BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

ADMINISTRATIVE LAW JUDGE AND ASSIGNED COMMISSIONER'S RULING ADOPTING A BUSINESS CASE ANALYSIS FRAMEWORK FOR ADVANCED METERING INFRASTRUCTURE

On April 14, 2004,[1] staff from the Commission's Energy Division and the California Energy Commission (CEC) circulated a report (Staff Report) setting forth a proposed analysis framework for implementation of advanced metering infrastructure. Parties had the opportunity to comment on the proposed framework and comments were filed by Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company (SCE), The Utility Reform Network, and California Coalition of Utility Employees.

Because installing an advanced metering infrastructure requires substantial utility investment and impacts all aspects of utility operations, the decision of whether, and if so, how, to proceed requires a detailed cost/benefit analysis. The costs of developing and deploying an advanced metering infrastructure are affected by (1) the performance characteristics and applications that utilities, regulators, and customers want supported (functional capability) and (2) the

[1] The report was not formally filed with the Docket Office until April 20, 2004.

hardware and engineering choices integrate the meters and communication systems of an advanced metering infrastructure into utility system network management functions.

Because the analysis framework we adopt today is designed to provide for numerous scenarios to be analyzed prior to determining whether to direct a particular AMI deployment approach, we have concluded that it is not necessary to issue a decision to adopt an analysis framework. The point to adopting the framework is to facilitate comparisons of cost and benefit estimates between utilities and scenarios, not to decide at this point, which scenario is best or should be adopted. This procedural approach is consistent with the November 24, 2003 Scoping Ruling which stated that "[a]t the conclusion of the working group process, the Commission should be in a position to issue a template that will result in the respondent utilities filing applications for authority to implement AMI and recover its costs."

Adopted Framework

The Staff Report is highly detailed and lays out a number of scenarios, different assumptions to be analyzed and considered within scenarios, and the rationale behind the various recommendations. After reviewing the report and the comments thereto, we have prepared a revised document (attached) that lays out the requirements for the utility AMI applications. In their applications, the utilities shall perform the analysis described in the attached document and propose a particular AMI deployment strategy (none, partial, full) and associated justification, timing, costs, and cost recovery based on the results of their analysis. Unless otherwise indicated in the attached document, the utilities shall explain how the various assumptions, tradeoffs, and staff recommendations described in the Staff Report were taken into consideration in reaching their recommendation regarding specific values to use in the analysis of the costs and benefits of deploying AMI. The Attachment identifies several different tariff structures to analyze but we wish to emphasize that in the near term (given legislative constraints on rate design modifications for some customer classes), we see the most potential benefits deriving from the operational cases and it is our expectation that the utilities will spend a considerable portion of their analytical time on the operations only cases.

The analysis the utilities will perform is crucial to the Commission's understanding of the tradeoffs made by utilities in developing their functional AMI specifications that underlie the benefit cost analysis. In order to enhance this understanding, the utilities should describe the underlying management philosophy or business vision used to develop its functional specifications and approach. Specifically we are interested in a discussion from each utility of how key market factors, regulatory constraints, or internal business constraints shaped or affected the development of its AMI specifications and cost benefit estimates.[2] Accordingly, we direct each utility to include a discussion in its filings that identifies key market factors, anticipated or current regulatory decisions, and forecasts of the future business and financing environment that have affected the development of cost and benefit estimates in this filing.

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[2] For example, SCE mentions in its comments its need to consider how new direct access rules, potential changes in the wholesale market structure and the state's renewable energy policies may have an impact on the costs and benefits of AMI systems. Staff mentions the need for the utilities to consider the industry wide trend toward outsourcing of certain billing and data collection functions to both improve customer service and reduce financing costs for AMI deployment.

The utilities should file a preliminary analysis in this (or its successor) docket no later than October 15, 2004. The purpose of this preliminary filing is to allow parties to review and discuss the findings, recommendations, and underlying assumptions prior to the applications being finalized. The utilities should file applications containing their final analysis no later than December 15, 2004. The applications should build on the draft analysis and any updates stemming from the 2004 Statewide Pricing Pilot results that modify the analytical findings in the preliminary analysis.

The utilities may choose to forgo filing a preliminary analysis and move straight to the application if so desired, or make its filing earlier than the dates reflected herein. Filing and review of these applications moves the Commission closer to being able to fulfill the objectives of the Energy Action Plan and we encourage the utilities to expedite their development and work on these applications.

Therefore, **IT IS RULED** that:

1. No later than October 15, 2004, the utilities shall file their preliminary analysis in this, or its successor, docket, consistent with this ruling.
2. The utilities shall file applications no later than December 15, 2004 that finalize their analysis described in the attachment and propose a particular AMI deployment strategy (none, partial, full) and associated justification, timing, costs, and cost recovery based on the results of their analysis.

Dated July 21, 2004, at San Francisco, California.

/s/ MICHAEL R. PEEVEY	/s/ MICHELLE COOKE
Michael R. Peevey	Michelle Cooke
Assigned Commissioner	Administrative Law Judge

ATTACHMENT A
SUMMARY OF ANALYTICAL FRAMEWORK

1 Overview

The following sections lay out the minimum requirements for successfully completing the preliminary benefit cost analysis of AMI that will be filed no later than October 15, 2004. The basic set of cases is illustrated in Table 1, and includes review of specific tariffs, as described in Section 3. This ruling supplements the baseline parameters and functionality levels set forth in the November 24, 2003 Phase 2 Scoping Memo and February 19, 2004 Joint Ruling.

2 Scenarios to be Analyzed

This section describes the scenarios to be analyzed. The Base Case analysis under the current tariffs will establish the baseline for evaluating cost effectiveness of the other scenarios. The scenarios described in this section will each be analyzed under different tariff assumptions, as described in Section 3 (and illustrated in Table 1) to allow for comparison between scenarios.

2.1 Base Case (Business as Usual)

This scenario includes the expected capital and maintenance costs associated with maintaining current metering and communication systems for all customer classes, including planned upgrades to metering and billing systems for the 2006 to 2021 period. Costs should be estimated on an annualized basis for the analysis period wherever possible.

Cost estimates to support the current information technology system used for processing current meter reads and converting them into bills for each cost category should be specified for the Base Case to ensure a fair comparison between the business as usual, partial, and full scale deployment of AMI.

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2.2 Partial Deployment

The Partial Deployment analysis should include a description of the functional capabilities of the new meters and supporting network, the AMI rollout options considered by the utility and its rationale for choosing its preferred case. The number of advanced meters to be installed each year by customer class for each Partial Deployment case should be identified, whether the meter will be capable of reading gas usage, and the utility's plans regarding using the new meter to collect gas readings. The criteria used to select the preferred partial deployment case (for example, contiguous neighborhoods with high "meter density", identification of zones or areas with high potential for price responsive demand, etc.) should be explicitly identified. This case should explicitly identify the costs of the billing system(s) needed to bill customers with the new meters and those customers that remain on the old meter system and integration of the two systems.

To facilitate the Commission's understanding of the implications of the preferred Partial Deployment cases (and options considered but eliminated), each utility should also separate the costs in its analysis into:

1. Start-up and design costs (design, contracting, training, hiring temporary installation crews, etc.)
2. Installation costs (purchase and installation of advanced meters, installation and testing at customer premise and system headquarters, new software, communications networks, etc.)
3. Operations and maintenance costs (cost of reading meters, translating data to bills, sending bills out and managing the network, etc.)

Appendix A separates the potential cost categories provided by the Working Group subcommittee into the above three categories. The categories listed in Appendix A generally correspond to those found in Appendices C and

D of the Staff Report, but some terms have been reworded to clarify the meaning of the language in the subcommittee report. In addition, additional cost and benefit categories have been added that were not originally included in the subcommittee report.[3]

The Partial Deployment case assumptions should be used to review the different AMI utilization scenarios as described below.

2.2.1 Operational Scenario

This scenario assumes that no new tariffs are established as a result of the partial deployment of AMI, so costs and benefits that derive from the rollout of new tariffs are excluded in this case. The cost categories[4] that must be analyzed in the Partial Deployment Operational Scenario are:

- Metering System and Installation Costs
- Communication System Costs
- Information Technology and Application Costs
- Customer Services Costs (CU-1, 3, 4, 6, and 7 only)
- Management and Other Costs (all except M-13 and M-14)
- Gas Service Costs (if applicable)

The benefit categories[5] that must be analyzed in the Partial Deployment Operational Scenario are:

- Systems Operation Benefits

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[3] This report was drafted by a subcommittee of WG 3 members including David Hungerford, CEC, Tim Vahlstrom, PG&E, Jana Corey, PG&E, Paul Kasick, SCE (by phone), Doug Kim, SCE, Jeff Nahigian, TURN, Tanya Guleserian, CUE, Ward Camp, DCSI, Chris King, CCEA, and JC Martin, SDG&E .

[4] References are to Appendix A.

[5] References are to Appendix A.

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- Customer Service Benefits (all except CB-6)
- Management and Other Benefits (all except MB-7 and MB-9)

Two different financing / implementation approaches should be analyzed and reported for the Partial Deployment Operational Scenario: (1) internal financing / implementation and (2) outsourcing. In the internal financing/implementation analysis, costs of AMI acquisition and installation are considered conventional assets owned by the utility and included in rate base with ongoing operation and maintenance provided in-house or by third parties. In the outsourcing analysis, AMI acquisition, installation, and operations and maintenance are obtained under contract, through leasing agreements, limited partnerships or other business arrangements with third party providers. Contractual arrangements determine the tax implications and whether the AMI asset and related implementation costs are rate based or treated as an operating expense.

2.2.2 Demand Response Scenario

This scenario assumes that new tariffs are established as a result of the partial deployment of AMI, so costs and benefits that derive from the rollout of a specified set of new tariffs are included in this scenario.[6] The Partial Deployment Demand Response Scenario includes all of the potential costs and benefits from the Operational Scenario as well as all categories listed in Appendix A that result from implementing the specified new tariffs for customers expected to receive new meters under the partial deployment scenario from the utility and societal

[6] The minimum set of tariffs to be offered are listed in Section 3 below.

perspectives. This scenario should explicitly describe the financing approach for any new metering, billing, or communications equipment necessary to support the partial deployment.

2.2.3 Demand Response + Reliability Scenario

This scenario assumes that the AMI systems installed in a partial deployment scenario are actively utilized to manage peak loads during times when reserve margins shrink to unacceptable levels, and to help restore power more quickly to customers in the event of temporary loss of power or rolling blackouts. This active utilization comes from the installation and use of automated control technology at the customer level to achieve reliability benefits. This analysis should allow assessment of whether deployment of AMI coupled with active use of automated control technology and price differentiated tariffs provides value by reducing the probability that rolling blackouts will be required in emergency situations.

The Partial Deployment Demand Response + Reliability Scenario includes the costs and benefits described in the Partial Deployment Demand Response Scenario plus the costs of any additional control and communication systems necessary to automatically reduce the load of customers who have agreed to a predetermined peak load reduction (of 10- 20%) during emergency conditions. This scenario should explicitly describe the financing approach for any new metering, billing, or communications equipment necessary to support the partial deployment and whether the controls to ensure load reduction would be utility or customer financed.

As shown on Table 1, the utilities need only perform the analysis on two tariff structures for this case, both analyses are for optional tariff structures.

Section 3 describes how to develop estimates of costs and benefits for these tariffs.

2.3 Full Deployment

Analysis of the Full Deployment scenarios should include a description of the functional capabilities of the new meters and supporting network, the AMI rollout options considered by the utility and its rationale for choosing its preferred case. The number of advanced meters to be installed each year by customer class for each Full Deployment case should be identified, whether the meter will be capable of reading gas usage, and the utility's plans regarding using the new meter to collect gas readings. The criteria used to select the preferred deployment schedule should be explicitly identified as well as the fraction of customers who would not be reached under the preferred case. In no event should the deployment schedule exceed five years or reach less than 90% of the utility's customer base. The analysis should include all costs associated with meter testing, beta testing of software interfaces between systems, and any other quality control milestones necessary during the transition period before AMI is fully deployed and integrated into the network.

To facilitate the Commission's understanding of the implications of the preferred Full Deployment case each utility should separate costs in its analysis into:

1. Start-up and design costs (design, contracting, training, hiring temporary installation crews, etc.)
2. Installation costs (purchase and installation of advanced meters, installation and testing at customer premise and system headquarters, new software, communications networks, etc.)
3. Operations and maintenance costs (cost of reading meters, translating data to bills, sending bills out and managing the network, etc.)

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Appendix A separates the potential cost categories provided by the Working Group subcommittee into the above three categories. The categories listed in Appendix A generally correspond to those found in Appendices C and D of the Staff Report, but some terms have been reworded to clarify the meaning of the language in the subcommittee report. In addition, additional cost and benefit categories have been added that were not originally included in the subcommittee report.

The Full Deployment case assumptions should be used to review three different AMI utilization scenarios as described below.

2.3.1 Operational Scenario

This scenario assumes that no new tariffs are established as a result of the full deployment of AMI, so costs and benefits that derive from the rollout of new tariffs are excluded in this case. The cost categories[7] that must be analyzed in the Full Deployment Operational Case are:

- Metering System and Installation Costs
- Communication System Costs
- Information Technology and Application Costs
- Customer Services Costs (CU-1, 3, 4, 6, and 7 only)
- Management and Other Costs (all except M-13 and M-14)
- Gas Service Costs (if applicable)

The benefit categories[8] that must be analyzed in the Full Deployment Operational Case are:

- Systems Operation Benefits

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[7] References are to Appendix A.

[8] References are to Appendix A.

- Customer Service Benefits (all except CB-6)
- Management and Other Benefits (all except MB-7 and MB-9)

The same two financing / implementation approaches analyzed and reported for the Partial Deployment Operational Scenario should also be performed for the Full Deployment Operational Scenario.

2.3.2 Demand Response Scenario

This scenario assumes that new tariffs are established as a result of the full deployment of AMI, so costs and benefits that derive from the rollout of a specified set of new tariffs are included in this scenario.[9] The Full Deployment Demand Response Scenario includes all of the potential costs and benefits from the Operational Scenario as well as all categories listed in Appendix A that result from implementing the specified new tariffs for customers expected to receive new meters under the full deployment scenario from the utility and societal perspectives. This scenario should explicitly describe its financing approach assumptions.

2.3.3 Demand Response + Reliability Scenario

This scenario assumes that the AMI systems installed in a full deployment scenario are actively utilized to manage peak loads during times when reserve margins shrink to unacceptable levels, and to help restore power more quickly to customers in the event of temporary loss of power or rolling blackouts. This active utilization comes from the installation and use of automated control technology to achieve reliability benefits. This analysis should allow assessment of whether deployment of AMI coupled with active use of automated control

[9] The minimum set of tariffs to be offered are listed in Section 3 below.

technology and price differentiated tariffs provides value by reducing the probability that rolling blackouts will be required in emergency situations.

The Full Deployment Demand Response + Reliability Scenario includes the costs and benefits described in the Full Deployment Demand Response Scenario plus the costs of any additional control and communication systems necessary to automatically reduce the load of customers who have agreed to a predetermined peak load reduction (of 10- 20%) during emergency conditions. This scenario should explicitly describe the financing approach used to procure the customer control equipment.

As shown on Table 1, the utilities need only perform the analysis on two tariff structures for this case. Section 3 describes how to develop estimates of costs and benefits for these tariffs.

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Advanced Metering Infrastructure Business Cases to be Analyzed

Tariff Assumptions	Current	Time-of-Use (two period)	Critical Peak Pricing- Fixed, Variable, RTP*	Current	Current	Utility Preferred
	n/a	Current or CPP-F	Current or TOU	Critical Peak Pricing- Pure^	CPP-F or CPP-V	
Case Assumptions						
Base Case	X					
Partial Deployment						
Operational- Conventional Financing	X					
Operational- Outsourced Financing	X					
Demand Response		X#	X#	X	X	O
Demand Response + Reliability				X	X#	O
Full Deployment						
Operational- Conventional Financing	X					O
Operational- Outsourced Financing	X					O
Demand Response		X	X	X	X	O
Demand Response + Reliability			X	X		O
Cases Required	5	2	3	4	3	
Total Cases	17					

(grey) Default Tariff
(black) Optional Tariff Choices

* Default Tariff based on customer type/size.

^ Customers electing to receive CPP-Pure would receive a discount on off-peak rates to compensate for CPP exposure.

Utilities should discuss the feasibility of implementing a new default tariff to some portions of a customer class in a partial deployment scenario.

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3 Tariff Structures to be Analyzed

WG 3 discussed the possibility of offering customers a number of different rate types as well as switching customers to a new default tariff on an opt out basis. For the purposes of comparative analysis, utilities shall analyze the impacts of the following 5 tariff structures:

1. Existing tariff structures are maintained and no price responsive demand tariffs are implemented (Operational Scenarios only)
2. By 2008 the default tariff for all customer classes is a two period time of use (TOU) rate; customers may elect to switch to their currently applicable tariff or Critical Peak Pricing- Fixed (CPP-F)
3. By 2008 the default tariff for:
    a. All residential customers is CPP-F; customers may elect to switch to their currently applicable tariff or TOU;
    b. All small commercial and industrial customers is Critical Peak Pricing-Variable (CPP-V); customers may elect to switch to their currently applicable tariff;
    c. All large commercial and industrial customers (> 200 kW) is two part real time tariffs;[10] customers may elect to switch to their currently applicable TOU tariff
4. Existing tariff structures remain the default; new tariff option is developed and available in 2007, Critical Peak Pricing-Pure (CPP-Pure), with lower off peak rates to compensate for exposure to CPP-Pure up to 5 hours / day, 15 days / year, not to exceed 90 hours / year
5. Existing tariff structures remain the default; CPP-F and CPP-V tariffs are offered to all customers on an optional basis

Analysis on the first tariff structure applies only for the Operational Scenarios. The next four tariff structures apply to the Demand Response Scenarios in the partial and full deployment cases. For each of the four tariff

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[10] Two part real time tariffs include a baseline load shape where customers are charged their current tariff for their baseline usage but a marginal (real) price for increases above the baseline.

structures, the utility should identify the relevant customer enrollment percentages for each class. The utility should identify the rate assumed for each year in the analysis period. For the tariff structures described that include adoption of new default tariffs, at least one scenario analysis should reflect a 20% opt out rate. Utilities may also develop other tariff structure scenarios that they believe make the most sense for economic or other reasons.

For the Demand Response + Reliability Scenarios in the partial deployment case we require the utilities to perform their analysis on the fourth and fifth tariff structures described above. For the Demand Response + Reliability Scenarios in the full deployment case we require the utilities to perform their analysis on the third and fourth tariff structures described above. For customers assumed to opt out in these scenarios, there would be no obligation to install control equipment to provide emergency load reductions.

4 Analysis Parameters

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 shall be performed. Some combination of the specific methods for gathering benefit and cost information (use of RFPs, 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

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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. Demand response savings estimates based on weighted average of savings under average and hot weather conditions developed using Monte Carlo or other simulation techniques;[11]
8. Avoided peak demand cost = $85 / kW-yr (see Appendix B);
9. Avoided energy cost = $63 / MWh (see Appendix B);[12]

To the extent that an analysis parameter is not defined here, but was listed in the Staff Report, utilities should identify the value used for that parameter and supporting rationale for their choice. Uncertainty should be captured in the analysis by using Monte Carlo or other statistical simulation techniques.[13]

Utility workpapers must clearly document the assumptions used for the following parameters in the benefit cost analysis:

1. Data collection interval by customer class (data granularity);
2. Frequency of utility data retrieval;
3. Meter functionality (data beyond usage collected by meter, e.g., voltage, power quality, etc.);
4. Means by which customer will have access to its usage data and projected use by customer class of this access;
5. Customer notification approach when CPP tariffs are triggered;

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[11] For purposes of this parameter average weather is defined as 1 in 2 year weather and hot is a 1 in 10 year weather condition.

[12] These avoided energy and demand cost assumptions should be used in all required scenarios, utilities may develop their own assumptions under the optional cases.

[13] The analysis should include a section discussing how uncertainty in estimated costs and benefits for the parameters discussed in this Attachment affect the results derived in the scenario analyses by providing examples of the range of benefit and cost values discovered during the uncertainty analysis.

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6. Prices and conditions in tariff structures (current tariffs, TOU, CPP-F, CPP-V, RTP, and CPP-Pure) used to model potential benefits;
7. Avoided transmission and distribution costs;[14]
8. Price elasticity assumptions;
9. Methods used to simulate customer price responsive demand;
10. Methods used to project customer choices of different tariffs and resulting share of customer participation in each rate;
11. Estimated cost to ensure that customer information systems (CIS) are compatible with collected data and rationale why utility chose to upgrade CIS, install (and ratebase) new CIS, or outsource CIS functions.

To the extent that the utilities use different assumptions from those recommended in the Staff Report, they must explain why they decided upon a different assumption.

(END OF ATTACHMENT A)

[14] The utilities may develop their own estimates or use the avoided transmission and distribution costs developed by E3 and presented to the Commission (Energy and Environmental Economics, A forecast of Cost Effectiveness, Avoided costs, and Externality Adders: Prepared for Eli Kollman: January 20, 2004). The Report can be downloaded at: http://www.cpuc.ca.gov/static/industry/electric/energy+efficiency/rulemaking/cpucdraft01082004.pdf.)

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PHASE 1 – START-UP AND DESIGN COSTS

Communication System

- C-1 ➢ Costs to review and specify systems to ensure physical and logical security, securing data transmission, infrastructure to support security, etc.
- C-2 ➢ Perform and review site surveys to determine placement of network equipment
- C-3 ➢ Mapping of network equipment on company facilities (asset facility mapping)
- C-4 ➢ Staging facilities for WAN/LAN equip and mounting hardware (pre-installation)
- C-5 ➢ Review and develop strategies to retrieve data from meters and process within billing system

Information Technology and Application

- I-1 ➢ Network planning and engineering - coverage studies, technology selection, field testing & engineering

Management and Other Costs

- M-1 ➢ Buy out of Current SCE- or other utility ITRON Contract for 2000 ERT Deployment (350K meters)
- M-2 ➢ Meter RFP process and contract finalization and administration

PHASE 2 – INSTALLATION COSTS

Meter System and Installation

- MS-1 ➢ Additional temporary meter reading staff for transitional period/mtr reader transition costs
- MS-2 ➢ Administration of contracts/supervision of installer workforce
- MS-3 ➢ Cost of purchasing meters, comm modules and related vendor support equipment & software
- MS-4 ➢ Installation and testing equipment costs (tools, equipment and vehicles)
- MS-5 ➢ Installation labor (incl workers comp, P&B, payroll taxes, etc.)
- MS-6 ➢ Meter installation tracking systems (Endpoint Link-other), Meter info/records admin/GPS
- MS-7 ➢ Panel reconfiguration/replacement costs (A base, other)/Meter socket repairs
- MS-8 ➢ Potential customer claims related to damages during meter installation

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	and/or panel upgrades
MS-9	➢ Salvage/Disposal process for removed meters
MS-10	➢ Supply chain management including development of staging facilities, shipment & handling of new meters
MS-11	➢ Training (meter installers, handlers, shippers)

Communication System

C-6	➢ Auxiliary equipment (e.g. remote antennas, isolation transformers, surge protection devices, etc).
C-7	➢ Costs of Pole replacement - to "fit" concentrators
C-8	➢ Development of communications link from meters to data center, LAN/WAN/servers for storage & processing
	➢ Development of Internet based usage data communication
C-9	➢ Install costs of Cross arms (e.g. streetlight arms for pole top installations) and other mounting
C-10	➢ Purchase network communications equipment and hardware
C-11	➢ Training for installation of WAN/LAN equipment (including install labor for wireless circuits)

Information Technology and Application

I-2	➢ Computing system implementation in data center (new hardware/software, IT security review & compliance)
I-3	➢ Data center facilities
I-4	➢ Develop and process dynamic rates in CIS billing systems
I-5	➢ New information management software applications
I-6	➢ Records - databases, drawings of field network and data center servers
I-7	➢ Update work management interface to process additional volume of meter changes, data scripts

Customer Services

CU-1	➢ Customer records/billing and collections work associated with roll-out of meter change process
CU-2	➢ Increased call center activity during transition from existing to new rates / meter change appointments
CU-3	➢ Modification and customer support costs for OIS and other system changes
CU-4	➢ Process meter changes for new meter installations and DA accounts

Management and Other Costs

M-3	➢ Customers access to usage information through communications

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M-4	➢ Employee communications and change management
M-5	➢ Employee training for deployment and O&M of new systems, rate structures, etc.
M-6	➢ Meter reader reroute administration (assuming gas meters are not included - will continue to be read)
M-7	➢ Overall project mgmt costs (and overhead) including customer service, IT and other functions
M-8	➢ Recruiting of incremental workers
M-9	➢ Supervision / overhead of contracts and technology personnel assigned to hardware and systems development
M-10	➢ Training for other traditional classifications (records, call centers, meter readers, T-men, etc)
M-11	➢ Work management tools

<u>Gas Services Impacts</u>

GS-1	➢ Gas Index / Module Purchases
GS-2	➢ Purchase / replacement of non-retrofittable gas meters
GS-3	➢ Replacement of gas meter module, battery purchases and replacement labor
GS-4	➢ Warehousing operations for gas modules

PHASE 3 – OPERATION AND MAINTENANCE COSTS (O & M)

<u>Meter System and Installation</u>

MS-12	➢ Cost of Maintaining Existing Metering Systems
	➢ Additional costs to O&M / more complex metering & comm infrastructure (labor, tools, equip, vehicles)
MS-13	➢ Pickup reads (remote retrieval not available / possible)
MS-14	➢ Potentially higher meter replacement costs relative to existing mechanical meters (shorter life cycle)

<u>Communication System</u>

C-12	➢ Cost of Existing communication systems that take data from meters on monthly basis and turn it into bills
	➢ Cost of attaching comm. concentrators (e.g., rent or lease charges by cities or other 3rd parties-not owned by utility)
C-13	➢ Costs of contracts to retrieve meter data and services
C-14	➢ Dispatching and O&M of field LAN / WAN and infrastructure equipment

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C-15	➢ Electric power consumed by LAN/WAN equipment and/or meter modules

Information Technology and Application

I-8	➢ Cost of Maintaining Existing hardware and software that translates meter reads to customer bills
I-9	➢ Aggregating, validating and creating billing determinant data for electric billing
I-10	➢ Contract administration and database management of public network connections
I-11	➢ Exceptions processing (develop, update, and execute data cleanup routines)
I-12	➢ License and O&M software fees
I-13	➢ Ongoing data storage and handling costs/incl test, QA environments, business continuity, disaster recovery
I-14	➢ Ongoing IT system operations & maintenance (usage, software, internet application)
I-15	➢ Operating costs - retrieval and delivery of mtr, maint & outage information systems data and alarms
I-16	➢ Server replacements (every 3-4 years) for 15 year life cycle

Customer Services

CU-5	➢ Additional rate analysis due to multiple TOU options.
CU-6	➢ Cost of complying w/ regulations - providing alternative safety measures (due to removal of electric mtr readers)
CU-7	➢ Cost of reduced customer safety (meter readers no longer available)
CU-8	➢ Customer education of rate changes/customer communications campaign
CU-9	➢ Customer support for internet based usage data communication
CU-10	➢ Out-bound communications (mass media costs, e.g., print, radio, TV)./CPP or other rate notifications

Management and Other Costs

M-12	➢ Capital financing costs- discuss alternative methods of procuring the equipment or services (such as leasing or outsourcing) reviewed and rejected.
M-13	➢ Cost of increased load during mid-peak and off-peak periods

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M-14 ➢ Customer acquisition and marketing costs for new tariffs
M-15 ➢ Risk contingencies (e.g., technology obsolescence / reliability)[15]

Gas Services Impacts

GS-5 ➢ Aggregation / Validation of monthly / hourly reads for gas billing
GS-6 ➢ Cost of complying w / regulations - providing alternative safety measures (due to removal of gas mtr readers)
GS-7 ➢ Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently MRs)
GS-8 ➢ Increased O&M on gas meters / modules due to addition of electronic modules
GS-9 ➢ Performing atmospheric corrosion inspections (currently performed by meter readers)

Potential Benefits

Systems Operations Benefits

SB-1 ➢ Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)
SB-2 ➢ Field service savings (turn-on's / turn-off's) and lower need for pickup reads
SB-3 ➢ Reduced energy theft-May provide ability to ID active accounts for metered accts not being billed, broken meters, wrong multipliers
SB-4 ➢ Phone Centers - Reduced FTEs in the long term due to anticipated lower customer call volume (estimated / disputed bills)
SB-5 ➢ Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change
SB-6 ➢ Outage management benefits (momentary checking for PG&E)
SB-7 ➢ Better meter functionality / equipment modernization
SB-8 ➢ Remote service connect / disconnect
SB-9 ➢ Meter accuracy- improved and more timely load information could increase forecasting accuracy and reduce resource acquisition costs and reduced customer complaints about faulty meter reads

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[15] If considered, these risks must be balanced by consideration of opportunity costs of not proceeding with the AMI system.

APPENDIX A

SB-10 ➢ System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and when they need to be replaced/repaired

SB-11 ➢ Reductions in Unaccounted for Energy (UFE)-CEC and ISO studies have identified significant percentages of total system energy deliveries that cannot be accounted for by retail sales or transmission losses. AMI systems identify the source and solution for these problems and reduce energy costs for all customers.

SB-12 ➢ Ability to monitor customer self generation into system on a real time basis

SB-13 ➢ Reduction in the amount of time to implement new rates and or load management programs.

Customer Service Benefits

CB-1 ➢ Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates "lock-outs"

CB-2 ➢ Early detection of meter failures and distribution line stresses can reduce outages and improve customer service

CB-3 ➢ May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions

CB-4 ➢ Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing

CB-5 ➢ Customer energy profiles for EE / DR targeting (marketing)

CB-6 ➢ Customer rate choice / new rate options

CB-7 ➢ Customized billing date

CB-8 ➢ Energy Information to customer can assist in managing loads

CB-9 ➢ Enhanced billing options could be a source of revenue and increased customer satisfaction

CB-10 ➢ Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits

CB-11 ➢ On-line bill presentment with hourly data / more timely and accurate information about electricity / info access

CB-12 ➢ Lower customer bills

CB-13 ➢ Value to customers of more timely & accurate bills

APPENDIX A

Demand Response Benefits

DR-1 ➢ Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, lower net emissions

DR-2 ➢ System reliability benefits (capacity buffer)- increased level of dispatchable load reductions could increase effective capacity margin and reduce loss of load probability.

DR-3 ➢ Dynamic fuel switching / Dynamic integration of conventional and distributed supplies

DR-4 ➢ Avoided / deferred transmission and distribution (T&D) additions / upgrade costs

Management and Other Benefits

MB-1 ➢ Reduced equipment and equip maintenance costs (software maintenance & system support, handheld reading devices, uniforms, etc.)

MB-2 ➢ Reduced misc. support expenses (including office equipment and supplies)

MB-3 ➢ Reduced battery replacement / calendar resets / meter programming

MB-4 ➢ Reduced meter inventories / inventory management expenses due to expanded uniformity

MB-5 ➢ Summary billing cash flow benefits (existing customers)

MB-6 ➢ Possible reduction in "idle usage", meter watt losses - at the very least quicker resolution of idle usage episodes

MB-7 ➢ Possible new rev source / new business ventures / new products & srvs/web based interval & power-quality data

MB-8 ➢ May facilitate ability to obtain GPS reads during mtr deployment- improving Franchise & Utility Users Tax processes

MB-9 ➢ Tariff planning - more flexibility of rate contacts & options within standard customer rate classes / dynamic tariffs

MB-10 ➢ Potential for tax savings from federal investment tax credits

(END OF APPENDIX A)

APPENDIX B
DERIVATION OF CAPACITY AND ENERGY VALUES FOR ON AND OFF PEAK PERIODS

Cost Calculation for a Peaking Turbine to Serve Peak Load

1. $ Fixed costs (levelized) = $85 per kW-year (Reference 1)
2. Operating Costs- Heat rate of 9, 300 Btu/kWh at $5 per MMBtu = 47 $ per MWh (fuel cost) + 16 $ per MWh for variable O&M = 63 $ per MWh. (Reference 1 and 2)

Reference 1- For CT costs see Electricity and Natural Gas Assessment Report, (CEC pub 100-03-001) Appendix D has the specific capital and O&M costs for combustion turbines.
Reference 2- Gas costs http://www.energy.ca.gov/reports/2003-08-08_100-03-006.PDF page 10 assume $ 5 per million Btu (year 2000 $) for natural gas.

Summary: These assessments suggest use of $ 85 per kW year and $ 63 per MWh for cost of peak generation facilities- actual costs will be higher because the costs estimates do not include higher transmission and distribution costs found during most critical peak periods when CPP rates are likely to be called. A conservative estimate to cover this “congestion cost is an additional $7/MWh or .7 cents/kWh resulting in a total on peak energy cost of $70/MWh.

(END OF APPENDIX B)

CERTIFICATE OF SERVICE

I certify that I have by mail, and by electronic mail to the parties to which an electronic mail address has been provided, this day served a true copy of the original attached Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure on all parties of record in this proceeding or their attorneys of record.

Dated July 21, 2004, at San Francisco, California.

/s/ KRIS KELLER
Kris Keller

NOTICE

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address to ensure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.