Decision 05-11-009 November 18, 2005

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing.	Rulemaking 02-06-001 (Filed June 6, 2002)

DECISION CLOSING THIS RULEMAKING AND IDENTIFYING FUTURE ACTIVITIES RELATED TO DEMAND RESPONSE

This decision closes Rulemaking (R.) 02-06-001 as most of the activities identified in the proceeding have been completed. We identify additional activities necessary to ensure that our demand response programs provide full value to California ratepayers and establish a timetable for moving forward on those activities.

1. Background

We began this rulemaking[1] in June 2002, as a policymaking forum to develop demand response as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment. The desired outcome of this effort was that a broad spectrum of demand response programs and tariff options would be available to customers who make their demand-responsive resources available to the electric system.

[1] The Commission's rulemaking named as respondents the following investor owned utilities: Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison Company (SCE).

At the outset we recognized the need for a strategic approach to the orderly development of demand response capability in the California energy market. To that end, we coordinated this rulemaking with decision makers from the California Energy Commission (CEC), and previously, the California Consumer Power and Conservation Financing Authority (CPA), based on an interagency working model developed by the assigned Commissioner.[2]

That model relied upon three working groups. The first, Working Group 1 (WG1), comprised of agency decisionmakers (assigned Commissioner Michael Peevey, CEC Commissioner Arthur Rosenfeld, and CPA Director Sunne W. McPeak, also known as "the WG1 principals"), and supported by the assigned Administrative Law Judge (ALJ) and advisory staff from the CPUC and CEC, was responsible for shaping the rulemaking record by providing overall policy guidance to parties at key points in the proceeding. WG 1 focused its efforts on the development of a long-term vision for the development of demand responsiveness in California by setting a framework, developing goals, and focusing on how demand response can and should be integrated with the utilities' overall procurement responsibilities.

The second, Working Group 2 (WG2), is comprised of active parties who are interested in developing demand response programs for large customers (>200 kilowatt (kW)) in peak monthly demand). The meetings of this group are facilitated by agency staff supporting WG1 decision-making activities. The third, Working Group 3 (WG3), is comprised of active parties who are interested in developing demand response programs for small commercial/residential

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[2] See, Ruling Following Prehearing Conference, dated August 1, 2002; and Assigned Commissioner's Ruling and Scoping Memo, dated August 16, 2002.

customers. Like WG2, the meetings of WG3 are facilitated by agency staff supporting WG1 decision-making activities.

The first year of this proceeding resulted in adoption of two main decisions. The first (Decision (D.) 03-03-036) adopted the Statewide Pricing Pilot (SPP) which was designed to test the impact of time-of-use and critical peak pricing tariffs on residential and small commercial customer usage patterns on a pilot basis. The second (D.03-06-032) adopted demand response program plans for customers with load exceeding 200 kW and established annual megawatt (MW) targets to be met through demand response.

On November 24, 2003, the Assigned Commissioner issued a scoping ruling for the second phase of this proceeding. The ruling set aside some issues for future proceedings and identified the following issues as the focus of Phase 2.

- Analysis Framework for the Advanced Metering Infrastructure Business Case, Utilizing Utility, Customer and Societal Perspectives
- AC Cycling as a Control Technology that Interfaces with AMI Elements
- Real Time Pricing (RTP) Tariff Development
- Ongoing Implementation Issues, specifically, resolution of:
  (1) CPA/Demand Reserves Partnership (DRP) program disputes between California Department of Water Resources (DWR) and the utilities;
  (2) delineated agricultural customer participation issues; and
  (3) delineated metering service "clean-up" issues.
- A planning process for any near term adjustments in 2004 goals as part of achieving 2007 demand response targets.

The rulemaking was also the forum for adoption of demand response budgets and program plans for 2004 and 2005.

The various Working Groups assisted in developing program plans and budgets as well as evaluating the results of the programs. In particular, WG3's Evaluation Subcommittee conducted numerous and extensive meetings concerning the proper methodology for analyzing the SPP results. The work of the evaluation subcommittee both contributed substantive to the final SPP Report issued by Charles River Associates as well as helped ensure broad support for the results of the consultant evaluation. This work is not reflected on the record as no reports were filed by the subcommittee or by WG3, but we note it here to recognize the efforts of all parties to assist in promoting demand response efforts outside of the formal Commission process.

2. Other Proceedings Addressing Demand Response Efforts

Over the course of approximately three years, we have made significant progress in advancing the agenda the initial rulemaking laid out on the program, pricing, and infrastructure fronts. The three utilities have filed applications for authorization of 2006-2008 demand response programs which are being handled in Application (A.) 05-06-006 et al. The Commission is considering adoption of critical peak pricing tariffs as a default for customers with demand exceeding 200 kW (A.05-01-016 et al.). PG&E has requested authority to begin deployment of an advanced metering infrastructure in 2006 (A.05-06-028) and SDG&E seeks similar authority (A.05-03-015). SCE has proposed to develop an Advanced Integrated Meter to improve the cost-effectiveness of an advanced metering infrastructure for its ratepayers (A.05-03-026).

3. Resolution of Phase 2 Issues

Because so many of the issues that were originally being developed in the rulemaking have advanced sufficiently to warrant their own applications, it is time to review the status of what remains to be addressed in this rulemaking.

On July 21, 2004, the Assigned Commissioner adopted an advanced metering infrastructure analysis framework for purposes of guiding utility development of advanced metering infrastructure business cases and the utilities have each filed business case analysis of advanced metering infrastructure projects. A February 19, 2004 Ruling had previously adopted minimum functionality criteria that any advanced metering infrastructure system must meet to be eligible for ratepayer funding. One of the criteria addresses compatibility with cycling and load control technologies and effectively resolves the second issue established for Phase 2. The Commission has not made further progress on development of an RTP tariff since the Phase 2 scoping memo was issued. Ongoing implementation issues have been addressed in various rulings (DRP disputes, agricultural customer issues) and decisions (metering) but some aspects of the DRP program management remain outstanding and are addressed below. The 2004 program goals were modified by a February 25, 2004 Ruling, and whether and how to adjust the 2007 program goal has been squarely raised in A.05-06-006 et al. The outcomes of several ongoing proceedings (CPP applications, resource adequacy, and advanced metering infrastructure cases) will impact the proper goals for demand response programs. The ALJ assigned to A.05-06-006 et al. will coordinate with other proceedings, as needed, in considering modifications to previously adopted goals.

Therefore, because the work laid out is substantially complete, the time has come to close this proceeding. Because there are a few remaining issues, and a few new issues have arisen, the next section lays out the process for addressing these continuing issues.

4. Process for Addressing Remaining and New Issues

4.1 Continuation of 2005 Programs Pending Decision on 2006-2008 Programs

D.05-01-056 adopted budgets and funding for 2005 demand response programs. That decision also required the utilities to file applications for adoption of 2006-2008 program plans. The current schedule for handling those applications in A.05-06-006 et al anticipates a Commission decision on the applications in March 2006, which could leave a funding gap for the first few months of 2006. On October 6, 2005, SCE filed a motion for authorization to continue to implement 2005 demand response programs in first quarter of 2006. PG&E filed a similar motion on October 27, 2005. The assigned ALJ and Commissioner, under authority delegated in D.03-06-032, have consistently carried over demand response program funding from one year into the next funding year to ensure fuller utilization of authorized funding before approving new funds. In the event that no Commission decision has been adopted in A.05-06-006 et al. by January 1, 2006, the utilities may carry over any 2005 authorized funding to continue to offer 2005 programs until such time as a decision is adopted for 2006 programs. This temporary bridge is a logical and simple means to ensure program continuity. SCE and PG&E's motions should be granted and extended to SDG&E.[3]

[3] On October 19, 2005, SDG&E filed a motion in A.05-06-006 et al. to accomplish this same objective. This decision obviates the need for the ALJ to rule on the motion in A.05-06-006.

4.2 Tariff and Bill Issues

As stated above, although establishing an RTP tariff was identified as a topic for Phase 2 of the rulemaking, the Commission did not make further progress on developing two-part RTP tariffs for the largest utility customers. This lack of progress was driven by the lack of a meaningful price signal in the California Independent System Operator (CAISO) market upon which a real time price could be established as well as the parties' fundamental disagreement about how to design key components of a two-part RTP tariff, and the difficulty in doing so given the non-bypassable DWR charges on customer bills.

As the CAISO moves to implement its market redesign, we anticipate that transparent pricing information will become available that will facilitate development and adoption of a true RTP tariff. However, design of such a tariff cannot be performed in isolation from comprehensive rate design examination. Therefore, we direct each utility, as part of its next comprehensive rate design proceeding application following development and final implementation of an hourly day-ahead market price by the CAISO, to submit a real time pricing tariff for consideration as part of its tariff offerings. By that time, the CAISO will have implemented its market redesign, costs associated with recovery of the DWR revenue requirement will be declining, and we will have a clearer picture of whether and how utilities have deployed an advanced metering infrastructure and the basis on which to develop and adopt an RTP tariff will be much clearer.

In addition, we would like to see the utilities propose additional price responsive tariff options for their customers to consider. These were first articulated in the vision statement for demand response, entitled "California Demand Response: A vision for the Future (2002-2007), which was

Attachment A to D.03-06-032. In that statement, we articulated the following set of options that different types of customers should ideally have access to:

> "Very large customers (over 1 MW): Hourly real-time pricing (RTP), critical peak pricing (CPP), or Time of Use (TOU) Pricing.
>
> Large customers (200 kW to 1 MW): CPP, TOU, or RTP
>
> Residential and small commercial customers (under 200 kW): CPP, TOU, or flat rate (the latter with an appropriate hedge for risk protection)"

Thus, we also require the utilities to make proposals for consideration for all of the above price-responsive tariff options for their customers in the next comprehensive rate design application.

In the short term, we will focus our efforts with respect to tariff offerings on reviewing the applications of each utility to implement a critical peak pricing (CPP) tariff for customers with load of over 200 kW (A.05-01-016 et al.), and PG&E's proposed tariffs to promote demand response as part of its AMI Project (A.05-06-028). Residential and small commercial customers are not currently able to sign up for CPP rates, with the exception of customers already enrolled on the experimental CPP rates that were developed as part of the SPP. Development of non-experimental time differentiated tariff options for these customer classes will need to occur fairly soon, and we direct each utility to include such tariffs in their next rate design application. Since effective implementation of more time-differentiated tariffs for smaller customer classes requires the installation of metering and communications technology more sophisticated than most currently have, requiring the utilities to file proposed time-differentiated tariffs in their next rate design applications will allow us to have more information about whether and when each utility might be deploying advanced metering infrastructure throughout its service territory, and therefore, whether designing a CPP tariff for smaller customers is an appropriate use of the resources of all parties.

Finally, we note that over the course of this proceeding there has been discussion about the importance of how information is communicated to customers on their bill, and that current bill formats may not be the most effective way to convey energy usage information to promote demand response. This is an issue that transcends just demand response; it affects energy customers generally. Having more customer friendly billing formats could assist in meeting demand response, energy efficiency, and other policy goals. Therefore, we direct the Commission's Executive Director to explore opening a new rulemaking to develop more customer friendly billing formats for energy bills and to report back to the Commission at the second Commission meeting in January 2006 on whether the Commission should open such a rulemaking, and if so, the schedule for presenting the rulemaking to the Commission. Several parties recommend a workshop prior to any recommendation to implement a bill format rulemaking. While this recommendation has merit, we will not mandate the process employed by the Executive Director to prepare his recommendation.

4.3 Demand Reserves Partnership

In D.04-11-034, the Commission directed PG&E to negotiate an agreement with the CPA for the future operation and management of the DRP program. The Commission believed that an alternative manager of the DRP program was necessitated because it appeared that the CPA's operating funding for the program would be depleted by the end of November 2004. Since the time that D.04-11-034 was issued, the CPA was able to engage a Fiscal Agent to operate and manage the DRP program. The program has been operating under this approach, without any apparent issues, since that time. Although CPA and PG&E worked to negotiate an agreement to allow PG&E to take over management of the program, sticking points remained. In addition, the Commission itself, along with DWR, identified potential conflict of roles concerns with PG&E assuming the CPA role and also scheduling and dispatching the program under an agency agreement with DWR. Because these issues have not been resolved, the Demand Reserves Purchase Agreement will expire May 2007; however, the CPA Fiscal Agent has been ably managing the DRP program. We see no need to disturb the status quo, and decline to approve the Proposed Management Services Agreement filed on February 4, 2005.

In response to the draft decision, DWR recommends that we consider transferring the DRP program to the utilities immediately. SCE and PG&E oppose this suggestion, stating that they are developing plans to offer a similar program in 2007 when the current program expires, but are not prepared to take over administration now. We are not convinced to modify the decision to require early assumption of the DRP programs. However, we encourage the utilities to incorporate the DRP resources into their respective portfolios so that they are transitioned immediately upon conclusion of the DRP.

In D.05-01-056, the Commission approved an additional $575,000 in funding to cover PG&E's incremental costs of implementing the management services agreement. Since PG&E has not been functioning in this capacity, this funding is unneeded. PG&E may shift those funds into other programs, consistent with the fund shifting guidelines adopted in Ordering Paragraph 4 of D.05-01-056. TURN opposes providing fund shifting flexibility to PG&E for these funds, arguing they should be returned to ratepayers. However, the $575,000 budget was authorized to be collected by PG&E as part of its various memorandum accounts but was not an adopted revenue requirement so there is nothing to return to ratepayers. If PG&E chooses not to shift the $575,000 to another program, nothing will be booked to the memorandum account or collected from ratepayers. We do not disturb the fund shifting flexibility set forth in the draft decision.

4.4 Measurement and Evaluation

One of the struggles that has become clear over the course of this proceeding is between our desire to promote price-responsive demand and how the utilities and the CAISO treat demand response resources for purposes of resource planning and meeting resource adequacy standards. Unlike energy efficiency, which has a long history of success, adopted measurement protocols, and is well integrated into the resource planning process, demand response programs have a shorter history, are not well integrated into the planning process, and do not have adopted measurement and evaluation protocols. At this time, it appears that the CAISO continues to purchase energy in the market in order to ensure sufficient energy in the event that all demand response resources do not deliver. It is our belief that until the industry develops further trust that demand response will deliver demand reductions when needed, demand response will continue to be dismissed in the resource planning and acquisition process. In order to build that trust, we need to develop industry protocols for measuring load response capability and results so that the ratepayers are not paying twice for the same capacity, once for demand response programs, and then again for short-term resource acquisition by the CAISO.[4] In

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[4] D.05-10-042 provides guidance regarding how emergency demand response resources should be counted for resource adequacy purposes. (See Section 7.2.)

addition, more precise demand reduction estimates derived from an accepted measurement methodology are a necessary prelude to performing accurate cost-effectiveness analysis.

By April 3, 2006, agency staff shall prepare a set of draft protocols for estimating load impacts for both price responsive and reliability demand response programs. This effort should be coordinated with efforts underway in the energy efficiency rulemaking, R.01-08-028, or its successor, and the resource adequacy rulemaking, R.04-04-003, or its successor. The draft should address whether the load impacts of all types of demand response programs (e.g., bidding programs, time-differentiated tariffs, reliability programs, interruptible tariffs) should be measured by the protocols. The draft protocols should include a list of data that must be collected on energy use or customer load profiles, program capital and operating costs, and incremental customer costs, including comfort changes or customer costs during curtailments. The draft protocols will provide us with a list of the types of load impacts that need to be estimated and other data collection requirements that any adopted protocols need to include. This information will support assessment of program cost-effectiveness. Several parties recommended that we hold workshops before agency staff serve the draft protocols. While we find the recommendations to have merit, we will not mandate the process employed by agency staff to prepare draft protocols.

Agency staff shall serve the draft protocols on the service list to this proceeding, or any related or successor proceedings, and schedule a workshop for interested persons to provide peer review and feedback. Agency staff shall make any necessary modifications to the draft protocols as a result of the comments and prepare a proposed rulemaking or recommend an alternative procedural approach for Commission consideration no later than six months after the draft protocols are circulated.

4.5 Cost-Effectiveness Methodology

Ensuring useful cost-effectiveness analysis will of course require the use of avoided cost inputs adopted in Rulemaking (R.) 04-04-025, the proceeding where the Commission is developing its general avoided cost principles. Of particular interest to demand response practitioners, is how to estimate avoided costs for the top 100 critical hours of peak, an issue that has been raised in A.05-06-004 et al. Parties with an interest in the avoided cost inputs to any specialized demand response cost-effectiveness tests should participate in R.04-04-025. The issue of developing an avoided cost methodology is separate from developing the cost-effectiveness tests themselves.

An industry accepted methodology for evaluating cost-effectiveness of demand response programs has not yet been established. This issue was identified by the assigned ALJ in A.05-06-006 et al., the 2006-2008 program plan applications. In that application, the ALJ required the utilities to submit cost-effectiveness analyses using the Standard Practice Manual (SPM) tests for energy efficiency as one possible measure of cost-effectiveness. Earlier in this proceeding, parties pointed out various shortcomings associated with using the SPM tests for evaluating demand response resources. The time has come that we should begin a process to adapt the SPM tests to the unique features of demand response programs or develop alternative tests for assessing cost-effectiveness.

Agency staff are directed to host a workshop with the objective of scoping the issues that parties believe must be addressed in developing relevant cost-effectiveness tests for demand response programs and identifying process options for developing the cost-effectiveness tests. The parties may believe that it is appropriate for the Commission to provide guidance on certain questions before beginning to develop cost-effectiveness tests for all types of demand response programs. For example, there may be dispute over the need to evaluate the cost-effectiveness of programs that rely on time differentiated tariffs to motivate demand response, as opposed to programs that provide incentives for customer participation. There may also be disputes over what types of societal costs, e.g., lower lighting levels, value of lost load, etc., should be included when evaluating cost-effectiveness. The workshop shall occur no later than March 2006 and notice of the workshop shall be served on the service list for this rulemaking and any relevant or successor proceedings. Within two months following the workshop, agency staff shall recommend to the Commission's Executive Director whether to open a new rulemaking to provide guidance on this topic, and if so, shall prepare a proposed rulemaking or recommend an alternative procedural approach for consideration. This effort should be coordinated with efforts underway in the energy efficiency rulemaking, R.01-08-028, or its successor. If following the workshop, agency staff believes that a set of proposed cost-effectiveness tests for each type of demand response program can be developed without upfront policy guidance from the Commission, they should prepare, using a process that allows for input from interested persons, a set of proposed demand response cost-effectiveness tests and a proposed rulemaking as the vehicle for adoption. If agency staff moves directly to preparation of a set of cost-effectiveness tests, then the proposed rulemaking and cost-effectiveness tests shall be prepared for Commission consideration no later than six months after the workshop occurs.

5. Outstanding Procedural Matters

On September 6, 2005, the USCL Corporation (USCL) filed a motion to add to the minimum functionality criteria that were established in the February 19, 2004 Assigned Commissioner Ruling (ACR).[5] The motion requests that the Commission require that any meter deployed as part of a utility advanced metering infrastructure project include a universal, nonproprietary local area network to wide area network bi-directional interface. On September 20, 2005, SDG&E filed a response opposing the motion. On September 21, 2005, PG&E filed a response opposing the motion. USCL replied on September 23, 2005.

We deny the motion to add new minimum functionality criteria at this time. Denial of the motion does not go to the merits of whether or not inclusion of a universal, nonproprietary local area network to wide area network bi-directional interface would be an appropriate decision by any given utility in selecting a particular advanced metering infrastructure technology. Rather, we conclude that it is too late in the process to modify the minimum functionality criteria. USCL is free to participate in the individual utility applications for approval of their advanced metering infrastructure deployment projects to advocate that a universal, nonproprietary local area network to wide area network bi-directional interface should be included in the selected project because of the incremental benefits that USCL believes would inure to ratepayers. The minimum functionality criteria are just that, minimum criteria that are not meant to limit any party's ability to advocate for selection of a technology that incorporates additional functionality.

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[5] USCL concurrently filed a petition to intervene. USCL is granted appearance status in this proceeding.

A number of research (evaluation and marketing) reports were completed that have not yet been filed. The utilities should file a list of completed research reports and one copy of any completed research reports that have not yet been filed within 10 days of the issuance of this decision.[6] There are a number of research reports that are underway in 2005 that are not expected to be completed before this rulemaking is closed. A copy of these research reports should be filed in this proceeding within 10 days of completion. An electronic copy or notice of availability of each report should be served on the service list to this proceeding, and any related or successor proceedings like A.05-06-006 et al. Filing of research reports will not reopen the proceeding.

Each month, the utilities file a report on interruptible load and demand response programs in R.02-06-001. The contents of this report should be reviewed in light of the reporting requirements in D.05-10-042. Although we are closing this rulemaking, the need for these monthly reports remains. The utilities shall file their monthly reports with the Director of the Energy Division who shall cause them to be made available on the Commission's website. The utilities shall serve the reports on the service list to this proceeding, and any related or successor proceedings.

The original scoping memo indicated that hearings might be necessary. No hearings have been held and we now reverse that determination because all issues for which resolution is possible have decided through opportunity to comment.

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[6] Given the length of these reports, the utilities may file one copy rather than the customary five with the Docket Office, and to provide an electronic link to all parties or hard copies on request.

We affirm all rulings made by the ALJ up to this point in the proceeding. To the extent that any motions remain outstanding, all such motions are denied.

6. Comments on Draft Decision

The draft decision of the assigned ALJ was mailed to the parties in accordance with Pub. Util. Code § 311(g)(1) and Rule 77.7 of the Rules of Practice and Procedure. Comments were filed on November 8, 2005 by PG&E, SCE, SDG&E, and TURN. On November 8, 2005, DWR served a memorandum in response to the draft decision.[7] Reply comments were filed by PG&E and SCE on November 14, 2005. Changes in response to the comments have been made throughout the text and ordering paragraphs to correct errors, promote coordination and consistency across Commission proceedings, and streamline follow up activities.

7. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Michelle Cooke is the assigned ALJ in this proceeding.

Findings of Fact

1. The current schedule for handling the 2006-2008 program plan applications in A.05-06-006 et al. anticipates a Commission decision on the applications in March 2006, which could leave a funding gap for the first few months of 2006.

2. Design of an RTP tariff cannot be performed in isolation from a comprehensive rate design examination.

3. The CAISO market currently lacks a meaningful price signal upon which a real time price could be established.

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[7] The memorandum has been placed in the correspondence file.

4. As transparent pricing information from the CAISO market redesign becomes available, that information will facilitate development and adoption of a true RTP tariff.

5. Residential and small commercial customers are not currently able to sign up for CPP rates.

6. Effective implementation of time-differentiated tariffs for smaller customer classes requires the installation of more sophisticated metering and communications technology than currently in place.

7. Since the time that D.04-11-034 was issued, the CPA was able to engage a Fiscal Agent to operate and manage the DRP program.

8. D.05-01-056 approved an additional $575,000 in funding to cover PG&E's incremental costs of implementing the DRP management services agreement with the CPA.

9. There are currently no adopted measurement and evaluation protocols for demand response programs.

10. High quality demand reduction estimates derived from accepted measurement methodologies are a necessary prelude to accurate cost-effectiveness analysis.

11. Because demand response programs are still in their infancy, there is not yet an industry accepted methodology for evaluating cost-effectiveness.

12. The minimum functionality criteria adopted in the February 19, 2004 ACR are not meant to limit any party's ability to advocate for selection of a technology that incorporates additional functionality, like a universal, nonproprietary local area network to wide area network bi-directional interface in the meter.

Conclusions of Law

1. In the near term, the Commission should focus its efforts with respect to tariff offerings on reviewing the applications of each utility to implement a critical peak pricing tariff for customers with load of over 200 kW (A.05-01-016 et al.), and PG&E's proposed CPP tariffs to promote demand response as part of its Advanced Metering Infrastructure Project (A.05-06-028) rather than on creation of a two-part RTP.

2. Requiring the utilities to file non-experimental CPP tariff options in their next rate design applications will allow us to know whether and when metering and communications technology necessary to implement such rates will be in place.

3. Since PG&E has not been functioning as the manager of the DRP program, the incremental funding approved in D.05-01-056 is unneeded.

4. PG&E may shift the DRP management agreement funds into other programs, consistent with the fund shifting guidelines adopted in Ordering Paragraph 4 of D.05-01-056.

5. Agency staff should develop draft measurement and evaluation protocols and a process for peer review.

6. Agency staff should follow the process described in Section 4.5 to prepare proposed cost-effectiveness tests.

7. The motion by USCL Corporation to add new minimum functionality criteria should be denied.

O R D E R

IT IS ORDERED that:

1. In the event that no Commission decision has been adopted in Application 05-06-006 et al by January 1, 2006, the utilities may carry over any 2005 authorized funding to continue to offer 2005 programs until such time as a decision is adopted for 2006 programs.

2. Southern California Edison Company's October 6, 2005 motion is granted, Pacific Gas and Electric Company's October 27, 2005 motion is granted, and transitional funding is extended to San Diego Gas & Electric Company.

3. Each utility, as part of its next comprehensive rate design proceeding application following development and final implementation of an hourly day-ahead market price by the California Independent System Operator, shall submit a real time pricing tariff for its largest customers as part of its tariff offerings.

4. Each utility, as part of its next comprehensive rate design proceeding application, shall also include proposals for critical peak pricing (CPP), time of use (TOU) and inverted rate tariffs (with an appropriate hedge) for small commercial and residential customers, as well as CPP and TOU tariffs for customers over 200 kilowatt in monthly demand.

5. Non-experimental CPP tariff options for residential and small commercial customer classes shall be included by each utility in its next rate design application.

6. The Executive Director shall explore opening a new rulemaking to develop more customer friendly billing formats for energy bills and report back to the Commission at the second business meeting in January 2006 on whether the Commission should open such a rulemaking, and if so, the schedule for presenting such a rulemaking to the Commission.

7. The Proposed Management Services Agreement between Pacific Gas and Electric Company and Conservation Financing Authority (CPA) that was filed on February 4, 2005, is not approved and CPA's Fiscal Agent shall continue to manage the Demand Reserves Partnership program.

8. By April 3, 2006, agency staff shall prepare a set of draft protocols for estimating load impacts for both price responsive and reliability demand response programs and a list of additional data that should be collected on program costs and incremental costs, including comfort changes or costs during curtailments.

9. Agency staff shall serve the draft measurement and evaluation protocols on the service list to this proceeding, and any related or successor proceedings, and schedule a workshop for interested persons to provide peer review and feedback.

10. Agency staff shall prepare a proposed rulemaking or recommend an alternative procedural approach for Commission consideration no later than six months after the draft measurement and evaluation protocols are circulated.

11. Agency staff shall host a workshop by March 15, 2006, with the objective of designing a process to scope the issues that parties believe must be addressed in developing relevant cost-effectiveness tests for demand response programs and within two months after the workshop, shall recommend to the Commission's Executive Director whether to open a new rulemaking to provide guidance on this topic, and if so, shall prepare a proposed rulemaking for consideration.

12. The motion by USCL Corporation to add new minimum functionality criteria is denied.

13. The utilities should file a list of the completed research reports and one copy of any completed research reports that have not been filed within 10 days of the issuance of this decision.

14. One copy of research reports on 2005 programs shall be filed in Rulemaking (R.) 02-06-001 within 10 days of completion. An electronic copy or notice of availability of each report shall be served on the service list to this proceeding, and any related or successor proceedings, like A.05-06-006 et al.

15. One search reports on 2005 programs shall be filed in R.02-06-001 within 10 days of their completion. An electronic copy or notice of availability of each report shall be served on the service list to this proceeding, and any related or successor proceedings.

16. Docket Office shall not reopen R.02-06-001 as a result of the filing of the research reports referenced above.

17. The utilities shall file a monthly report on interruptible load and demand response programs with the Director of the Energy Division.

18. The utilities shall serve the monthly report on interruptible load and demand response programs on the service list to this proceeding, and any related or successor proceedings.

19. The Energy Division Director shall cause the monthly report on interruptible load and demand response programs to be made available on the Commission's website.

20. To the extent that any motions remain outstanding, all such motions are denied.

21. No hearing is necessary.

22. Rulemaking 02-06-001 is closed.

This order is effective today.

Dated November 18, 2005, at San Francisco, California.

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
SUSAN P. KENNEDY
DIAN M. GRUENEICH
JOHN A. BOHN
Commissioners