilities state the program is designed to pay on an operating month basis, not an event basis. Thus it is not feasible to make payments within 30 days of an event as directed by the proposed resolution. The utilities must also validate the customer's meter data, and reception of that data could be after the last day of the operating month depending on the customer's meter read date. The Utilities recommend that the resolution be modified so that payment shall be due no later than 60 days after the end of the operating month.

EnergyConnect states that PG&E should be required to make payments within 30 days after they are presented with an invoice or 35 days after the end of the month, whichever occurs later.

Energy Division concludes that the Utilities' point is valid as settlements are determined at close of the operating month, and not on an event basis. Thus the resolution has been modified to reflect a payment schedule based on operating month.

The Utilities are proposing that Aggregators meet certain credit-worthiness requirements. The Aggregators feel that all participants should be required to meet those requirements, not just aggregators. Energy Division finds this protest to be without merit.

SDG&E and PG&E state that they already require all participants to meet the same credit-worthiness requirements. In addition, PG&E points out that they, unlike the other Utilities, propose no credit requirements to become an aggregator, unless the aggregator is late in making payments, in which case they must satisfy credit requirements just as any other customer is required to do. SCE states that all aggregators face the same participation rules. Energy Division recognizes that the need to protect ratepayers may require credit-worthiness requirements for third parties providers of energy services that may be more stringent than the credit-worthiness requirements imposed upon directly-enrolled customers.

The Aggregators propose creation of a "CBP Advisory Group" to oversee CBP marketing and outreach efforts. Energy Division recommends that the Utilities, in consultation with the Aggregators, develop a means by which aggregators could have input into the Utilities' advertising and marketing of CBP, and report the details of that plan to the Energy Division by November 30, 2006. Energy Division also recommends that a portion of the M&E funds be used to evaluate the Utilities advertising and marketing of CBP.

Aggregators argue that the Utilities are requesting a "sizable ratepayer-funded marketing budget" and they would like to insure that these marketing efforts do not "favor direct utility enrollment over Aggregators, but rather fully inform customers of the benefits, costs, and risks for each CBP enrollment option." They ask that "descriptions and contact information for all qualified and approved Aggregators . . . be included with any marketing and outreach materials developed using ratepayer funding."

The Utilities feel that an advisory group is unnecessary because it is already in their interests to maximize participation in the CBP. SDG&E argues that this would add to the cost of the program. PG&E and SCE offer that the working group created under D.06-03-024/A.05-06-006 is a sufficient body for any needed materials review. In addition, SCE argues that they cannot include information about "all qualified and approved aggregators" in their marketing materials because they have no way of knowing anything about the Aggregators other than their credit-worthiness.

Energy Division agrees that aggregators are likely to be extremely knowledgeable about marketing and advertising, and their input could substantially improve customer participation in demand response programs. However, we do not think that creation of a new working group is necessary.

In their comments on the draft resolution, the Utilities repeat their assertion that the existing collaborative process as outlined in D.06-03-024 provides for adequate input by Aggregators on CBP marketing and outreach.

The Aggregators request that the resolution specify in greater detail the nature of Aggregator involvement in providing input on marketing and outreach efforts, such as creating an Advisory Group.

Energy Division does not agree with the Utilities that the existing collaborative process as outlined in D.06-03-024 is an adequate process for the Aggregators to provide input as that process requires only two meetings per year with all other intervenors to discuss program issues. The collaborative process appears to be set up for broader issues and would not be well-suited for a focused dialogue on marketing and outreach as the Aggregators request. Energy Division encourages the Utilities to develop a plan with the Aggregators on how to best incorporate their input for marketing and outreach. Upon receipt of that plan, Energy Division shall determine if an Advisory Group is still necessary.

The Aggregators ask that the CBP program not be limited in size to the MW levels projected in the Utilities' budgets. Energy Division believes that the MW levels projected by the Utilities' budgets in no way constitute a cap on program size.

The Aggregators point out that each of the utilities have submitted budgets based on achieving particulars levels of demand response and ask if these projections amount to a cap on the size of the CBP program. PG&E and SDG&E state that they have no plans to limit the size of the program and that procedures already exist for the Utilities to request additional resources if necessary.

Energy Division concurs that there is no reason to limit the size of the programs to the MW levels projected by the Utilities' budgets, and does not perceive any intent to do so by the Utilities. If customer interest in participation in the CBP exceeds the Utilities' 2007-2008 incentive budget estimates, the Utilities already have the ability to shift funds, which should be sufficient to cover any unexpected increase in enrollment. Furthermore, if enrollment is so high that existing DR funds are exhausted, the Utilities may request additional budget.

UCAN argues that the proposed program conflicts with SDG&E's recently-filed AMI application. Energy Division believes that UCAN is inaccurate.

UCAN states that in SDG&E's recently-filed AMI application, the utility lists the future avoidance of DR programs for large customers as an operational benefit of AMI. SDG&E responds that "UCAN has misconstrued SDG&E's AMI application….the initial deployment of an AMI infrastructure would commence in 2008, and not be fully deployed until 2010….SDG&E's proposed CBP program would become a component of the existing 2006-2008 DR program portfolio." SDG&E's response conforms with Energy Division's understanding of the timeline of both the CBP program and the AMI process.

DRA recommends that the resolution should defer any conclusions about this issue to the process started by the August 9, 2006 Assigned Commissioner's Ruling where it and other parties have filed comments regarding it. Energy Division declines to modify the resolution as suggested by DRA as it simply states Energy Division's understanding of SDG&E's AMI and CBP timelines. The Commission has the latitude to address this issue in either SDG&E's AMI proceeding or the demand response proceeding.

Aglet argues that SCE is underestimating the price of natural gas in its cost-effectiveness calculations and budget estimates. Energy Division does not find it necessary for SCE to change its budget or cost-effectiveness calculations at this time.

Aglet points out that SCE is basing the CBP energy incentive payment on the trigger heat rate of 15,000 BTU/kWh. At the same time, the amount of money SCE has budgeted for 2007 energy incentives is based on an average payment of $73.40/MWh. This implies that SCE expects the 2007 gas price to average $4.89/MBTU, which is far lower than current gas prices.

SCE responds that "whether the energy price estimate is too high or too low is immaterial to the cost effectiveness analysis, because the energy payments to participants for delivered MWh are based on SCE's actual avoided energy costs, at whatever the city gate gas price may be."

Energy Division notes that SCE's statement that an underestimation of the energy price is immaterial to the cost effectiveness analysis is not precisely accurate. If the predicted energy price that SCE used in its cost-effectiveness calculations is indeed lower than the actual energy price, then SCE's avoided costs, and also, therefore, the customers' incentives will be higher than predicted. As a result, program cost-effectiveness will also be **higher** than predicted. The only problem with SCE's possible miscalculation of future gas prices is that the predicted amount budgeted for energy incentives may be insufficient to actually cover payments. However, there is considerable uncertainty as to program enrollment, and therefore the actual amount SCE will need for incentive payments. There is already sufficient fungibility in SCE's demand response budget so as to enable SCE to add money to their CBP energy incentive budget if necessary.

DRA is concerned that the proposed CBP may not conform with Resource Adequacy (RA) rules, and asks that all participants be required to bid for at least 2 of the 6 summer months, so as to satisfy RA counting rules, which require a minimal seasonal performance level of 48 hours. Energy Division believes that the CBP as proposed does conform with RA counting rules.

SDG&E argues that because the RA protocols are still being developed, it is not appropriate to make any changes. SDG&E states that they will change the CBP rules if future RA decisions warrant it. PG&E and SCE respond that the RA counting rules do not require each customer to participate for a total of 48 hours, only that the program as a whole do so, and that the CBP already meets that requirement.

The RA counting rules require that a program be available for at least 48 hours per year. It does not require that each individual participant contribute to that availability, only that the larger program be able to contribute some level of demand reduction if called upon to do so. If this were a new program, with a possibility that *no* customer would bid during a given month, it is possible that the program would not be available for the minimum 48 hours. However, the CBP is the successor to the DRP program, which has proven to be available during each of the months of its operation, and therefore conforms to RA requirements.

COMMENTS

Public Utilities Code section 311(g)(1) provides that this Resolution must be served on all parties and subject to at least 30 days public review and comment prior to a vote of the Commission. Section 311(g)(2) provides that this 30-day period may be reduced or waived upon the stipulation of all parties in the proceeding.

The 30-day comment period for the draft of this Resolution was neither waived or reduced. Accordingly, this draft Resolution was mailed to parties for comments, and will be placed on the Commission's agenda no earlier than 30 days from today.

Comments are due on **October 6, 2006** and reply comments on **October 12, 2006**.

DRA, TURN, the Demand Reserves Partnership (the Aggregators), ECS (an Aggregator) PG&E[11], SCE, SDG&E and TURN filed comments on October 4, 5 and 6, 2006. Reply comments were filed by PG&E, SDG&E, SCE and EnergyConnect, Inc. on October 11 and 12, 2006. The following paragraphs summarize the comments submitted by the parties. The details of the comments are further elaborated and addressed in the Discussion section of this resolution.

The Utilities oppose the capacity payment differential, the customer participation threshold, and the requirement that payments be made within 30 days of an event. They individually have other objections such as the budget reductions as proposed in the resolution.

DRA recommends that the CBP capacity payments be adjusted once cost-effectiveness tests are developed. DRA also recommends that the program trigger be flexible so that the program could be used in emergency situations.

[11] PG&E amended its comments on October 11. The amended comments correct an error in PG&E's proposed energy price for its Day-Of CBP option.

DRA recommends that the Commission provide guidelines to the utilities regarding a day-of option and further opportunity for comment by parties.

TURN opposes the 3-day baseline, the size of the capacity payment, and the administrative budgets as proposed in the draft resolution.

The Aggregators recommend that the differential in the capacity payment between themselves and directly-enrolled customers be set at 30%, their original proposal. They also recommend that the resolution adopt their original proposal to pay participants 100% of their capacity payment for actual reductions in the 90-100% range. ECS recommends that customers be compensated on sliding scale, rather than the ramp-down structure as proposed in the resolution.

EnergyConnect, Inc. recommends that customers have the freedom to enroll in the program through either an aggregator or utility, regardless of the customer's size, and it also recommends that PG&E be required to make payments to participants within 30 days of being presented an invoice or 35 days after the end of the month.

FINDINGS

1. D.06-03-024 directed Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric (the Utilities) to file Advice Letters to propose a successor to the California Power Authority Demand Reserves Partnership program.

2. The Capacity Bidding Program was proposed by the Utilities to replace the Demand Reserves Partnership.

3. This Resolution is not the proper forum for parties to debate the cost-effectiveness of the CBP because (1) there is another Commission process to address cost-effectiveness; (2) there are additional costs and benefits of DR programs which were not considered by the Utilities in their current cost-effectiveness analyses; and (3) the cost-effectiveness tests used by the Utilities were designed for energy efficiency programs and may not be appropriate for demand response programs.

4. The budgets proposed by the Utilities for this program are not completely consistent with program needs and should be reduced to the amounts displayed in Table 4.

5. To facilitate the participation of the third-party service providers known as aggregators, it is necessary to provide a price differential. Aggregators will receive the full amount of the proposed capacity payments, while directly-enrolled participants will receive 80%.

6. The capacity payment structure should be modified so as to reward customers for partial demand reductions, as shown in Table 6.

Table 6

Actual reduction	Capacity Payment
100%	100%
90%-100%	90%-100% (proportional)
75%-89.99%	50%
50%-74.99%	0
< 50	participant pays penalty

7. The Utilities should add a Day-of option to their Capacity Bidding Programs, with higher capacity payment rates than the Day-ahead option and specific triggering conditions.

8. The capacity payment rates for the CBP should be fixed for 2007 and 2008.

9. This resolution is not the proper forum to determine the appropriate baseline to be used for customer settlement.

10. PG&E should be directed to submit its proposal for the wholesale contract with the California State Water Project within 30 days of the effective date of this Resolution.

11. The CBP should be triggered when the day-ahead market anticipates the use of generation resources that are the equivalent of a gas-fired power plant that takes 15,000 BTUs of natural gas to generate one kWh of electricity.

12. Utilities should strive to pay both directly enrolled customers and aggregators by 30 days after the end of the operating month, but not more than 60 days after the end of the operating month.

13. Utilities should, in consultation with aggregators, develop a means by which aggregators could have input into the Utilities' advertising and marketing of CBP, and report the details of that plan to Energy Division.

14. The MW levels projected by the Utilities' budgets in no way constitute a cap on the program size.

15. The CBP as proposed does conform with RA counting rules.

THEREFORE IT IS ORDERED THAT:

1. The requests of Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric to replace the CPA DRP program with the Capacity Bidding Program as requested by Advice Letters 2839-E filed by PG&E, AL 2010-E filed by SCE, and AL 1799-E filed by SDG&E, are partially approved, subject to the modifications adopted in this Resolution.

2. The modifications stated below will apply to the Capacity Bidding Program. The Utilities shall file supplemental advice letters with the modifications described below within 10 days of the effective date of this Resolution:

   - Aggregators will receive the full amount of the proposed capacity payments, while directly-enrolled participants will receive 80%.
   - The capacity payment structure will be modified so as to reward customers for partial demand reductions as shown in Table 6.
   - SDG&E's Day-of option should have specific triggering conditions.
   - The amounts of the capacity incentive payments paid to participants by PG&E, SDG&E and SCE are to be fixed for 2007 and 2008.
   - The budgets proposed by PG&E, SDG&E and SCE are modified as shown in Table 4.
   - PG&E, SCE and SDG&E shall strive to pay both directly enrolled customers and aggregators by 30 days after the end of the operating month, but not more than 60 days after the end of the operating month.

3. PG&E is directed to submit its proposal for the wholesale contract with the California State Water Project within 30 days of the effective date of this Resolution.

4. PG&E, SDG&E and SCE are directed to consult with Aggregators in developing a means by which aggregators could have input into the Utilities' advertising and marketing of CBP, and report the details of that plan to Energy Division by November 30, 2006. Energy Division is delegated authority to direct the Utilities to form an advertising and marketing Advisory Group if Energy Division concludes that the plan is insufficient.
5. A portion of the allocated M&E funds for the CBP shall be used to evaluate the advertising and marketing of CBP.
6. PG&E and SCE shall file new advice letters proposing their Day-of options for the CBP within 20 days of the effective date of this Resolution.

This Resolution is effective today.

I certify that the foregoing Resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on October 19, 2006; the following Commissioners voting favorably thereon:

STEVE LARSON
Executive Director

MICHAEL R. PEEVEY
PRESIDENT
GEOFFREY F. BROWN
JOHN A. BOHN
RACHELLE B. CHONG
Commissioners

Commissioner Dian M. Grueneich, being necessarily absent, did not participate.