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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Southern California Edison Company's (U 338-E) Application for Approval of Advanced Metering Infrastructure Deployment Activities and Cost Recovery Mechanism.	Application 07-07-026 (Filed July 31, 2007)

(See Appendix B for a list of appearances.)

DECISION APPROVING SETTLEMENT ON SOUTHERN CALIFORNIA EDISON COMPANY ADVANCED METERING INFRASTRUCTURE DEPLOYMENT

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DECISION APPROVING SETTLEMENT ON SOUTHERN CALIFORNIA EDISON COMPANY ADVANCED METERING INFRASTRUCTURE DEPLOYMENT

1. Summary

This decision adopts a settlement proposed by Southern California Edison Company (SCE) and the Division of Ratepayer Advocates (DRA) to allow $1.63 billion in ratepayer funding for SCE's proposed Advanced Metering Infrastructure (AMI) Project from 2008 through 2012. We find that there are between $9 million and $304 million in net benefits for the Settlement Agreement. In this decision, we analyze the Settlement Agreement in light of the litigation positions of the parties in order to consider its reasonableness. We find the Settlement Agreement to be reasonable in light of the whole record, consistent with the law, and in the public interest.

This decision is part of our effort to transform California's investor-owned utility distribution network into an intelligent, integrated network enabled by modern information and control system technologies. SCE's deployment is scheduled to begin in 2008. From 2008 through 2012, SCE will install approximately 5.3 million new, AMI-enabled electric meters that can, among other things, measure energy usage on a time-differentiated basis. The deployment will improve customer service by providing customer premise endpoint information, assisting with electric systems outage detection, and providing real near-term usage information to customers.

2. Background

2.1. Commission Guidance

For the last several years, this Commission has encouraged California's investor-owned energy utilities to increase demand response (DR) and implement dynamic pricing tariffs as a means of reducing electricity demand during peak periods. In order to implement dynamic pricing, utilities must deploy advanced meters that can measure energy usage on a time-differentiated basis.

In June 2002, the Commission initiated Rulemaking (R.) 02-06-001, with the goal of increasing the level of DR "as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment."[1] The Rulemaking clarified that the "Commission anticipates that full scale implementation of AMI will provide all customers in all rate classes with the option to choose between dynamic and static rate structures."[2] AMI consists of metering and communications infrastructure as well as the related computerized systems and software. SCE filed its AMI application in response to the directives of this rulemaking.

On July 21, 2004, a joint assigned Commissioner and Administrative Law Judge (ALJ) Ruling was issued in R.02-06-001 that established a business case analysis framework for AMI. The ruling specified that the following parameters should be used consistently for each required scenario analyzed:

1. 2006 to 2021 analysis period.
2. Benefits and costs calculated relative to the Base Case.
3. Costs and benefits presented as 2004 present value dollars, with annualized nominal values in work papers.
4. An extensive literature search to identify data or methods used by other electric or gas utilities to estimate benefits

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[1] Order Instituting Rulemaking (R.) 02-06-001, p. 1.

[2] Joint Assigned Commissioner and Administrative Law Judge Ruling dated February 19, 2004 in R.02-06-001, p. 5.

shall be performed. Some combination of the specific methods for gathering benefit and cost information (use of Requests for Proposals (RFP), benchmarks from other utilities, indirect benchmarks, in-house cost analysis and actual in-house costs) should be used to estimate the benefits for all of the categories above.

5. Potential costs and benefits that cannot be easily quantified or for which no dollar value can be derived because of uncertainty or lack of data should be reflected in the analysis by including a qualitative assessment of that value.

6. Discount rate equals utility cost of capital.

7. DR savings estimates based on weighted average of savings under average and hot weather conditions developed using Monte Carlo or other simulation techniques.

8. Avoided peak demand cost = $85/kilowatt-year (kW-yr); Avoided energy cost = $63/megawatthour (MWh).

This Ruling provided guidance for this application, as well as the applications filed on March 15, 2005, by SDG&E (A.05-03-015) and Pacific Gas and Electric Company (PG&E) (A.05-03-016).

In D.06-07-027, the Commission authorized PG&E to deploy a new AMI, including authorization for PG&E's rate proposal for critical peak pricing tariffs. The Commission concluded it was reasonable for PG&E to deploy its AMI system, finding PG&E's proposal had sufficient probable and quantifiable economic operating and DR benefits, including sufficient flexibility to upgrade for enhanced features, over the expected 20-year useful life.[3] The decision authorized ratepayer funding for $1.6846 billion of project costs, with associated

[3] D.06-07-027, p. 9.

ratemaking provisions. On December 12, 2007, PG&E filed Application (A.) 07-12-009 requesting an additional $623 million[4] to upgrade the previously approved system.

On April 16, 2007, the Commission adopted D.07-04-043, a settlement among San Diego Gas & Electric Company (SDG&E), DRA and Utility Consumers' Action Network (UCAN) to allow $572 million in ratepayer funding for SDG&E's proposed AMI Project from 2007 through 2011. The Commission found that there are between $40 million and $51 million in net benefits under the SDG&E Settlement Agreement.

2.2. Procedural History

On July 31, 2007, SCE filed an application seeking authorization of its AMI deployment activities and associated cost recovery mechanism.[5] This application is the third related to SCE's proposed AMI project. SCE's application on Phase 1 of its AMI project resulted in a settlement adopted by the Commission in D.05-12-001. The Phase 1 decision authorized SCE to spend up to $12 million to develop the requirements for and work with industry to determine the availability of an AMI with the functions proposed by SCE. SCE completed Phase 1 in late 2006 and filed its Phase 2 AMI application on December 21, 2006. In Phase 2, SCE requested approval and funding for AMI pre-deployment activities related to developing and testing specific AMI technology solutions and preparing its deployment business case. In D.07-07-042, the Commission authorized $45.22 million for specified pre-deployment activities.

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4 PG&E later revised the upgrade costs to $572 million.

5 AMI consists of both metering and communications infrastructure.

In A.07-07-026, SCE requests Commission approval of over $1.6 billion for activities associated with the proposed deployment of SCE's SmartConnect™ AMI system during a five-year period beginning in 2008. In addition, this application requests Commission approval to implement a voluntary Programmable Communicating Thermostat (PCT) load control program and to conduct outreach, marketing, and education on dynamic rates and demand response program offerings for customers receiving the new AMI meters. SCE also requests approval of its proposed cost-recovery mechanism for its AMI deployment costs. SCE's original application estimated that its AMI proposal would deliver about $109 million in net benefits, with operational savings covering approximately 63% of the AMI deployment costs. SCE expected demand response and energy conservation benefits to cover the additional costs and provide the estimated net benefits.

The Commission received three timely responses to this application. On August 30, 2007, Southern California Gas Company (SoCalGas) filed a response expressing its intention to monitor this proceeding, and stating that it may later choose to request full party status. The Alliance for Retail Energy Markets (AReM), an organization of electric service providers (ESPs) that serve most direct access customers in the state, filed a response on September 4, 2007. AReM's response noted that some customers that would be included in SCE's AMI deployment proposal are direct access customers, and requested that the scope of this proceeding include issues of interest to ESPs and their direct access customers. Also on September 4, 2007, DRA filed a protest to this application. DRA expressed its intention to conduct an analysis of several general issues related to SCE's AMI deployment proposal and cost recovery mechanism, and suggested a schedule that included evidentiary hearings for resolving issues found to be within the scope of this proceeding.

Following a prehearing conference on September 26, 2007, the assigned Commissioner and ALJ issued a Scoping Memo and Ruling on October 17, 2007, establishing a schedule for this proceeding, under which DRA and other parties were to serve testimony by December 14, 2007.

On December 5, 2007, SCE served updated testimony reflecting several changes to the estimated costs of its project, and shortly thereafter provided parties with updated work papers. According to DRA, representatives of SCE, TURN, and DRA (the main parties active in this proceeding) met and conferred, and agreed on a proposed schedule that they believed would provide DRA and TURN with sufficient opportunity to analyze the changes to SCE's testimony and address these changes in their own opening testimony.

On December 24, 2007, the assigned ALJ issued a ruling extending the schedule to allow parties sufficient time to review SCE's updated testimony and prepare rebuttal testimony. The extended schedule also adjusted the dates for hearings and briefs. On March 10, 2008, SCE filed two motions, one for adoption of a settlement agreement between SCE and DRA, and one for adoption of numerous stipulations between SCE and TURN. All items contained in the stipulations between SCE and TURN are also contained in the settlement agreement filed the same day, but unlike the settlement agreement, the stipulations do not represent an agreement to resolve all contested issues in the case.[6] Hearings addressing the testimony and the settlement agreement were held from March 12-14, 2008. Parties filed opening briefs on third party metering issues, as well as separate briefs on the rest of the issues in the case, on April 4, 2008;[7] most parties filed reply briefs on April 18, 2008.[8]

3. Late-Filed Exhibits

Two exhibits were received from parties after hearings. At hearings, TURN requested permission to submit a corrected version of two figures and a table from the testimony of William Marcus. No objections were raised to providing this correction after the end of hearings, and the errata exhibit was identified as Exhibit 200A. TURN served this late-filed exhibit, titled "Southern California Edison's Advanced Metering Infrastructure Program: Supplemental Testimony of William B. Marcus Updating Figures and Table," on parties on March 17, 2008, with a request that it be received into the record. No parties have subsequently objected to including this exhibit in the record. Exhibit 200A is hereby received.

Also at hearings, ALJ Hecht requested that parties prepare and enter into the record a joint comparison exhibit identifying all disputed issues in the case and the location in the record (testimony, settlement, or stipulations) of parties'

[6] RT 5, Janet Combs: "There are more points agreed to in the settlement with DRA than are agreed to in the stipulations, but all of the points that are agreed to in the stipulations are also contained in the settlements."

[7] DRA, TURN and SCE filed opening briefs on the settlement agreement and related issues, and SCE, SoCalGas, and DRA filed additional briefs related solely to issues of third-party metering.

[8] TURN and SCE filed reply briefs on the settlement agreement and related issues, and SCE and SoCalGas filed additional reply briefs related solely to issues of third-party metering.

initial and final positions on each disputed issue. This comparison exhibit was identified as Exhibit 16, and on March 20, 2008, SCE filed "Motion of SCE to Submit Joint Comparison Exhibit into Evidence." No parties have subsequently objected to including this exhibit in the record. SCE's motion is granted, and Exhibit 16 is hereby received.

The record is composed of all documents that were filed and served on parties. It also includes all testimony and exhibits received at hearing, and the two exhibits identified at the hearings and served on all parties in response to direction at the hearing. Also, the ALJ sealed as confidential various exhibits and filings. We affirm all assigned Commissioner and ALJ rulings in this proceeding. All motions not previously ruled upon or addressed in this decision are denied.

4. TURN Motion to Reopen the Record

On July 2, 2008, TURN filed a motion to reopen the record and submit an additional exhibit. This exhibit consisted of a presentation by Ron Hofmann, a consultant to the California Energy Commission (CEC), which TURN states was made at a CEC Load Management Workshop on Enabling Technologies on June 19, 2008. This presentation includes a bill of materials showing a cost of $29.65 for the components of a PCT, and sites a "rule of thumb" that the retail cost of goods is generally three to four times the bill of materials. According to TURN, this document supports TURN's position that the cost of a two-way communicating thermostat would be significantly higher than SCE's cost estimate of $50, which would reduce the cost effectiveness of SCE's program.

SCE filed a response opposing this motion on July 11, 2008. In its response, SCE notes that, as TURN acknowledges in its ruling, the costs for materials listed in this presentation match the costs in a similar bill of materials provided in hearings. Also, the "rule of thumb" cited in the presentation relates the cost of the bill of materials to the retail cost of an item; in testimony and hearings, however, SCE explains its intention to purchase PCTs wholesale and in bulk. For these reasons, SCE believes that the presentation does not represent a "material change in facts" that justifies reopening the record.[9] SCE also argues that if the record is reopened to admit this evidence, SCE should have an opportunity to cross examine a sponsoring witness, and that if this updated cost is included, that SCE has many other "updated" costs and benefits that it could include.[10]

Reopening the record to admit this piece of evidence would necessitate providing SCE with an opportunity to cross examine a sponsoring witness, and if this information is included, SCE should also have an opportunity to provide updated information in support of its own position. The information on the costs of PCT component materials in the CEC presentation is consistent with a bill of materials provided at hearings, and is therefore not new information. The "rule of thumb" provided in the CEC presentation describes a relationship between the costs of materials and the retail cost of a final product, and therefore is not material to the wholesale cost of PCTs used in SCE's business case. In addition, at some point, it is necessary to close the record and examine the business case on its merits. For these reasons, TURN's motion to reopen the record is denied.

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9 "Response of Southern California Edison Company to Motion of The Utility Reform Network to Reopen Record and Admit Evidence," (SCE Response) filed in A.07-07-026 on July 11, 2008, p. 3.

10 SCE Response, p. 4.

5. Alliance of Retail Energy Market/Electric Service Provider Issues

The October 17, 2008, scoping memo in this proceeding addressed a request made by the AReM that this proceeding consider whether "ESPs and Direct Access customers have special metering or data access issues related to SCE's AMI proposal and, if so, how … those issues [should] be addressed."[11] The scoping memo required AReM and SCE to attempt to settle issues related to the needs of ESPs and Direct Access customers, and to provide a report within this proceeding outlining mutually agreeable solutions to AReM's concerns by November 16, 2007. On November 16, 2007, SCE and AReM sent a letter to the assigned ALJ that was served on all parties, concluding that there is no special metering or data access issues that related to ESPs or Direct Access customers that require litigation in this proceeding. No parties to this proceeding objected to this conclusion or provided testimony on ESP or Direct Access issues related to the deployment of SCE's proposed AMI system. We agree that no related issues must be resolved in this proceeding, and so ESP and Direct Access issues are not further addressed in this decision.

6. Litigation Positions of Parties

This section provides an overview of SCE's application and the litigation positions of the active parties in this proceeding, to provide context for the analysis of the settlement agreement and the remaining issues disputed by TURN. The settlement agreement and stipulations are discussed in Section 8.

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[11] Assigned Commissioner and Administrative Law Judge's Scoping Ruling (Scoping Ruling), p. 4.

6.1. SCE

In testimony served with its initial Phase 3 AMI deployment application in July of 2007, SCE describes the overall objective of its proposed AMI system as providing "customers with lasting value through a cost effective AMI investment that can empower them to manage their own energy costs and enable new services through smart technology."[12] SCE expects the project, which it calls Edison SmartConnect™, to provide "a powerful tool to support federal and state energy policy objectives."[13]

According to SCE, its proposed AMI deployment would "install state-of-the-art 'smart' meters in every household and business under 200 kW throughout its service territory,"[14] a total of approximately 5.3 million meters over five years. SCE's AMI deployment proposal includes installation of both meter and communication systems intended to offer new functionality, including improved reliability, improved customer service, convenient remote service connection and disconnection, new billing and payment options, and measurement of interval electricity usage to support new rate structures and improved customer information.[15] In addition, SCE maintains that its AMI proposal supports communication interfaces with technology such as programmable communicating thermostats and load management devices, as well as meter reading of third-party gas and water meters. SCE attests that its proposed AMI technology is compatible with broadband over power line use by

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[12] Exhibit 1, p. 2.

[13] Exhibit 1, Executive Summary.

[14] *Id.*

[15] Exhibit SCE-1 p. 2.

third parties, is capable of remote upgrades, and would support future expansion.[16]

SCE's application requests $1.645 billion for deployment of AMI meters and associated communications technology over a five-year period beginning in 2008. According to SCE testimony, its proposed project would have been cost effective with $116 million in net benefits over the life of the project.[17] SCE proposes recovering the costs of deployment through a balancing account mechanism, with the revenue requirement allocated among customer classes according to SCE's proposed distribution allocator. SCE also requests Commission approval to implement a voluntary PCT load control program, and to conduct outreach, marketing, and education to recipients of new AMI meters.

6.2. DRA

DRA's initial litigation position, reflected in its opening testimony, was that the Commission should adopt SCE's AMI deployment proposal with certain modifications, and approve $1.611 billion for deployment period costs. Among other adjustments recommended by DRA, DRA urged that the costs and benefits of a prepayment metering program should be removed from the original SCE proposal, estimated benefits of energy conservation should be reduced, and other changes should be made to reduce costs or increase benefits.[18]

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[16] Exhibit SCE-1, p. 2; RT 211-212.

[17] Exhibit SCE-1, p. 9.

[18] Geilen, Exhibit 100, Chapter 1, pp. 3-5.

6.3. TURN

TURN's litigation position in its opening testimony, served on January 25, 2008, is that the AMI proposal presented in SCE's application should not be approved. TURN disputes several assumptions, including some related to the amount of demand response and associated benefits that may be expected from demand response and dynamic pricing programs made possible by advanced metering. Based on its calculations, TURN believes that the proposed project will not be cost effective over its expected useful life. To address concerns related to the demand response benefits, TURN proposes that if the Commission approves AMI deployment, it should also adopt a penalty mechanism requiring SCE to pay financial penalties if it fails to achieve at least 65% of the demand response forecast in its application.[19]

7. Standard of Review

SCE bears the burden of proof in this proceeding. SCE's burden in this application is to establish that its proposal is cost effective, and meets the Commission's criteria for functionality and reasonableness.

In order to approve this application, we must find that the proposed AMI system affirmatively answers the following questions:

a. Does the proposal satisfy State Energy Policy Objectives?

b. Are the various elements of SCE's AMI business case and deployment plan reasonable?

c. Is SCE's AMI proposal cost-effective, and will it provide lasting value for SCE's customers?

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[19] Marcus, Exhibit 200, p. 19.

d. Is SCE's AMI technology selection reasonable based on the AMI technologies available in the market?

Items a. and d. are discussed in Section 12, below. In order to assess Items b. and c., we will analyze the settlement agreement between DRA and SCE, and the stipulations between SCE and TURN, and compare them to the parties' initial litigation positions. The standard of review for the settlement agreement is established in Rule 12.1 of the Commission's Rules of Practice and Procedure, which states that "[t]he Commission will not approve settlements, whether contested or uncontested, unless the settlement is reasonable in light of the whole record, consistent with law, and in the public interest."[20] Because all elements of the stipulations are also part of the settlement agreement,[21] all issues that are contained in the stipulations are considered to be uncontested issues; these issues are discussed in Section 10 below. The remaining contested issues, generally those contained in the settlement but not in the stipulations, will be reviewed individually for reasonableness in Section 9 below.

8. Summary of the DRA/SCE Settlement Agreement and TURN/SCE Stipulations

On March 10, 2008, SCE and DRA filed a motion for adoption of a settlement agreement that they believe would resolve all issues related to SCE's application. DRA and SCE have proposed a settlement that they contend would allow approval of a project that is cost effective over the expected 20-year life of the system, providing approximately $9 million in total net benefits. The

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[20] Commission Rules of Practice and Procedure, Rule 12.1(d). (http://docs.cpuc.ca.gov/published/RULES_PRAC_PROC/70731.htm#P765_142281)

[21] RT, pp. 4-5.

settlement agreement recommends approval of $1,633.5 million in ratepayer funding for AMI deployment activities, to be collected through a balancing account mechanism. According to DRA and SCE, the AMI plan recommended in the settlement is reasonably expected to generate $1,174 million in operational benefits and $816 million in energy conservation, load control, and demand response-related benefits. DRA and SCE estimate that "additional societal benefits" from the system, including benefits that had not been quantified in the past, could add approximately $295 million in net benefits over the expected life of the project benefits. The settlement would resolve DRA's initial concerns about pre-payment meters and certain assumptions used in SCE's business case, as well as other issues including the ratemaking mechanism for project costs. The DRA/SCE settlement would allow for cost-sharing between shareholders (10%) and ratepayers (90%) of project costs up to $100 million in excess of the proposed $1.63 billion funding, without further Commission review.

Appendix A contains the settlement agreement.[22] In summary, the settlement agreement includes the following provisions and recommendations:

- SCE's proposed deployment activities (as revised in the settlement agreement) and estimated deployment period ratepayer funding of $1.6335 billion are reasonable. Approval of the settlement agreement would authorize SCE to deploy its proposed AMI system (Edison SmartConnect™) to all metered accounts in its service territory with demands less than 200 kW (approximately 5.3 million meters) over a five-year period beginning in 2008.

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[22] The settlement agreement was filed as an attachment to "Motion of Southern California Edison Company and the Division of Ratepayer Advocates for Adoption of Settlement Agreement," filed March 10, 2008.

- With the revisions made in the settlement agreement, SCE's business case is reasonably expected to generate $1,174 million in operational benefits and $816 million in energy conservation, load control, and demand response related benefits. This results in net forecast benefits of approximately $9 million.

- The ex ante energy conservation participation goals and forecasted energy conservation benefits of $164 million included in the settlement agreement are reasonable.

- The Commission should authorize $3.5 million in funding for information display devices for residential customers who want to receive near real-time information on their personal computers through the Home Area Network included in Edison's SmartConnect™ .

- The cost and benefit assumptions associated with an energy prepayment service have been removed from the Settlement Agreement.

- SCE's plan for meter inspections and use of the SmartConnect™ system capabilities during the deployment and post deployment periods to minimize meter tampering and theft are reasonable.

- SCE's business case shall be revised to reflect the following changes:

    - Estimated costs for meter panel repairs, billing, and project management, organization change and career planning, shall be reduced by amounts specified in the settlement agreement.

    - Estimated benefits for increased accuracy of meter reads and working cash shall be increased as specified in the settlement agreement.

- A risk sharing mechanism under which ratepayers pay 90% and shareholders pay 10% of cost overruns up to $100 million without additional reasonableness review is reasonable.

- Under a force majeure provision, SCE may recover up to $100 million beyond the authorized $1,633.5 million in rates without additional reasonableness review, shareholder contribution or penalty, if the increased costs are due to events beyond SCE's control, as described in the settlement agreement.

- SCE will work with gas and water utilities in its service territory to explore the possible use of its AMI system for contract meter reading. SCE will hold and report to the Commission on at least four workshops that explore these issues.

- SCE will propose a two-tiered Peak Time Rebate program under which participants with enabling technology such as automated load reductions devices will be paid a higher incentives to than participants without such devices or displays.

- SCE will credit capital operational benefits of SmartConnect™ to ratepayers, as described in the settlement agreement.

- SCE will not recover SmartConnect™ costs in its 2009 General Rate Case (GRC), and if any are included in its 2012 GRC, SCE will ensure that there is no double-recovery of such costs and that any such recovery is consistent with the limits on recovery of such costs adopted in this proceeding.

- Potential costs and benefits from revenue protection and meter electricity usage and benefits from meter accuracy will not be included in the SCE business case, but will be reflected as societal benefits. The settlement agreement estimates the previously unquantified societal benefits at approximately $295 million.

- SCE will recover costs consistent with the SmartConnect™ Balancing Account tariff contained in the settlement agreement.

- Allocation of Edison SmartConnect™ revenue requirement among customer groups should be litigated in Phase 2 of SCE's GRC; pending the outcomes of this issue in the GRC, allocation will be made using the distribution allocators in place when the costs are recovered in rates.

- SCE's proposals that were not contested are reasonable and should be adopted.

In its cost benefit analysis, the settlement agreement does not consider benefits associated with additional programs and services that may be made possible by AMI in the future; for example, the settlement agreement removes from the business case the costs and benefits of the prepayment meter program SCE described in its initial application. It is appropriate that this program and others that depend on future Commission policy decisions are not included in the settlement agreement analysis and business case at this time. These and other new programs may be the source of additional benefits in the future, however.

8.1. SCE /TURN Stipulations

TURN does not support the settlement agreement. However, SCE and TURN filed a motion for adoption of a set of stipulations that comprise a subset of the complete settlement agreement.[23] Many of the stipulations echo specific language included in the settlement agreement; others reflect either TURN's agreement to a provision previously contested by TURN and reflected in the full settlement agreement, or SCE's explicit agreement to a modification that is reflected in the settlement agreement business case but not specifically enumerated in the settlement. In addition to provisions specifically enumerated in the settlement agreement, the stipulations include the following provisions:

[23] RT, pp. 4-5.

- SCE shall remove $2.17 million (nominal) in estimated costs for power purchases from SCE's Deployment Period costs.

- The Parties agree that SCE shall remove $5.7 million (nominal) in estimated costs for increased field supervisors and analysts from SCE's Post-Deployment costs.

- SCE shall be limited to recording the actual Results Sharing costs in the Edison SmartConnect Balancing Account, but capped at the target level amounts included in the forecast Edison SmartConnect revenue requirement; and

- SCE shall reduce the GRC memorandum account authorized Results Sharing level by the amount of Results Sharing benefits included in the forecast Edison SmartConnect revenue requirement.

- If SCE's 2009 GRC proposal to eliminate the Results Sharing memorandum account is adopted, SCE will file a supplemental advice letter to update the $1.4246 of average operations and maintenance (O&M) benefits per meter per month to include results sharing benefits.

- SCE's estimated costs for meter panel repairs during the Deployment Period of $29.7 million shall be reduced by $11.1 million.

- SCE's tariffs on service connection and disconnection do not require revision as a result of Edison SmartConnect deployment. To the extent future changes are required to SCE's tariffs on service connection and disconnection, such changes shall be presented in SCE's 2012 GRC, or through other appropriate regulatory proceedings.

- SCE's proposal for crediting to ratepayers the capital operational benefits of Edison SmartConnect™ as described in the proposed SmartConnect Balancing Account tariff is reasonable.

- For each Edison SmartConnect™ meter purchased during the Deployment Period, SCE shall credit the $1.4246 of O&M operational benefit per month during the Deployment Period to ratepayers via the Edison SmartConnect Balancing Account beginning eight months after reflecting such meter in rate base, consistent with the operation of the proposed SmartConnect Balancing Account tariff attached to the settlement agreement.

- The Parties reserve the right to dispute costs in the 2009 and 2012 GRC if the included costs amount to double recovery of Deployment Period costs.

- The Parties agree that separate accounting in SCE's GRCs for Edison SmartConnect™ costs and benefits is not necessary.

The Commission's Rules of Practice and Procedure do not explicitly allow for stipulations, nor do they define a process for adoption of stipulations. In this case, because the stipulations are a subset of the settlement, the stipulations are essentially a partial settlement of the issues; in our consideration of the settlement agreement as a whole, we consider the provisions in the stipulation to be unopposed, and focus the majority of our detailed analysis on the disputed issues that are not contained in the stipulations.

9. Discussion of Remaining Contested Issues

TURN contests aspects of the settlement agreement business case, and maintains that if its suggested modifications are made the business case would not be cost effective. In addition, TURN opposes several other elements of SCE's AMI deployment and funding proposal, and recommends adoption of a penalty mechanism if the AMI deployment project is approved and does not result in at least 65% of the expected demand response benefits. In order to find these aspects of the settlement agreement reasonable, it is necessary to analyze TURN's specific objections to these terms, including analyzing the settlement agreement assumptions and the alternatives recommended by TURN. TURN's proposed penalty mechanism is discussed in Section 16, below.

9.1. Cost Effectiveness of the Business Case

In this section, we address the contested assumptions in SCE's business case, and analyze TURN's arguments for modifying those assumptions.

9.1.1. Use of the Cost-Effectiveness Framework Proposed by Parties to R.07-01-041

In the business case contained in SCE's initial cost-effectiveness testimony and in that contained in the settlement agreement, SCE uses a business case analysis framework similar to that proposed in the July 21, 2004 ruling in R.02-06-001, and used in the analysis of the AMI proposals of PG&E and SDG&E. TURN argues that instead, the proper framework for the AMI project cost effectiveness analysis is the "consensus framework" for cost effectiveness proposed by parties in R.07-01-041.[24] TURN further argues that if the proposed Total Resource Cost (TRC) test is used to evaluate SCE's business case, incentives paid to customers would be included as a cost in the analysis, and these additional costs would make the overall case not cost effective.

The "consensus framework" is not the appropriate tool to use in assessing the cost effectiveness of SCE's AMI project for several reasons. First, this proposed framework has not been adopted by the Commission for use in

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[24] Joint Commments of California Large Energy Consumers Association, Comverge, Inc., Division of Ratepayer Advocates, Energyconnect, Inc., Enernoc, Inc., Ice Energy, Inc., Pacific Gas and Electric Company (U 39-M), San Diego Gas & Electric Company (U 902-E), Southern California Edison Company (U 338-E) and The Utility Reform Network Recommending a Demand Response Cost Effectiveness Evaluation Framework, filed November 19, 2007, in R.07-01-041 Phase 1.

evaluating DR programs, and in fact had not yet been proposed when SCE filed its initial application. At least one additional proposed cost-effectiveness methodology is still being considered in the cost-effectiveness phase of R.07-01-041, and no methodology for assessing the cost effectiveness of demand response programs has yet been adopted. In addition, if a cost effectiveness methodology for demand response programs had been adopted, it is not clear that such a methodology would be appropriate for estimating the cost effectiveness of an AMI system, which includes additional metering equipment and associated functionality. For these reasons, SCE cannot be expected to have applied this framework to its cost-effectiveness analysis. As discussed above, the Commission established in R.02-06-001 a specific framework for analyzing AMI proposals, and SCE properly applied the analytical framework also used in the SDG&E and PG&E AMI cases. TURN's objection is not persuasive, and the analytical framework used in the settlement agreement is reasonable and consistent with law and Commission policy.

9.1.2. Programmable Communicating Thermostat Proposal

TURN contests several of the assumptions used to calculate the costs and benefits of SCE's proposed PCT program included in the business case, and specifically contends that the settlement agreement underestimates the costs of PCTs and overestimates participation in the PCT program as well as the benefits that can be expected from PCTs. Specifically, TURN argues the following:

1. The business case underestimates the costs of the PCTs SCE will use in the program, resulting in the use of an erroneously low estimate of program costs in the business case.

2. By assuming a statewide mandate of the use of PCTs from the CEC by 2012 and a high enrollment percentage in PCT programs, the settlement agreement overestimates participation in the

proposed PCT program and therefore the benefits that may accrue from the program.

3. SCE further overestimates the expected savings from participation in the proposed PCT program by failing to reduce the kilowatt-hours saved by the program to account for estimates of average air conditioning tonnage, inoperative air conditioning (A/C) units, and customer overrides.

9.1.2.1. Cost of PCTs

TURN contends that the $50 cost to purchase a PCT that SCE includes in its business case underestimates the actual cost of the PCTs SCE will need to utilize the functionality of its proposed AMI system. The SCE/DRA settlement provides that $50 is a reasonable cost for PCTs based on the product design specifications and evidence presented of the costs of PCT component parts, and budgets an additional $75 per unit for installation. SCE provided a bill of materials for most of the PCT components,[25] along with separate estimates of the additional parts needed to complete a PCT; SCE also notes that it intends to buy PCTs in bulk at wholesale rates. TURN argues that PCTs whether bought retail or wholesale, would cost more than $50 per unit, and more than $125 installed, and believes that SCE underestimates the actual cost of this program.[26] Based on the evidence provided by SCE, the $50 per unit wholesale cost estimate for a PCT is reasonable. TURN has not provided compelling evidence that the wholesale cost of a PCT purchased in bulk will be higher than SCE's estimate.

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[25] DeMartini, Exhibit 14.

[26] Schilberg, Exhibit 203, p. 23.

9.1.2.2. Estimates of PCT Participation

TURN argues that two assumptions made in the settlement agreement business case reflect unrealistically high estimates of customer participation in PCT programs enabled by AMI, and recommends that these assumptions be modified to reduce estimates of customer participation. First, TURN contends that it is speculative to assume that the state will adopt a mandate for PCTs in new construction by 2012,[27] and that without a mandate, SCE's participation estimate is unrealistically high.[28] In addition, TURN argues that SCE's assumption that 25% of customers with PCTs installed under a Title 24 mandate will enroll in the PCT program is overly optimistic.[29]

SCE, on the other hand, states that its participation estimates do not depend on a CEC PCT mandate in 2012. SCE addresses TURN's concerns by including the cost of PCTs for its PCT program in its business case, so achieving the benefits of the PCT program does not depend on the possible state mandate.[30] SCE and DRA agree that the enrollment rate of customers offered a free PCT is reasonable.[31] While there is some uncertainty in this assumption, as in many assumptions, the settlement agreement business case estimates of PCT penetration and participation are reasonable.

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27 Opening Brief of The Utility Reform Network Concerning Southern California Edison Company's Application for Approval of Advanced Metering Infrastructure Deployment Activities and Cost Recovery Mechanism (TURN Opening Brief), p. 30.

28 TURN Opening Brief, pp. 31-32.

29 TURN Opening Brief, p. 32.

30 Reply Brief of Southern California Edison Company, p. 29.

31 SCE Exhibit 3 pp. 7-8, pp. 16-17.

9.1.2.3. Estimates of Expected Savings

TURN further claims that SCE overestimates the expected savings from participation in the proposed PCT program by failing to reduce the kilowatt-hours saved by the program to account for estimates of average A/C tonnage, inoperative A/C units, and customer overrides. TURN advocates for reducing the expected savings of 1 kW of demand response for four hours to reflect the following adjustments:

- Derate by 1% to adjust for average air conditioning tonnage,
- Reduce forecast DR by 15% to account for already-inoperative air conditioning units and
- Reduce forecast by 10% to account for customer overrides.

SCE argues that if it had used TURN's adjustment for A/C tonnage, the change would actually increase its expected PCT load reduction by 32%, not lower it by 1%,[32] and shows that the effects of customer overrides and inoperative units are already accounted for in its model.[33] Based on the evidence provided by SCE, the settlement assumptions appear to be reasonable, are within the range of value we would expect from a litigated outcome, and should be adopted for the purposes of the business case.

[32] SCE Opening Brief, p. 46.

[33] SCE Reply Brief, p. 28.

9.2. Peak-Time Rebate Benefits Assumptions

9.2.1. Participation Rates and Underlying Assumptions

TURN takes the position that the settlement agreement business case overstates the likely benefits of a Peak-Time Rebate (PTR) program, and the assumptions underlying the analysis of PTR should be adjusted to reflect lower expected benefits. Specifically, TURN does not believe that the 50% awareness rate of the PTR program that is used in the calculation of program benefits is reasonable, and suggests that it should be reduced to a 25% participation rate, to reflect that not all customers aware of PTR events are likely to reduce load in response to a program event. In support of its position, TURN calls into question the applicability of participation rates from the State Pilot Program (SPP) to a broader mandatory PTR program, such as is used in the business case. TURN posits that the SPP population differs from the general population of the state because they have already shown a willingness to voluntarily participate in demand response programs, and are therefore more likely to participate than typical customers.

SCE counters by noting that analysis of the earlier SPP study looked for possible participation bias and found none, so concern over possible participation bias is not a sufficient reason for reducing the awareness and participation rates of customers enrolled in a PTR program, despite the differences between the SPP and general customer populations. Furthermore, the 50% awareness rate is comparable to the rate accepted by the Commission in evaluating the settlement of SDG&E's AMI business case. While approval of a settlement does not set a precedent nor imply a Commission endorsement of specific settlement elements, the same reasoning used in the comparable SDG&E case to accept this assumption is relevant here. In accepting this number, D.07-04-043, p. 51 states, "use of a conservative figure is prudent in order to allow for potentially improved results using different rate designs and/or improved communications and technologies in the future.''

9.2.2. PTR Elasticities

In addition, TURN believes that it is inappropriate to use the customer elasticity of demand results from the SPP in evaluating the PTR, because the SPP study did not test a PTR rate. Instead, SPP customers were subject to a Critical Peak Pricing (CPP) rate, which TURN expects would be more effective in encouraging customers to lower their demand during an event then an equivalent PTR rate (i.e., a PTR with an incentive for load reduction equivalent to the penalty for increased use under a CPP rate). TURN argues that while the incentive for saving a kilowatthour (kWh) under the PTR rate is the same as under an equivalent CPP rate, that the cost of consuming an extra kWh is different under the two programs, and significantly higher under a CPP rate than under a PTR rate. TURN posits that "customers respond more to the threat of high prices than to the temptation of rebates,"[34] and that customers under a CPP rate will be charged a high rate for every kWh used during a CPP event, while PTR participants will only receive incentives on the kWh saved during the same period, leading to a much greater savings from an CPP rate than a PTR, and large difference in bills between participants of the different programs. TURN argues that the PTR elasticities are more likely to be comparable to elasticities measured in a different pilot conducted in Ontario by Hydro Ottawa. Based on the results of this different pilot, TURN recommends adjusting the

[34] TURN Opening Brief, p. 15.

elasticities calculated from SPP data by 30% to account for these program differences.

SCE counters that TURN's position has no empirical basis, and provides analyses that the demand elasticities computed for CPP under the SPP are "statistically indistinguishable" from the elasticities of PTR pilots conducted elsewhere.[35] The fact that two numbers are statistically indistinguishable does not necessarily mean that the underlying calculations used to arrive at those numbers will always lead to the same outcome. However, TURN does not provide a solid basis for its suggested reduction; as TURN acknowledges, when the margins of error of the two studies are considered, the apparent 30% difference between the elasticities calculated from the different pilots is not statistically significant.[36] The best available comparison between the elasticities of the CPP and PTR rates do provide some reasonable confidence that at the levels studied, the two rates lead to similar outcomes.

In addition, TURN bases its argument that load reductions from PTR will go down over time on the assumption that customers can drop only a small portion of their load, and therefore will receive small savings from a PTR rate. TURN believes that a combination of a lack of a penalty for increased use combined with a low absolute level of savings available under a PTR rate would over time discourage customers from reducing usage under a PTR rate. TURN argues that this will lead to customer fatigue and a reduction in long-run elasticities of demand that are lower than the short-run elasticities. SCE counters

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[35] SCE Opening Brief, p. 38.

[36] RT pp. 51-52.

that customers responding to a PTR rate would likely be able to reduce their load by 50% or more, leading to a much greater savings than TURN predicts, and also cites economic theory, under which long-run elasticities are generally higher than short-run elasticities.[37]

Current evidence does not provide a definite picture of customer behavior under a PTR rate, since such rates are not currently in widespread use. However, based on existing evidence it is reasonable to conclude that the elasticity of customer electric demand under a PTR rate may be comparable to under a CPP rate. Similarly, though it is not possible to be certain how customers will react to a PTR rate on a long-term basis, it is reasonable to apply economic theory to this question and assume that long-run elasticities will not be lower than short-run elasticities. Over the long run, for example, customers may have access to more enabling technology allowing them to respond more easily to PTR rates and increase their resulting demand response. For these reasons, the elasticities used in the settlement agreement business case, which are based on elasticities calculated from CPP rates and are assumed to remain stable over time, are reasonable for the purposes of estimating future energy savings from PTR rates and their associated benefits.

9.3. Transmission and Distribution Costs

SCE forecasts that its AMI project will provide approximately $221 million in benefits for deferred or avoided transmission and distribution (T&D) costs. TURN argues that in order to avoid or defer T&D investments through demand response, a utility must show that the specific demand programs meet "right

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[37] SCE Reply Brief, p. 21.

place" and "right certainty" criteria identified in the proposed cost effectiveness Consensus Framework introduced by parties in R.07-01-041. TURN further requests that if the Commission includes T&D benefits in the business case analysis, that it adjust the T&D amounts to remove impacts from its Air Conditioner Cycling Program (ACCP). TURN argues that SCE has already used its ACCP to mitigate some local and regional emergencies in the absence of an AMI system, making it inappropriate to attribute associated T&D benefits to the AMI system. Finally, TURN states that even if some T&D costs are included in the business case, that only the costs of some limited transformer costs should be included, because other T&D costs are not allowed under the Consensus Framework proposed in R.07-01-041.[38]

SCE counters that its estimate of a 20% benefit for T&D is reasonable and its simplified assumptions for calculating the T&D benefit are consistent with the Commission's adopted business case framework. SCE also notes that TURN does not demonstrate that use of the consensus framework would provide results materially different from those used by SCE.[39]

As discussed in Section 9.1.1 above, the consensus framework for cost effectiveness analysis proposed in R.07-01-041 is not the appropriate tool to use in assessing the cost effectiveness of SCE's AMI project. SCE properly applied the analytical framework established for AMI proposals in R.02-06-001, and that has been used in the SDG&E and PG&E AMI cases. Section 9.1.2 accepts the reasonableness of including the settlement agreement's PCT benefits in the

[38] TURN Opening Brief, p. 33.

[39] SCE Reply Brief, pp. 30-32.

business case. Therefore, it is not appropriate to exclude T&D benefits associated with the PCT cost. TURN's suggestion that benefits related to the ACCP program are not appropriately included because the ACCP program has been dispatched in local areas in the absence of an AMI system does not account for the likelihood that the AMI system will enable SCE to dispatch the ACCP program more frequency and in more targeted areas, which may significantly increase the benefits of that program and increase its T&D benefits. The level of estimated T&D benefits used in the settlement business case is reasonable in the context of the whole record.[40] TURN's objection is not persuasive, and the analytical framework and estimated values used in the settlement agreement are reasonable and consistent with law and Commission policy.

9.4. Societal Benefits

The settlement agreement identifies benefits beyond the financial benefits included in the business case, and quantifies these benefits at approximately $295 million. The societal elements that provide net benefits in the settlement agreement are the costs and benefits related to unaccounted-for energy and energy theft, which are estimated to result in a net benefit of $39 million, and benefits associated with increased meter accuracy, which the settlement agreement estimates at approximately $256 million. The settlement agreement does not include these additional benefits in the business case, but SCE and DRA agree that these benefits are real and can now be quantified. TURN argues that both of these proposed societal benefits are not sufficiently supported in the record. TURN argues that AMI technology does not by itself reduce energy theft

[40] SCE Exhibit 4, p. 27.

and that the inclusion of this benefit contradicts SCE's own previous statements about AMI and energy theft.[41] TURN also notes the relative absence of information in the record supporting the $256 million estimate for increased meter accuracy.

Both of these societal benefits are included in the settlement agreement, and while it would be helpful to have more information in the record on these specific issues, parties had an opportunity to question witnesses about the derivation of these benefits during hearings on the settlement agreement. SCE addresses energy theft in its rebuttal testimony, estimating savings from energy theft reduction at between $96 million and $150 million, in contrast to DRA's estimate of $26 million.[42] The settlement agreement estimates the value of this societal benefit at $39 million, which is in the range defined by the testimony, and is reasonable in light of the record. Though there is little information in the record on meter accuracy benefits, TURN does acknowledge that in principle solid state meters may have accuracy benefits over older electromechanical meters,[43] and the calculation of the estimated benefit for meter accuracy appears consistent with the Commission's acceptance of similar benefits in the SDG&E AMI case.[44] In addition, even if, as TURN suggests, the meter accuracy benefits turn out to be minimal, estimated societal benefits of $39 million from energy theft benefits would be enough to support the cost effectiveness of the settlement.

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[41] TURN Opening Brief, pp. 42-43.

[42] SCE Exhibit 3, pp. 42-43.

[43] TURN Reply Brief, p. 42.

[44] D.07-04-043, pp. 38-39.

The settlement agreement as a whole appears to be reasonable in the context of the overall record, and we are inclined to consider these societal benefits (which are not considered a part of the main business case) to be reasonable estimates of possible future benefits of AMI that have until recently been difficult to quantify. This is consistent with D.07-04-043 in SDG&E's AMI deployment application, which recognized some level of benefits of SDG&E's AMI system for both meter accuracy and energy theft.[45] We will consider these societal benefits in our analysis of the settlement as a whole.

10. Uncontested Aspects of the Business Case

In order to adopt the uncontested aspects of the SCE business case, it is necessary to find that "the settlement is reasonable in light of the whole record, consistent with law, and in the public interest."[46] To determine the reasonableness of the uncontested aspects of the settlement, we analyze them within the context of the initial litigation positions of the parties. We find the uncontested aspects of the settlement reasonable in light of the whole record, consist with the law, and in the public interest, based on the discussion set forth below on each aspect.

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[45] D.07-04-043, pp. 38-39.

[46] Commission Rules of Practice and Procedure, Rule 12.1(d).

10.1. Settlement Agreement Adjustments to Costs and Benefits of Business Case

10.1.1. Costs and Benefits of Prepayment Services

In its initial application and opening testimony, SCE included the costs and benefits of prepaid meter services, under which customers would have the option of paying for electricity services in advance of using the electricity. Under SCE's original proposal, SCE expected prepaid metering to be a source of significant benefits of the AMI system. Both DRA and TURN objected to the inclusion of the costs and benefits associated with prepayment metering in the business case, as described, unless specific customer protections were included. The settlement agreement removes these costs and benefits from the business case. This change is consistent with the litigation positions of the TURN and DRA, and is appropriate given the fact that the Commission has not expressed a policy position on the appropriateness of prepaid meter programs or the customer protections needed to support them.

10.1.2. Field Inspections and Meter Tampering

SCE's initial application forecast an annual inspection rate of 0.5% of meters during the deployment period. DRA's opening testimony advocates for increasing annual meter inspections and the associated revenue requirement. TURN contests SCE's forecasts and calls for a reduction of $25.8 million in costs for meter tampering. The settlement agreement modifies the forecast annual inspection rate of 0.5% to apply also to the post-deployment period, and increases saving through use of the AMI system's capabilities to minimize loss from meter tampering and energy theft. This addresses the parties' concerns with the initial proposal by increasing meter inspections in the post-deployment period to capture the AMI system's ability to reduce energy theft.

10.1.3. Meter Panel Repairs

SCE initially forecast costs of $29.7 million for repairing weathered meter panels. DRA did not context this forecast; TURN recommended that these costs be reduced by $29.1 million. The settlement agreement provides that the initially forecast meter panel repair cost be reduced by $11.1 million. This reduction is within the range defined by the testimony.

10.1.4. Billing Costs

SCE forecast $55.2 million for increased billing costs during the deployment period; DRA recommended that this be reduced by $16 million. The proposed settlement agreement reduces the original forecast by $2.2 million. This reduction is within the range defined by the testimony.

10.1.5. Increased Accuracy of Meter Reads

SCE's opening testimony did not anticipate benefits from working cash and increasing the accuracy of meter reads; TURN recommended that benefits for these characteristics totaling $37 million be included in the business case. DRA did not contest SCE's initial proposal. The settlement agreement resolves this issue by including $2.2 million in benefits related to a reduction of billing services exception work. This adjustment is within the range defined by the testimony.

10.1.6. Increased Power Purchase Costs During Deployment Period

SCE's initial business case included power purchase costs in its cost-benefit analysis, as well as in the deployment period. TURN contests SCE's forecast of power purchase costs. The settlement agreement makes an adjustment to power purchase costs to remove $2.17 million for deployment period power purchase costs from its analysis.

10.1.7. Increased Field Supervisors and Analysts

SCE's initial business case forecast increased cost for field supervisors and analysts during the deployment and post deployment period. TURN objected that increased resources should not be required in the post-deployment period. In the settlement agreement cost-benefits analysis and stipulations, SCE removed $5.7 million in post-deployment costs.

10.2. Cost Overrun Risk-Sharing Mechanism

SCE did not propose a mechanism for sharing risks related to cost overruns; DRA proposed such a mechanism in its opening testimony. The DRA mechanism, adopted in the settlement, provides that to the extent the deployment period expenditures exceed the adopted amount by up to $100 million, 10% of the overrun would be borne by shareholders and 90% by ratepayers, without the need for future Commission review of the overrun. TURN did not address the issue of risk-sharing in its testimony. The risk sharing mechanism is unopposed by parties to this case and is reasonable in the context of the whole record. This mechanism is also consistent with a similar provision in the settlement the Commission adopted in the SDG&E AMI proceeding, A.05-03-015.[47]

10.3. Credit Operational Benefits to Ratepayers When Funds are Spent

SCE's opening testimony proposed crediting operational benefits to ratepayers each month, beginning approximately four months after equipment installation. DRA's counter-proposal in testimony was to credit these benefits to ratepayers when the money is spent on the equipment to be installed. TURN did

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[47] SDG&E: D.07-04-043 Appendix A, p. 6.

not address this issue in its opening testimony. The proposed settlement agreement provides that SCE will credit $1.4246 per meter of operational benefits per month through the deployment period, beginning eight months after the meter is reflected in rate base.

10.4. PTR Program Two-Tiered Rebate

SCE originally proposed calculating the costs of its peak-time rebate program using a rebate of $0.66 per kWh. DRA recommended that the business case calculations instead use a higher rebate for customers with installed enabling technology, such as automated response equipment or information feedback systems. TURN did not take a position on this issue in its opening testimony. The proposed settlement calculates the costs and benefits for the business case using a two-tired rebate to participating customers, with higher rebates to those with installed enabling technology. SCE has proposed such a two-tiered rebate structure for the PTR program included in its 2009 General Rate Case. The Commission may or may not adopt a similar rate structure in the SCE GRC, and we do not prejudge that issue here, but this settlement term is reasonable in light of the record for the purposes of SCE's business case.

10.5. Avoid Double-Recovery of AMI Costs in GRCs

SCE proposed to avoid double-recovery of AMI costs through the use of a balancing account mechanism, and used a "business as usual" approach in its GRC. DRA's initial position was that the Commission should deny SCE the opportunity to recover any AMI-related costs in its 2009 and 2012 GRCs. TURN requested that the Commission remain vigilant in reviewing costs in this case and SCE's upcoming GRCs to avoid possible double-recovery. The settlement agreement provides that SCE will not recover any AMI-related costs in its 2009

GRC, will ensure that it avoids double-recovery of AMI costs in its 2012 GRC and will ensure any recovery of AMI costs in its 2012 GRC are consistent with the limits on recovery that the Commission adopts in this proceeding. This position is within the range defined by the testimony, and is reasonable in the context of the whole record. This issue also resolves additional disputes over the need for separate accounting for AMI costs and benefits in its GRC. In order to ensure the aspect of the settlement is more easily monitored, we require SCE to make an affirmative showing in its (2012) GRC that it has avoided double recovery of any requested AMI costs, and that any requested costs in its 2012 GRC are consistent with the limits on recovery adopted in this decision.

10.6. Allocation of Revenue Requirement for Deployment Period Costs

SCE proposed allocating the revenue requirement associated with deployment period costs using a distribution allocator defined in its application and opening testimony. TURN and DRA each proposed alternative methodologies for allocating the revenue requirement among customer classes. The settlement agreement defers this issue to be litigated in Phase 2 of SCE's GRC, with costs in the meantime allocated consistent with SCE's proposed distribution allocator. It is reasonable to defer litigation of this issue to Phase 2 of SCE's GRC, which is an appropriate venue for determining revenue allocation among customer classes. Using SCE's allocator on an interim basis is reasonable in light of the whole record.

10.7. Remote Connect/Disconnect Policies

SCE proposed no changes to its existing policies related to connection and disconnection of customer electric service. TURN initially raised questions about whether cost savings to SCE of remote connection and disconnection should be reflected in changes in SCE's tariffs. The settlement agreement provides that SCE's connection and disconnection tariffs do not require revision at this time, and that subsequent changes to these tariffs will be brought to the Commission for approval. This outcome is reasonable in light of the whole record, and recognizes that if changes are needed in SCE's tariffs, there are existing avenues for the Commission to consider those changes.

10.8. Ratemaking for Results Sharing

SCE originally proposed that results sharing be consistent with GRC methods. TURN objected to this mechanism. In the settlement and stipulations, SCE agreed to record actual costs up to a cap, and reduce the GRC memorandum account authorized amount consistent with the benefits forecast. The settlement agreement also provides that if the ratemaking memorandum account is eliminated, SCE will file an advice letter addressing this issue.

11. Cost Effectiveness of the Settlement Agreement Business Case

As discussed in Sections 9 and 10 above, the settlement terms are within the range of reasonable outcome if the matters were fully litigated on the existing record, and we adopt the final calculation of operational benefits and costs contained in the settlement agreement.

The settlement terms provide for a cost-effective business case in which approximately 59% of project costs are covered by expected operational savings, with additional costs expected to be covered by DR, conservation, and load control benefits. SCE's AMI business case, by its nature, depends on a very long-term forecast of operational savings and demand response benefits forecast for the next 20 years. We must act with the best information that is available now even though we know no forecast is ever fully accurate. In performing its cost effectiveness analysis, the business case analysis appropriately applies an analytical framework similar to that set forth in R.02-06-001 for evaluating AMI deployment proposals. Based on the best information currently available, the settlement business case is cost effective with at least $9 million of documented benefits. Though this margin of benefits appears slim, the settlement agreement also documents approximately $295 million in additional societal benefits from the AMI system, providing some margin of benefits to ensure a reasonable value to ratepayers from this investment.

While there is always some uncertainty in the cost and benefit projections, the SCE/DRA settlement is cost effective based on an appropriate analysis of the best existing information.

12. Reasonableness of the Chosen Technology

In order to find that SCE's AMI system meets state energy policy objectives and that the technology choice is reasonable based on the AMI solutions available today, it is necessary to determine whether the system meets the Commission's minimum functionality requirements, will support future upgrades, and can be expected to retain its value throughout the 20-year expected useful life of the project.

12.1. Minimum Functionality Requirements

A ruling issued on February 19, 2004 in R.02-06-001 established six minimum functionality requirements that a proposed AMI system must meet. According to this ruling, AMI systems must support the following functions in order to receive approval:[48]

[48] Assigned Commissioner's Ruling dated February 19, 2004 in R.02-06-001, pp. 3-4.

- Implementation of the following price responsive tariffs for:
  - Residential and small commercial customers (200 kW) on an opt out basis:
    - Two or three period time-of-use (TOU) rates with ability to change TOU period length;
    - Critical peak pricing with fixed (day-ahead) notification;
    - Critical peak pricing with variable or hourly notification; and
    - Flat/inverted tier rates.
  - Large customers (200 kW to 1 megawatt (MW)) on an opt out basis:
    - Critical peak pricing with fixed or variable notification;
    - TOU pricing; and
    - Two part hourly real-time pricing.
  - Very large customers (over 1 MW) on an opt out basis:
    - Two part hourly real-time pricing;
    - Critical peak pricing with fixed or variable notification; and
    - TOU pricing.
- Collection of usage data at a level of detail (interval data) that supports customer understanding of hourly usage patterns and how those usage patterns relate to energy costs.
- Customer access to personal energy usage data with sufficient flexibility to ensure that changes in customer preference of access frequency do not result in additional AMI system hardware costs.
- Compatibility with applications that utilize collected data to provide customer education and energy management information, customized billing, and support improved complaint resolution.
- Compatibility with utility system applications that promote and enhance system operating efficiency and improve service reliability, such as remote meter reading, outage

management, reduction of theft and diversion, improved forecasting, workforce management, etc.

- Capability of interfacing with load control communication technology.

No party disputes that SCE's proposed AMI system and the system described in the settlement agreement meets these six requirements. Commission D.07-04-043 in A.06-12-026, SCE's Phase 2 AMI pre-deployment application, found that SCE's proposed AMI system meets these minimum functionality requirements.[49]

12.2. Flexibility and Value Over the Life of the Project

As described by SCE and DRA, the AMI project described in the settlement agreement provides a flexible platform that supports the types of AMI functionality currently available. The proposed AMI system will support at least two types of solid-state AMI meters from different vendors,[50] uses open standards protocols within portions of the system,[51] and the meters have the capability to accept some remote software upgrades if necessary.[52] In addition, the system meets other Commission directives by including interface with a Home Area Network (HAN) compatible with the HAN adopted for use in the SDG&E AMI deployment proceeding last year. SCE and DRA attest that both its HAN system and its meters are being used by other utilities across the country,

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[49] D.07-04-043, FOF 1.

[50] RT 212:15-19.

[51] RT 210-214.

[52] RT 212:2-14.

ensuring a base of between 11 million[53] and 20 million[54] meters using this communication technology, which is expected to be enough to ensure that the technology remains supported for years to come.

The business case also allows for one part of the communications system to be replaced at seven-year intervals, reflecting conservative assumptions to ensure that this portion of the system is not overly vulnerable to obsolescence.[55] In addition, SCE and DRA testify that the system supports two-way communication between the utility and the customer's premise, making the technology appropriate for use if the state moves towards adoption of a smart grid.[56] SCE and DRA also attest that the bandwidth of the chosen communication system is adequate for reasonably foreseeable uses, including those that may be associated with a future smart grid.[57]

Over all, the technology choice is reasonable when compared to existing AMI and related technology that is currently available, and can reasonably be expected to retain its value over the 20-year expected useful life of the program. The system also meets state policy objectives. Based on SCE's representations of the flexibility and expandability of the system, we will not look favorably on future requests for ratepayer funding to upgrade the chosen technology to adapt to changes related to demand response, smart grid, or similar projects.

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53 RT 214:11-12.

54 RT 232:15.

55 RT 218:4-9.

56 RT 212:26-213:11.

57 RT 228:2-229:3.

13. Reasonableness of the Settlement

As described in Sections 9 through 11 above, the settlement agreement adopted here is reasonable in light of the whole record, and is in the range of outcomes that would be expected if the elements of the case were fully litigated.

The settlement agreement is consistent with law and state policy and is in the public interest, providing for adoption of a cost effective AMI system that meets the Commission's minimum functionality requirements and can reasonably be expected to support state energy policy objectives such as increasing demand response, energy conservation, and load control, and providing near-term energy usage information to customers, and increasing the availability of dynamic rate options. The balancing account mechanism and associated cost recovery provisions of the settlement agreement are uncontested by parties and are reasonable, consistent with law, and consistent with the record. The settlement agreement is also cost effective and will provide net benefits of between $9 million and $304 million of net benefits over the project's expected useful life.

SCE's AMI application and the Settlement Agreement include ratepayer expenditures for marketing, education and outreach regarding the AMI program. Our decision today approves funding for this purpose. Today we also consider the California Long-Term Energy Efficiency Strategic Plan ("Plan") which includes goals and strategies to better integrate California's Demand Side Management (DSM) activities, including AMI, and in particular marketing, education and outreach. For example, the Plan calls for integrated marketing of DSM opportunities with AMI deployment. We direct SCE to work with Commission staff to ensure SCE's AMI marketing, education and outreach program is consistent with the goals and strategies set forth in the Plan regarding DSM integration and coordination of marketing, education, and outreach.

14. Third-Party Metering Issues

The settlement agreement adopted in this decision addresses third-party metering, finding that SCE has taken reasonable steps to ensure that its system is capable of providing automated meter reading services to gas and water utilities, and requiring SCE to work with gas and water utilities in its territory through a series of workshops, the results of which will be reported to the Commission.[58] One interested company is SoCalGas, which intends to develop its own AMI system and is interested ensuring that its system is compatible with SCE's system, and in utilizing SCE's AMI capability for automated third-party meter reading in areas in which their territories overlap. At hearings on March 12, 2008, the assigned ALJ asked three questions for expedited briefing on the possibility of and cost basis for third party metering under SCE's AMI system. These three questions were:

1. Should SCE be required to provide meter reading and related support services through their AMI and associated communication system to gas and water utilities within their territory?

2. If so, should these services be provided on a tariffed basis, or should they be nontariffed?

3. If SCE provides these services, how should the charges for them be determined? Should they reflect the fully loaded incremental costs, or should they be calculated on some other basis?

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[58] Settlement Agreement, Section J, pp. 8-9.

In order to provide some additional level of direction to SCE in its discussions with other interested utilities, beyond the settlement terms, this decision addresses these policy issues related to the appropriate terms for proving meter reading and related services to other utilities through SCE's AMI system.

14.1. Party Positions

SCE and SoCalGas submitted a joint brief addressing the first two questions: whether SCE should be required to provide contract meter reading and related services to other utilities, and whether these services should be provided on a tariffed basis. SCE and SoCalGas agree that SCE should be required to negotiate in good faith with interested utilities on providing such services, but SCE should not be required to provide metering services to other utilities.[59] A good-faith negotiation process would enable SCE and the other utilities to determine the technical feasibility of providing automated meter reading and related services to a particular utility given that company's particular situation and needs, and whether automated meter reading makes financial sense in a given situation. SCE and SoCalGas agree that it is not appropriate to charge for meter reading services through a tariff, because the cost of the connection between SCE's AMI system and other utilities' metering systems may vary, and the charge to the utility should reflect the actual costs of the service.[60] For this reason, SCE and SoCal Gas also agree that these services

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[59] Opening Brief of Southern California Edison Company on Issues Related to Third Party Use of Advanced Metering Infrastructure (hereafter referred to as SCE Opening Brief on Metering Issues), filed April 4, 2008, p. 3.

[60] SCE Opening Brief on Metering Issues, p. 4.

should be provided on a non-tariffed basis through contracts negotiated between SCE and other utilities that reflect terms acceptable to the companies. SCE and SoCalGas further recommend that any contracts for third party metering of other Commission's jurisdictional gas or water utilities through SCE's AMI system be submitted to the Commission for review and approval through an application process.[61]

On the third question, SCE and SoCalGas take different positions. SCE and SoCalGas agree that charges for meter-reading services through SCE's AMI system should include SCE's fully-loaded costs, but SCE argues that the appropriate cost basis for any third-party metering services it may provide is the incremental cost plus some portion of the fixed cost of the system.[62] SoCalGas, in contrast, argues that charges should not include a portion of the fixed costs of the AMI system.[63]

On the first question, DRA recommends that SCE be required to provide automated meter reading services to SoCalGas,[64] and on the second question DRA takes a position somewhat consistent with the joint position taken by SCE and SoCalGas, saying that these services should be provided through bilateral contracts, with the rate negotiated between SCE and SoCalGas, rather than

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[61] SCE Opening Brief on Metering Issues, p. 3.

[62] SCE Opening Brief on Metering Issues, p. 6.

[63] Response of Southern California Gas Company to Administrative Law Judge Hecht's Questions for Expedited Briefing on SCE AMI Deployment Activities and Costs, April 4, 2008, p. 4.

[64] Division of Ratepayer Advocate's Opening Brief and Response to Administrative Law Judge Hecht's Questions for Expedited Briefing (hereafter DRA Opening Brief on Metering Issues) April 4, 2008, p. 1.

through a tariffed rate.[65] DRA further urges that SCE should offer similar services to water companies on the same terms as those extended to SoCalGas. On the third question, DRA suggests that the negotiated rate for contract meter-reading services reflect a "cost plus" contract structure.[66]

TURN offers its view that SCE should work with other Commission-jurisdictional utilities, as provided in the settlement agreement, but that the Commission should review reports of the settlement workshops and be prepared to take an active role in encouraging SCE to provide services in this area, and should be prepared to direct other jurisdictional utilities to cooperate with SCE in this effort.[67] Unlike other parties, TURN recommends that automated meter-reading services should be offered on a tariffed basis.[68] TURN believes that the tariffed cost should reflect incremental costs of offering the services, and may include a portion of costs for system aspects and capabilities that serve both SCE customers and customers of the other utility.[69]

14.2. Discussion

All parties support the settlement agreement provision requiring SCE to hold workshops on automated meter reading services. SCE, SoCalGas, and DRA all take the position that SCE must work in good faith to ensure that its AMI system will support the provision of meter-reading and related services to third parties. These three parties also recommend that SCE should be strongly

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[65] DRA Opening Brief on Metering Issues, pp. 2-3.

[66] DRA Opening Brief on Metering Issues, p. 3.

[67] TURN Opening Brief, p. 45.

[68] TURN Opening Brief, pp. 46-47.

[69] TURN Opening Brief, p. 48.

encouraged to work with other utilities to provide meter reading and related support services when it makes sense to both parties to do so. The settlement agreement provides a framework that will make this possible, and in fact SCE has already held and reported on at least one meeting with some interested utilities to explore this possibility. DRA further suggests that SCE be required to provide automated meter reading services to SoCalGas; neither SCE nor SoCalGas take this position. We agree that SCE should negotiate in good faith to provide SoCalGas and other utilities with automated meter reading services. Whether an agreement with any given utility is reached will depend on many things, including the services requested by the other utility, the technical feasibility of providing those services, and the cost effectiveness of having SCE provide those services. For these reasons, we do not require SCE to provide these services on a tariffed basis.

All parties also agree that in cases in which metering services are provided, the charges for these services should be based on the costs of actually providing the services; parties do not agree on whether the charges should include costs beyond incremental costs. In order to ensure that the charges for automated meter reading services reflect the costs of providing those services, we find that the appropriate charges for services should be provided on a contract basis, rather than though a tariff, with appropriate charges determined through negotiation by the parties to the contract. Any contract for automated meter reading services between SCE and another Commission-jurisdictional utility shall be submitted to the Commission for review through a future application. We agree that the charges for these services provided in a contract should include the incremental cost of providing the services, but it is not necessary to decide here whether those costs should be limited to incremental costs of providing the service or should include a portion of the system's fixed costs.

TURN's main argument for tariffing meter-reading services is that the Commission should actively monitor and regulate these services. In addition, TURN expresses concern over the appropriate treatment of revenues SCE receives through meter-reading contracts. To address these concerns, SCE should submit any contract it negotiates to provide metering services for other Commission-jurisdictional utilities to the Commission for approval by application, so the costs and appropriate rate treatment, including the treatment of revenues, can be determined based on the specifics of the case.

15. PCT Program

SCE proposes and the settlement agreement recommends approval of a voluntary PCT program. This program is essentially a demand response program that would enable SCE to reduce load in specific areas if needed to maintain system reliability or respond to a local transmission or distribution emergency. SCE proposes that this PCT program would replace its existing Air Conditioner Cycling program. The settlement agreement estimates the cost of this program at $58.1 million. In another context, it might be appropriate to subject this proposal to a more rigorous cost effectiveness analysis based on a DR cost-effectiveness methodology. As discussed in Section 9.1 above, however, we have not yet adopted a cost effectiveness methodology for demand response programs in R.07-01-041. Also this program proposal is part of a settlement agreement that we find to be reasonable overall. Rather than pick apart elements of the settlement, it is reasonable to approve this program in the context of the settlement agreement based on the business case analysis. Consistent with Section L of the settlement agreement, SCE shall file an advice letter proposing a specific PCT tariff for Commission approval within 15 days of this decision's effective date. SCE shall also include a discussion of this PCT program in its amended Demand Response application in A.08-06-001.

16. Penalty Proposal

In its testimony and briefs, TURN recommends that if the Commission chooses to adopt the settlement agreement, that it should also adopt a penalty mechanism under which SCE would be required to pay a penalty in the event that it failed to reach 65% of its forecast demand response.[70] TURN recommends a penalty mechanism equal to one-half of the annualized cost of a peaking power plant adjusted for losses and multiplied by the unachieved savings.[71] Using this mechanism, the further SCE is below its estimated savings from demand response, the greater the penalty SCE would pay. SCE argues that it would be unreasonable to impose a penalty. Among other reasons, SCE notes that many of the circumstances necessary to reach its forecasts are not under its control; for example, the exact return SCE can expect from its demand response programs depends on the specific rates and rate designs in place over the years that the AMI meters are in use.[72] The details of these rates have yet to be adopted by the Commission, and may change over time.

As discussed above, any forecast of costs and benefits that goes out far into the future is subject to great uncertainty. We approve the settlement agreement based on the best available current information, but many of the rates and programs assumed for the purposes of the business case have not been adopted

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[70] Marcus, Exhibit 200, pp. 19-20.

[71] TURN Opening Brief, p. 48.

by the Commission, and must ultimately be considered on their merits when specific proposals are made. Similarly, we have used the best available estimates for program participation in the business case analysis, but because CPP and PTR rates are not currently in widespread use for residential customers in California, these estimates, too, are subject to uncertainty. Future information on customer behavior in response to these or other dynamic rates may provide more accurate information on participation rates and demand elasticities, but we must analyze the settlement agreement based on the information available today. For these reasons, it is not reasonable to penalize SCE for failing to meet the forecasts made in the business case.

It is, however, reasonable and desirable to determine how closely the demand response, conservation, and load control forecasts, and forecasts of associated benefits, match the forecasts made here. The collection of data the actual demand response achieved with the AMI system will provide us with valuable information on customer behavior, and enable us to track progress towards state energy policy goals associated with AMI, DR, and related issues. For this reason, in addition to approving the settlement agreement, we require SCE to report to the Commission on the energy savings and associated financial benefits of all DR, load control, and conservation programs enabled by AMI, including PCT programs, Peak Time Rebate programs, and other dynamic rates for residential customers. SCE should work with Energy Division develop a reporting format for this information, and should file annual reports in April of each year in R.07-01-041 or a successor proceeding until April 2019. If no

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[72] SCE Opening Brief, pp. 53-54.

successor proceeding exists, SCE should send these reports to the Director of the Energy Division and serve the service list of the most recent Commission demand response rulemaking. To the extent possible, SCE shall base its estimates of energy savings on the Commission's adopted load impact protocols contained in D.08-04-050 or successor protocols adopted in the future.

17. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed by SoCalGas, TURN, and SCE and DRA jointly, on September 8, 2008, and reply comments were filed on September 15, 2008 by SCE and TURN.

Based on these comments, additional text has been added to the decision to clarify the discussion and analysis of several of the contested issues, including estimated PTR elasticities, estimated societal benefits, and TURN's proposed penalty mechanism. Language has also been added to Ordering Paragraph 5 to improve its clarity and consistency with the Settlement Agreement. In addition, small changes have been made throughout the decision to improve its clarity and correct typographical and other small errors.

18. Assignment of Proceeding

Dian M. Grueneich is the assigned Commissioner and Jessica T. Hecht is the assigned ALJ in this proceeding.

Findings of Fact

1. The settlement agreement would authorize SCE to deploy it proposed AMI system (Edison SmartConnect™) to all metered accounts in its service territory

with demands less than 200 kW (approximately 5.3 million meters) over a five-year period beginning in 2008.

2. In order to approve this application, we must find that the proposed AMI system affirmatively answers the following questions:

a. Does the proposal satisfy State Energy Policy Objectives?

b. Are the various elements of SCE's AMI business case and deployment plan reasonable?

c. Is SCE's AMI proposal cost-effective, and will it provide lasting value for SCE's customers?

d. Is SCE's AMI technology selection reasonable based on the AMI technologies available in the market?

3. The settlement agreement recommends approval of $1,633.5 million in funding for AMI deployment activities,

4. The AMI deployment plan contained in the settlement agreement is reasonably expected to generate $1,174 million in operational benefits and $816 million in energy conservation, load control, and DR-related benefits.

5. Additional "societal benefits" from the system, including meter accuracy and reduced energy theft, could add approximately $295 million in net benefits over the expected life of the project benefits.

6. The proposal for AMI deployment contained in the Settlement Agreement is cost effective.

7. The stipulations filed by SCE and TURN comprise a subset of the SCE/DRA settlement.

8. Because all elements of the stipulations are also part of the settlement agreement, all issues that are contained in the stipulations are considered to be uncontested issues.

9. For the Commission to approve a settlement, whether contested or uncontested, the settlement must be reasonable in light of the whole record, consistent with law, and in the public interest.

10. The analytical framework used to determine the cost effectiveness of the settlement agreement business case is reasonable.

11. The "consensus framework" for determining DR cost effectiveness proposed by parties in R.07-01-041 is not appropriate for use in analyzing the AMI business case.

12. The $50 per unit wholesale cost estimate for PCTs included in the settlement agreement is reasonable.

13. The settlement agreement estimate of 25% participation in a PCT program is reasonable.

14. The kWh savings assumed in the settlement agreement are reasonable, and do not need to be adjusted for average air conditioning tonnage, inoperative air conditioning units, or customer overrides.

15. For the purposes of analyzing the settlement agreement business case, it is reasonable to assume 50% of households would both be aware of SCE's proposed Peak Time Rebate program and take action to reduce peak energy usage in response to it.

16. The PTR customer elasticities used in the settlement agreement business case, which are based on elasticities calculated from CPP rates and are assumed to remain stable over time, are reasonable for the purposes of estimating future energy savings and associated benefits from PTR rates.

17. It is reasonable to include a 20% benefit to the T&D system from AMI deployment for the purpose of the business case analysis.

18. It is reasonable to consider benefits for reduced energy theft and increased meter accuracy as additional societal benefits beyond the primary AMI business case in our review of the AMI deployment proposal included in the settlement agreement.

19. The AMI deployment proposal in the settlement agreement is cost effective, with between $9 million and $304 million in net benefits over the life of the project based on an analysis of the best available information.

20. The AMI system proposed in the settlement agreement meets the Commission's Minimum Functionality Criteria for approval of an AMI system.

21. SCE's AMI technology choices are reasonable when compared to existing AMI and related technology that is currently available.

22. SCE's AMI technology choices meet state policy objectives for supporting demand response programs and providing increased information about their electricity usage to consumers.

23. Based on SCE's representations, SCE's AMI technology choices should support the possible development of a smart grid, and should contain flexibility that will allow for reasonably foreseeable updates and improvements to the system.

24. The technology chosen for SCE's AMI system is reasonable, and will support state energy policy goals.

25. The settlement agreement includes ratepayer funding for marketing, education, and outreach related to the AMI program.

26. It is reasonable to require SCE to work with Commission staff to ensure that SCE's AMI marketing, education, and outreach program is consistent with

the goals and strategies set forth in the California Long-Term Energy Efficiency Strategic Plan.

27. Reporting of data on demand response achieved with the AMI system will provide valuable information, and will assist in tracking progress towards state energy policy goals.

28. The balancing account mechanism and associated cost recovery provisions of the settlement agreement are uncontested by parties and are reasonable and consistent with law.

29. SCE shall negotiate in good faith with SoCalGas and other utilities to provide about providing automated meter reading services through its AMI system.

30. Automated meter reading services through SCE's AMI system should be provided on a contract basis, and should not be a tariffed service.

31. Appropriate charges for contract meter reading services shall be negotiated between the parties to the contract; it is not necessary to determine here whether those costs should be limited to incremental costs of providing the service or should include additional costs.

32. It is reasonable to require SCE to submit any contract it negotiates to provide automated meter reading services to other Commission-jurisdictional utilities to the Commission for approval.

33. It is reasonable to approve SCE's proposed PCT program as part of the Settlement Agreement, and to require SCE to file an advice letter proposing a specific PCT tariff within 15 days of this decision's adoption.

34. It is not reasonable to penalize SCE for failure to meet the demand response forecasts made in the AMI deployment business case.

35. It is reasonable to require SCE to report to the Commission on the energy savings and associated financial benefits of the demand response, load control, and conservation programs enabled by AMI.

Conclusions of Law

1. The settlement agreement is reasonable in light of the whole record, consistent with the law, and in the public interest.

2. No Commission rule provides for the adoption of stipulations between parties, but the stipulations between SCE and TURN constitute a partial settlement of a subset of the issues included in the Settlement Agreement.

3. SCE should file an advice letter for Commission approval of the tariffs for its voluntary PCT program approved in this decision.

4. SCE should offer automated meter reading and related services to other utilities on a contract basis, and should negotiate these services and the associated charges in good faith to other utilities.

5. SCE should submit any contract to provide automated meter reading services to other Commission-jurisdictional utilities to the Commission for approval.

6. SCE should ensure that the AMI marketing, education and outreach funding approved in this decision is used in a manner consistent with the California Long-Term Energy Efficiency Strategic Plan.

O R D E R

IT IS ORDERED that:

1. The March 10, 2008 Settlement Agreement between Southern California Edison Company (SCE) and the Division of Ratepayer Advocates (DRA) on SCE's Application for Approval of Advanced Metering Infrastructure (AMI)

Deployment Activities and Cost Recovery Mechanism, Application (A.) 07-07-026 (Appendix A to this decision), is adopted.

2. The March 10, 2008 Stipulations between SCE and The Utility Reform Network are adopted to the extent that they represent a subset of the terms of the SCE/DRA Settlement Agreement.

3. SCE shall report to the Commission on the energy savings and associated financial benefits of all demand response, load control, and conservation programs enabled by AMI, including programmable communicating thermostat program programs, Peak Time Rebate programs, and other dynamic rates for residential customers. SCE shall work with Energy Division develop a reporting format for this information, and shall file annual reports in April of each year in Rulemaking 07-01-041 or a successor proceeding until April 2019. If no successor proceeding exists, SCE shall send these reports to the Director of the Energy Division and serve the service list of the most recent Commission demand response rulemaking. SCE shall base its estimates of energy savings on the Commission's adopted load impact protocols contained in Decision 08-04-050 or successor protocols adopted in the future.

4. Consistent with Section L of the settlement agreement, SCE shall file an advice letter proposing a specific Programmable Communicating Thermostat tariff for Commission approval within 15 days from the effective date of this decision. SCE shall also include a discussion of this PCT program in its amended Demand Response application in A.08-06-001.

5. Consistent with the provisions of the Settlement Agreement, SCE shall file an advice letter no later than 30 days from the effective date of this decision, establishing the SmartConnect Balancing Account. SCE is authorized to recover costs of up to $1,633.5 million in this account, plus additional amounts, if any,

consistent with the terms and conditions of the Risk Sharing Mechanism for Deployment Cost Overruns set forth in the Settlement Agreement.

6. In its next (2012) General Rate Case, SCE shall make an affirmative showing that it has avoided double recovery of any requested AMI costs, and that any requested costs in its 2012 GRC are consistent with the limits of recovery adopted in this decision.

7. SCE shall work with Commission staff to ensure its AMI marketing, education and outreach program is consistent with the goals and strategies set forth in the California Long-Term Energy Efficiency Strategic Plan regarding DSM integration and coordination of marketing, education, and outreach.

8. A.07-07-026 is closed.

This order is effective today.

Dated September 18, 2008, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
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(END OF APPENDIX B)