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October 18, 2010

Arizona Corporation Commission
DOCKETED
OCT 18 2010
DOCKETED BY

Commissioner Gary Pierce
Commissioner Paul Newman
Commissioner Sandra Kennedy
Commissioner Bob Stump
Parties to the Docket

RE: **Draft ACC Policy Statement regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures, Docket Nos. E-00000J-08-0314 and G-00000C-08-0314.**

Dear Colleagues and Parties to the Docket:

Attached you will find a Draft ACC Policy Statement regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures. You will see that it includes a detailed account of the Commission's workshops on these issues held over the course of this year, as well as a series of policy statements, followed by an ordering paragraph.

I welcome the comments of all those involved with the workshops on this proposed policy statement. In addition to providing their input on the draft policy statement, I would like the utilities that participated in the workshops to answer the following question:

1. The Lawrence Berkeley National Laboratories' ("LBNL") analysis of the benefits associated with the commission's Energy Efficiency Standard, as presented and discussed in the workshops, identified $5.2 billion of ratepayer bill savings at Tucson Electric Power ("TEP") and Arizona Public Service Company ("APS") combined, even accounting for the rate impacts associated with decoupling. Please confirm for the Commission the basis of these savings, i.e. I would like both TEP and APS to identify which generation plants, both baseload and peaking, will be deferred as a result of the energy efficiency standard and for how long those plants will be deferred.
2. If any utility that advocated for decoupling now believes that any of the deferrals identified in the LBNL analysis will not occur, please state so and any reasons for this change in assessment.
3. Please tell the Commission what your 2011 Integrated Resource Plans, to be filed soon with the Commission pursuant to the ACC's IRP rules, will state with regard to the Energy Efficiency Standard's impact on generation deferrals at your utility.

I would like the Participants in this docket, as well as any of the interested Parties, to file written comments regarding the draft in Docket Control within 10 days.

Thank you for your attention to this draft policy statement and I look forward to scheduling with my colleagues a time for further discussion of the draft and the responses filed to it.

Sincerely,

Kris Mayes
Commissioner

Cc: Ernest Johnson
Lyn Farmer
Janice Alward
Steve Olea

ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures

Introduction

Several factors underscore the need for increased energy efficiency in Arizona. Historically, Arizona has experienced high population growth and corresponding increases in demand for energy which has required significant investments in distribution, transmission and generation facilities and led to increased utility infrastructure and operational expenses.

While growth is anticipated to continue in the future, expanded demand side efforts, such as energy efficiency and demand response, can moderate rate pressures otherwise experienced from growth and reduce customer utility bills. Expansion of demand side management programs is cost effective, promotes price stability, mitigates exposure to volatile fuel prices, creates cost savings opportunities for customers and limits unnecessary load growth.

Since June 2008 the Commission, in this generic docket (08-0314) and subsequent Notice of Inquiry ("NOI"), has been investigating utility financial disincentives to energy efficiency and considering how it can address these issues and maximize energy efficiency efforts at Arizona's utilities.

On December 18, 2009, the Commission issued a Notice of Proposed Rulemaking on Electric Energy Efficiency, which adopted an energy efficiency requirement for Arizona's electric utilities. The proposed rules require cumulative annual energy savings of 22% by December 31, 2020 for Arizona's largest electric utilities. The proposed energy efficiency rules recognize potential utility disincentives to achieving the Energy Efficiency Standard ("EES") and include provisions providing for Commission review of

measures designed to address these disincentives in future rate cases. Similar energy efficiency rules are currently being developed for Arizona's gas utilities. On August 25, 2010, the Commission issued a Notice of Proposed Rulemaking on Gas Energy Efficiency, which adopted an energy efficiency requirement for Arizona's gas utilities to achieve cumulative annual energy savings of 6% by December 31, 2020.

Purpose

Properly addressing disincentives to energy efficiency is important to the Commission, the companies involved, and Arizona's utility consumers. Traditionally, Arizona's utilities have been disincented to vigorously utilize demand-side management programs to meet their resource needs. An internal conflict exists for utilities between sales growth and promotion of programs or technologies which reduce sales, as these sales offer the opportunity to recover fixed costs and earn profit; sales erosion may impact recovery of fixed costs and investment returns. To the degree to which utility fixed costs are recovered from volumetric sales, a net lost revenue and profit erosion effect exists which could act as a distinctive to utilities robustly seeking to implement energy efficiency measures. This utility disincentive to reduce sales discourages demand-side management programs which could ultimately benefit customers and minimize utility rates and customer utility bills.

In recognition of the need to fully utilize supply and demand side options for meeting resource needs in Arizona, the Commission has been considering alternate approaches it could adopt to spur the use of demand side programs. On February 23, 2010 the Commission issued a Notice of Inquiry to solicit input on utility disincentives and decoupling frameworks. The responses to the Notice of Inquiry led to Commission

Workshops on decoupling and a study by the Lawrence Berkeley National Laboratory ("LBNL") examining the potential impacts of energy efficiency savings goals and decoupling through 2030. The Regulatory Assistance Project also participated in and provided technical assistance during the Commission Workshops.

Description

A revenue decoupling mechanism is a ratemaking design which reduces or removes the linkage between sales and utility revenues and/or profits, reducing utility disincentives to the adoption of programs that benefit customers by saving energy, but which also contribute to sales erosion and under-recovery of authorized fixed costs. Several states have utilized decoupling as a means of bolstering their energy efficiency efforts and the American Recovery and Reinvestment Act of 2009 (ARRA) has asked participating states to consider general policies that ensure that utility financial incentives are aligned with helping customers use energy more efficiently. Arizona, in accepting ARRA funding, agreed to analyze and consider these policies.

Mechanically, revenue decoupling compares actual versus authorized revenues or revenues per customer over a period and either credits or collects any differences from customers in a subsequent period. This collection would include, among other things, revenue impacts associated with implementation of demand side programs.

States which have implemented revenue decoupling have addressed several issues within the decoupling design. Among the design and implementation issues are the application of the mechanism to all or only some customer classes; whether to include or exclude weather related sales fluctuations; and the frequency, nature, and allowed amount of true-ups or decoupling adjustments.

Revenue decoupling achieves the primary purpose of reducing utility disincentives to implementing demand side programs and reducing energy consumption. While decoupling alone does not directly lead to increases in utility promotion of energy efficiency, decoupling paired with energy efficiency requirements creates an effective environment for the implementation and promotion of demand side programs.

The Commission recognizes that alternative mechanisms to addressing utility disincentives may exist, such as implementation of fully-cost based rates, development of lost revenue mechanisms or incorporation of anticipated energy efficiency effects into rate case forecasts. While these measures address some utility disincentives, they can lead to significant bill impacts or prove complex and administratively challenging to implement.

The Commission believes that, properly structured, decoupling offers significant advantages over alternative mechanisms to addressing utility disincentives which furthers the utilization of demand-side resources.

DECOUPLING WORKSHOPS

The Commission conducted workshops in April, May, and June of 2010 to address issues raised by the Notice of Inquiry, stakeholder concerns and an analysis of energy efficiency goals and decoupling prepared by LBNL at the Commission's request.

April 15-16, 2010 Workshop

The April 15-16, 2010 workshops principally provided background information on decoupling and addressed stakeholder responses to the Notice of Inquiry, highlighting areas of agreement and issues which required further consideration.

Participants noted that the Commission's EES "...changes the landscape for energy efficiency in the state"[1] and that significant growth in energy programs results in "...growth in the impacts...."[2] Modest sales reductions, such as those likely to result from utility energy programs, were alleged to have significant impacts on utility earnings. Decoupling was identified as a means of holding revenues constant by fluctuating prices up and down in the opposite direction of sales changes.[3]

Among the issues identified regarding decoupling, parties spoke to the timing of true-ups, the benefits of full versus limited decoupling, and limitations or collars on the decoupling adjustments.[4] Extensive discussion centered on the effect of decoupling on utility risk and cost of capital, and whether recognition of the risk mitigation implied by decoupling could be synchronized with the adoption of decoupling. The Commission was cautioned that adoption of decoupling through a pilot program or limited term may not provide investors sufficient certainty to merit cost of capital benefits at the outset.[5] Explicit adoption of decoupling with a periodic review was identified as an alternative option to pilot adoption.[6]

Utility representatives spoke on behalf of Arizona Public Service Company ("APS"), Tucson Electric Power ("TEP"), Southwest Gas ("SWG"), and the Grand Canyon State Electric Cooperative Association ("GCSECA"). Utility representatives generally argued that decoupling, or similar mechanisms, were necessary to support the

[1] TR Vol I, Pg 15, 24-25.
[2] TR Vol I, Pg 30, 18-19.
[3] TR Vol I, Pg 68, 4-5.
[4] TR Vol I, Pgs 79-90.
[5] TR Vol II, Pg 164, 12-18; TR Vol II, Pg 170, 9-14.
[6] TR Vol II, Pg 187, 6-16.

Commission's energy efficiency requirements[7] and largely advocated a revenue per customer form of full decoupling.[8]

In supporting decoupling, utility representatives identified the need to align utility and customer interests,[9] the generation infrastructure that could be deferred as a result of decoupling, [10] environmental benefits which would result from deferral of future generation,[11] a heightened focus on operational expenses[12] and the likelihood of better and less expensive resource portfolios for customers in the long run.[13] Utilities preferred full decoupling to limited decoupling, for its administrative simplicity, stating that it would result in cost minimization and lessen adversarial hearings.[14]

In response to questions as to whether Arizona should engage in a broad approval of decoupling, utilities responded that a rulemaking would provide a framework and parameters but the expectation was that utilities would more fully address issues within a rate case proceeding.[15] When asked which time interval should be used to reconcile revenues - annual, semi-annual or quarterly - utilities supported at least annual reconciliation with several arguing in favor of more frequent adjustments allowing customers to receive offsets in the event of extreme weather events.[16]

In response to questions about how to control for excessive rate impacts associated with decoupling and whether a "dead-band" would be appropriate, utilities

[7] TR Vol II, Pg 198, 3-12; TR Vol II, Pgs 203, 18 through 204, 15; TR Vol II, Pg 213, 14-21; TR Vol II, Pgs 222, 25 through Pg 225, 13.
[8] TR Vol II, Pg 198, 14.
[9] TR Vol II, Pg 200, 17-18; Pg 205, 1-6.
[10] TR Vol II, Pg 201, 6-10.
[11] TR Vol II, Pg 201, 10-13.
[12] TR Vol II, Pg 223, 10-18.
[13] TR Vol II, Pg 207, 8-10.
[14] TR Vol II, Pgs 300, 10 through 303, 19.
[15] TR Vol II, Pgs 304, 13 through 305, 19.
[16] TR Vol II, Pgs 305, 20 through 311, 15.

supported a dead-band in concept and favored annual caps or a collar of at least three percent.[17]

The Residential Utility Consumer Office ("RUCO") indicated it is not opposed necessarily to decoupling, however it believed "...any recovery mechanism must, one, be cost effective; two, contain a detailed commitment to energy efficiency;...three, have a high degree of accountability and transparency; and four, have a cap on the amount that may be recovered."[18] Parties largely agreed with RUCO's position and believed planned and existing requirements under the Commission's EES addressed some of the expressed concerns.[19]

Commission Staff recognized impacts to utility fixed cost recovery from energy efficiency[20] and indicated a need to balance the incentives of the utilities wanting to sell more and policies asking customers to use less.[21] Staff further stated it believed it would be appropriate to adjust capital structures to the extent decoupling enhanced revenue stability.[22] In addressing decoupling, Staff indicated that Arizona's utility companies were unlikely to achieve the EES without some kind of cost recovery, whether decoupling or other form of rate recovery.[23]

Representatives for Arizonans for Electric Choice and Competition ("AECC") opposed decoupling, stating that any discussion would best be had in a general rate case[24] and arguing that industrial consumers were probably not a good target for revenue

[17] TR Vol II, Pgs 312, 10 through 315, 3.
[18] TR Vol II, Pgs 232, 22 through 233, 4.
[19] TR Vol II, Pgs 233, 12 through 234, 3; Pgs 234, 15 through 235, 11; Pg 236, 3-19; Pg 237, 2-13.
[20] TR Vol II, Pgs 254 line 25 through 255, line 3.
[21] TR Vol II, Pg 256, 20-23.
[22] TR Vol II, Pgs 259, 16 through 260, 3.
[23] TR Vol II, Pg 265, 3-15.
[24] TR Vol II, Pg 284, 5.

decoupling.[25] While AECC indicated its opposition to revenue decoupling, it further stated that if decoupling was adopted AECC would want to see clear and careful review on return on equity.[26]

Representatives for the Arizona Investment Council ("AIC") spoke in favor of decoupling, arguing that there are benefits that accrue to consumers from such a mechanism.[27] AIC further stated that the Commission must pay attention to energy efficiency programs to be able to reach out and get as many customers as possible engaged in conservation.[28]

Marshall Magruder noted that avoided costs could result for both utilities and consumers, from aggressive adoption of energy efficiency, where lower operational demands ease maintenance requirements.[29]

In concluding the meeting, specific questions were posed to utility representatives regarding appropriate decoupling designs. In response to questions as to whether Arizona should engage in a broad approval of decoupling, utilities responded that a rulemaking or policy statement would provide a framework and parameters but the expectation was that utilities would more fully address the adoption of decoupling within a rate case proceeding.[30] When asked which time interval should be used to reconcile revenues, annual, semi-annual or quarterly, utilities supported at least annual reconciliation with several arguing in favor of more frequent adjustments allowing customers to receive offsets in the event of extreme weather events.[31]

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[25] TR Vol II, Pg 284, 14-18.
[26] TR Vol II, Pg 286, 1-8.
[27] TR Vol II, Pg 294, 13-22.
[28] TR Vol II, Pg 296, 7-11.
[29] TR Vol II, Pgs 297, 13 through 298, 7.
[30] TR Vol II, Pgs 304, 13 through 305, 19.
[31] TR Vol II, Pgs 305, 20 through 311, 15.

In response to questions about how to control for excessive rate impacts associated with decoupling and whether a "dead-band" or collar would be appropriate, utilities supported a dead-band in concept and favored annual caps of at least three percent.[32] When asked whether changes to capital structure to reflect reduced risk were in order, utilities encouraged caution and a fuller record to develop the issue.[33] In addressing questions regarding appropriate reporting and evaluation, utilities and stakeholders responded that the reporting required under the energy efficiency rules was significant, however, additional information specifically related to decoupling would likely be needed.[34] In response to concerns raised about maintaining customer service standards, stakeholders and utilities asserted that decoupling would not minimize the focus on customer service and the energy efficiency rules would require the development of enhanced customer relationships and interaction.[35]

In response to questions regarding the reception of the investment community to decoupling, electric utilities responded that some concerns had been expressed regarding details and more specifically about how a decoupling mechanism would address growth.[36] SWG stated its discussions with ratings agencies indicated a positive reception for decoupling.[37]

In response to questions regarding application of decoupling to customer classes, APS indicated that there were merits to both class specific and aggregated mechanisms,[38]

[32] TR Vol II, Pgs 312, 10 through 315, 3.
[33] TR Vol II, Pgs 322, 2 through 329, 12.
[34] TR Vol II, Pgs 330, 14 through 336, 7.
[35] TR Vol II, Pgs 336, 11 through 344, 9.
[36] TR Vol II, Pg 344, 16-23; Pgs 345, 22 through 346, 4.
[37] TR Vol II, Pg 349, 19-25.
[38] TR Vol II, Pg 351, 6-12.

TEP expressed a preference for a by class mechanism,[39] and SWG expressed a preference for application to all classes.[40]

May 3, 2010 Workshop

The May 3, 2010 workshop principally addressed rate design issues associated with decoupling, common concerns raised regarding decoupling, impacts on participating and nonparticipating customers and a discussion of technical issues amongst participants.

It was argued that decoupling is a means of pursuing rate designs better structured to drive energy efficient outcomes. Stakeholders noted that decoupling "…allows the Commission to… set rates that are based on long-run marginal costs without creating the new revenue volatility for the utilities."[41] Energy efficiency benefits were identified where rates were based on long-run marginal costs.[42] Stakeholders stated that properly designed rates have resulted in dramatic conservation effects.[43] It was asserted that the Commission must ensure that its actions on rate design now and in the future must be internally consistent with energy efficiency programs and internally consistent with ratemaking treatment and decoupling, with each reinforcing the other and moving utilities in the same direction.[44]

Stakeholders highlighted common criticisms of decoupling, including that it is a different approach to ratemaking,[45] it could serve as a disincentive for a utility's management to control costs,[46] that it diminished risk for investors,[47] that it should

[39] TR Vol II, Pg 351, 16 through 352, 1.
[40] TR Vol II, Pg 352, 8-11.
[41] TR Vol III, Pg 369, 21-24.
[42] TR Vol III, Pgs 373, 25 through 374, 4.
[43] TR Vol III, Pg 407, 3-4.
[44] TR Vol III, Pg 376, 10-16.
[45] TR Vol III, Pg 411, 5-13.
[46] TR Vol III, Pgs 411, 25 through 412, 13.
[47] TR Vol III, Pgs 412, 14 through 413, 2.

require a demonstrated commitment to energy efficiency,[48] that it could diminish utility support for economic development,[49] and that energy efficiency savings are not necessarily being caused by utilities.[50]

Other concerns raised with respect to decoupling included the differences between new and existing customers in a decoupling design. With straight revenue per customer decoupling, new customers utilizing less gas or electricity than existing customers could drive upward rate pressure as rates for existing customers would need to make up the difference between revenues received at current rates from new customers and the allowed revenue per customer.[51] In response to this issue, some parties stated that decoupling models could adjust revenues per customer downward year by year to reflect what would happen in the absence of decoupling, or a bifurcated approach could be used for existing and new customers.[52]

Stakeholders addressed impacts of decoupling on customers who participated in energy efficiency programs and nonparticipating customers. For customers who adopted energy efficiency measures, decoupling slightly eroded some of the savings they received.[53] For nonparticipants, decoupling contributed to slight increases in rates.[54] Robust customer participation was identified as a means of addressing impacts to all customers, with particular focus on low income customers who could be most at risk.[55] Particular attention was paid to utility plans for scaling up programs, reaching as many

[48] TR Vol III, Pg 413, 3-13.
[49] TR Vol III, Pgs 413, 14 through 414, 14.
[50] TR Vol III, Pg 424, 4-13.
[51] TR Vol III, Pg 417, 2-1.
[52] TR Vol III, Pgs 418, 12 through 419, 2.
[53] TR Vol III, Pgs 426, 14 through 429, 4.
[54] TR Vol III, Pgs 426, 14 through 429, 4.
[55] TR Vol III, Pgs 429, 21 through 430, 13.

communities as possible and touching all customers with energy efficiency programs, so that the number of nonparticipants would be minimized.[56]

In response to questions regarding maintenance of service quality standards,[57] the utilities responded that service quality was being addressed in existing operations, but that the key consideration with respect to decoupling was establishing the appropriate performance benchmark that utilities would be required to achieve.[58]

In response to questions regarding opposition to decoupling by ratepayer advocates and the National Association of State Utility Consumer Advocates[59]("NASUCA"), parties recognized a need to explain to the public the policies that the Commission is adopting and implementing.[60] Utilities were encouraged to develop plans for communicating decoupling and energy efficiency to their customers.[61]

In response to questions regarding third party administration of energy efficiency, parties noted that the third party administrator model has been successful where implemented but was not necessarily superior to a utility based model.[62] Existing third party involvement was identified in the areas of measurement, evaluation and research.[63] It was suggested by some parties that utility administration of energy efficiency programs has largely been successful in Arizona and it was further noted that the regulatory compact accorded the Commission better opportunities to steer regulated utilities than with a third party administrator operating under a contract.[64]

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[56] TR Vol III, Pgs 435, 15 through 436, 20.
[57] TR Vol III, Pg 438, 4-23.
[58] TR Vol III, Pgs 437, 24 through 442, 13.
[59] TR Vol III, Pg 454, 10-22.
[60] TR Vol III, Pg 457, 20-25.
[61] TR Vol III, Pg 461, 13-25.
[62] TR Vol III, Pgs 466, 22 through 467, 18.
[63] TR Vol III, Pg 469, 18-21; Pg 472, 11-19.
[64] TR Vol III, Pg 471, 2-20.

In technical discussions, parties outlined decoupling models which could be appropriate for Arizona. Assuming revenue per customer decoupling, which was supported by many workshop participants: principal concerns revolved around the customer classes that would be affected, distribution of adjustments, rate design, accrual methodology, weather risk, caps on decoupling adjustments and whether new customers merited different treatment than existing customers.[65]

In response to the issue of treating new customers distinctly from existing customers, parties noted that one approach by a Washington utility was to leave new customers entirely out of the decoupling mechanism and apply adjustments solely to existing customers between rate cases.[66] Electric utilities noted little difference between new and existing customers[67] and remarked that the issue would likely be more pronounced for gas utilities. Parties suggested that further analysis was needed to examine whether any difference existed between new and old customers and whether such a difference required particular treatment.[68]

Parties raised concerns regarding the application of decoupling adjustments to customer classes, particularly with respect to industrial customers, arguing that some customer classes lacked enough homogeneity to lend themselves to revenue decoupling, and that industrial classes often do not contribute significantly to the recovery of fixed costs.[69] Some parties argued that application of decoupling adjustments may be inappropriate for small customer classes with fewer than one hundred customers.[70] Others

[65] TR Vol III, Pgs 482, 2 through 483, 23.
[66] TR Vol III, Pgs 486, 3 through 488, 2.
[67] TR Vol III, Pgs 488, 17 through 490, 8.
[68] TR Vol III, Pg 493, 11-24.
[69] TR Vol III Pgs 494, 14 through 496, 15.
[70] TR Vol III Pg 497, 11-22.

asserted that decoupling should lean towards broad inclusion with participation from all customers through a certain demand level.[71] Recognizing the unique issues faced by individual utilities, some argued that these issues would best be dealt with on a utility-by-utility basis.[72]

Related to the customer class issue was the question of whether shortfalls or over recoveries should be spread evenly across classes or specifically within classes.[73] Parties noted that states have approached this issue in both ways; class distribution was seen as keeping costs and adjustments focused within a class but potentially leading to larger per unit adjustments, while across-class adjustments smoothed out overall impacts but potentially led to some level of subsidy between classes.[74] In addressing the distribution of adjustments among customer classes, parties noted that adjustment collars could minimize fluctuations and could be seasonally tailored where more current adjustments were utilized.[75]

Discussion segued into whether decoupling adjustments should be current, monthly, or annualized. Parties noted that further examination of the utilities' billing system infrastructure would be necessary to determine whether a utility's existing systems could functionally support more current adjustments.[76] In response to questions regarding administrative burdens, parties noted that monthly decoupling adjustments would likely require less work than fuel cost adjustments, as the data for the former would come directly from the billing systems.[77]

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[71] TR Vol III, Pg 499, 3-18; Pg 502, 5-9.
[72] TR Vol III, Pgs 502, 22 through 503, 25; Pg 508 4-12.
[73] TR Vol III, Pg 513, 6-13.
[74] TR Vol III, Pgs 515, 22 through 516, 11.
[75] TR Vol III, Pgs 516, 19 through 518, 18.
[76] TR Vol III, Pg 521, 6-14.; 522, 4-16.
[77] TR Vol III, Pg 523, 15-21.

Parties addressed the ability of decoupling to facilitate improved rate designs that could encourage conservation and other goals.[78] Rate designs which solely utilized volumetric rates with no customer charges and use of inverted block rates were identified as concepts worthy of discussion.[79] While decoupling was recognized for facilitating rate designs, caution was urged, particularly if decoupling was adopted as a pilot and not a permanent mechanism.[80] Cooperatives were open to exploring changed rate designs, but expressed reluctance toward any elimination of customer charges.[81] If straight fixed/variable cost rates were adopted in lieu of decoupling, utility customer charges alone would range from $22 to $70 per month with additional charges for variable costs.[82]

In response to questions regarding adoption of a pilot program or implementation with review, RUCO noted it did not support decoupling, nor was RUCO opposed.[83] RUCO's stated concerns were the perception that decoupling adjustments were driven by factors other than utility efforts, such as weather, and impacts of decoupling on customers who implemented no energy efficiency measures.[84]

In response to questions about whether decoupling was appropriate for cooperatives, parties stressed the need for administrative simplicity, given the cooperatives' more limited resources.[85] Parties remarked on the unique characteristics of

[78] TR Vol III, Pg 525, 15-25.
[79] TR Vol III, Pg 526, 2-19.
[80] TR Vol III, Pg 526, 20-24; Pg 532, 1-9; Pg 533, 11-18.
[81] TR Vol III, Pg 529, 4-19.
[82] TR Vol III, Pgs 537, 23 through 538, 13.
[83] TR Vol III, Pg 545, 3-6.
[84] TR Vol III, Pgs 545, 7 through 546, 7.
[85] TR Vol III, Pg 556, 7-18.

rural cooperatives and noted that the cooperatives were beginning to implement programs and would need to be very aggressive in the future in order to comply with the EES.[86]

Echoing the cooperatives comments regarding administrative simplicity, parties reiterated that full decoupling offered more straightforward calculations than if weather and other non-efficiency related effects were removed.[87]

May 24, 2010 Workshop

The May 24, 2010 workshop focused on utility historical analyses of rates if decoupling had existed between 2000 and 2010, LBNL's preliminary analysis of the impact of the electric Energy Efficiency Standard and decoupling on APS and its customers, and follow-up on recommended decoupling designs and related issues.

APS presented a ten-year look back analysis that had been requested by Commissioners and noted that if decoupling had existed over that interval, customers would have experienced both refunds and surcharges of roughly one and a half percent.[88] Similar conclusions were reached whether the examination was based on an actual sales basis or a weather normalized approach, though the weather normalized approach produced slightly more revenue over the ten-year period.[89] APS analyzed a revenue per customer approach, modeling the fixed cost by class, excluding fuel costs, transmission costs, regulatory assets, special surcharges and system benefits from the calculation.[90] Parties noted that APS' findings underscored other research which contends that,

[86] TR Vol III, Pgs 558, 17 through 559, 8.
[87] TR Vol III, Pgs 560, 11 through 562, 13.
[88] TR Vol IV, Pgs 586, 21 through 587, 12.
[89] TR Vol IV, Pgs 587, 19 through 588, 2.
[90] TR Vol IV, Pg 589, 12-22.

nationally, decoupling mechanisms tend to result in adjustments that are less than three percent.[91]

TEP's decoupling calculations resulted in similar findings to APS, largely falling below three percent.[92] Similar results were identified for both UNS Electric and UNS Gas, as they stayed within a three percent cap; however, greater volatility was identified for UNS Gas.[93] In response to greater gas volatility, parties suggested that a larger collar or cap be utilized and that balances be allowed to carry forward if the collar is exceeded.[94]

SWG's decoupling calculations reflected modest customer impacts, with a minimum impact of $.86 to a maximum impact of $2.61, with an average of $1.53.[95] The company noted that the decoupling impact on a customer bill was relatively small in relation to the total customer bill.[96] While SWG acknowledged that the adjustments exceeded three percent, rising to nearly six percent in some cases, they argued that the dollar impact remained modest considering that the average gas bill was lower than the average electric bill.[97] In response, parties argued that consideration could be given to a larger cap for gas utilities.[98]

Following the utility presentations of their historical analyses, LBNL presented its preliminary analysis of APS with the implementation of the electric EES, with and without decoupling. LBNL's analysis examined "...future impacts of current resource plans and adopted policies of the Commission and strategies for dealing with energy

[91] TR Vol IV, Pg 595, 1-11.
[92] See June 9, 2010, TEP Decoupling Calculation Chart.
[93] TR Vol IV, Pg 605, 8-13; Pg 607, 21-24; Pg 609, 7-22.
[94] TR Vol IV, Pgs 609, 23 through 610, 9.
[95] TR Vol IV, Pg 613, 6-14.
[96] TR Vol IV, Pg 615, 8-11.
[97] TR Vol IV, Pg 621, 1-11.
[98] TR Vol IV, Pgs 622, 22 through 623, 14.

efficiency, utilities and their customers."[99] The LBNL analysis documented the benefits, costs and financial impacts on ratepayers and shareholders of achieving energy efficiency savings goals consistent with the Commission's EES, and the potential impact of a decoupling mechanism.[100]

The LBNL analysis began with establishing a business as usual case, based on publicly available information, where APS offers efficiency programs as if the EES was not enacted and continues on its preexisting savings path. This presumed APS would meet the annual energy savings targets in its 2010 Rate Settlement Agreement and thereafter meet a one percent annual energy savings target the 2010-2012 period covered in the APS rate case settlement.[101] Fuel and purchased power costs which were passed through to customers and nonfuel expenses, such as return of and on capital expenditures and O&M expenses for new generation and transmission and distribution resources, were expected to grow in excess of five percent per year.[102] Rate cases were assumed to be filed every three years or when capital expenditure budgets exceeded a billion dollars, rates were assumed to take effect two years from the time of filing, and compliance with the Renewable Energy Standard ("RES") was presumed.[103] In order to capture the full benefits of the energy efficiency measures installed in the business as usual case or under the standard, a 20-year planning horizon was utilized.[104]

The business as usual scenario reflected ten year savings of more than 600 megawatts of peak demand, and more than 43,000 gigawatt hours of energy savings over

[99] TR Vol IV, Pg 627, 15-18.
[100] TR Vol IV, Pg 631, 9-22.
[101] TR Vol IV, Pg 635, 2-17.
[102] Id.
[103] TR Vol IV, Pg 640, 11-23.
[104] TR Vol IV, Pg 642, 4-16.

the measure lifetimes, with net benefits of $943 million (present value at 4.0%).[105] Roughly a third of the projected energy savings and half the peak demand savings came from residential portfolio programs.[106] Among its assumptions, the business as usual case assumed growth in nominal operation and maintenance costs of 3.5 percent per year, fuel and purchased power budget growth of 6.8 percent per year, rate-base related cost (e.g., return on rate base, interest on debt, and depreciation) growth of 6.0 percent per year and retail sales growth of 2.2 percent a year.[107] Under the business as usual case, the analysis showed that APS is expected to under-earn relative to its authorized level in almost every year during the 20-year time horizon.[108]

Under the high energy efficiency scenario (i.e. to meet the EES), APS was assumed to offer energy efficiency and demand response programs to comply with the Commission's EES, with estimated program costs, measure lifetimes and on-peak/off-peak savings.[109] Energy efficiency program costs to the utility were estimated at about $35/MWh.[110] Up to 6,800 gigawatt hours of cumulative annual energy savings were expected to be achieved in 2020 with the Standard.[111]

Comparing the business as usual case to the high efficiency scenario demonstrated additional offsets to load growth.[112] Under the high efficiency scenario, annual retail sales growth drops from 2.2 percent to 1.1 percent and to about 1.4 percent growth in peak demand.[113] Following the ten-year EES, the 2021-2030 period was

[105] TR Vol IV, Pgs 647, 25 through 648, 15.
[106] TR Vol IV, Pg 651, 1-4.
[107] TR Vol IV, Pg 652, 4-21.
[108] TR Vol IV, Pg 656, 7-15.
[109] TR Vol IV, Pg 657, 9-24.
[110] TR Vol IV, Pgs 658, 25 through 659, 16.
[111] TR Vol IV, Pg 662, 10-15.
[112] TR Vol IV, Pg 662, 16-21.
[113] TR Vol IV, Pg 662, 22 through 663, 4.

assumed to resume normal underlying load growth of about 3 percent a year; this was done solely for modeling purposes.[114] The cost to meet the EES in 2020, including program administration, measure incentives and customer measure cost contributions, were projected to be about $41 per lifetime megawatt hour for the whole portfolio, and $55 per lifetime megawatt hour for the residential portfolio.[115] Achievement of the EES more than doubles the lifetime energy savings compared to the business as usual scenario, from about 43,000 gigawatt hours to 95,000 gigawatt hours and increases peak demand savings from 600 to more than 1,500 megawatts.[116] Total net resource benefits increased to $1.4 billion from $943 million (present value at 4.0%).[117] The Commission was cautioned to recognize the degree of variability in the numbers, which could increase or decrease projected benefits.[118] Variability could result from changes in assumed conditions, such as increased/decreased program costs or increased/decreased avoided costs.

The high efficiency scenario resulted in direct bill savings to ratepayers on the order of $4.6 billion between 2011 and 2030, compared to the business as usual case.[119] Bill savings were principally driven by utility plant deferrals and by reductions in utility fuel and purchased power budgets.[120] In response to questions about the potential impacts from avoided externalities, LBNL responded that the planning model was not well suited

[114] TR Vol IV, Pg 664, 16-21.
[115] TR Vol IV, Pg 665, 23 through 666, 4.
[116] TR Vol IV, Pg 667, 4-11.
[117] TR Vol IV, Pg 667, 7-11.
[118] TR Vol IV, Pg 669, 13-23.
[119] TR Vol IV, Pg 676, 2-8.
[120] TR Vol IV, Pg, 676, 24 through 678, 22.

for identifying those benefits;[121] however, LBNL re-emphasized that the identified benefits were conservative numbers.[122]

Following LBNL's presentation, the Commission continued discussion of recommended decoupling designs and rate related issues. In prior discussions, the Commission had taken up issues concerning customer classes, collars, types of deferrals, pilot programs and other issues.[123] AECC commented that decoupling could result in recession-induced rate increases and urged caution.[124] AECC further argued that the concept of "average customer" was best applicable to residential customers but made little sense for industrial customers.[125] Rather than utilizing decoupling, AECC advocated for adoption of projected test years to address some of the potential utility challenges.[126] AECC noted that other jurisdictions which had adopted decoupling segregated some or all nonresidential customers.[127] AECC's principal objections included a perceived risk shift between the utility and customers, through the incorporation of weather and other factors affecting electricity usage in the decoupling mechanism.[128]

In response to AECC's concerns, APS noted that no conclusions had been drawn regarding which customer classes would be involved in a decoupling mechanism, as this is a policy decision for the Commissioners; however, benefits would inure to all customers from deferred capacity.[129] With respect to the issue of weather risk, APS noted

[121] TR Vol IV, Pgs 717, 21 through 718, 2.
[122] TR Vol IV, Pg 720, 1-8.
[123] TR Vol IV, Pg 747, 7-11.
[124] TR Vol IV, Pg 748, 18-25.
[125] TR Vol IV, Pg 752, 5-16.
[126] TR Vol IV, Pgs 755, 22 through 756, 13.
[127] TR Vol IV, Pg 757, 1-5.
[128] TR Vol IV, Pgs 777, 18 through 778, 20.
[129] TR Vol IV, Pg 781, 5-17.

that the analysis demonstrated that APS would have been better off if weather effects were excluded, to the tune of $15 million.[130]

Stakeholders further noted that large customers, like mines, were typically excluded from decoupling mechanisms, largely because their operations would not be contributing to fixed cost recovery through variable charges.[131] As a result, these customers would not be making material impacts on the underlying problem decoupling addresses.[132] Others argued that there could be good reasons for excluding certain customer classes, but that the Commission should begin from the presumption that all customers should be included absent contrary evidence.[133] Commission staff recognized that each company presents a unique mix of customers which may require each company to figure out the best way to address those customers under a decoupling mechanism.[134]

Stakeholders highlighted different approaches used to address large utility customers, which included rate collars to minimize rate dislocation, use of a pure net lost revenue adjustment, and use of adjustments other than revenue per customer.[135]

June 10, 2010 Workshop

The June 10, 2010 workshop principally addressed LBNL's analysis of APS and TEP with the implementation of the EES, with and without decoupling.

LBNL examined the incremental benefits and costs of achieving higher levels of energy efficiency on ratepayers and utility shareholders.[136] The analysis addressed

[130] TR Vol IV, Pg 783, 14-23.
[131] TR Vol IV, Pg 789, 2-8
[132] TR Vol IV, Pg 789, 9-13.
[133] TR Vol IV, Pg 790, 13 through 791, 7.
[134] TR Vol IV, Pg 791, 9-15.
[135] TR Vol IV, Pg 793, 12 through 794, 23.
[136] TR Vol V, Pg 812, 3-10.

impacts to customer bills, rates, earnings and return on equity.[137] LBNL's approach included a long-term 20-year analysis, allowing stakeholders to better understand impacts from utilization of efficiency as a resource over a long-term.[138]

LBNL reiterated and finalized its preliminary findings for APS which LBNL had presented earlier at the May 24, 2010 workshop. For the business as usual case (with about one percent annual energy savings), LBNL identified about 43,000 gigawatt hours in total energy savings and 600 megawatts of peak demand savings, producing combined benefits of about $1.6 billion on a present value basis at a cost of about $730 million,[139] with net benefits of $946 million and a benefit/cost ratio around 2.[140] The high efficiency scenario, when compared to the business as usual case, reduced sales growth in half because of the EES.[141] When compared with the business as usual scenario, the energy efficiency scenario produced more than twice the total energy savings, a 150 percent increased in peak demand savings and a 50 percent improvement in net resource benefits.[142] LBNL identified net benefits, on a present value basis (4.0%) of $1.4 billion under the high efficiency scenario versus $946 million in the business as usual case.[143] The LBNL analysis also estimated that customer bill savings in the high efficiency case would be about $4.6 billion more than the bill savings achieved in the business as usual case.[144]

LBNL conducted a separate but similar analysis for TEP, examining energy efficiency impacts on customer bills and rates, the Company's earnings and return on

[137] TR Vol V, Pg 812, 10-13.
[138] TR Vol V, Pgs 813, 22 through 814, 4.
[139] TR Vol V, Pg 822, 7-17.
[140] TR Vol V, Pg 826, 20-21.
[141] TR Vol V, Pg 832, 13-21.
[142] TR Vol V, Pg 833, 1-5.
[143] TR Vol V, Pg 833, 18-20.
[144] TR Vol V, Pgs 835, 2 through 836, 8.

equity. While the TEP analysis made similar assumptions to those in the APS analysis, key differences included substantially lower growth rates for nonfuel costs[145] and two year intervals between rate case filings rather than three.[146]

For the TEP business as usual case, a one percent annual efficiency savings level was assumed, to be consistent with the APS business as usual case, though TEP's existing level of savings is at or about 0.4 percent per year.[147] Under the business as usual case (which included the one percent annual efficiency savings level), LBNL identified about 13,000 gigawatt hours of energy savings and 230 megawatts of peak demand reductions[148] with a value of $472 million (present value at 4.0%) in total net resource benefits.[149] Under the EES, TEP would achieve cumulative annual savings in excess of 2,000 gigawatt hours in 2020.[150] The EES flattened retail sales growth and dropped peak demand growth to half a percentage point.[151] Overall savings associated with the EES more than doubles total lifetime energy savings relative to the business as usual case of one percent savings (i.e. about 27,900 vs. 13,000 GWh), producing a 210 percent increase in peak demand levels and a 44 percent increase in net resource benefits.[152] The present value of customer bill savings totaled $570 million over the 20 year period between 2011-2030.[153]

Comparing the high efficiency scenario to the business as usual case revealed shareholder impacts of $38 million (present value at 4.0%) between 2011-2020, reducing

[145] TR Vol V, Pg 846, 13-18.
[146] TR Vol V, Pg 846, 20-22.
[147] TR Vol V, Pg 847, 5-19.
[148] TR Vol V, Pg 848, 5-13.
[149] TR Vol V, Pg 849, 2-10. Revised numerical value from LBNL Analysis, June 14 Update, Slide 30.
[150] TR Vol V, Pg 853, 3-6.
[151] TR Vol V, Pg 853, 16-20.
[152] TR Vol V, Pgs 853, 21 through 854, 2. Revised numerical value from LBNL Analysis, June 14 Update, Slide 35.
[153] LBNL Analysis, June 14 Update, Slide 38.

the utility's average return on equity by 46 basis points.[154] Incorporation of revenue per customer decoupling added $36 million (present value at 4.0%) to TEP earnings over the 10-year period, or 59 basis points to return on equity.[155] Decoupling resulted in a 0.7 percent increase to customer bills, or $70 million (present value at 4.0%) as compared to $570 million of projected ratepayer bill savings achieved under the EES.[156]

Combining results for TEP and APS, LBNL identified total resource net benefits on the order of about $2 billion without a decoupling mechanism in the high efficiency case with the EES, and approximately $670 million more in total net benefits than the business as usual case.[157] Customer bill savings totaled about $5.2 billion between the two utilities for the high efficiency scenario compared to the business as usual case, even after accounting for the rate increases.[158] Retail rates rose between 1 and 1.8 cents higher for APS and TEP respectively for the high efficiency case compared to the business as usual case.[159] Without decoupling, APS and TEP average utility return on equity decreased by about 50 basis points over the 10-year period compared to the business as usual case.[160] The inclusion of a decoupling mechanism added about 45 to 60 basis points to the utilities' return on equity.[161]

While LBNL's analysis revealed consistent results between APS and TEP, several assumptions drove distinct results. Assumed avoided costs were lower for APS than for TEP; [162] TEP utilized lower DSM program costs;[163] nonfuel cost growth assumptions

[154] TR Vol V, Pg 857, 16-23.
[155] TR Vol V, Pg 858, 6-11.
[156] TR Vol V, Pg 859, 1-24. Revised numerical value from LBNL Analysis, June 14 Update, Slide 42.
[157] TR Vol V, Pg 861, 15-21. Revised numerical value from LBNL Analysis, June 14 Update, Slide 44
[158] TR Vol V, Pg 861, 21-24.
[159] TR Vol V, Pg 862, 1-5. Revised numerical value from LBNL Analysis, June 14 Update, Slide 44.
[160] TR Vol V, Pg 862, 6-9.
[161] TR Vol V, Pg 862, 9-12.
[162] TR Vol V, Pg 863, 4-12

were higher for APS;[164] and APS forecasted higher retail sales, customer, and peak demand growth rates.[165] TEP noted that differences in avoided cost estimates were largely the result of whether the utility was long or short on resource capacity.[166] Parties noted that assumptions could change some of the total resource benefits; however, concerns about these benefits were dwarfed by net incremental customer bill savings of $5.2 billion (combined APS and TEP) over the business as usual case and $8.7 billion over a case with no energy efficiency savings.[167]

Parties clarified that the bill savings figures presented were net of rate impacts for energy efficiency programs and emphasized the need to address utility disincentives to align the interests of customers in saving energy and the interests of utilities in maintaining their rates of return.[168]

ISSUES

The Commission's extensive workshop process unearthed significant benefits for ratepayers and utilities and clarified stakeholder concerns. The Commission's analysis revealed that customer bill savings for APS and TEP from achieving the EES, including implementation of decoupling, would total $8.7 billion relative to a scenario in which no EES existed. Customer bill savings would total about $5.2 billion under the EES with decoupling when compared to a scenario in which the utilities only achieved one percent annual energy efficiency savings. This encourages the Commission to move forward with

[163] TR Vol V, Pg 863, 13-16.
[164] TR Vol V, Pg 863, 17-18.
[165] TR Vol V, Pg 863, 23-25.
[166] TR Vol V, Pg 872, 11-15.
[167] TR Vol V, Pgs 880 5 through 881, 15.
[168] TR Vol V, Pgs 883, 1 through 884, 17.

steps that support the Standard, including eliminating disincentives to the pursuit of energy efficiency.

Among the issues stakeholders raised in workshops were: the proper mechanism for aligning utility and customer incentives; whether differences between new and existing customers necessitated different treatment; whether adjustments to cost of capital should be undertaken; whether the Commission should adopt decoupling on a pilot or permanent basis; whether full or partial decoupling should be adopted; the appropriate timing for adjustments; applicability of decoupling across customer classes; whether adjustments would be blended across customer classes or segregated by class; and whether collars or caps on adjustments were necessary and the appropriate bandwidth for such collars or caps.

The Commission believes it is critical that utility disincentives to demand side management programs and energy efficiency be addressed. As stakeholders recognized, it is unlikely that the EES can be met without addressing financing disincentives and impacts to utilities' revenues and earnings. LBNL's analysis estimated that the utility bills of APS and TEP customers would be reduced by about $5.2 billion through compliance with the EES, relative to the business as usual case. Similar benefits are anticipated at other utilities. Absent achievement of the EES, APS and TEP ratepayers will unnecessarily pay between $5.2 billion and $8.7 billion in higher energy bills.

The Commission's workshops, while not limited to decoupling, demonstrated significant interest in decoupling as a means of addressing utility disincentives. Revenue per customer decoupling is uniquely suited for Arizona as it establishes a target revenue per customer and responds to customer growth in between rate case cycles. While the

target revenues per customer are established in traditional rate cases, revenues are allowed to increase with customer growth, better matching utility costs and revenues. As recognized in workshops, further analysis is necessary to determine whether new and existing customers should be expected to consume similar amounts, require similar infrastructure costs and generate similar revenues. If new customers, whether through decreased costs to serve or decreased usage, would bring in less revenue than existing customers, this dynamic must be considered.

Other proposals discussed in the workshops included fixed cost/variable cost pricing and mechanisms to address lost margin recovery. Though these and other proposals may be appropriate for some utilities, the Commission believes they have limited application. Fixed cost/variable pricing would result in larger customer charges, which impact low-income customers, and reduced variable charges, which discourages efficient energy use. Lost margin recovery mechanisms allow for recovery of margins attributable to decreased energy sales from energy efficiency programs; however, this mechanism may be subject to prolonged litigation, and would not allow for other beneficial actions on rate design or contribute to improved costs of capital.

Some stakeholders proposed that the Commission adopt decoupling as a pilot and refrain from broader adoption. The Commission believes that adoption of decoupling should occur in rate cases, with evaluation and review occurring after an initial three year period. This would demonstrate a stronger commitment to decoupling and better facilitates action on complimentary rate designs and on costs of capital. The Commission recognizes that Arizona's largest utilities, while improving, are not well-rated by financial ratings agencies. The Commission believes it is important to send long-term

signals and demonstrate commitment to decoupling before taking action on costs of capital. Adoption of decoupling on a pilot basis would not send appropriate signals and would not demonstrate the requisite commitment to eliminating financial disincentives to the adoption of energy efficiency.

Parties have argued that full decoupling may draw in effects from factors other than energy-efficiency, such as weather or economic effects. However, full decoupling is preferable as it enhances utility and customer billing stability, is administratively more manageable and would allow for rate relief during extreme weather events. Utility analyses indicated ratepayer benefits even if weather effects had been considered. With decoupling in place, these ratepayer benefits would have been directly distributed to customers rather than benefitting the utility. With respect to economic effects, utilities would be capable of filing rate cases or emergency rate increase requests with or without decoupling. The Commission believes a collar or cap on the size of decoupling adjustments appropriately addresses concerns raised by parties as it limits effects from extraordinary economic downturns or unforeseen circumstances.

Decoupling adjustments occur over periods of time, whether annually, quarterly or monthly. The Commission believes that more current adjustments respond better to extreme weather events and allow for ratepayer relief. Appropriate collars or caps on adjustments ensure that rates will not vacillate between periods. While annual adjustments may smooth and moderate changes, as a longer tine interval may dampen seasonal variations, they lack responsiveness to weather events.

ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures

POLICY STATEMENTS

1. Diversity and utilization of both demand and supply side options for meeting Arizona's energy resource needs is beneficial and should be actively pursued by Arizona utilities as a way of moderating capital expenses, encouraging greater flexibility, ensuring reliability, and minimizing rate impacts and customer energy bills.

2. Arizona utilities should pursue all cost-effective energy efficiency and demand side management resources, and should meet Arizona's Electric and Gas Energy Efficiency Standards of at least 22% electric energy savings and at least 6% gas savings by 2020.

3. Revenue decoupling may offer significant advantages over alternative mechanisms for addressing utility financial disincentives to energy efficiency, as it establishes better certainty of utility recovery of authorized fixed costs and better aligns utility and customer interests. However, if properly designed, alternative mechanisms could be implemented that would provide significant incentives to utilities to go beyond complying with the Commission's Energy Efficiency Rules just because they are required to do so, but to actually promote energy efficiency. Some form of decoupling or utility financial incentives must be adopted in order to encourage aggressive use of demand side management programs and the achievement of Arizona's Electric and Gas Energy Efficiency Standards, which will benefit ratepayers and minimize utility costs. These types of mechanisms offer short term and long term benefits: in the short term it they allow for customer bill savings through increased energy efficiency, achieved through Commission-approved energy efficiency programs; in the long term they contribute to plant deferrals and may contribute to improvements in costs of capital.

4. While other decoupling models are appropriate in general, revenue per customer decoupling may be well suited for Arizona as it responds to customer growth and is better suited to address the issues associated with customer growth. Utilities interested in revenue per customer decoupling must address whether new customers should be treated distinctly from existing customers.

5. Adoption of decoupling (or any other alternative mechanism that provides utility incentives to promote energy efficiency) should not occur as a pilot, as this insufficiently supports demand side management efforts, discourages beneficial changes to rate design and is unlikely to encourage financial ratings improvements. In lieu of pilot adoption, an initial three-year review period should be utilized which allows for evaluation and redress of decoupling models and related issues. The initial review period should be three years or until the company files its next rate case after a decoupling or alternative mechanism is approvied. The formal review of the mechanism should begin 20 months after it is approved, to allow adequate time for review by the Commission prior to the beginning of the subsequent period. If Commission Staff is not able to conduct this review due to resource constraints, an evaluation contractor shall be hired by the utility.

6. Commitment to and early implementation of decoupling should precede significant adjustments to cost of capital if a revenue per customer decoupling mechanism is approved for a utility. Therefore, decoupling-specific adjustments to cost of capital should not be proposed for the initial review period. The review of the initial three-year period following adoption of revenue per customer decoupling should include analysis and discussion of possible adjustments to cost of capital to recognize any modified risk at the utilities, as well as benchmarking and comparisons to other utilities operating with revenue per customer decoupling.

7. Utilities are encouraged to develop customer rate designs that support energy efficiency and work well in tandem with decoupling (or alternative mechanisms). Utilities may propose preliminary rate designs for the initial three-year period, and the preliminary rate designs should be evaluated during the review of the initial period. Revisions to the preliminary rate designs based on the results of the review should be proposed for the subsequent period.

8. Full decoupling is preferable to partial decoupling as it contributes to greater rate stability which would encourage improvements in financial ratings, is administratively more manageable, and offers opportunities for rate relief following extreme weather events.

9. Weather normalization in the application of decoupling is discouraged because such normalization would reduce the size of decoupling surcredits to customers following an extreme weather event.

10. Decoupling adjustments should occur more frequently than on an annual basis, as this may provide ratepayers with weather-related rate relief following extreme events. Current adjustments, on a monthly or even quarterly basis, where technologically and administratively feasible, allow for weather related rate relief and are encouraged.

11. Broad participation in decoupling is preferred; however, the unique characteristics of each utility may merit different treatment of some customer classes. Utilities should address any proposed distinct treatments and justify why certain customer classes may merit different treatment.

12. Decoupling adjustments should be blended and applied across customer classes to discourage dramatic changes experienced by any one class.

13. Decoupling adjustments applied in a manner to encourage energy efficiency are preferred, such as applying decoupling surcharges to rates and higher-usage blocks to encourage energy efficiency, and applying decoupling surcredits to reward customers who use less energy.

14. Collars or caps on decoupling adjustments should be designed to encourage gradualism, and to minimize the short-term effects on customers. If the decoupling

adjustments are to occur on a monthly, quarterly, or less-than-annual basis, the utility should propose a cap for the periodic decoupling adjustments. Customers should receive the full amount of any refund in a timely manner in the event that achieved revenue per customer exceeds authorized revenue per customer. Therefore, it is not necessary to cap the amount of surcredit decoupling adjustments or refunds to customers.

ORDER

A utility may file a proposal for alternative mechanisms for addressing utility financial disincentives to energy efficiency, including revenue per customer decoupling, in its next general rate case. A utility filing such a decoupling proposal should address this policy in its filing and should use this policy as a guideline in development of its proposal.