BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC,	)
	)
Request for a General Rate Revision.	)

SURREBUTTAL TESTIMONY

OF THE

CITIZENS' UTILITY BOARD OF OREGON

October 6, 2006

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Our names are Bob Jenks and Lowrey Brown, and our qualifications are listed in CUB Exhibits 101 and 102 respectively.

I. Introduction

In our Surrebuttal Testimony, CUB responds to PGE's Rebuttal Testimony. PGE's Rebuttal provided no argument that changed our determination that PGE's proposal for a PCA with no deadband is inconsistent with recent OPUC decisions and sound regulatory policy. The Company's attempt to come up with a new way to describe risk is not convincing. PGE's proposal to retain a new version of the RVM, while additionally implementing a PCA, creates two simultaneous mechanisms to recover power cost variations between general rate cases, and would create a significant regulatory burden. PGE's Rebuttal does not demonstrate that it has prudently implemented the action plan from the Company's last Least Cost Plan. PGE's revised business case for Advanced Metering Infrastructure fails to make the case that such an investment is cost effective. Finally, CUB supports Staff's and ICNU's proposal to use NERC data to establish a forced outage rate for Boardman and Colstrip. CUB and ICNU have co-sponsored a cost of capital witness, Michael Gorman, who will also be filing Surrebuttal Testimony.

II. The Risk Of Power Cost Variations

In this docket, PGE wants to shift almost all risk of power cost variations onto customers through a PCA, raise rates overall, and increase the Company's rate of return. In other words, PGE wants customers to pay more, and shoulder more risk.

A. What Is The Appropriate Balance Of Risk?

Currently, between general rate cases, PGE gets to annually update its variable power cost forecast. This update is passed through to customers without a deadband or any sharing. PGE takes the risk that power costs in the following year will be greater than forecast; the Company also stands to benefit if costs are lower than forecast. Only if the power cost variance is large enough to warrant deferred accounting, may the Company burden customers with those variations.

Apparently, PGE is not happy with this system. Even though the Company updates its variable power cost forecast every year, PGE does not want to take the risk that actual power costs might be higher than were forecast. In this docket, PGE asks that nearly all of this risk be shifted to customers, such that customers would pick up 90¢ of the very first dollar of power cost variation. Yet PGE is the only party that can manage power costs. On top of this, PGE is asking for higher rates and a higher return on equity, the rate that shareholders are supposedly paid in part to manage risk.

Instead of addressing its proposed shift of risk in a direct manner, PGE embarks on a long-winded attempt to obscure the real issue. Instead of explaining why the Company feels it is appropriate to shift the risk of power cost variations primarily onto customers by eliminating any deadband and abbreviating any sharing, PGE claims that the Company's proposed annual update and PCA would serve to reduce risk overall. Instead of acknowledging that it is proposing to shift the risk of power cost variation onto customers because the Company no longer wants to carry it, PGE attempts to explain that its proposal is a win-win situation.

Unfortunately, this is not a win-win situation. An investor-owned utility's shareholders are paid a rate of return to manage risk. Actual power costs will always be higher or lower than were forecast, and someone will receive the benefit or cost of this variation. If PGE is not to bear the risk of power cost variation, then its business is considerably less risky and its return on equity should be considerably reduced. In denying that its proposal shifts risk, PGE also avoids tackling the fundamental questions about the appropriate balance of risk and how best to achieve that balance.

B. PGE Attempts To Redefine Risk

We have been discussing risk, the RVM, PCA mechanisms, and deferrals with PGE for years now. During this time we have developed some common principles and language. In PGE's Rebuttal, however, the Company invents a new risk, the "cost of service risk," that is mitigated by a PCA or deferral. According to PGE, the risk that the parties and the Commission should be concerned about is not the risk that actual power costs will be different from those that were forecast, but rather is the risk that regulation will not fully true-up the difference between forecasted and actual costs.[1] In the framework of PGE's new risk, a PCA only serves to reduce risk. A deadband, sharing bands, or any other mechanism that allocates variations in power costs to PGE, only interferes with the ability of a PCA or deferral to reduce the "cost of service" risk.

PGE acknowledges that "perhaps" parties have a different understanding of risk that leads us to the conclusion that a PCA shifts risk rather than reduces it.[2] Perhaps? Perhaps, after five years of discussions concerning power cost adjustment mechanisms and deferrals, PGE would have a better understanding of how parties view the risk of power cost variability.

PGE claims that the "parties never explain what the risk is that PGE's proposed NVPC regulatory framework allegedly shifts,"[3] so let us be clear. Rates in this case will be set on a forecasted future test year.[4] The risk that a PCA or deferral shifts is the risk that power costs will be higher or lower than were forecast. Without a PCA or deferral, the utility bears the risk of power cost variations. A PCA or deferral shifts that risk to customers. While PGE might not understand this description of risk, the Company's consultant in this case does. PGE hired PA Consulting Group to define a basic simulation model for net variable power costs. The following quote is from PA Consulting's report which PGE submitted with its testimony.

> During the course of this project, Portland General Electric staff explained to PA some of the context in which the project was initiated. Apparently there have been discussions between Portland General and the Public

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[1] UE 180 PGE/1800/Lesh/8-9.
[2] UE 180 PGE/1800/18.
[3] UE 180 PGE/1800/Lesh/8.
[4] In footnote 2 at PGE/1800/Lesh/9, PGE suggests that CUB believes the only way to set rates is through future test years. This is incorrect. CUB has participated in general rate cases with both future and historic test years. In addition, we have seen and supported rate adjustments due to PCAs, deferrals, automatic adjustment clauses, and alternative forms of regulation. However, UE 180 is a general rate case that PGE filed with a future-looking forecast test year.

> Utility Commission of Oregon about the variability in PGE's power costs, and whether it is appropriate for ratepayers to cover that variability, at least in part, through an annual true-up. If there were no true-up then PGE shareholders would bear that risk…
>
> Utilities are generally given the opportunity to earn a return, but not a guarantee that the return will be earned. The return is put at risk to the utility's operational performance and to factors under the control of the utility management. Whether fuel price risk, for example, is appropriately placed on the utility may depend on the tools the utility has or has not been given with which to mitigate it. Certain risks may just be too large for the utility reasonably to mitigate. In that case ratepayers, with greater overall financial resources, may appropriately be asked to bear the risk.

UE 180 PGE/1803/Lesh/49.

We agree with PGE's consultant. The risk that power costs will be seriously over or under what was forecast may appropriately be shared with customers. PGE argues, however, that the risk of power costs being $1 over what was forecast is appropriately shared with customers, who should shoulder 90¢ of that $1. We disagree. The risk that actual power costs will be $1 more than forecast is a not a risk that is appropriately placed on customers.

This brings us back to the central issue in designing a PCA: what is the deadband and sharing that is necessary to ensure that the shift of risk from shareholders to customers is appropriate?

C. Rates Are Frequently Reset Between General Rate Cases

In Rebuttal, PGE argues that no one challenged the Company's claim that re-setting rates between rate cases is a common practice:

> With respect to non-Oregon cost of service electric utilities, no party has rebutted the conclusions in our opening testimony that:
>
> - The use of regulatory tools that allow frequent re-setting of cost of service prices for power cost components, outside of a general rate case, is common among other states.
>
> - The use of regulatory tools that adjust rates for differences between forecasted power cost components and actual power cost incurred is common in other states.
>
> The parties variously argue that their approach is "traditional" (Staff/800, Galbraith/15) and that PGE's is "absurd" or "unrealistic" (CUB/200, Jenks-Brown/6 and 12). Most states apparently, do not follow this tradition or view taking action to reduce the cost of service risk as absurd or unrealistic.

UE 180 PGE/1800/Lesh/37-38.

While it is true that CUB did not address regulatory tools outside of Oregon, PGE's point confuses our position and the state of regulation ***in*** Oregon. We did not rebut PGE's claim that frequent resetting of prices for power cost components outside of a general rate case is common in other states, because the use of regulatory tools that allow frequent resetting of cost-of-service prices for power cost components outside of a general rate case ***is common in Oregon***. Between this general rate case and UE 115, PGE's last general rate case, we have seen the following dockets that have reset the cost-of-service prices for power costs:

Docket		Rate Change (Millions)	
UM 1039	2001-02 PCA	Raised by[5]	$ 37
UE 139	2003 RVM	Lowered by[6]	$261
UE 149	2004 RVM	Lowered by[7]	$ 3
UE 161	2005 RVM	Raised by[8]	$ 41
UE 172	2006 RVM	Raised by[9]	$140
UM 1014	Beaver Rate Base	Raised by[10]	$ 14
UM 1234	Boardman Deferral	Raised by	$?

In addition, PGE could have used dockets UE 137 and UE 165 to implement a mechanism to reset power costs between rate cases. UE 137 was a docket for a PCA that PGE withdrew before the Commission decision. A Commission decision in that docket would likely have established a PCA that would have allowed PGE to adjust rates for power costs between general rate cases. In UE 165, the Commission set design criteria for a hydro PCA and invited PGE to re-file, but PGE again walked away from implementing a mechanism that would have reset rates between general rate cases. In addition, there have been a series of cases (UM 1071, UM 1187, and UM 1239) where PGE requested power costs deferrals, but the Company's applications were withdrawn or denied.

Quite simply, no party is arguing that rates should not be adjusted between general rate cases to reflect power cost changes in Oregon. In addition, neither CUB nor Staff is arguing against "regulatory tools that adjust rates for differences between forecasted power cost components and actual power cost incurred." CUB and Staff both proposed PCAs in this docket and have proposed or expressed acceptance of them in

[5] UE 137 CUB/100/Jenks/4.[5] UM 1039 OPUC Order No. 04-293, page 3.
[6] UE 139 OPUC Order No. 02-772.
[7] Staff public meeting memo, 12/9/03.
[8] Staff public meeting memo, 12/21/04.
[9] Staff public meeting memo, 12/14/05.
[10] UM 1014 OPUC Order No. 04-740, page 2.

other dockets. CUB has never stated or implied that PCAs, RVMs, or deferrals (all of which are regulatory tools that the Oregon PUC has used to reset rates between general rate cases) are "absurd" or "unrealistic." As PGE's proposal comes only months after the Commission's Order in UE 165, however, we stand by our characterization of the Company's proposal. CUB has a history of support for reasonable proposals that adjust rates for differences between forecasted power costs and actual power costs.

The issue is not whether rates should be adjusted for differences between forecasted power cost components and actual power costs incurred, but under what circumstance rates should be adjusted and by how much. It is regarding the terms and conditions for such adjustments that we disagree with PGE.

D. The Utility Has The Ability To Control Costs & Mitigate Risk

According to PGE, CUB has an extreme view on the issue of the Company's ability to control costs:

> CUB's opinion on PGE's ability to manage NVPC is perhaps the most extreme. CUB asserts that: "If an electric utility performs well between rate cases, it can keep the benefit of the low costs; if the utility performs poorly, its financial performance will suffer accordingly." (CUB/200, Jenks-Brown/11). Outcomes within the range of cost of service risk have little to do with our performance or management ability.

UE 180 PGE/1800/Lesh/28.

CUB's description quoted above is only extreme if the general regulatory bargain is extreme. Generally, when costs are below what was forecast, the Company's earnings (performance) are above what was projected, and when costs are above what was forecast, the Company's earning (performance) suffers.

Our use of the word performance was not intended to imply anything about management's ability, it simply states that costs impact earnings. This is not an extreme position, it is simply the general way regulation works in Oregon. We forecast costs and the Company bears the risks and reaps the rewards of changes in costs. At the same time, CUB recognizes that, under some circumstances, the ability of the Company to absorb this risk is too great, and customers must step in and help. This is why we believe a central issue in designing a power cost adjustment is the use of a deadband and sharing to define how much power cost variation is reasonable for a utility to absorb.

While the part of our Opening Testimony that PGE labels "extreme" is not intended to reference the ability of PGE's management to control costs, we do believe that PGE is more than just a "price taker" when it comes to managing power costs.[11] Regulation of a monopoly is supposed to substitute for the price-constraining competition of a market. Many businesses find costs going up for things that are outside of their control, but are unable to raise prices because their prices already are at the level that the market allows. These businesses are then forced to look for other efficiencies and strategies. Is it too much to expect utilities to do the same?

A case in point is early 2005, when hydro conditions were low. PGE joined BPA and other utilities and issued a call for customers to conserve.[12] To the degree customers conserved, the Company would not have to replace the lost hydro or the Company could sell power to the market and use that to offset power costs. Around the same time, Jim Lobdell, of PGE, appeared before the Commission and described what the Company was doing to deal with the hydro shortfall:

> To manage the volatility of our hydro energy position, PGE Power Operations constantly monitors market fundamentals. As we reviewed these fundamentals in the fall of last year we noticed the existence of the El Nino condition and began gradually reducing the amount of estimated

[11] UE 180 PGE/1800/Lesh/27.
[12] UE 165 CUB/205/Jenks-Brown/1-3.

> hydro generation in our portfolio. This adjustment allowed us to purchase some of our replacement energy in advance of increasing market price levels therefore reducing our replacement energy costs by approximately $6 million.

UE 165 CUB/209/Jenks-Brown/1.

In 2001, PGE rates went up 30-50%. The combination of this price increase and a general economic recession caused PGE's load to fall. When the Company forecasted its load, it did not take into account the customer response to significantly higher rates. By 2002, however, it was clear that load was down significantly, which caused the Company to implement a cost-cutting effort. In January, 2002 PGE identified $14.8 million in cost reductions.[13] The Company's Capital Review Group set a goal to delay or cancel $16.1 million in capital projects and required that all "hiring whether a replacement or new position, must be approved by our CEO."[14]

This means, of course, that the utility has some ability to manage fluctuations in power costs. As described by PA Consulting, PGE has some ability to mitigate the risk of changes in power costs. The Company does not have full control over loads, the weather, or the gas and electricity markets, but PGE does control how it responds to loads, weather, and markets. In other words, it can mitigate some, but not all changes in power costs.

By proposing no deadband and asking customers to pay 90¢ of the first dollar of higher costs, the Company is failing to recognize that it does have some control over these costs, far more control than customers have. It is only when power cost variations become too great that they should be shifted onto customers.

[13] UE 139 CUB/100/Jenks/10.
[14] *Id*. at 11.

E. SB 1149

In support of the Company's new concept of risk – the risk that power costs are not trued-up – PGE suggests that a power cost true-up is what the legislature intended as part of SB 1149:

> The risk that a Commission must address when it uses test year ratemaking as part of its regulatory framework for a utility such as PGE is the risk that a utility's prices – and what customers pay for on-demand retail electricity services – will not reflect that utility's cost of service. A close connection between price and cost of service is a critical component of the regulatory bargain for both sides. Oregon's statutory framework is quite specific about the importance of cost: the Legislature has directed electric utilities to offer all of their customers a "regulated, cost-of-service rate option" (ORS 757.603(1)(a))…

UE 180 PGE/1800/Lesh/9. Footnotes omitted. Emphasis in original.

> Q. If adoption of a PCA mechanism does not shift cost of service risk between utilities and customers, is there another way to understand the parties' assertions regarding risk?
>
> A. Perhaps. The parties' assertions may reflect a view of the on-demand retail electricity service that PGE must offer our customers different from PGE's view. We understand that product to be "cost of service" retail electricity, consistent with the Legislature's requirements adopted in 2001.

UE180 PGE/1800/Lesh/18.

PGE is attempting to suggest that its proposal, which includes a power cost true-up without a deadband, is consistent with the legislature's mandate to provide cost-of-service rates.[15] The legislature, however, never intended this. SB 1149 grew out of docket UE 102, where PGE advocated for retail deregulation. In that docket, PGE opposed allowing customers to retain even an option of cost-of-service rates, and so there was a great deal of discussion about cost-of-service rates. Cost-of-service rates were

[15] The original legislative mandate required cost-of-service rates for residential and small commercial customers and was contained in SB 1149 which passed in 1999. The 2001 Legislature delayed implementation of SB 1149, and broadened the requirement of cost-of-service rates to other customers.

viewed as the form of ratemaking that currently was in place. In UE 102, the Commission rejected PGE's proposal and retained cost-of-service rates for residential customers:

> The cost basis for the rate would derive from the cost of resources retained by PGE, plus market purchases or sales needed to match loads and resources, plus the cost of any BPA purchases dedicated to eligible residential and small farm customers. Transition costs would also be included in the calculation of the rate. The rate would be regulated by the Commission under the statutory standard that rates must be "just and reasonable."

UE 102 OPUC Order No. 99-033, page 31.

PGE, however, opposed offering cost-of-service rates. In its Order, the Commission describes PGE's position:

> PGE and other parties assail Staff's cost-of-service rate proposal as a vestige of regulation at odds with the movement towards real competition. Moreover they argue that the cost-of-service rate could distort the market. The assignment of certain supply assets, in this case hydroelectric assets, to serve the one rate could guarantee that the rate is lower than market rates. According to the opponents, such a rate would be artificially low - the product of government fiat rather than the product of efficiency and innovation … PGE also argues that a cost-of-service rate is not necessary as a default because a governmental body or other entity could aggregate to provide a default service. PGE also claims that the pressures of the market would cause ESPs to shield customers from the price volatility feared by Staff. In any event, PGE argues, changes in market prices are beneficial as price signals which increase efficiencies.

UE 102 OPUC Order No. 99-033, page 32.

The reason that SB 1149 contained a requirement for cost-of-service rates for residential and small commercial customers was simple: PGE wanted to take away traditional ratemaking that set rates based on a forecast of the cost of the utility's generation assets and market purchases, and instead kick all customers out into a retail market. PGE also believed that the Commission had the power to eliminate traditional ratemaking, and force customers into the retail marketplace for electricity. In the development of SB 1149, it was CUB that advocated for the cost-of-service requirement, because we wanted to ensure that residential customers could continue to purchase electricity from PGE at prices that were based on a forecast of costs. It had nothing to do with a rate true-up through a PCA.

This of course, does not mean that cost-of-service ratemaking is incompatible with a PCA, a deferral, or even an AFOR, but it is clear that cost-of-service ratemaking does not require a PCA with no deadband, as PGE suggests.

III. The Deadband In A PCA

The Commission has clearly stated policy reasons for the use of a deadband. In UM 1071, the Commission called for a deadband in deferral dockets "reasoning that the band represent[s] risk assumed, or rewards gained, in the course of utility business."[16] In UE 165, the Commission called for a deadband for a PCA to limit recovery to "unusual" events.[17] Both of these share the same policy basis. Under normal circumstances, the utility takes the risk of variations in costs from what was forecast. In circumstances that are outside the normal course of utility business or are unusual, this risk can reasonably be shifted to customers. A deadband is used to represent this normal course of utility business and to define what constitutes unusual. Recent dockets that have adjusted rates to recover the difference between forecasted power costs and actual power costs have reflected this policy view and included a deadband. This has been true of both deferrals and PCAs.

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[16] UM 1071 OPUC Order No. 04-108, page 9.
[17] UE 165 OPUC Order No. 05-1261, page 9.

A. PGE Tries To Dismiss The Commission's Use Of A Deadband

PGE tries to ignore the Commission's history of using a deadband by arguing that none of these precedents count.

i. Deferrals Don't Count Because A Deferral Is Not "An Automatic Adjustment" [18]

A deferral is a mechanism that allows recovery of costs between rate cases. The policy view that a deadband represents the normal risk that a utility will take between rate cases is true of both deferrals and PCAs. PGE states that UM 995, UM 1071, and UM 1187 don't count as precedents, because they were deferral dockets,[19] but the policy reason for establishing a deadband is the same in a deferral as in an automatic adjustment clause. While it could be argued that a PCA, because it is not as one-sided as a deferral, might include a different deadband, there is no good policy reason why a deferral should have a deadband and a PCA should not.

ii. UM 1008/1009 Don't Count Because They Contained A Stipulation[20]

We strongly object to PGE's complaint that we cite UM 1008/1009, "but should not because the parties here all signed that stipulated result and agreed that it would not serve as precedent."[21] The stipulation in UM 1008/1009 states:

> This stipulation represents a settlement and compromise of the positions of the parties with respect to the matters contemplated by this stipulation. Accordingly this Stipulation may not be cited or used as precedent by any party or any person in any proceeding.

UM 1008/1009 Stipulation, page 8.

CUB did not cite the Stipulation. We noted that the Commission used a deadband in UM 1008/1009, but made no reference to the stipulation, the parties who signed the

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[18] UE 180 PGE/1800/Lesh/43.
[19] *Id.* at 43-44.
[20] *Id.* at 43.
[21] *Ibid*.

stipulation, or anything solely found in the stipulation.[22] It is not a violation of the stipulation to say that the Commission issued an order that included a deadband. The Commission itself cites UM 1008/1009 as precedent in its Order in UE 165.[23] Ironically, the only party we know of that has directly violated this term of this stipulation is PGE in its UE 180 Opening Testimony, where the Company directly cites the stipulation:

> PGE stipulated to a dead-band in another deferred accounting request (Docket UM 1008/1009).

UM 180 PGE/400/Lesh-Niman/41.

The stipulation does not prohibit parties from referring to the docket or the Commission Order in the docket, which is what CUB did. While this may be a legal issue, we do not think a stipulation can prohibit a party from citing a published Commission order. The stipulation in UM 1008/1009 prohibits parties from citing the stipulation. CUB did not do that; PGE did.

The bigger issue, however, is that dockets that end in stipulation exist, and are part of the record of this Commission. As a stipulation often represents a compromise of a party's position based on an evaluation of the entire contents of the stipulation, it may not be fair to single out a particular part of a stipulation and use that as evidence of a binding precedent for that party's position in a later docket. However, to suggest, as PGE does, that any docket that includes a stipulation must be removed from the public record is not a reasonable position.

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[22] UE 180 CUB/200/Jenks-Brown/16, 20 & 22.
[23] UE 165 OPUC Order No. 05-1261, page 9 footnote 42.

iii. UE 137 Doesn't Count Because PGE Withdrew It Before A Final Decision

In UE 137, PGE filed for a PCA and included a deadband in its proposal.[24] Staff proposed a different mechanism with a 250 basis point deadband and 50/50 sharing up to 400 basis points.[25] CUB argued that, because PGE had the highest rates in the region for a major utility, a PCA should contain an asymmetrical deadband that would only allow the Company to recover additional costs under extreme circumstances.[26] While PGE withdrew its proposal prior to a Commission Order, the Company did so only after a record was established that supported a deadband – no party argued for a PCA that did not contain a deadband.

iv. UE 115/UE 143 Don't Count Because They Contained a Stipulation

In UE 115, the PUC established a 15-month PCA. PGE claims that, because it was a stipulation, it does not count as precedent.[27] Regardless, in its Order, the Commission established a PCA with a $28 million deadband.

> …the Commission adopts a Power Cost Adjustment (PCA) mechanism that will lower rates if the company's power costs decline. The PCA establishes how PGE will account for variations between expected power costs included in base rates and actual power costs, and describes the method by which the company and its customers will share in the benefits and burdens of such variations. This mechanism will track the fluctuations in power costs and require a refund to customers of overcollections exceeding a preset amount.

UE 115 OPUC Order No. 01-777, page 2.

It should be noted that, in this circumstance, PGE's rates were to go up 30-50%, and the Order is clear that the Commission believed the PCA would reduce rates as market prices came back down from record levels. Nevertheless, the Commission and

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[24] UE 180 Staff/800/Galbraith/10.
[25] UE 137 Staff/100/Galbraith/4.
[26] UE 137 CUB/100/Jenks/8-9.
[27] UE 180 PGE/1800/Lesh/46.

the parties still included a $28 million deadband and a 50/50 sharing band of another $10 million.[28] CUB supported this because we believed that the deadband represented the normal risks and rewards of utility business.

v. UE 165 Doesn't Count Either

UE 165, a docket concerning a power cost adjustment, presents a little more difficulty for PGE, and the Company had to stretch to identify reasons why UE 165 does not apply to its proposed PCA. Though UE 165 contained a stipulation, the Commission rejected the stipulation, and instead described design criteria for a hydro-related PCA. PGE begins its discussion of UE 165 pointing out that the Commission's Order does not require a deadband in any tariff the Company files for a PCA.

> Q. Do you agree that Order No. 05-1261 requires that any tariff PGE might propose to address the differences between actual and assumed NVPC must include a deadband?
>
> A. No, we do not for two reasons. First the Order states: "The inclusion of a deadband around expected power costs is a reasonable way to identify whether an event is unusual." Order No. 05-1261 at 9 (emphasis added). The parties imply that "a reasonable way" actually reads "the only reasonable way." This is not what the order says.

UE 180 PGE/1800/Lesh/46.

PGE misses the point. The key issue is not whether the Commission is saying a deadband is "the only reasonable way," "a reasonable way," or "one of a thousand reasonable ways." The key point is the rest of that sentence. A deadband is a reasonable way "to identify whether an event is unusual." (Emphasis added.) PGE offers no other way – reasonable or not – to identify whether an event is unusual. Instead, PGE ignores the Commission Order's intent to limit a PCA to unusual events, and instead proposes a PCA that would shift the risk of power cost variations onto customers in the most usual

[28] UE 115 OPUC Order No. 01-777, Appendix D, page 19.

of circumstances. In fact, with no deadband, it would be an unusual year indeed that did not activate the Company's proposed PCA.

Commission decisions concerning a deadband within a PCA or a deferral have consistently called for a deadband as a way to limit the mechanism to unusual and extraordinary circumstances, both by measuring the financial impact of the event and by ensuring that the utility bears the normal risk of power cost variation. We agree with PGE that the Commission has not declared a deadband to be the absolute, only way to limit PCAs and deferrals to unusual or extraordinary circumstances, but the Commission has been consistent that the goal is to limit the mechanisms to unusual events.

The second reason PGE discounts UE 165 is that the Commission referred to "expected power costs," so this "design criterion appears to apply only when the Commission has used expected power costs for forecasting test year NVPC."[29] PGE's conclusion, that it appears that the Commission meant to only apply a deadband when the Commission uses "expected power costs for forecasting NVPC," is convenient. Since no utility in Oregon uses expected power cost modeling (stochastic) for power costs, the Commission's design criteria can be ignored. However, the Commission also has used the term "expected power costs" when referring to the UE 115 PCA, when PGE was modeling power costs in a similar manner as today:

> It also establishes a mechanism by which PGE will account for variations between expected power costs included in base rates and actual power costs, and the method by which the company and its customers will share in the benefits and burdens of such variations.

UE 115 OPUC Order No. 01-777, page 6.

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[29] UE 180 PGE/1800/Lesh/46.

However, the policy behind the design criteria – to limit the transfer of risk to unusual events – should not be ignored, and has little to do with whether a utility uses a deterministic or stochastic forecasting model. Again, Commission decisions in recent years have been consistent.

vi. PGE's Additional Policy Reasons For A PCA with No Deadband

PGE makes two arguments as to why a PCA benefits customers, and neither is a good argument:

> Q. Does reducing cost of service risk for customers have any benefits?
>
> A. Yes. Reducing cost of service risk for customers has at least two benefits consistent with sound regulatory policy. First, reducing this risk means that, on a relatively current basis, cost of service prices will more closely reflect cost of service. The resulting price signal will enable better consumption decisions. Second, reducing this risk also improves inter-generational equity among customers because we have no idea how the outcomes of actual NVPC will array themselves around the forecast NVPC. Customers could, for 10 years, experience the risk of actual NVPC lower than those forecasted only to have this flip in the following 10 years. Over 20 years, the customer base is likely to undergo significant change.

UE 180 PGE/1800/Lesh/31.

a. Price Signals

Rather than improve price signals to customers and enable better consumption decisions, a PCA obscures good price signals. Consumption decisions a customer makes today are based on the price that the customer is charged today. Adding a surcharge in a future year to recover costs associated with the current year will have little or no impact on current consumption decisions.

PGE proposes that the Company make a filing each June that calculates the PCA variance from the proceeding year. The Commission and other parties would have six months to review the Company's filing, and conduct an earnings test and prudence review. Rates would be adjusted the following January. This means that, for the current test year (2007), the PCA adjustment would happen beginning January 1, 2009. It is hard to see how this improves the price signal in 2007. In 2009, rather than charge customers the best available forecast for 2009, the Company would charge customers that forecast plus or minus the PCA variance from 2007. Again, it is hard to see how this improves the price signal in 2009.

In fact, it may send the wrong price signals. In a period of time where fuel or other costs are increasing, the PCA might amortize a credit from 2 years earlier that causes customers to miss the price signal that prices are increasing. In a period where costs are falling, the PCA might amortize a surcharge that hides the true price signal.

b. Intergenerational Equity

PGE's argument that a PCA improves intergenerational equity is also weak. A PCA inherently charges the wrong people for costs. Under a PCA, someone who moves into PGE's service territory could be charged a surcharge for costs that were incurred two years ago, and would pay for costs that person did not cause. Likewise, when someone leaves PGE's service territory, costs incurred that year would be charged in a surcharge two years later, and that person would not be responsible for paying them.

The two reasons PGE claims a PCA with no deadband benefits customers, actually are harms to customers. In both cases, a deadband would have the effect of benefiting customers by reducing this harm.

B. The Policy Reason For A Deadband

A deadband in a power cost adjustment mechanism serves two purposes: A deadband limits the mechanism to unusual and extraordinary circumstances by measuring the financial impact of the event, and it ensures that a utility bears the normal risk of power cost variation.

i. A Deadband Ensures That The Utility Bears An Appropriate Level Of Risk

PGE argues that no party had "demonstrated" that a deadband will produce benefits to customers:

> Q. Have the parties demonstrated that not reducing this cost of service risk, or reducing it only partly by applying a deadband, will produce benefits for customers?
>
> A. No. No party has attempted such a demonstration.

UE 180 PGE/1800/Lesh/31.

We disagree. We believe the parties, as well as PGE's consultant, PA Consulting, have made a compelling case that a PCA shifts the risk of cost variations from the Company to customers. This cannot be considered a benefit for customers. However, we repeat, under some circumstances it is appropriate to shift some of this risk onto customers. A deadband and sharing are an effective way to limit any shifting of risk to only those circumstances that warrant such a shift.

ii. Deadband Equivalent To Basis Points Of ROE Used To Define Unusual Events

PGE argues that it is unfair to put a utility's distribution earnings power at risk through a PCA deadband.[30] Parties often design a deadband using basis points of return on equity (ROE) applied to a utility's entire rate base, instead of only the generation portion of rate base. PGE argues this is unfair, but, of course, opposes any deadband at all, whether applied to generation rate base, or all rate base.

Again, PGE misses the point. The reason to use basis points of ROE to define a reasonable deadband is that this can measure an unusual event, and do so in a manner that

[30] UE 180 PGE/1800/Lesh/49.

is fair to a variety of electricity providers.[31] CUB could propose a $30 million deadband as a way to limit the shift of risk associated with a PCA for PGE, but such a proposal would offer very little guidance when examining PacifiCorp or Idaho Power. We could try to define it as a percentage of revenue and call for a deadband of 2% of retail revenue, but this would hit PGE harder than PacifiCorp or Idaho Power because PGE has higher rates.

CUB supports the use of ROE, as it relates to a utility's entire rate base, to identify unusual circumstances, because it is a simple way to represent the normal risk of power cost variation, and the magnitude of the band would be proportional according to the size of the utility. After discussing this issue for five years, we do not see another alternative that appears to work better. It may be that Staff is correct, and that stochastic power cost modeling will give us a better tool for defining unusual events. Regardless, we do not have stochastic modeling in this case, and PGE offers no alternatives, as the Company prefers to abandon the practice of limiting these mechanisms to unusual events.

C. The Policy Reason For An Earnings Deadband

In UE 165, the Commission proposed a PCA earnings deadband that would prevent adjustments to rates if the utility's earnings were within 100 basis points of its approved ROE. PGE opposes this design criteria:

> It restores some of the risk that a power cost adjustment mechanism otherwise would reduce. In other words, it decreases the probability for both our customers and PGE that our cost of service prices for on-demand retail electric service will reflect actual cost of service.

UE 180 PGE/1800/Lesh/58.

[31] Over the years, we have come to understand that one of the reasons Staff supports stochastic modeling is that such modeling would provide a more precise methodology for defining unusual events.

PGE then goes on to say that +/- 100 basis points of return on equity is not the earnings test used for natural gas companies' purchased gas adjustments, and no party has "articulated a reason why electricity customers and electric utilities should bear greater risk of cost-of-service variances than gas customers and gas utilities."[32]

First, in our Opening Testimony, CUB discusses the differences between gas utilities and electric utilities when it comes to the risks associated with costs being higher or lower than what was forecast.[33] Gas utilities do not own and manage generation supply. Gas utilities do not have rate base dedicated to gas supply. Gas utilities have more limited opportunities to mitigate changes in costs. Gas utilities have a different operational and risk profile than electric utilities, and a mechanism that is used for a gas utility cannot be assumed to be appropriate for an electric utility. Finally, it should be noted that the Purchased Gas Adjustment (PGA) mechanism has been under review through a series of workshops. At this stage in the review process, we are not willing to speculate on what a PGA mechanism will look like beyond the current year.

In addition to ignoring CUB's testimony that differentiates between an electric PCA and the annual purchased gas adjustment, PGE ignores the policy reason for an earnings deadband in general. Annual adjustments add volatility to rates. If a utility is earning a reasonable return, rate volatility should not be increased by charging or crediting customers. It is not unusual to look at a utility's earnings in relation to its return on equity as a range instead of a precise point. For example, the Alternative Form of Regulation (AFOR) adopted for PacifiCorp's Distribution costs in the 1990s had a +/- 250 basis point earnings band to define a reasonable range of earnings. While the

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[32] UE 180 PGE/1800/Lesh/59.
[33] UE 180 CUB/200/Jenks-Brown/10-11.

AFOR applied to distribution costs, the ROE deadband applied to all rate base. The AFOR allowed for modest increases in rates, inflation minus a productivity factor, but no other increases or decreases were allowed as long as the Company's earnings were within this 250 basis point range of its 10.0% ROE.[34]

CUB's proposed earnings deadband in this case serves a similar purpose. It is designed to recognize that, if a utility's earnings are within a reasonable range of its authorized return on equity, then no adjustment, with the ensuing rate volatility, is warranted. An AFOR has different attributes than a PCA. For example, a goal of many AFORs, including the PacifiCorp AFOR, has been to increase price stability by prohibiting general rate case increases, and a larger deadband contributes to this stability. For PGE's PCA we propose the +/- 100 basis point earnings deadband described by the Commission in Order No. 05-1261.[35]

D. PGE's Position On A Deadband Has Regressed

After five years of discussing the very same issues, PGE's stance in this case has retreated even further from those of other stakeholders.

In UE 115, a PCA was adopted that contained a deadband of $28 million with 50/50 sharing of variations up to $38 million. From $38 million to $100 million customer sharing was 85%. Only after the variation got to be greater than $100 million, were 90% of the costs allocated to customers.[36] PGE offers no explanation of why, during the height of the Western Energy Crisis, a PCA with a large deadband and multiple sharing tiers was a reasonable policy, but it is not today. PGE offers no explanation of why the Company could wait until there was a $100 million variation

[34] UE 94 Phase II OPUC Order No. 98-191, page 4.
[35] UE 165 OPUC Order No. 05-1261, page 10.
[36] UE 115 OPUC Order No. 01-777, Appendix D, page 19.

before costs would be shared 90/10 then, but today the first dollar must be shared 90/10. One possible explanation is that this was during the Western Energy Crisis, and it was generally believed that costs would fall and the PCA would pass through lower costs to customers. In the Summary of the Commission's Order in that case, the Commission twice suggests that the PCA would lower rates, but there is no reference to the PCA going in the other direction:

> In addition, the Commission adopts a Power Cost Adjustment (PCA) mechanism that will lower rates if the company's power costs decline…The mechanism will track the fluctuations in power costs and require a refund to customers of overcollections exceeding a preset amount.

UE 115 OPUC Order No. 01-777, page 2.

In UE 137, PGE proposed a PCA with a deadband of $22.4 million.[37] Staff and CUB each proposed a larger deadband, but the Company withdrew the docket before the Commission could rule on the appropriate size of the deadband. PGE states that this was based on the "deadband approach of the prior stipulated PCA."[38] In addition PGE argues that gas prices were lower in 2002 than they are today and high gas prices increase risk.[39] If the deadband approach is based on the UE 115 PCA, then this should be viewed as an acceptable division of risk, not based on 2002 prices, but on the record gas and electricity prices of the Western Energy Crisis.

In UE 165, the Company again proposed a deadband. First, PGE proposed a deadband of $2.5 million,[40] then the Company settled with Staff and proposed an

[37] UE 180 Staff/800/Galbraith/10.
[38] UE 180 PGE/1800/Lesh/45.
[39] *Ibid*.
[40] UE 165 CUB/100/Jenks-Brown/2.

asymmetric deadband of $7.5 million for costs that were lower than forecast and $15 million for costs that were higher than forecast.[41]

PGE has supported a deadband for five years, yet seems surprised that parties are opposed to its proposal to shift the risk of power cost variations to customers with no deadband at all. Compounding our frustration is the Company's failure to offer an explanation as to why its position on this issue has moved away from those of CUB, Staff, and the Commission. The Company has offered no answer as to why a deadband was justified in the past, but is not today. PGE offers no explanation as to why a PCA today should be more generous to the Company than what was considered reasonable at the height of the Western Power Crisis.

After discussing this very issue with the Company for five years we did not expect the Company's position to fall back. We thought the Commission's Order in UE 165 pointed the parties to a regulatory solution for power cost variations. Instead we are wasting yet another year debating a deadband in a PCA, except that this time we have regressed from discussing what an appropriate deadband should be, to discussing why a deadband is appropriate in the first place.

IV. CUB's Proposed PCA

Our original proposal for a PCA was made before the Commission issued the rules implementing SB 408. As we stated in our Opening Testimony, we believe it is appropriate to adjust a deadband for the impact of SB 408, as the amount covered by a deadband will no longer create a tax deduction that can be retained by the utility. As the Commission has now issued its Order, we update our proposed deadband and sharing

[41] UE 165 CUB/Jenks-Brown/4. We should note that, because CUB was not a party to that stipulation, CUB is free to cite it.

bands based on the impact of that Order. If SB 408 is changed and the benefits of these tax deductions remain with the utility, the deadband and sharing bands should revert to their original sizes.

- Deadband and Sharing Bands: We started using a deadband with an upper bound equivalent to +250 basis points of return on equity, because of the Commission's use of 250 basis points in the past for exceptional events, and the Commission's confirmation that this represents a reasonable amount for a utility to absorb. We now adjust that deadband by reducing it by 39.2% (PGE's effective tax rate). This reduces the deadband by 98 basis points, which we round off to 100. So the deadband becomes 150 basis points. We selected asymmetric bands in an attempt to make the mechanism revenue neutral over time and now adjust the -125 basis point deadband to -75 basis points. The sharing percentages are unchanged from our Opening Testimony.[42]

	Basis Points of ROE Equivalent		Sharing Customers - PGE
Deadband	above -75	below +150	0% - 0%
Inner Sharing Band	-120 to -75	+150 to +240	50% - 50%
Outer Sharing Band	below -120	above +240	90% - 10%

- Earnings Deadband: We recommend the same earnings deadband that is contained in our Opening Testimony, an earnings deadband equivalent to +/- 100 basis points of return on equity.
- Amortization Cap: Currently, amortization of deferrals is limited to 6% of rates so as not to place undue hardship on customers. This is also important for a power cost adjustment mechanism, and we recommend the same 6% cap in general, but ask the Commission to consider extenuating circumstances such as an economic recession when amortization may need to be extended.

[42] UM 1008/UM 1009 OPUC Order No. 01-420, page 5.

- A Prudence Review: A prudence review before amortization is an important regulatory check. The review would focus on whether the incurred power costs were part of a prudent response to conditions.

V. RVM or Annual Update

A PCA is only one form of updating rates between general rate cases. The RVM (or what PGE now proposes to call the Annual Update) is another. PGE proposes to continue updating the Company's variable power cost forecast every year with no deadband or sharing. Between general rate cases, PGE is asking customers to take on 100% of the forecasted changes in costs, and 90% of the variation from that forecast. Both in the Company's Rebuttal and in the NERA report included in the Company's Opening Testimony, PGE fails to take into account the effect of its annual RVM.

For example, the table presented in Section II.C., which lists dockets that have changed the cost-of-service rate between rate cases, shows the annual adjustments made through the RVM. When discussing a utility in another state that has a PCA with a sharing mechanism, it is important to know whether that utility has an RVM-like mechanism. In 2006, PGE's RVM passed through to customers an increase of $140 million in costs. A utility with a PCA that had a 90/10 sharing arrangement, but without an RVM, would have had to absorb $14 million of that increase.

Annual variable power cost updates and power cost adjustment mechanisms both shift the risk of power cost variability from shareholders to customers. A power cost update does so on a prospective basis, and a power cost adjustment does so on a retrospective basis. We do not believe it is good policy to adopt both. Under PGE's proposed regulatory framework, we would have two simultaneously open dockets each year, one that sets the forecasted costs for the following year and one that addresses the actual costs from the previous year.

As the Commission is well aware, the RVM process has been far more burdensome than we anticipated, and we have little doubt that an annual PCA docket would also be burdensome. The regulatory burden created by PGE's proposal is worrisome and unnecessary. CUB believes that if a PCA were to be adopted, then PGE's annual power cost update, call it an RVM or an Annual Update, should be eliminated. One annual regulatory proceeding to allocate power costs between rate cases is more than sufficient.

VI. The Prudence Of Port Westward

In CUB's Opening Testimony, we raise the concern that PGE has not sufficiently made the case that the inclusion of Port Westward is prudent in light of other actions taken consistent with PGE's most recent acknowledged IRP.[43] In this case, where the prudence of Port Westward is at issue, PGE has not provided any evidence in the record that it has acquired or will acquire the resources included in the Company's IRP action plan.

In its Rebuttal, PGE says that it met its prudence showing by sending CUB an LC 33 compliance filing on March 23, 2006.[44] First, a showing of prudence must be made in the proceeding where the prudence determination is being made. Second, we are not sure that what PGE has provided is yet sufficient. When the Commission acknowledged (with conditions) PGE's 2002 IRP in LC 33, the Commission said that acknowledgement…

[43] UE 180 CUB/200/Jenks-Brown/26.
[44] UE 180 PGE/1900/Tinker-Schue-Drennan/56.

> … means that the specific resource actions, when combined with other action items, should result in "the mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs."

LC 33 OPUC Order No. 04-375, page 12, quoting OPUC Order No. 89-507, page 2.

In other words, what is being acknowledged is a combination of action items. It is not a sufficient evidentiary record for the purposes of a prudence finding to say that a gas plant is a good idea. A gas plant is a good idea if the increased risk of relying on additional natural gas is partially offset by acquiring resources that have no commodity cost. The prudence of one resource is dependent on the prudence of the whole plan.

PGE tells us that it is currently 38 aMW short of its 2002 Action Plan goal of additional wind resources.[45] While there is time left remaining before the end of 2007, we were looking for an update on the wind resource so we could verify that PGE is indeed on its way to meeting the expectations of the best combination of expected costs and variance of costs. PGE's proof of this is the Commission's approval of a utility property sale.[46] This doesn't really tell us how PGE is progressing toward its optimal resource diversity.

In fact, in other parts of the filing, there is an implication that PGE may not be successful in completing the wind project before 2007. The MONET run of forecasted power costs does not include any wind in the system beyond that of the pre-existing Foote Creek. Does this indicate that PGE's plans for Biglow Canyon are not far enough along to warrant any assumptions? Does PGE think that Biglow Canyon may come on-line the last day of 2007, and so it does not impact the 2007 power cost MONET run? In any case, prior to adding a major generating resource to rate base, it is necessary to

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[45] UE 180 PGE/1900/Tinker-Schue-Drennan/57.
[46] *Ibid*.

establish a relationship between that resource and other resources that are called for in the Company's IRP. PGE has not adequately done this.

Though we are not comfortable that the Company's investment in Port Westward is prudent in the context of PGE's actions to implement its Integrated Resource Plan, we cannot yet say that Port Westward is definitely an imprudent investment. The prudence of such an investment will become more clear over time, as PGE does or does not acquire the renewable resources it needs in order to achieve the fuel diversity that is envisioned in its Integrated Resource Plan.

In CUB's Opening Testimony, we recommend that the Commission place three conditions on Port Westward rate recovery, and here we recommend a fourth:

1. As the Commission expects Port Westward to be used and useful early in this test period, the tariff associated with Port Westward will only be valid within 30 days of March 1, 2007;
2. If Port Westward is not used and useful within 30 days, the Company must reopen UE 180. Staff and intervenors should be given a limited period of time to review the Company's actual costs to determine whether there is new information that requires a reexamination of PGE costs before Port Westward is included in rates;
3. If, after six months, Port Westward is not used and useful, the Company must file a new rate case in order to add the plant to rate base; and
4. If PGE fails to achieve the fuel diversity that was envisioned in the Company's IRP, the prudence of Port Westward should be revisited.

These conditions alleviate the problem of establishing a revenue requirement before the cost in question becomes legally recoverable, and before the cost is even relevant. The fourth condition makes clear that the prudence of the Company's investment in Port Westward will be revisited in the future, and depends upon PGE's pursuit and completion of the other items in its Action Plan that, together with Port Westward, make up an integrated resource portfolio.

VII. Advanced Metering Infrastructure

In the Company's Rebuttal Testimony, PGE tweaks its business case for advanced metering, and attempts to deflect CUB's arguments that compare PGE's business case for advanced metering to those of a few California utilities. The result is a minor rearrangement of cost and O&M estimates, the removal of a book value write-off assumption (which accounts for $12 million of the $16 million increase in net present value for PGE's updated AMI business case),[47] and a cursory brush-off of CUB's fundamental concerns.

A. PGE Provides No Fundamental Defense Of Its Business Case

In refuting CUB's argument that PGE had not adequately taken into account other utilities' business cases on AMI, PGE dismisses each example, and, in so doing, completely misses the fundamental concern that CUB was demonstrating. PGE distances itself from Pacific Gas and Electric's (PG&E), San Diego Gas & Electric's (SDG&E), and Southern California Edison's (SCE) business cases on advanced metering by providing a single example of why PGE is not exactly like each of these utilities. No one suggested that PGE is. We do, however, suggest that PGE could learn from the extensive business cases prepared by these western, investor-owned utilities.

To excuse itself from a comparison with PG&E's business case, PGE simply points out that PG&E includes a contingency in its estimate, and that PGE does not. However, neither utility has undertaken a project that required every meter for every

[47] UE 180 PGE/2300/Carpenter-Tooman/4.

customer to be replaced with a new and different technology. While much can be forecast and presumed, much is also unknown. With variables that are uncertain, PG&E felt it necessary to include a sizeable contingency in its business case. This is prudent on PG&E's part, and strengthens its business case. PGE points out that its business case does not include such a contingency. This does not strengthen PGE's business case. We understand the Company's dilemma, however, because PGE's business case is so tenuous – and, therefore, in need of a buffer – it cannot support a contingency.

The entirety of Southern California Edison's 2005 business case, which found advanced metering not to be cost effective,[48] is dismissed by pointing out that, in late August, SCE announced "its plans to begin an advanced metering initiative in 2007."[49] To be more precise, SCE has been examining advanced metering for a number of years, and plans to begin field testing a new generation of meters in 2007. CUB Exhibit 301 is an SCE press release from August 21, 2006. SCE's Conceptual Feasibility Report, from August 2006, goes into great detail as to why the utility now finds advanced metering to be cost effective, when its earlier analysis had not. CUB Exhibit 302 is an excerpt from this report. The lynchpin of SCE's new business case is "the rapid evolution of metering and communication systems technology over" the last eight months.[50] SCE's plan to field test a new generation of meters is a far cry from PGE's description of its plan to install "a mature technology," asserting that "PGE would not be a pioneer in the field of AMI."[51]

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[48] UE 180 CUB/209/Jenks-Brown/1.
[49] UE 180 PGE/2300/Carpenter-Tooman/12.
[50] UE 180 CUB/302/Jenks-Brown/2.
[51] UE 180 PGE/800/Hawke-Carpenter-Tooman/2.

In dismissing San Diego Gas & Electric's business case, PGE misses CUB's point. PGE explains that SDG&E, like PG&E and SCE, has a regulatory impetus to examine demand response benefits in examining advanced metering, and that PGE has not included demand response in its business case.[52] Apparently this is enough to make SDG&E's business case irrelevant. CUB's point, however, is not that PGE's business case doesn't exactly mirror SDG&E's business case. CUB's point is that neither PG&E, SDG&E, nor SCE found advanced metering to be cost effective without demand response programs.[53] In light of this, it seems odd that PGE's business case <u>does</u> find advanced metering cost effective in the absence of demand response programs.

PGE fails to explain why its business case for advanced metering shows the program to be cost effective without time-of-use pricing, critical-peak-pricing, or load control, when California utilities have found that these programs are necessary to make advanced metering cost effective. Certainly, PGE is not identical to Southern California Edison, but PGE has not presented an analysis to differentiate its operations from those of its California counterparts, such that the parties can understand why advanced metering is comparatively less cost effective for those utilities than it would be for PGE.

B. PGE's AMI Business Case Update Is No Better

In rebuttal, PGE updates its estimate for the initial system cost, O&M savings, and end-of-period book value. The $16 million drop in projected system cost is based on prices provided by meter vendors, and the $1 million decrease in savings is based on PGE's O&M assumptions.[54] The combination of these factors increases PGE's estimated

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[52] *Ibid*.
[53] UE 180 CUB/200/Jenks-Brown/40.
[54] UE 180 PGE/2300/Carpenter-Tooman/2-3.

net present value of advanced metering by $4 million.[55] PGE also removes the Company's assumption that the remaining book value at the end of the 20-year period would be written off.[56] This increases PGE's estimated net present value by $12 million, bringing the Company's business case to a net present value total of $20 million over 20 years.[57]

This final so-called "update," which accounts for 75% of PGE's new-found net present value, does not hold water. The Company assumes that this new system will be at the end of its useful life and ready to be replaced with new meters in 2026. In PGE's Opening Testimony, the Company's case assumed that, in 2026, there would be meters and equipment that had been installed during the life of the project, but had not been fully amortized by 2026. These meters and equipments would need to be replaced as part of a new system in 2026, and so their book value written-off. In the Company's Rebuttal, PGE's AMI business case removes this assumption altogether.[58]

There are two problems with this. First, PGE is assuming that this system will last 20 years, but the Company's last AMI system, approved in UE 115, lasted about 5 years. SCE plans to install "first-in-the-industry, two-way home communications devices."[59] Jesse Berst, advanced metering proponent, writes: "This is a dangerous time to be a metering buyer," and "The sector is in such turmoil – and so many people are blind to what's around the corner – that a utility can easily end up with a dead end system."[60] Considering that PGE's initial estimate of not writing off the AMI system

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[55] *Id.* at 4.
[56] *Id.* at 3.
[57] *Id.* at 4.
[58] *Id.* at 3-4.
[59] UE 180 CUB/301/Jenks-Brown/1.
[60] UE 180 CUB/211/Jenks-Brown/1.

until 20 years appears to be decidedly optimistic; not writing it off at all stretches this optimism even thinner.

Second, even if the system were to last until 2026, when PGE replaced it, the system would include meters and equipment that hadn't been fully amortized. In PGE's current proposal, the meters are assumed to have an 18-year life, and so meters added to the system after 2008 would not have had the full 18 years of amortization. It is unlikely that PGE's service territory would stop growing in 2008; there will most likely be new houses and new meters that would not be amortized over the full 18 years.

PGE could recognize this by assigning a shorter expected life to these meters, *i.e.,* meters installed in 2009 would have a 17-year life, those installed in 2010 would have a 16-year life, and so on. The Company could also assume, as it did in its Opening Testimony, that there is some equipment that has to be written off in 2026. In Rebuttal, however, PGE instead completely removes these unamortized costs from its business case. The costs would still be there, but PGE is not recognizing them in its analysis which shows its proposed AMI investment to be cost effective.

The Company states that the assumed 18-year meter life already includes a significant amount of replacement costs, and that "the net present value (NPV) of the proposed AMI system is already burdened with the write-off of a system – the status quo system."[61] This is not a good reason to ignore costs the Company proposes to put on the system. If PGE plans to ask customers to pay for these costs, they belong in the Company's business case.

[61] UE 180 PGE/2300/Carpenter-Tooman/4.

C. PGE Does Not Address CUB's Fundamental Concerns

Though PGE updates a few of its business case numbers, the Company fails to address some of the fundamental concerns expressed by CUB that go to the foundation of PGE's AMI proposal. PGE fails to substantiate its business case as being solid in light of other utilities' findings, its assessment of the state of the industry as mature, or its decision that this is an appropriate time for PGE, as a specific utility, to invest in an advanced metering system.

As quoted earlier, PGE assures the parties that AMI is a "mature technology,"[62] yet twice in the Company's Rebuttal, PGE touts the value of "timely information," suggesting that a little temporal change can make a significant difference.[63] One of these references relates directly to the evolving technology of advanced metering, as PGE points to SCE's August AMI announcement. Certainly, technology is always changing and to wait for the perfect meter is to wait forever, but this does not mean that there is never a time to wait. Despite PGE's assurance of the maturity of AMI technology, the Company's own experience with advanced metering, SCE's research into advanced metering, and even AMI supporter Jesse Berst's view of AMI, all suggest that advanced metering is in a state of rapid evolution.

PGE's current AMI proposal includes a plan to write off, at customers' expense, meters installed as part of the Company's last foray into AMI.[64] Some of these meters were purchased as recently as 2004.[65] SCE's business case is based on advanced

[62] UE 180 PGE/800/Hawke-Carpenter-Tooman/2.
[63] UE 180 PGE/2300/Carpenter-Tooman/11-12. "In short, this is simply an example of the relevance of timely information." & "This, however, is another example of the relevance of timely information."
[64] UE 180 PGE/800/Hawke-Carpenter-Tooman/7. UE 180 CUB/200/Jenks-Brown/39-40.
[65] UE 180 CUB/204/Jenks-Brown/2.

metering capability that hasn't yet been field tested,[66] and Jesse Berst describes the advanced metering industry thus:

> Everything in this sector is changing – regulations, pricing, business models and, of course, technology. It's exciting, but confusing and risky as well.

UE 180 CUB/211/Jenks-Brown/1.

SCE, concerned about the significance of investing in a rapidly evolving technology, actively participates with vendors, utilities, and regulators, as well as collaborative groups such as OpenAMI, UtilityAMI, and AMI MDM, to both understand and shape the development of metering technology.[67] In its August Feasibility Report, SCE writes:

> If the AMI products and services obtained by SCE are inconsistent with the AMI technology adopted and used by most of the utility industry, then SCE would face the risks associated with having something that is "one of a kind." … The open collaboration approach is not intended to discourage development of niche products, which may be of value and use to utilities, but to affirmatively encourage development of products and services that have broad utility appeal by meeting not only SCE's basic requirements but the basic requirements of many other utilities as well.

UE 180 CUB/302/Jenks-Brown/38-39.

To the best of our knowledge, PGE's metering system is working fine, and PGE does not suggest in its testimony that a weakness in the current system is prompting the Company to look at other options. On the other hand, PGE enjoys the benefit of a joint meter reading program with NW Natural; it has a single-state, contiguous, compact service territory; and the Company plans to add Port Westward to its rate base in 2007 adding significant upward pressure on the Company's already-high rates. Given PGE's

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[66] UE 180 CUB/301/Jenks-Brown/2.
[67] UE 180 CUB/302/Jenks-Brown/38-39.

circumstances and rapidly evolving state of metering technology, this is not the time for PGE to embark on an expensive program to install an advanced metering system.

D. PGE Testimony

We take issue with a number of arguments that PGE makes to support its AMI proposal in its Rebuttal Testimony, especially the Company's position that asking the Commission for acknowledgement here is neither unusual nor supportive of future expenditure prudence; that CUB's use of Jesse Berst's editorial is inappropriate because Berst supports current AMI implementation; and PGE's continued suggestion that NW Natural will soon abandon its joint meter reading arrangement with PGE.

i. Prudence

In this rate case docket, PGE is asking the Commission:

> to acknowledge that the move to AMI technology is correct at this time.[1]
> 1. PGE is referring to an acknowledgement similar to that received for Port Westward in Commission Order No. 04-375, Docket LC 33.

UE 180 PGE/2300/Carpenter-Tooman/8.

What does "acknowledgement" in a rate case mean? The integrated resource planning process involves many parties; an in-depth look at the utility's system, loads, and resources; an assessment of market fundamentals; an exploration of possible circumstances, such as carbon regulation, that might impact the utility's operation; and a lengthy report to the Commission on the findings. In contrast, in support of its AMI proposal, PGE presents brief opening and rebuttal testimony, and will provide sur-surrebuttal testimony. Rather than a collaborative process that attempts to make sure the analysis is right, a rate case results in opposing analytical view points.

We think that an IRP is a better process to determine the appropriateness of a major investment, and a rate case is better used to determine its prudence. We are also concerned that "acknowledgement" in a rate case may actually mean more than "acknowledgement" in an IRP. In addition, resources such as load control, which may be integral to an AMI business case, are typically explored in a utility's IRP process. A rate case does not appear to be the proper proceeding to ask for acknowledgement, and we are not sure what the implication might be of any acknowledgement or approval that resulted from this process.

CUB is concerned that PGE, in a future proceeding addressing the inclusion of advanced metering costs in rates, would point to the Commission's "acknowledgement" of the Company's AMI plan in this docket as a reason the Company's expenses were prudently incurred. PGE finds CUB's concern to be a "speculative assertion," that "it would be disingenuous for PGE to make such a claim in the future," and that the Company has "no intention of doing so."[68] Yet PGE notes the Commission's acknowledgement of a gas plant in LC 33 and waiver of OAR 860-038-0080 when defending the inclusion of Port Westward costs in rates.

> Commission Order No. 04-376 approved inclusion of Port Westward in the revenue requirement on a cost basis. [note: this statement is incorrect, see CUB/200/Jenks-Brown/24.]

> Development of an approximately 400 MW G-class combine-cycle combustion turbine (CCCT) facility was a major element of the Final Action Plan, which the Commission acknowledged in Order 04-375.

> In Order No. 04-375, the Commission acknowledged the following action items: Build or acquire 350 MWa of a high efficiency gas-fired resource.

UE 180 PGE/300/Quennoz-Schue/35, 39, and 41 respectively.

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[68] UE 180 PGE/2300/Carpenter-Tooman/9.

> … LC 33, the docket under which the Commission acknowledged PGE's Final Action Plan.

UE 180 PGE/1900/Tinker-Schue-Drennan/56.

We find it difficult to imagine that, if the inclusion in rates of costs associated with AMI were in question, PGE would not mention the Commission's acknowledgement of the Company's initial decision. This is especially true given the Company's claim that:

> It would, however, be unreasonable for PGE to proceed with full deployment of AMI, without this acknowledgement, only to be informed in a subsequent rate case that the system was entirely inappropriate and all costs are disallowed…

UE 180 PGE/2300/Carpenter-Tooman/8.

Apparently, PGE is not planning to rely on the Commission's acknowledgement of the Company's AMI decision in this docket to support inclusion of AMI expenses in rates at a later date, but PGE does not want to be in the position of having <u>all</u> AMI costs disallowed. Should the Commission acknowledge PGE's decision to proceed with AMI, and should any portion less than 100% of PGE's AMI costs be in question for disallowance, we trust the Company will not cite any Commission acknowledgement that might result from this docket.

ii. Jesse Berst's Editorial

CUB cited an editorial by Jesse Berst, a supporter of advanced metering, to counter PGE's argument that now is the time for PGE to implement advanced metering. The statement we referred to was Berst's estimation that meter prices would drop by 50% by 2009.[69] Berst's editorial was written in February 2006, yet PGE argues that, without a starting price, these price reductions "may have already been 'wrung out' of the

[69] UE 180 CUB/200/Jenks-Brown/46.

market."[70] It is certainly possible that Berst's envisioned price drop over 4 years somehow got compressed into the past 6 months, but that's not an assumption we would hang our hats on.

In addition, PGE argues that CUB's point about meter prices cannot be used to oppose advanced metering, because "citations should be made within the context of an entire article."[71] PGE's point is that, if Berst's article supports current investment in advanced metering, his forecast for meter prices is not properly used in an argument against current investment in advanced metering. According to PGE, when opposing an idea, one may not use information from a text supporting that idea to make one's argument.

iii. Joint Meter Reading Arrangement With NW Natural

NW Natural's shared meter reading arrangement with PGE is an issue in this discussion, but it is not the issue PGE makes it out to be. If PGE abandons its joint meter reading arrangement with NW Natural, NW Natural would have to invest an additional $4.6 million in capital expenditures and an additional $1.6 million in annual O&M.[72] These are costs that would be paid by NW Natural customers, and this cost should be accounted for when evaluating the cost effectiveness of PGE's advanced metering plan.

PGE would like to be able to point to a NW Natural plan to abandon the joint meter reading arrangement as an impetus for its decision to pursue advanced metering. Unfortunately, NW Natural has no such plan, and though PGE acknowledges this, the Company continues to suggest an imminence to NW Natural's shift to automatic meter

[70] UE 180 PGE/2300/Carpenter-Tooman/13.
[71] UE 180 PGE/2300/Carpenter-Tooman/13.
[72] UE 180 CUB/201/Jenks-Brown/1.

reading. Ostensibly when addressing how PGE is coordinating with NW Natural on PGE's plan to install an advanced metering system, PGE points out:

> In fact, through July 2006, NWN has deployed approximately 6,500 AMR meters within the joint meter reading area, at an approximate rate of 1,000 to 1,500 meters per month. Based on this, it appears that: 1) NWN plans to deploy their AMR system within the joint meter reading area at some point in the future, dependent on PGE's timing with AMI deployment, or 2) NWN's AMR deployment could surpass PGE's AMI deployment, which would require bilateral coordination between NWN and PGE in order to minimize costs for both companies.

UE 180 PGE/2300/Carpenter-Tooman/6.

Despite the fact that PGE conditions its statement with the vague phrase "at some point in the future" (2 years? 20 years?) and the obvious "dependent on PGE's timing," PGE's conclusion doesn't seem unreasonable, given that NW Natural is already installing advanced meters, but wait. A few pages later in PGE's Rebuttal, the Company states:

> We now understand that NWN will not deploy their AMR system absent any change to the joint meter reading arrangement with PGE.

UE 180 PGE/2300/Carpenter-Tooman/11.

> NWN is deploying AMR meters within the joint meter reading area, albeit at new locations.

UE 180 PGE/2300/Carpenter-Tooman/11.

In case there is any uncertainty as to NW Natural's position on abandoning the joint meter reading arrangement, we provide an excerpt from NW Natural's response to Staff data requests.

> Should PGE decide not to install its proposed AMI system, in the short run NW Natural would continue with joint meter reading … NW Natural has not performed a revenue requirement analysis for an automatic metering system to read gas meters in the joint meter reading area. A preliminary analysis indicated that installation of a gas AMR system in the joint meter reading area would not be economic as long as the joint meter reading program continued in that area.

UE 180 CUB/201/Jenks-Brown/2.

NW Natural has given no indication that it plans to abandon its joint meter reading arrangement with PGE, so, should PGE choose to abandon the arrangement, that cost to NW Natural customers should be included in any cost/benefit analysis.

VIII. Forced Outage Rates

In CUB's Opening Testimony, we recommend the Commission normalize the Boardman event out of the forced outage rate by either using only three years to calculate the average, 2002-2004, or continuing to use four years, but using 2001-2004, years that are more representative of Boardman's normal operation.[73] In Staff's Opening Testimony, Maury Galbraith recommends using industry-wide averages of generating units of similar fuel and size to establish forced outage rates. Specifically, Staff recommends using North American Reliability Council (NERC) data to establish forced outage rates.[74]

Given that the parties and PGE disagree as to the proper treatment of the 2005-06 Boardman outage in Boardman's forced outage rate, using independently-produced numbers makes a great deal of sense. CUB has testified to our concern over the use of Company-produced forward price curves, as opposed to independently-produced curves, in annual power cost updates.[75] It is clear to us, from past experience and from the current debate about Boardman's forced outage rate both in this docket and UM 1234, that, to the extent reasonable, the use of independently-produced, verifiable data for modeling inputs increases transparency, while reducing controversy and regulatory burden.

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[73] UE 180 CUB/100/Jenks-Brown/7.
[74] UE 180 Staff/100/Galbraith/14.
[75] UE 161 CUB/100/Jenks/11-15; UE 170 CUB/100/Jenks/26 & CUB/200/Jenks/22-23; and UE 172 CUB/100/Jenks/9.

Specifically in regard to the 2005-06 Boardman outage, PGE seems to be trying to twist the forced outage rate, a forecasting tool, into an outage recovery mechanism. Though the Company argues that the Boardman outage is best addressed as a deferral,[76] PGE includes the 2005 portion of the Boardman outage in Boardman's forced outage rate in this case. PGE then goes on to say that "to the extent that PGE receives recovery of the cost of replacing Boardman, the forced outage rate calculation should not reflect days included in that recovery."[77] If the Boardman outage is a scenario event, as the Company argues, then it is properly normalized out of rates, yet PGE plans to use the forced outage rate to recover costs from the Boardman outage to the extent the Company does not receive its requested recovery in UM 1234. This is not appropriate.

We support Staff's and ICNU's approach of using NERC data to establish a forced outage rate for Boardman and Colstrip; Staff recommends adjusting that data for forced maintenance hours. PGE provides a number of reasons it thinks that using NERC data is not a good idea. The Company argues that using a single year of data is inappropriate, that parties have not demonstrated that such a methodology would be less volatile, that parties have not demonstrated that such a methodology would be more accurate, and that there are weaknesses in the NERC data.[78]

The purpose of using the average of four years of data to compute a plant's forced outage rate is to smooth the variations in availability that can happen from year to year. One year of NERC data, however, can include hundreds of data points; Boardman's peer group averaged 147 units from 2000 through 2004.[79] Not only does this serve to smooth

[76] UM 1234 PGE/100/Lesh/5.
[77] UE 180 PGE/400/Lesh-Niman/5.
[78] UE 180 PGE/1900/Tinker-Schue-Drennan/39-44.
[79] UE 180 Staff/100/Galbraith/9.

the year-to-year variation of any given plant, it does so with hundreds of plants rather than four years.

Finally, the Company's arguments that no party has demonstrated that using NERC data would be more accurate, and that there are weaknesses in the NERC data are themselves weak. As we have said, PGE's attempt to include the Boardman outage is not about improving the forecasting of forced outage rates in 2007. But when it comes to using NERC data, PGE is now concerned with accurate forecasting. The forced outage rate is a forecast, not a precise data point. PGE offers no demonstration that using NERC data would be less accurate, other than pointing to what it sees as weaknesses in the NERC data, but the use of a plant's four-year rolling average is not a perfect prediction of future performance either. Forecasts are not perfect; they aren't intended to be. Ratemaking is not an exact science, and where reasonable forecasts can be obtained from independent entities, there are many good reasons to take advantage of them.

IX. Conclusion

CUB recommends that the Commission:

Power Cost Adjustment and RVM.

- Reject PGE's proposed Annual Variance mechanism;
- Adopt CUB's proposed Power Cost Adjustment mechanism containing a deadband and sharing bands, an earnings deadband, an amortization cap, and a prudence review. CUB's proposal in Surrebuttal is adjusted to recognize the impact of SB 408; and
- Reject PGE's proposal to continue a new version of the RVM, now called the Annual Update. While it is not inappropriate to have a mechanism to update power costs between general rate cases, having two such mechanisms that

operate simultaneously is unnecessary and would create a burden on the regulatory system.

Port Westward

- Condition approval of the tariff associated with Port Westward such that it will only be valid within 30 days of March 1, 2007;
- Condition approval of the tariff associated with Port Westward such that, if Port Westward is not used and useful within 30 days, the Company must reopen UE 180;
- Condition approval of the tariff associated with Port Westward such that, if Port Westward is not used and useful within 6 months, the Company must file a new rate case in order to add the plant to ratebase; and
- Make it clear that, if PGE fails to achieve the fuel diversity that was envisioned in their IRP, the prudence of Port Westward should be revisited.

Advanced Metering

- Find that PGE's business case for Advanced Metering Infrastructure does not demonstrate that such an investment is reasonable and prudent; and
- Deny accelerated depreciation of AMI costs that have been incurred since UE 115.

Forced Outage Rates

- Adopt Staff's and ICNU's approach of using NERC data to establish a forced outage rate for Boardman and Colstrip.

Edison Announces Advanced New Meter Will Reach Customers Sooner Than Expected

August 21, 2006

Trade associations label SCE meter initiative the industry's best

ROSEMEAD, Calif., Aug. 21, 2006—Southern California Edison (SCE) has informed state officials the utility's advanced metering initiative (AMI), a plan to replace five million residential and small commercial customer meters with first-in-the-industry, two-way home communications devices, is ahead of schedule. The speed-up primarily resulted from assurances by the metering industry they can meet SCE's request faster than expected for a new generation of meters with advanced customer benefits.

"We have asked meter manufacturers for enhanced meter functions and capabilities that provide customers with significantly more control over their energy use and costs," said SCE Senior Vice President of Customer Service Lynda Ziegler. "The industry's response has been impressive and we believe the devices being developed could benefit every home and small business we serve."

Two trade organizations are citing SCE's meter initiative as the industry's leader. Utility Planning Network, a membership-based peer group of utility professionals worldwide that facilitates the annual Metering Awards Program, has recognized SCE's entry as winner of the "AMR Initiative by a North American investor-owned utility" category. The Electric Power Research Institute (EPRI) has recognized SCE's approach to advanced metering as the industry leadership position. SCE is the first U.S. utility to adopt EPRI's IntelliGrid Architecture for a system-wide advanced metering deployment.

The SCE meter initiative is part of a California Public Utilities Commission (CPUC) study of the feasibility of replacing the state's residential and small commercial electricity meters, that currently measure total energy use by the month, with more advanced devices that measure usage by the hour. Once such meters are installed, the commission would implement the same type of time-of-use rates for the state's residential and small business customers that have been available to larger business customers for years. Such rates will allow SCE to provide customers with pricing options that can lower their costs.

Subject to approval by the CPUC, SCE plans to begin field testing the new, advanced meters next year in 5,000 to 25,000 homes and small businesses, and fully deploy the units between 2008 and 2012.

Features and Benefits of SCE's Next Generation Meter

- SCE's new meters would provide a communications link with other household devices such as personal computers, feeding PCs real-time energy information that helps customers control usage and costs.
- The devices would link to household and business devices required for rate discount "demand response" programs.
- The one million SCE customers who relocate each year would be able to request that their service be turned on and turned off when it is most convenient.
- The new SCE meter would provide a communications link to the smart thermostats and appliances of the future, allowing customers to automatically manage costs.

# # #

An Edison International (NYSE:EIX) company, Southern California Edison is one of the nation's largest electric utilities, serving a population of more than 13 million via 4.7 million customer accounts in a 50,000-square-mile service area within central, coastal and Southern California.

Conceptual Feasibility Report

August, 2006

SOUTHERN CALIFORNIA EDISON COMPANY'S ADVANCED METERING INFRASTRUCTURE CONCEPTUAL FEASIBILITY REPORT

EXECUTIVE SUMMARY

SCE's AMI Vision is Being Realized

Southern California Edison Company (SCE) has held the conviction that the cost effectiveness of Advanced Metering Infrastructure (AMI) deployment could be greatly improved if certain critical functions and capabilities were added to the metering and communication systems. Although the ability to automatically connect and disconnect electric services and an "open" (non-proprietary) communications standard were technically feasible at the outset of SCE's Phase I AMI development effort, these functions and capabilities were not yet fully integrated into available metering products. Such added functionality and capabilities could substantially reduce the cost of field operations, encourage competition among meter and communications vendors, and enhance customer acceptance of time-differentiated pricing and direct load control by enabling communication with multiple in-house load control devices and information systems. SCE's vision is to develop the meter and communications systems technical requirements necessary to fully integrate currently available modern-day technology into a new generation of meters that can provide SCE additional operational benefits that outweigh any cost increase associated with the enhanced functionality.

In part due to SCE's efforts over the last eight months, and in part due to the rapid evolution of metering and communication systems technology over this same period of time, SCE's vision is being realized. As fully described in Chapter III of this report, SCE is now confident that an AMI solution that meets its metering and communication systems requirements will soon be available from vendors. The added functionality of this "next-generation" of meters is expected to reduce costs and add benefits that will result in a positive business case for full AMI deployment.

At this stage, SCE has determined that its proposed AMI solution is conceptually feasible. This conclusion is based on the conceptual design, the market assessment, product demonstrations and the positive financial assessment SCE has conducted. The results of these activities are presented in this report.

Overview

This report provides a mid-term Phase 1 update summarizing the status of SCE's progress toward completing the scheduled activities of Phase 1 of its AMI Project. It also summarizes and provides access to the deliverables related to the Concept Definition stage of Phase 1.[1]

There are two objectives in this stage of the AMI Project. The first objective is to define the conceptual design requirements that support a cost-effective, system-wide deployment of AMI. The second

[1] The Phase 1 activities are described in the Settlement Agreement adopted in Commission Decision (D.)05-12-001, issued December 1, 2005 in Application (A.)05-03-026.

objective is to conduct a market assessment to determine if there are metering and communication systems that can meet SCE's AMI requirements. Both of these objectives have been met and are addressed in Chapters III and IV of this report. SCE is now well underway with completing the second stage of activities associated with Phase 1.

The key activities of the Concept Definition stage are described briefly in this summary and more thoroughly in the report. This "Conceptual Feasibility Report" is itself one of the interim Phase 1 deliverables. Other deliverables discussed in this report include the AMI Requirements Documentation, and the results of the Market Assessment. Results of the market assessment are the subject of Chapter III of this report. AMI requirements documentation is available on SCE's website[2] and is described in **Appendix A** of this report.

Newly Identified Benefits Drive Financial Feasibility in a Positive Direction

SCE has conducted a preliminary AMI business case analysis, and the results indicate that the potential benefits exceed the costs. From the negative net present value (NPV) of $490 million determined in the March 2005 analysis, SCE now shows a significant directional improvement resulting in a positive NVP estimate of $24 million. Chapter II of this report addresses the financial impact of the new system functionality and related assumptions which form the basis for SCE's continued positive outlook regarding the financial feasibility of AMI. A full assessment of the potential benefits and costs of SCE's AMI concept will be a major focus of the remainder of Phase 1 activities, incorporating the results of the Request For Proposals (RFP) for meters, communications, information systems and installation.

SCE's AMI Project is On-Target and Ahead of Expectations

SCE's accomplishments in the Concept Definition stage are ahead of expectations. As described in this report, all objectives associated with the first stage of Phase 1 have been met or exceeded, and the results are universally positive. The second stage of Phase 1 includes the documentation of engineering specifications and the release of a metering and a communications system Request for Proposal (RFP). SCE originally planned to conduct additional product design activities and testing of metering prototypes. However, it now appears that no further product design activities are necessary, and SCE now expects first-run production models will be available for testing in the second stage of Phase 1. Revised assumptions consistent with the functional improvements described throughout this report will support SCE's application for Phase 2 AMI funding expected to be filed in Fall 2006.

SCE is making every attempt to shorten the overall time-frame required for the program, and is optimistic that there will be opportunities to accelerate the schedule.

SCE's Collaborative Efforts with Other Stakeholders Have Helped to Encourage Product Development

Through a deliberate collaborative process, SCE has proactively involved manufacturers of promising AMI technologies in ongoing dialogue focused on product enhancements and SCE's desired system functionality. Chapter III of this report describes how SCE shared its design requirements and concept

[2] http://www.sce.com/PowerandEnvironment/ami/TechDevelop.

definition with communications vendors, meter vendors and utility industry groups over the last eight months. This process is helping to establish standards for a new generation of AMI-related meters and communication systems that can better address electric utility needs. These discussions, and the independent decisions that result from them, are acting as a catalyst to spur industry-wide product development efforts. A recent press release from one major meter manufacturer announced the deployment of its "New and Advanced Metering and Communication Technology" at Manitoba Hydro.[3] The capabilities of this new technology bear a strong resemblance to the metering capability requirements developed by SCE over the last eight months, illustrating that SCE's approach to AMI is already obtaining support from the vendor community as well as from other stakeholders across the country and around the world.

Market Assessment Confirms Technical Feasibility of SCE's AMI Solution

Chapter III of this report provides a summary of the results of SCE's market assessment. These results show that the capabilities defined through SCE's requirements gathering process are, in fact, feasible from a technical perspective. SCE's market assessment involved contacting over 100 vendors and followed a rigorous process with multiple steps and activities designed to influence the direction and timing of vendor AMI product development work. SCE's assessment of meter and communications vendors indicates that many are developing next generation technologies that closely align with SCE requirements. SCE's current assessment also indicates that prices for next generation meter and communications technologies should make these meters and technologies worthy of serious consideration by SCE and other utilities.

SCE has drawn two primary conclusions from its market assessment:

- SCE's "buy or design" question is no longer an issue. SCE will not need to engage in AMI product design work, because vendors are developing next generation technologies that closely align with SCE requirements; and
- SCE expects metering and telecommunications products containing the necessary features and functionality will become commercially available from vendors in 2006.

Meter Data Management System Plays a Key Role

As described in Chapter III of this report, the business Use Case development and conceptual architecture activities identified the requirement for a Meter Data Management System (MDMS) to manage and process meter data for multiple uses. A market survey conducted during Phase 1 indicated that currently available products meet a majority of SCE's requirements. SCE expects the product development cycles of these vendors will deliver systems that will meet SCE's meter data management requirements.

SCE's AMI Meter and Communications Systems Requirements are Complete

By using a rigorous systems engineering methodology, SCE has defined a set of conceptual meter and communication system requirements for AMI that serve as a foundation for SCE's engagement of AMI

[3] Manitoba Hydro / ITRON Corp. Joint News Release, dated June 29, 2006.

product vendors. The systems engineering approach employed a "Use Case" process involving 44 separate internal workshops and the participation of all of SCE's operations departments. SCE's systems engineering and Use Case processes are described in Chapter IV of this report. This set of requirements was also used to develop a conceptual architecture describing how the AMI system is expected to perform. This process resulted in documentation of over 400 requirements that are consistent with the recently ratified Utility/AMI High-Level Requirements.[4] The SCE requirements are described in **Appendix B** of this report. The Use Case documents and the complete set of requirements documentation are available on SCE's website (www.sce.com/PowerandEnvironment/ami) under the "Technology Development" and "Vendor Information" sections.[5]

Use Case Process Defines Operational Benefits

Besides defining the technical requirements of the metering and communications systems needed for AMI, the Use Case process provided the basis for determining what practical end uses and functionality can be added to SCE's financial assessment of AMI deployment. This process determined what benefits can be included in the revised business case and cost benefit analysis. Significant changes from SCE's previous assumptions include:

- Advances in communications coverage are expected to enable SCE to reach nearly all customers rather than the previously assumed 90%. This results in cost reductions associated with meter reading activities and billing costs due to fewer billing exceptions and fewer billing inquiries.
- Meter failure rates are expected to be cut in half as a result of a more stringent quality assurance and control approach working with vendors.
- Significant reductions in Field Service labor cost due to new customer services enabled by the remote connect/disconnect capability.
- More realistic assumptions related to customer participation in price response programs result in a significant reduction in marketing and customer communication costs.
- New assumptions relating to customer participation in direct load control programs reflect the fact that more reliable peak load reduction will enable SCE to defer capital investment in upgrades to existing sub-transmission and distribution facilities.

Technology Demonstrations Are Underway

Technology demonstrations and tests are an important part of SCE's feasibility assessment and project planning. SCE has conducted research on Home Area Network (HAN) communications protocols and mediums. The research examined both wired and wireless solutions including HomePlug, WiFI, ZigBee, Z-wave and proprietary solutions. The conclusion is that the "ZigBee" standard appears to be the industry's leading choice for HAN communications protocol for residential applications. This research was done in connection with developing requirements for the California Energy Commission's

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[4] UtilityAMI recently adopted a set of high-level requirements for AMI meter and telecommunications systems to provide vendors some general guidelines as to currently desired AMI system functionality.

[5] The output of SCE's Use Cases has been adopted for integration with EPRI's IntelliGrid Architectural Model, which is widely used throughout the energy industry.

(CEC) Title 24 Programmable Communicating Thermostat (PCT) that will be enabled by the AMI system in SCE's service area.

In addition, SCE has just begun two component level tests that will be completed by the end of Phase 1. The first of these evaluates two types of remote disconnect switches. The second component test is a preliminary evaluation of radio frequency (RF) reception quality that SCE is conducting at a vacated residential site on a former military base to validate the RF coverage assumptions.

Other related tests outside the funding purview of AMI are being monitored for potential application to AMI. One example is the recently completed six-month pilot test of narrowband power line communications, which tested remote, on-demand meter reading with 200 residential meters. This pilot involved three components: network management, substation control, and meters with an AMR module. These tests are helping SCE gain a better understanding of the feasibility and operating implications of these technologies.

ADVANCED METERING INFRASTRUCTURE CONCEPTUAL FEASIBILITY REPORT

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I. INTRODUCTION

On December 1, 2005, Southern California Edison Company (SCE) received approval from the California Public Utilities Commission (the "Commission") to implement Phase 1 of SCE's preferred strategy for deployment of an Advanced Metering Infrastructure (AMI) to SCE's business and residential customers.[6] Phase 1 is an eighteen-month process of developing the AMI concept that involves two stages: Concept Definition and Design and Feasibility. The Concept Definition stage consists of the following key activities: i) developing AMI technical and system requirements, ii) conducting technology demonstrations to validate functionality, iii) conducting cost trade-off analysis, iv) performing AMI conceptual feasibility analysis, v) developing reference architecture, vi) conducting market assessments, and vii) developing and releasing a request for proposal for an Engineering Design Contractor.[7]

SCE estimated that the Concept Definition stage would require eight months from project approval to complete. Upon completion of the Concept Definition stage, SCE agreed to deliver several documents and assessments: AMI Requirements Documentation, Results of Market Assessment, and a Conceptual Feasibility Report.[8]

Consistent with the activities described above, the first eight months of SCE's Phase 1 AMI project have included the following activities:

- A System Design process, in which "Use Cases" were used to identify the requirements of the desired AMI metering and communication systems;

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[6] *See* Decision (D.)05-12-001, approving the all-party Settlement Agreement on the outstanding issues of Phase 1 of SCE's Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery (A.05-03-026).

[7] In the process of completing the first eight months of Phase 1 activities, SCE has determined there is no need for an Engineering Design Contractor, since it now appears that vendor products will be able to meet SCE's defined requirements.

[8] *See id.* at Settlement Agreement, Attachment A.

- A detailed review of 18 separate "Use Cases," in which SCE identified those areas of its operations where various conceptual AMI features may be put to use to help reduce costs or otherwise improve overall operating efficiency;
- The System Engineering and Architectural Design of a conceptual architecture and associated reports defining SCE's AMI requirements;
- Cost trade-off analysis in conjunction with prioritizing identified system requirements;
- Use of the Technology Capabilities Maturity (TCM) methodology (described in Chapter III) for evaluating the ability of currently available metering products to meet SCE's identified AMI requirements;
- A market assessment of the metering and communication systems products available in today's marketplace;
- A "Gap Analysis" to identify the difference between currently available metering and communications products and SCE's requirements. This included a risk/reward analysis of proceeding with currently available products versus waiting for improvements that may likely become available in the near future;
- A market assessment of meter data management systems to determine whether there are existing systems to support SCE's AMI project; and
- Initiation and assessment of several metering and technology demonstrations.

The results of these activities were then used to assess the feasibility of SCE's AMI concept, including the availability of vendor products to meet SCE's requirements, and to validate and update the assumptions SCE used in its directional cost/benefit analysis to gauge the overall financial feasibility of replacing SCE's current metering infrastructure with a modern, solid-state metering and communications system.

At this stage, SCE has determined that its AMI solution is conceptually feasible, based on the following findings and conclusions:

- Advancements in meter and communications systems provide additional functionality resulting in significant increases in the operational benefits of AMI. SCE's revised assumptions relating to communication system coverage, remote connect/disconnect capability, reduced meter failure rates, increased demand response benefits and other previously unidentified benefits have moved SCE's cost benefit results in a positive direction from a net-present-value (NPV) of minus $490 million in the March 2005 analysis to plus NPV of $24 million in SCE's preliminary Phase 1 analysis.

- SCE believes next-generation commercial products will be available from vendors for testing and evaluation within the next six months based on responses from industry leading vendors.

This report presents the conceptual design work, initial technical review and market assessment (including product demonstrations and review of financial aspects of acquiring AMI) that SCE has conducted to date. Specifically, in this report, SCE summarizes all of the Concept Definition deliverables,[9] as well as an initial technical assessment of the Meter Data Management System and evaluation of the Demand Response System. In addition, SCE presents updated demand response assumptions and a directional financial assessment of SCE's preferred strategy utilizing revised assumptions resulting from the Phase 1 activities completed to date.

[9] The AMI technical and system requirements documentation is too voluminous for inclusion in this report. These documents have been made available on SCE's AMI website (http://www.sce.com/PowerandEnvironment/ami/TechDevelop) under "Vendor Information."

II. FINANCIAL ASSESSMENT

In previous financial analyses filed with the Commission in January and March 2005,[10] SCE concluded that currently available metering and communication systems could not be expected to deliver sufficient operational and demand response benefits to offset the cost of implementing such systems. In August 2005, SCE demonstrated that certain key metering and communication technology improvements could conceptually result in a positive cash flow.[11] These anticipated improvements included:

- Improved communications capabilities, improved reliability, and an open communications protocol;
- Remote connect/disconnect capability; and
- Reduced meter failure rates.

The positive financial expectation was supported by SCE's directional AMI cost benefit analysis, in which SCE supplemented its best full-deployment business case analysis (Scenario 4) from the March 30, 2005 Application to reflect significant changes in assumptions based on the conceptual functionality improvements in AMI as they were envisioned at the time.

The directional improvement in SCE's overall financial assessment of AMI remains positive as SCE heads into the second stage of Phase I. SCE's Market Assessment, discussed in Chapter III of this report, has confirmed that the anticipated improvements in certain key metering and communication technologies are likely to become available in the near future. In addition, SCE's rigorous Use Case process, described in Chapter III of this report, successfully identified several new areas of

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10 *See* SCE's Advanced Metering Infrastructure Revised Preliminary Business Case Analysis, filed January 12, 2005 in R. 02-06-001, and SCE's Testimony Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism, filed March 30, 2005 in A. 05-03-026.

11 *See* SCE's Supplemental Testimony Supporting SCE Company's Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism, filed August 1, 2005 in A. 05-03-026, p.9.

potential cost savings and benefits not included in the previous study. Thus, from the negative net present value (NPV) of $490 million demonstrated in the March 2005 analysis, SCE now shows a significant directional improvement resulting in a positive NPV estimate of $24 million.

This Chapter addresses the bases for SCE's continued positive outlook regarding the financial feasibility of AMI as SCE proceeds with the remainder of Phase 1 of its AMI program.

A. Financial Feasibility of SCE's AMI Solution Remains Directionally Positive

Once SCE obtains firm bids for metering and communication systems that meet SCE's technical needs, SCE will be able to fully assess the financial feasibility of its AMI solution. In the interim, SCE has conducted a preliminary business case analysis, incorporating revised assumptions based on SCE's new AMI conceptual design. The results of this recent preliminary analysis have been compared to the previous analysis conducted in March 2005 to determine the magnitude and direction of the most significant changes. The March 2005 analysis was expressed in 2004 dollars, two years prior to the assumed deployment in 2006. By casting the current study in 2008 dollars, two years prior to the assumed deployment in 2010, SCE has effectively normalized the present value dollar differences that would arise simply from timing assumptions between the two studies. This allows SCE to isolate the actual cost or benefit changes and provides a reasonably accurate comparison.

Though not definitive at this stage, the results of this updated preliminary analysis indicate the overall benefits are above the break-even point. By comparing the results of this latest analysis to SCE's earlier cost benefit analysis, SCE is able to estimate the directional improvement attributable to those areas where anticipated advancements in metering and communications technology are expected to either add net benefits or reduce costs.

The system design process described in Chapter IV of this report identified not only the technical requirements, but explored the operational requirements and potential benefits that would accompany each of the identified uses for SCE's AMI system. The Use Case process provided a more comprehensive approach to identifying costs and benefits than the approach used in SCE's previous analysis. The earlier analysis was also constrained by a Commission mandated project schedule and certain demand response assumptions and limitations. By making some changes in the timing related to AMI deployment, SCE expects considerable savings to occur in certain logistical and personnel related transition costs. These savings are largely due to the ability to manage vendor product quality and deploy and enhance the Meter Data Management (MDM) system in advance of meter installations.

While improvements in meter functionality and communication system coverage and reliability may add costs to the AMI infrastructure, these increases in cost are offset by the expected benefits to be derived through these functional improvements.

Table II-1 summarizes the results of SCE's directional cost benefit analysis, showing the contribution of each operational area to the overall $514 million (in 2008 present value dollars) directional improvement over SCE's March 2005 analysis.

Table II-1
AMI Directional Cost – Benefit Analysis
(Increased Benefits Compared to March 2005 Analysis)

Operational Area	**Incremental Improvement in Benefit or Cost (Millions of 2008 PV $)**
Communication System Coverage	45
Remote Connect/Disconnect	298
Reduced Meter Failure Rates	33
Demand Response	315
Previously Unidentified Benefits[12]	70
Meter & Telecomm. Cost Increase/Other	(247)
Total Directional Improvement	**514**

These results are preliminary, order-of-magnitude estimates. The comparison must be viewed with considerable caution, not only due to the preliminary nature of the major cost elements (*i.e.*, metering and communication system costs), but also because the time-frame reference points for the two studies being compared are separated by four years. Other differences between the two estimates, such as the study term and cost escalation over the four year differential of the study periods, have not been taken into consideration. Even given these cautionary considerations, SCE is confident that the more thorough financial analysis to be completed later will confirm the positive net present value of SCE's AMI solution going forward.

The following sections describe in more detail the assumptions and specific findings attributable to each of the key technical improvements and program changes resulting from SCE's Phase 1 work to date.

[12] These benefits are discussed in Section II, A.5 below.

1. Improvements in Communication System Coverage

The initial technical review and market assessment of available AMI communications systems placed a high priority on coverage with the goal of reaching 100% of all meters all the time. This would be a significant improvement over the estimated 90% coverage assumed in previous cost-benefit analyses. SCE now believes that with a combination of communication technologies available on the market today, and anticipated improvements to become available soon, SCE will be able to approach the 100% goal. The capability of AMI to have multiple backhaul communications paths provides for improved “reach,” effectively including more meters in the automated polling communications network. This capability allows for additional reductions in field forces and associated personnel required to support manual meter reading activities in those areas where communications were either not available or intermittent.

Telecommunication network costs are expected to increase to achieve the coverage and home-area network improvements. This increase is expected to be offset somewhat by the need for fewer servers and less data storage capacity than previously expected.

Table II-2 lists the major benefit and cost changes expected to occur as a result of improved communication system capabilities.

Table II-2
Communication System Improvements
(Compared to March 2005 Analysis)

Operational Area	Incremental Change in Benefit or Cost (Millions of 2008 PV $)
Meter Reading and Field Services	89
Telecomm Infrastructure Cost	(44)
Total	**45**

Improved communication system capabilities will also provide the ability to read meters "on-demand" which, when combined with the remote connect/disconnect feature (discussed below) will provide the means to facilitate "Prepayment Services" that are expected to increase service levels as well as improve cash flow and reduce write-offs.

Other benefits attributable to communication system improvements are due to the assumption of an open, non-proprietary standards based Home Area Network solution that will facilitate the ability of device manufacturers to develop products for the consumer market. These include but are not limited to in-home displays and PCTs. These improvements are expected to contribute to customer demand response to time-of-use (TOU) and Critical Peak Pricing (CPP) rates as well as enhance and expand SCE's direct load control programs. Demand response and load control improvements are described further in Section 4 of this Chapter.

2. **Remote Connect / Disconnect Capability**

Significant cost savings are expected to result from the ability to integrate a 200 Amp service disconnect switch into nearly all the residential solid state meters that can be operated through the AMI communications infrastructure. The cost of the service disconnect switch is significantly reduced based on product economies at large volumes represented by the approximate five million meter scale of the SCE system-wide deployment. The service disconnect capability will eliminate the need for field visits required to manually complete turn-on and turn-off orders and to disconnect and reconnect services for non-payment. Elimination of these field operations results in a $230 million reduction in field labor costs over the duration of the analysis period. Additionally, SCE expects this capability will eliminate the backlog for credit related disconnects, reducing write-off and improving cash flow. This capability will also enable new prepayment programs, which are expected to further improve cash flow and reduce write-offs.

Table II-3 lists the major benefit and cost changes expected to occur as a result of the remote connect / disconnect capability.

Table II-3
Remote Connect / Disconnect Capability
(Compared to March 2005 Analysis)

Operational Area	**Incremental Improvement in Benefit or Cost (Millions of 2008 PV $)**
Field Order Cost Reduction	230
Write-off / Billing Reduction	15
Prepayment Services (Cash Flow)	50
Prepayment Services (Write-off)	20
Call Center Cost Reduction (Disconnect)	18
Call Center Cost Increase (Prepay and Turn-on)	(35)
Total	**298**

The automatic disconnect feature is expected to reduce operating costs by more than $300 million, this savings is partially offset by the $35 million estimated increase in call center costs due to customer verification prior to automatically connecting or re-connecting service.

3. <u>Deployment Schedule Changes and Reduced Meter Failure Rates</u>

The stringent deployment schedule previously assumed for AMI required a less than nine-month ramp-up for installation of the metering and communications infrastructures and meter data management system. This created a potential for significant quality issues and systems integration issues for the AMI deployment similar to that SCE experienced several years ago with the rapid deployment of the real time energy metering (RTEM) project for large commercial and industrial customers. The likelihood of this was further compounded by the fact that all three California investor-owed utilities were planning on simultaneous deployments.

Previous analyses assumed meter failure rates as high as 25 percent over the duration of the AMI system life. By incorporating a more stringent quality assurance and controls program in addition to vendor contractual obligations, SCE expects to reduce the expected meter failure rate by at least 50 percent. The result will be significantly lower meter replacement costs, reduced trouble-report field tests, and reduced exception billing costs. Non-quantifiable customer benefits will also result from the elimination of estimated bills that inevitably result from meter failures.

These costs are summarized in Table II-4.

Table II-4
Reduced Meter Failure Rates
(Compared to March 2005 Analysis)

Operational Area	**Incremental Improvement in Benefit or Cost (Millions of 2008 PV $)**
Meter Procurement Cost Savings	23
Meter Replacement (Labor)	10
Total	**33**

4. Demand Response Results Improved by Changes in Program Assumptions

As discussed in Chapter IV "System Design," the AMI system is expected to be capable of interfacing with in-home and around-the-home premise units (including in-home display devices), resulting in better usage and cost information being provided to customers. This improved information is expected to enhance customer acceptance of and response to new tariffs and direct load control programs while reducing the cost of customer communications.

SCE believes AMI can enable a significant summer peak load reduction through various pricing and load control programs. In October 2004 and January 2005, SCE analyzed the impact of numerous rate scenarios as mandated by the Commission in R. 02-06-001.[13] The approach herein explores an alternative set of assumptions that provide significant benefits that improve the directionally positive outcome of the AMI financial assessment. As explained later in this Chapter, SCE now assumes a TOU default rate with 57.6% participation and a CPP option with 11.5% participation, rather than the 10% participation in TOU and 80% participation in CPP assumed in the March 2005 analysis.

In addition, in SCE's March 2005 filing best case, SCE did not include the benefits of load control programs or the benefits of capital avoidance related to upgrades to existing distribution related facilities. In this analysis, SCE includes three load control options for residential customers and the benefits of sub-transmission and distribution related capital avoidance for all demand response tariffs and programs. This approach results in a net demand response benefit of $481 million compared to the previous estimate of $166 million.[14] This is an improvement of about $315 million (in 2008 PV dollars). A large portion of the improvement is attributed to the elimination of most of the marketing costs in the March 2005 analysis of $220 million thought to have been needed to sustain the previously assumed 80% participation level in CPP tariffs. The results of SCE's updated analysis of demand response programs are summarized in Table II-5.

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13 *See* Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure, issued 7/21/2004 in R.02-06-001, setting forth assumptions for various AMI deployment scenarios.

14 The demand response benefit of Scenario 4 was about $386 million. The net benefit of that approach was $386 million minus $220 million in marketing and enrollment costs or $166 million.

Table II-5
Demand Response Benefit Changes
(Compared to March 2005 Analysis)

Tariffs and Programs	**Incremental Changes in Net Benefits (Millions of 2008 PV $)**
Price Response (TOU & CPP)	180
Title 24 PCT	56
Air Conditioning Cycling	53
Smart Thermostat	26
Total Improvement from 2005	**315**

5. Previously Unidentified Benefits

SCE's Phase 1 System Design Process has extended the potential applications of AMI to a broader range of functions, resulting in the identification of several areas of potential cost savings that were not identified in earlier studies. SCE's Transmission and Distribution Business Unit (TDBU) expects to gain approximately $27 million in benefits, attributable to transformer overload prevention and reduced "no-power" field calls. SCE's Billing Organization is estimating $8 million in billing related benefits due to a reduction in billing exceptions. A $12 million reduction in field services and meter reader worker's compensation costs has also been identified. An additional $23 million benefit is attributable to cash flow improvement resulting from elimination of the billing-lag associated with summary billing accounts.

In previous studies, it was assumed that SCE's existing Transformer Load Management (TLM) program would not be improved upon through an AMI deployment. New assumptions relating to distribution system monitoring capabilities of AMI have resulted in revised assumptions relating to the prevention of transformer overloads and the resulting elimination of premium-time emergency responses to system outages. Additional cost reductions have been identified for avoidance of dispatching distribution crews to respond to "no-power" customer calls. Based on technology improvements, SCE assumes such calls can be resolved by the call center using the AMI system to confirm that power is actually "on" when the problem is on the customer side of the meter (usually attributable to the main breaker being turned off).

These previously unidentified benefits are summarized in Table II-6.

Table II-6
Previously Unidentified Changes
(Compared to March 2005 Analysis)

Operational Area	Incremental Changes in Benefit or Cost (Millions of 2008 PV $)
Transformer Overload Prevention	16
Reduced "No Power" Field Visits	11
Billing Exception Processing Reduction	8
Summary Billing Lag	23
Meter Reader and Field Service Workers Comp. Reduction	12
Total Improvement from 2005	**70**

6. Benefits and Other Financial Aspects Under Evaluation

SCE is continuing to explore several benefits resulting from the deployment of the AMI that: a) create benefits for customers but that do not result in cash flow benefits, such as theft deterrence; b) create societal benefits; and c) provide new business opportunities that may result from services such as automated contract meter reading of gas and/or water meters for other utilities. SCE is planning to address these aspects completely in its final business case. SCE is also monitoring the potential for a federal tax credit for smart metering that is under consideration in the federal energy bill currently in development, which could have a significant impact on the financial assessment of AMI.

B. SCE's Phase 1 System Design Demand Response Assumptions and Considerations

1. Demand Response Overview

The principal focus for the AMI system is to empower customers to manage their energy costs. As such, demand response is the clear driver of five of the six minimum functionality requirements previously identified by the Commission for AMI deployment.[15] Those functionality requirements relate to how price response, load control and pricing information may help customers reduce energy consumption and/or demand. AMI-enabled demand response is a critical element to meeting the state's energy policy goals as well as to the assessment of benefits of the AMI program. SCE estimated the benefits of demand response in its prior AMI filing; however, there are significant changes in the assumptions and approach currently being used to estimate this critical component of AMI. This section updates SCE's assumptions and various other considerations relating to pricing and direct load control options that are essential to a comprehensive evaluation of the conceptual feasibility of AMI.

There are many ways to create demand response, including time-differentiated tariffs and load control programs. Residential air conditioning is the largest source of discretionary peak electricity usage in Southern California, and AMI enables various ways to accomplish load reductions that can yield generation supply and distribution benefits. AMI will enable time-differentiated pricing for SCE's residential and small commercial customers and facilitate automated load control of air conditioning. Because many issues related to dynamic pricing and direct load control remain undecided

[15] *See* Joint Assigned Commissioner and Administrative Law Judges Ruling Providing Guidance for the Advanced Metering Infrastructure Business Case Analysis, issued February 19, 2004 in R.02-06-001, pp. 3 & 4.

at this time, the assumptions and analysis of demand response contained in this report should be viewed as an update rather than a final or optimal approach.

SCE currently estimates that demand response enabled by AMI can yield total benefits of about $481 million in 2008 present value dollars.

a) Regulatory Considerations and Avoided Cost

There have been three key developments that helped shape the current analysis. First, the California Energy Commission's (CEC) Title 24 building code initiative for Programmable Communicating Thermostats (PCTs) has allowed SCE to define an opportunity for AMI to enable reliable demand response benefits with a targeted PCT program. Second, the Commission approved SCE's proposal to install an additional 180,000 load control devices under its air conditioning cycling program during 2006 to 2008. AMI can enable a new approach to load control with these devices to yield reliable peak shaving. This can provide additional sub-transmission and distribution related capital deferral benefits over the existing air conditioning cycling program. Third, assumptions for future avoided capacity and energy costs have escalated since the Commission's suggested assumptions for these parameters in July 2004.[16]

b) Tariff and Program Design Considerations

As the AMI system requirements and capabilities evolve through the remainder of Phase 1, SCE will continue to work toward a final approach to AMI-enabled demand response. There are many rate design approaches and load control programs that can accomplish cost-effective peak load reductions. The approach herein offers a reasonable estimate of demand response benefits. SCE anticipates that further

[16] *See* Appendix A of Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure, issued July 21, 2004, in R.02-06-001.

analyses of tariff and program approaches may yield load reductions in ways that are more cost-effective if greater emphasis is placed on rate designs and pay for performance. For example, load control programs could be modified to pay for performance, measured by the AMI system, rather than by seasonal or credit payments. Moreover, load control program participants could be placed on CPP rates in lieu of receiving incentive payments. SCE could use smart thermostats or cycling devices as enabling technology for load reductions in response to CPP rates. Also, SCE could place all customers on TOU rates compliant with Section 80110 of the California Water Code enacted by Assembly Bill (AB) 1-X, or enroll them on a voluntary basis in TOU or CPP rates.

SCE has followed the progress of the AMI applications of SDG&E and PG&E and will be looking for guidance from the Commission's approval of various demand response parameters and assumptions. An important element of rate design in the AMI business case analyses is how compliance with AB1-X is interpreted by the Commission. Since AB1-X affects rates on consumption at 130 percent of residential baseline and below, a significant portion of consumed energy is shielded from price signals. At this time, in accordance with the Commission's guidance in R.02-06-001, SCE has not taken into account the effects of AB1-X. However, SCE is aware that the Commission approved PG&E's AMI deployment application, which relied on voluntary enrollment in TOU and CPP rates. SCE is also following the development with SDG&E's AMI deployment application for ABI-X compliant tariffs.

The following subsections describe SCE's assumptions pertaining to demand response and the resulting load reduction impacts and benefits. The benefits include avoided capacity and energy purchases and deferred spending on distribution related capacity.

2. Key Assumptions to Demand Response Benefits Analyses

Overarching assumptions in the analysis of Demand Response benefits include:

- All customers below 200kW will be equipped with an AMI meter per the deployment schedule.
- Residential meters will provide at least hourly interval data. Commercial and industrial customer meters will provide 15 minute interval data.
- Two-way communications with the meter and any associated PCTs will be enabled.

Procurement benefits include avoided capacity and avoided energy. Avoided capacity benefits include the value of capacity provided by a particular tariff or load control program. The value of capacity is based on the cost of an avoided combustion turbine ("CT") as a proxy. The CT proxy value assumed is $80.10/kW in 2006 and escalated each year. The value of peak reductions from a CPP tariff is adjusted (de-rated) because of the limitation of an assumed number of CPP events per summer season, compared to a combustion turbine, which is available near 100 percent throughout the year. The value of load control programs is also de-rated for similar limitations. The assumption for avoided peak energy value is $98.80/MWh in 2006 and escalated each year for energy avoided during a CPP event.[17] These avoided procurement cost assumptions are higher than what was assumed in SCE's March 2005 filing, reflecting increases in both the construction costs of a CT and a significant escalation in the cost of natural gas.

3. Approach to Estimating Demand Response Benefits

SCE used a portfolio approach to achieving demand response for several reasons. First, SCE has a successful residential air conditioning load control program and

[17] SCE has not included the cost of congestion associated with transmission of peak energy at this time.

is in the process of roughly doubling enrollment in that program. Those customers are important to achieving demand response goals because they are willing to have their air conditioning loads curtailed. Other utilities with successful load control programs, such as Florida Power and Light, Xcel Energy and Progress Energy, have enrolled more than 25 percent of their residential customers on load control programs.[18] SCE believes that a similar level of enrollment is possible in its service territory.

Second, the CEC is pursuing Title 24 -Building Code changes requiring PCTs for residential new construction and residential HVAC retrofits. SCE assumes that these PCTs would be available for a load control program. Moreover, the PCTs developed from standards in Title 24 would likely become available for customers generally. SCE could promote a load control program using PCTs compliant with Title 24. The devices would be activated and controlled via the AMI infrastructure.

Third, SCE expects many customers would prefer TOU and CPP rates. There are various rate alternatives that could be offered to customers including mandatory TOU or CPP for Tiers 3, 4 and 5 only (Tiers 1 and 2 would comply with AB1-X); default TOU or CPP with opt out to other choices; or simply voluntary enrollments in TOU or CPP. There is also a range of rate designs that could be applied. For the purpose of this report, SCE has updated its March 2005 and August 2005 rate approaches. In the remainder of Phase 1, SCE will undertake additional study that will consider future Commission rulings on AMI rate designs.

SCE's approach to estimating demand response benefits for this study is provided below in two categories, time differentiated tariffs and load control programs.

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[18] SCE's 2004 Long-Term Procurement Plan Testimony served in R.04-04-003, Volume 1, p. 115, Table V - 18.

a) Time Differentiated Tariffs

For the purpose of analyzing the conceptual feasibility of AMI, SCE assumes that the Commission will authorize SCE to implement time-differentiated pricing in the form of TOU and CPP rates. When an AMI meter is installed, the customer will be defaulted to a TOU rate and will be offered a choice to opt-out to a CPP rate or a tiered-rate structure. SCE relied on the results of the Statewide Pricing Pilot (SPP) studies to estimate the percent enrollment of customers on rate choices by customer class as well as the load reduction amounts. SCE also used the rate designs and bill impacts for TOU and CPP developed for its March 2005 AMI application (A.05-03-026) and the Momentum Market Intelligence model for estimating customer enrollments based on projected bill savings. The estimates for sustained enrollment by rate offering for all classes are 57.6 percent TOU, 11.5 percent CPP and 30.9 percent tiered (current rate schedules).[19] This approach differs from SCE's best-case March 2005 AMI application, which used 80% CPP, 10% TOU and 10% tiered rates for all classes below 200kW.

SCE used the same methodology to calculate price related demand response as that used in its March 2005 AMI application. This approach relies on the SPP studies' findings on price elasticity and customer responsiveness to time-differentiated rates. The resulting estimated peak load reductions by rate in 2015, after full deployment, are shown in Table II-7.

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[19] Commission required assumptions used in SCE's March 2005 AMI Application included default rates that were not AB1-X compliant. This analysis continues to rely on those assumptions.

Table II-7
Estimated Peak Load Reduction in 2015
for TOU and CPP Rates (All Classes)

Rate	Meters Enrolled	MW Savings
TOU	3,160,400	188
CPP	628,900	181
Total TOU & CPP	3,789,300	369

b) Load Control Programs

SCE's approach to calculating demand response benefits assumes that the AMI system will enable the economic dispatch of load control that will provide procurement cost reductions and deferral of distribution related spending by shaving the system peak. The AMI system will enable two-way communications with devices such as PCTs to enable the dispatch of command signals, provide information about event status and allow event override. Such features can enhance the appeal of load control and increase customer enrollment in programs. SCE assumed that load control can be provided in three types of air conditioning peak saver programs: Title 24 PCTs, Economic Dispatch of A/C Cycling, and the Residential Smart Thermostat Program. These programs are described in the following sections. SCE's current approach covers the residential class only. The recent SPP report for 2004 and 2005[20] indicates that significant load reductions could be achieved with enabling technology in the commercial and industrial classes as well. SCE will consider load control programs for the commercial and industrial classes in the remainder of Phase 1.

The estimated enrollments and MW savings in 2015 for these three load control programs above are shown in Table II-8.

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20 CRA International. California's Statewide Pricing Pilot: Commercial and Industrial Analysis Update, May 30, 2006.

Table II-8
Estimated Peak Load Reduction in 2015 for Load Control Programs – Residential Class Only[21]

Program	Meters Enrolled	MW Savings
Title 24 – Smart Thermostat	133,636	120
Air Conditioning (A/C) Cycling	321,720	524
Smart Thermostat	226,198	196
Total Load Control	681,554	840

1) Residential Title 24 Programmable Communicating Thermostats (PCTs)

Beginning in 2009, when the new California Building Code is effective, SCE assumes that 25% of customers with PCTs (residential new construction and a portion of residential retrofit construction) and AMI meters will enroll in an SCE load-control program. Under the program, customers would be paid an incentive of $25 per summer. The PCTs on the program would provide air conditioner compressor curtailment during peak by increasing the thermostat set point for short durations but frequent dispatches. This program would provide procurement savings and distribution related capital spending deferral benefits. SCE used 1 kW/hour load reduction for a four-degree thermostat temperature setback for customers on the load control program, which has been demonstrated empirically by SCE and other utilities.

2) Economic Dispatch of Existing Residential Air Conditioning Cycling Program

SCE expects to have approximately 340,000 customers enrolled in its Summer Discount (Air Conditioner Cycling) Plan by 2009. The current

[21] MW savings are calculated mid-year but meters enrolled are end of year.

program is dispatched for reliability purposes only. With AMI, SCE will be able to more accurately estimate available load curtailment potential of customers on the program. Thus, SCE will be able to use the cycling devices for economic dispatch of the program where air conditioner compressors would be curtailed for short durations but on a frequent basis throughout the summer thereby shaving the system peak load. Because procurement benefits already exist, they are not considered incremental to AMI. Although AMI may enhance procurement benefits because of economic dispatch, SCE has not included additional procurement benefits at this time. SCE includes only the incremental sub-transmission and distribution capital spending deferral benefits for this program. SCE used 1.6 kW/hour load reduction for customers on the Air Conditioning Cycling program, which has been demonstrated empirically by SCE.

3) Residential Smart Thermostat Program

SCE believes that it can reasonably enroll about 25 percent of residential customers with central air conditioning either on its existing Air Conditioner Cycling program, or a new Smart Thermostat program involving Title 24 compliant thermostats. To reach this market penetration of customers not already on the two programs mentioned above, SCE assumes another 250,000 customers could be enrolled on a Smart Thermostat program, and that SCE would pay for the cost of thermostats and incentives. Residential incentives are assumed at $25 per summer. For this program, there are procurement savings benefits and distribution related capital spending deferral benefits. SCE used 1 kW/hour load reduction for a 4 degree thermostat temperature setback for customers on the load control program.

4. Analysis of Demand Response Benefits

Demand response benefits accrue from discretionary load reductions by customers. AMI enables the price signals, provides a means of two-way communications to make load control more effective and convenient, and assures a means for the accurate and reliable measurement of load reduction capability. There are various ways to accomplish load reductions. The analysis of demand response benefits offers one approach that yields $481 million in present value net benefits (2008 PV $). Other approaches are possible and SCE intends to further refine its plans for time-differentiated rates and load control that optimize enrollment, load reductions and net benefits to customers.

SCE's demand response approach assumes that by 2015, about 24 percent of customers would be enrolled in either CPP rates or a load control program. In total, it is assumed that about 75 percent of customers would participate in some form of time differentiated rate or load control program.

Distribution related capital deferral related to avoidance of upgrades to existing facilities enabled by AMI provides a significant cash flow benefit to SCE. SCE assumed that 30 percent of the projected distribution capital growth related to existing infrastructure could be deferred due to the AMI projected MW peak load reductions. The remaining 70 percent of sub-transmission and distribution required capital growth related to existing facilities is unavoidable because of necessary upgrades. The deferred capital spending is based on a 10-year average of estimated sub-transmission and distribution capital costs or $463,430 per MW.

Procurement benefits vary by tariff and load control program depending on tariff/program-specific attributes of how often the demand reduction can take place and whether the load reduction is firm or predictable. The avoided procurement capacity and energy benefit assumptions by program are shown in Table II-9.

Table II-9
Assumptions for Avoided Procurement Costs
(Nominal $2006)

Program	Avoided Capacity ($/kW)	Avoided Peak Energy ($/MWh)	Avoided Off Peak Energy ($/MWh)
TOU	92.12	91.80	73.20
CPP	56.07	91.80	73.20
Title 24 PCT	48.86	91.80	73.20
Air Conditioning Cycling	N/A	N/A	N/A
Smart Thermostat	48.86	91.80	73.20

Demand response tariffs and programs involve certain implementation and operational costs. These costs include program or tariff marketing, CPP event notification, increased call handling costs, load control equipment and installation costs, program incentive costs and program administration costs.

Demand response benefits, net of these program related costs are summarized in Table II-10. Procurement benefits and incentive costs relating to the Air Conditioning Cycling program are not included in this table because they already exist and are not incrementally attributable to the AMI project.

Table II-10
Net Demand Response Tariff and
Load Control Program Benefits
(Millions of 2008 PV $)

Program	Procurement Benefits	Distribution Related Capital Deferral Benefits	Program Incentives and Costs	Net Benefits
TOU Rate	227	22	9	239
CPP Rate	113	21	27	107
Title 24 PCT	83	25	53	56
Air Conditioning Cycling	-	53	-	53
Smart Thermostat	91	23	87	26
Total	$514	143	$176	$481

III. MARKET ASSESSMENT

A. Approach to Market Assessment

1. Overview

This Chapter presents the results of SCE's "Market Assessment", which is one of the Phase 1 deliverables. The market assessment involved an evaluation of whether any currently available products and systems are likely to evolve in a way that would meet SCE's AMI requirements. In addition, this Chapter provides an assessment of the Meter Data Management System (MDMS) vendors, describes various technology demonstrations that are underway, and provides an overview of other utility experience with AMI systems.

As described in Chapter IV, SCE is using a comprehensive process to define the meter and communications system requirements for its AMI solution and to determine the level of engineering design and development work required to meet those requirements. The market assessment is a necessary step in that process, providing closure on the "buy or design" decision related to acquiring a viable AMI solution.

SCE's overall market assessment strategy goes beyond a simple evaluation of what is currently available in the marketplace. To realize its AMI design concept, SCE's vision of the potential for additional technology capabilities in future AMI products will need to be endorsed by both the vendor community and other potential purchasers of AMI products and systems. The vendor collaboration approach described in this Chapter uses the system engineering framework described in Chapter IV to influence the development of a new generation of AMI meters by leveraging the experience and knowledge of the vendor community, while minimizing SCE's own development costs. The open innovation process that was outlined by SCE to the vendor community closely resembles a process that is used by many leading firms in industry today. This process was most recently described for Proctor and Gamble's own "Connect and Develop" strategy, which has proven to be very successful in leveraging its research and development resources.[22]

SCE cannot expect vendors to develop new AMI systems solely in response to SCE's requirements, so SCE has adjusted its own requirements, where necessary, so SCE's requirements are more compatible with SCE's perception of the needs of others in the utility industry. SCE believes technology vendors will be far more responsive to SCE's requirements if other major utilities and utility regulators have similar needs and requirements. As a result of our participation in AMI user groups, SCE has learned that many other utilities have similar needs and requirements, and that the vendor community is responding by developing new products and services to address utility needs.

2. Stakeholder and Industry Acceptance

SCE also recognizes the risk that accompanies use of a custom engineering design that is different from the design eventually adopted by the rest of the utility industry. If the AMI products and services obtained by SCE are inconsistent with the AMI technology adopted and used by most of the utility industry, then SCE would face the risks associated with having something that is "one of a kind." With a one of a kind product, there is the potential for increasing life-cycle costs due to maintenance, replacements and repair that would not exist if SCE's design were more in line with what is likely to become the industry standard.

To address this risk, SCE supports efforts by the entire utility industry (*i.e.*, vendors serving the utility industry, utilities and utility regulators) to identify basic requirements that are common to most utilities. Through the process of open

[22] *Connect and Develop: Inside Proctor and Gamble's New Model for Innovation*, Harvard Business Review, Huston, Larry and Sakkab, Nabil, March 2006.

collaboration in technology innovation, these stakeholders can provide input and ideas on design concepts so they can be evaluated during the process rather than after most of the design work is complete. The open collaboration approach is not intended to discourage development of niche products, which may be of value and use to utilities, but to affirmatively encourage development of products and services that have broad utility appeal by meeting not only SCE's basic requirements but the basic requirements of many other utilities as well.

SCE has kept other interested parties apprised of its desire to encourage development of products and services that meet basic utility needs through active participation in "OpenAMI",[23] "UtilityAMI",[24] and AMI MDM.[25] Through this OpenAMI process, AMI concepts and architectures are continually evolving and being refined.

SCE's active participation in OpenAMI has been acknowledged by the industry. This is evidenced in the minutes of the UtilityAMI meeting of April 25, 2006. One key factor cited as "changing the focus of OpenAMI" is:

> *"The pending submission of Use Case and requirements work from SCE. By applying hundreds of person-hours of labor, SCE has produced in a short time much of the work that OpenAMI had hoped to accomplish in developing requirements through Use Cases. The requirements may end up being less generic than if OpenAMI had developed them independently, but they still represent a huge step forward."*[26]

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23 OpenAMI is a collaborative initiative consisting of utilities, vendors, consultants, and other industry stakeholders.

24 UtilityAMI is an advisory group to OpenAMI.

25 AMI-MDM provides a network for discussing issues related to Meter Data Management System adoption and implementation. Membership in the group includes utilities, vendors, regulators, ISOs, consumer advocates and others interested in Advanced Metering, Demand Response and Meter Data Management.

26 Minutes of UtilityAMI Meeting, April 25, 2006, pp.3-4

B. Meter and Communications Market Assessment

1. Objectives

The purpose of performing the AMI vendor and technology market assessment was to gauge next generation product availability and viability as it relates to SCE's AMI system requirements. The goal was to develop a level of confidence that more than one commercial option for AMI meters would be available containing the necessary features to justify costs for broad scale deployment.

A rigorous process was used involving multiple steps and activities designed to influence the direction and timing of vendor AMI product development work. Through this collaborative process, SCE has proactively involved leading manufacturers of Advanced Metering Reading (AMR) and/or AMI technologies through formal and informal settings where ongoing dialogue focused on product enhancements and desired system functionality that could prove beneficial not only for supporting SCE's business case, but also to serve as a platform that could potentially meet the needs of other North American utilities.

Two important questions needed to be answered to accomplish SCE's market assessment objectives:

1. Whether SCE would need to buy or design an advanced metering solution; and
2. Whether the metering and telecommunications products containing the right features and possessing the necessary functionality would be available in a timely fashion.

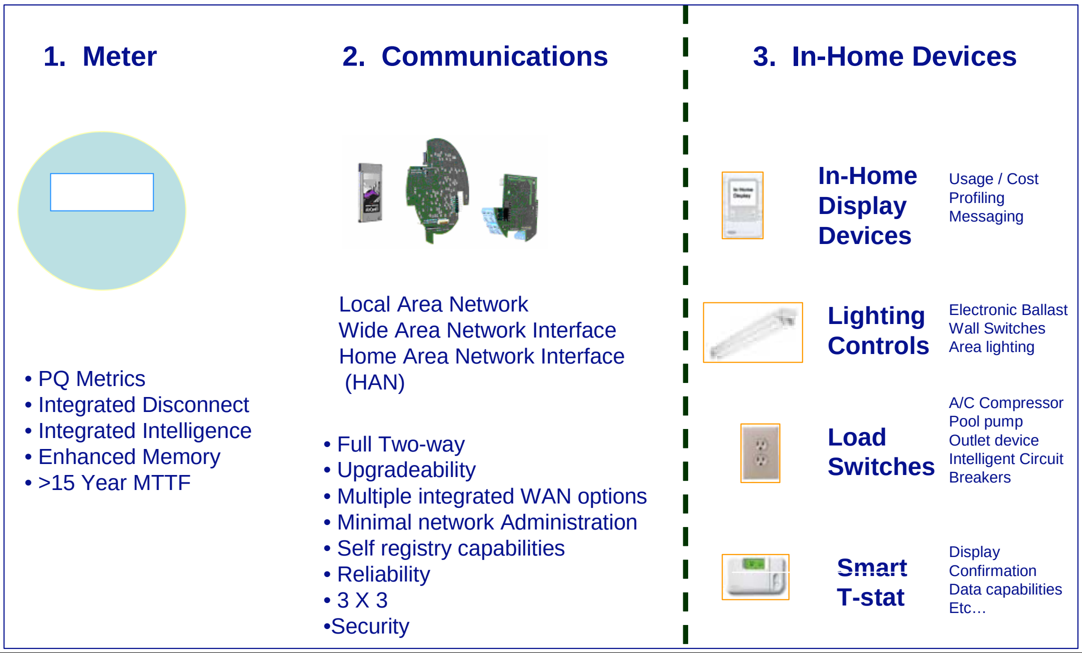
SCE has no intention of entering into the meter manufacturing business, thus the success of its AMI development program relies on strong vendor support. SCE continues its discussions with the vendor community, attempting to share its vision relating the additional benefits to be derived from incorporation of advanced features, most of which were not previously available.

2. Product Segmentation

From the very beginning, SCE has expressed a desire for vendors to pursue interoperability (between meter and communications solution providers) and to use non-proprietary standards-based on Home-Area-Network solutions. SCE's goal is to have multiple meter manufacturers working with multiple communications vendors to ensure metering products can be integrated to accept various communications modules. And conversely, for communications vendors to work with multiple meter manufacturers to ensure their communications modules can be adapted to multiple solid state residential metering platforms. This approach is illustrated in Figure III-1 below.

Among other benefits, vendor interoperability would provide for much greater technology choice for customers. Using a non-proprietary standard based Home-Area-Network solution for the AMI system would also prevent vendor "lock-in" and facilitate the ability of device manufacturers to develop many products for the consumer market. SCE recognizes that a growing market for energy smart devices will be important to enable customers to manage their energy costs. These include smart communicating thermostats, in-home displays, smart lighting control systems, and smart major appliances.

Figure III-1
SCE Market Segmentation Approach



With these issues in mind, SCE began to view AMI as involving three separate parts that would need to work together: (i) meters (sometimes referred to as "metrology"); (ii) communications and supporting network infrastructure; and (iii) networked devices in the home. The goal was to encourage "interoperability" by encouraging "mixing-and-matching." This approach was intended to replace the historical "meter selection by default" approach to meter procurement typically associated with AMR system acquisitions.

3. Product Supplier Research

As a starting point in getting the vendor community more actively engaged, SCE needed to identify the universe of vendors providing AMR/AMI solutions to the marketplace. SCE performed detailed research and used public information and fee based reports and services to identify an initial pool of potential vendors for AMI related products or services. The next step in the process involved obtaining a better understanding of the potential vendors' technology development efforts and how these efforts related to the conceptual capabilities desired in a next generation solution. To achieve this, SCE developed a Market Survey and distributed it in December 2005 to over 100 potential vendors. This included all the North American and International AMR/AMI product suppliers that had been identified as a result of the earlier work.

4. Status of "Next Generation" AMI Technology Development

SCE received encouraging feedback as reflected by the significant response rate to the Market Survey, the level and extent of product development activities among vendors, and the apparent alignment with core feature integration between meter and communication vendors. SCE was also encouraged by the indicated development time-lines and the quoted target product prices. SCE found that significant technology advancements are underway as compared to what was found to be commercially available in the market only 12 months earlier. The information obtained through the survey instrument served as a first "screen" to better identify active industry players.

Telephone interview sessions were scheduled and conducted with respondent vendors. Discussions focused on the response received to the Market Survey and explored core aspects of component level features. The interviews provided SCE with a better understanding of each vendor's AMI technology roadmap and the level of corporate and senior management commitment to their product development efforts and revealed some significant differences between potential vendors. The process served to identify a sub-set of vendors that appeared to be further along in development of products and services that would meet SCE's AMI requirements. The interviews also served to identify future due diligence activities that would need to be undertaken

5. Framing Conceptual Capabilities – TCM Model

Following the telephone interview sessions, SCE evaluated the information it had collected and determined that it needed to merge internally generated system capability requirements those developed through the Use Case process (see Chapter IV) -with the realities of external, near-term product development activity. This was deemed necessary to help shape a set of realistic system and architecture requirements for SCE. The result was development of a Technology Capability Maturity (TCM) Model. This model is a tool that better describes the “meter” and the “communications” elements of an AMI solution. The tool is structured in a matrix format and provides descriptive elements of various architectural and component level features. The matrix serves to ensure uniform comparisons of metering and/or communication system capabilities while capturing data in a format to assist with gauging near term market development activities. The metering and communications TCM models are described more thoroughly in Chapter IV of this report, and are included as **Appendices C and D** respectively.

6. Ongoing Development Efforts

Once the TCM framework was complete, it was again important to obtain feedback from the vendor community. The vendor community was invited to one of two teleconference sessions conducted to explain the TCM and SCE’s intended approach. Following these briefing sessions, SCE conducted a survey using the TCM model. Responses received confirmed various levels of technical maturity in the product development process. The results also revealed that development activity was moving towards products that would likely meet SCE’s needs.

7. Component/Product Testing and Risk Assessment

Based on the information gathered to date, SCE has identified important work that still needs to be accomplished in the remainder of Phase 1. This work includes:

1. Ensuring that candidate AMI products will be available within quoted time-frames for testing;
2. Component level / Functionality testing - SCE will need to perform lab testing of key metrology and communication solution components, along with limited testing of product functionality;
3. Meter and Communications product testing - SCE will need to test pre-commercial and commercial products to ensure that the AMI metering and communications elements meet SCE's requirements and successfully pass select lab testing routines;
4. Integrated Product Testing - SCE will need to perform lab testing on pre-commercial and commercial products containing the desired matching of the metrology platform with the communications module to ensure the fully integrated solution is tested and successfully passes SCE rigorous lab testing environments;
5. Performing risk assessment activities as it relates to evaluating various potential AMI product suppliers' strengths, processes and technologies; and
6. Leveraging, incorporating, and re-testing product enhancement features that may be developed during the late 2007 time-frame.

In addition, near term activities will focus on determining on whether promising meters can work with promising communication module products (as they are prescribed by various network architectures) as part of an integrated AMI solution. SCE is also currently involved in an extensive Local Area Network / Wide-Area Network engineering analysis to evaluate bandwidth, capability, and other criteria that would allow SCE to determine which technology solutions are likely to best meet SCE's AMI goals. These efforts are likely to be helped as it becomes more apparent that the ZigBee standard will likely be the industry's leading choice for Home Area Network communications protocol for residential applications (see Chapter IV). Because this is an open (*i.e.*, non-proprietary) protocol, SCE believes use of this protocol will spur the development of Title 24 compliant PCTs and energy information displays. Getting devices built and available for testing by SCE in advance of or concurrent with Phase 2 field testing will be beneficial SCE's assessment of customer participation in and response to TOU and CPP rates and direct load control programs.

8. Market Assessment Key Findings

The market assessment was an important and necessary undertaking to help answer key questions related to SCE's pursuit of viable technology alternatives. The information obtained reveals that significant technology development activities are underway with a large number of industry suppliers. It further reveals that many of the important features and characteristics that will improve SCE's economic justification for wide-scale AMI deployment, such as integrating a service disconnect switch, will be included in the next generation of AMI products and services.

SCE's plan to pursue next generation AMI technology as described above appears supported by the following key findings:

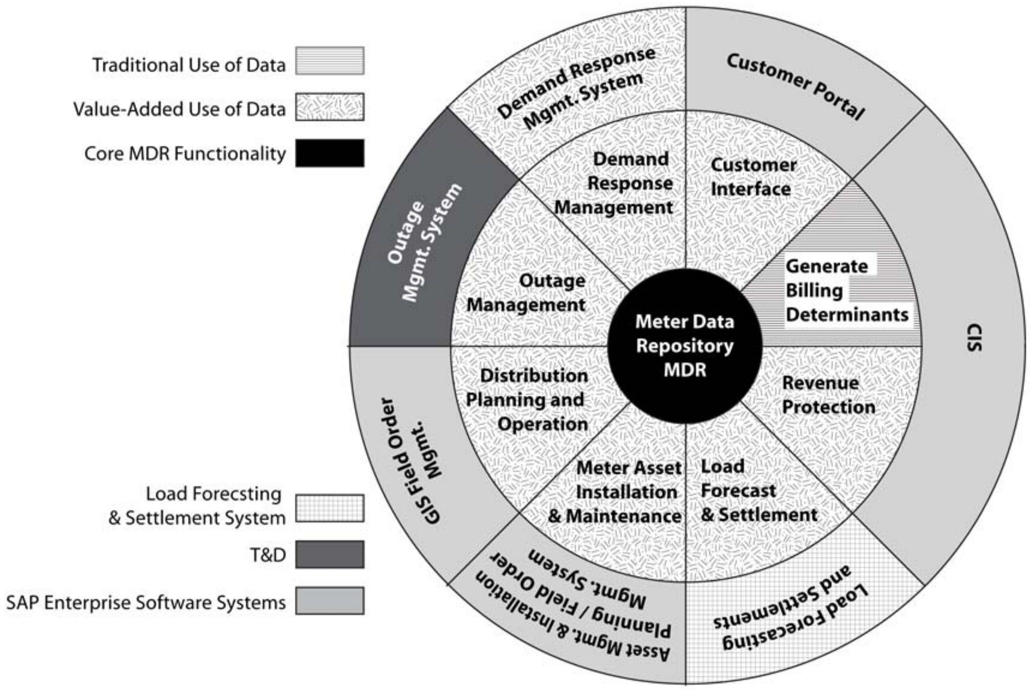
- Many AMI vendors are developing next generation technologies that appear to closely align with SCE conceptual capabilities and system requirements;
- Estimated prices for the next generation technology appear, for the most part, to be within expected ranges;
- Significant cost reductions have been achieved in integrating a connect / disconnect device with a residential solid state meter;
- All of the largest North American meter manufacturers and some international manufacturers are developing next generation metering technology integrating the disconnect / current limiting devices; and
- Products will be available for SCE acceptance testing in 2006.

C. Meter Data Management System (MDMS) Market Survey

1. Role of Meter Data Management in AMI

The Meter Data Management System (MDMS or MDM System) will serve as the system of record for all metered data and will play a central and crucial role in creating and capturing the key benefits from AMI. Data gathered, processed, and made available from AMI via the MDMS will provide near real-time intelligence in many of SCE's utility operations. SCE has adapted the functionality map shown in Figure III-2 from Accenture to serve as a representation of the MDMS Conceptual Design. The diagram illustrates the SCE business functions (as defined through the AMI Use Cases) that interface directly with meter data. The outer circle illustrates other SCE applications for each of the business areas that will be integrated with the MDMS.

Figure III-2
MDM System Functionality



A meter data repository of processed and raw data is accessible to users in eight business areas and interfaces with other SCE applications, which are also able to communicate with SCE's advanced meters through the MDM System. Traditionally, meter data has been used primarily to generate bills and facilitate current demand response programs. As the illustration shows, the functions of the MDMS will provide a substantial expansion of the uses for meter data. The MDMS will enable many other functions to access data and use it to improve SCE's business operations.

2. <u>MDMS Market Research and Survey</u>

SCE has researched the availability of MDMS vendors and packaged software during this first phase of the AMI project. This effort has led to some key discoveries and direction for developing a MDM System. SCE also joined AMI-MDM in early 2006.

SCE's engaged Accenture to conduct a formal market survey of meter data management software packages. The purpose of this survey was to assist SCE in understanding the scope of currently available MDMS solutions, developing a framework for evaluating solution options, and evaluating these options against the framework. The market survey investigated seven leading MDMS vendors, and evaluated each using the 12 criteria listed here:

1. Functional Fit
2. Scalability
3. Flexibility/Configurability
4. Solution Direction – Technical
5. Solution Direction – Functional
6. Ease of Integration
7. Ease of Use/Access to Data
8. Vendor Business Risk
9. Proven Track Record
10. Organizational Impact
11. Total Cost of Ownership
12. Speed to Implement

To evaluate how well vendors' products aligned with SCE's business requirements, Accenture utilized the Functionality Map (see Figure III-2 above). The market survey provided SCE an analysis of how well each MDMS vendor's product matched SCE's expected business functions under the AMI program.

The analysis looked at the functionality, costs, risks, implementation time, development time, and license fees, and concluded that the most effective approach is to acquire a Commercial Off-the-Shelf (COTS) software package.

It was further identified that while existing products do not yet meet all of SCE's requirements, the leading MDM Systems could be enhanced to provide the functionality required in time to support the AMI program deployment. Discussions with MDMS vendors confirms this conclusion, and SCE will further test this assumption through validation responses to the MDMS Request For Information (RFI) release in June and selected product testing in the remainder of Phase 1.

3. MDMS Business Requirements

SCE has done extensive work during Phase 1 to develop business requirements for the MDM System. The 18 Use Cases to be described in Chapter IV of this report provided a base foundation for defining these requirements. Further work has been done to develop business requirements and define the requirements for the process of "validating, editing and estimating" (VEE) billing data. The requirements for accurately processing 720 data points for each residential customer (24 hours/day x 30 days) will need to be significantly more detailed than the process that currently validates only one data point per residential customer each month. SCE has developed and published a preliminary set of requirements for MDMS in conjunction with the RFI. SCE expects to complete work to define the detailed VEE requirements, which will be included with a full set of business requirements for the system functionality in a MDMS Request for Proposal (RFP) to be issued by SCE in the fourth quarter of 2006.

D. Technology Demonstrations

Product demonstrations are an important component of SCE's market assessment. These demonstrations include the following.

1. SCE recently completed a 6-month pilot test of narrowband power line communications,[27] which tested remote, on-demand reading with 200

[27] The powerline carrier pilot is funded outside the AMI Program.

residential meters. This pilot involved three components: network management, substation control, and meters with an AMR module. This pilot test provided a better understanding of project costs, equipment installation, reporting capabilities, alarms and other features. It also gave SCE experience with polling strategies and capabilities, and provided an opportunity to test vendor support/ availability and responsiveness.

2. SCE initiated a proof of concept of Broadband over Power Line (BPL) communication technology in 2005[28] to determine potential utility uses for communications over an energized power line. This testing includes two electric meters and demand response devices in the context of AMI.

   One objective of the ongoing testing and evaluation is to understand the real-world operating implications of such a system and examine the feasibility of utilizing BPL in support of AMI.

3. SCE has just acquired three different remote disconnect switches, and will perform component level evaluation of these devices in preparation for conducting tests on the meters with integrated switches once those products are received. (SCE expects to begin receiving integrated meter products in August 2006).

4. SCE will conduct an evaluation of 900MHz Radio Frequency (RF) at a vacated residential area in a former military base to help us understand certain characteristics of RF and do some high level validations of our computer models.

E. Acceptance of AMI Systems Among Other Utilities

SCE has researched the current status of AMI acceptance across the nation and in other parts of the world.[29] The outcome of this research shows there is clearly a significant trend towards new technologies with the utilities themselves providing much of the impetus for manufacturers to advance their products.

Worldwide, utility adoption of advanced metering is increasing for a number of reasons. Technology is enabling cost-effective robust solutions that provide more benefits than remote meter reading alone. There is growing interest in using

[28] The BPL proof of concept is funded outside the AMI Program.

[29] A more complete description of this research is contained in a separate report sponsored by SCE entitled *AMI Project Assessment and Analysis*, authored jointly by Positive Energy Directions and Corepoint Associates, Inc., dated June 9, 2006.

advanced metering for demand response, grid automation applications and other customer benefits. Prices for AMI systems are declining, making the range of solutions more attractive than in the past. Utilities are still deploying AMR systems but the number of utilities pursuing business cases and deployments for advanced AMI systems is increasing. For example, Manitoba Hydro in Canada recently announced it will be the first utility to deploy a new, advanced metering and communication technology[30] that comes very close to SCE's vision for AMI. This technology combines two-way communications to each meter with an open-protocol, standards-based architecture. It provides options for radio frequency, power line carrier, broadband over powerline as well as many other public, private, wired and wireless Internet Protocol-based communications networks operating as standalone or in combination.

In addition to California's AMI initiative, many other utilities across North America and Europe are investing in technology to replace manually-read meters. U.S. utilities have installed over 27 million remote-read meters out of a total market of 130 million and have announced plans to install another 30 million meters. Many other utilities are also considering their options as the technology improves and costs decline.

The factors behind this recent increase in interest and visibility have been well documented: state regulatory policies; the federal Energy Policy Act of 2005 ("EPACT");[31] the need for operational improvements; cost savings through personnel reductions, opening of markets (necessitating different billing methodologies); and the "buzz" of the smart grid and potential new business opportunities. These factors are coupled with advances in technology and computational power, which finally allow some of the promises of advanced systems to be realized.

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30 Manitoba Hydro / ITRON Corp. Joint News Release, dated June 29, 2006.

31 EPACT specifically requires all state commissions to analyze the potential for intelligent metering and report back in 18 months but fails to provide any penalties—or rewards.

Utilities are investing in a wide range of metering technologies and systems. The largest electric deployments recently announced include a 3.8 million unit deployment of a fixed radio network advanced meter system (DTE Energy), a 5 million electric meter 2-way communicating power line carrier based AMI system (Pacific Gas and Electric) and a 2 million meter BPL deployment by TXU. Some utility deployments, such as Progress Energy's 2.7 million meter deployment, involve installing meters that initially communicate to a mobile "drive-by" receiver that can be upgraded to a fixed network communications system later.

The French utility EDF and the Netherlands' utilities Nuon and Energined are all pursuing advanced metering, representing a combined total of over 40 million total meters. Although different electric technical standards exist between Europe and North America, innovation to meet a growing advanced meter market on both continents is getting meter vendors' attention.

Growing interest in AMI by state and federal regulators in the United States is causing many large utilities to consider advanced meter technology. As a result, the market for AMI is clearly growing and vendors are taking notice. All of the major meter manufacturers are adding AMI functionality to their basic residential meter. AMR/AMI solution vendors are expanding their communications throughput capability and reach.

CERTIFICATE OF SERVICE

I hereby certify that on this 6th day of October, 2006, I served the foregoing Surrebuttal Testimony of the Citizens' Utility Board of Oregon in docket UE 180 upon each party listed below, by email and U.S. mail, postage prepaid, and upon the Commission by email and by sending 6 copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

Respectfully submitted,

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W=Waive Paper service, Q=Confidential

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