Energy Efficiency and Regulatory Process Arizona Style: Existing Barriers and a Suggested Path Forward

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ABSTRACT

In 2009, the Arizona Corporation Commission (ACC) initiated a rulemaking proceeding to establish one of the most aggressive energy efficiency resource (EER) standards in the United States with a goal of 22% cumulative energy savings by 2020. In order for regulated utilities in Arizona to achieve these DSM targets, existing DSM programs will need to be dramatically expanded and new programs submitted for regulatory approval. The purpose of this paper is to highlight several of the key DSM calculations and methodologies, or lack thereof, in the spirit of identifying a better path forward for utility preparation of DSM plans that are clear and consistent with regulatory requirements. As Arizona adopts more aggressive DSM goals, the need for an efficient utility/regulator review process is a crucial factor for statewide DSM success. This paper addresses some key components of DSM plan development and the regulatory review process in Arizona that are in need of revision. Like many states, Arizona uses the societal cost test (SCT) as the primary method of assessing the cost effectiveness of energy efficiency investments. The paper will identify issues with the SCT, and propose clarifications in how various components of this test are interpreted and calculated. The paper also addresses a range of other topic areas related to the calculations of DSM benefits and costs as currently interpreted in Arizona, and propose suggested changes that will facilitate the expansion of cost-effective DSM portfolios to achieve Arizona's aggressive energy efficiency resource standard.

Introduction

Arizona, with a population of 6.5 million, which makes it the 14th largest state in the United States, is undergoing a transformation with respect to the development of more aggressive energy efficiency goals. Over the past two years, the Arizona Corporation Commission (ACC) initiated, through rate case proceedings and special dockets, numerous items and directives for more aggressive energy efficiency goals. This activity culminated in 2009 with a rulemaking process that will establish the Arizona energy efficiency resource (EER) standard to achieve 22% cumulative energy savings by the year 2020. The standard starts with savings goals of 1.25% of energy savings as a percent of sales in 2011 and increase in 0.25% increments until 2016 when it remains fixed at 2.5% per year through 2020. These goals represent one of the most aggressive energy efficiency resource standards in the United States.

Table 1: Proposed Arizona Energy Efficiency Resource Standard

Calendar Year	**Annual Energy Efficiency Standard** (Annual Energy Savings in Each Calendar Year as a Percent of the Retail Energy Sales in the Prior Calendar Year)	Cumulative Energy Savings
2011	1.25%	1.25%
2012	1.75%	3.00%
2013	2.00%	5.00%
2014	2.25%	7.25%
2015	2.25%	9.50%
2016	2.50%	12.00%
2017	2.50%	14.50%
2018	2.50%	17.00%
2019	2.50%	19.50%
2020	2.50%	22.00%

As DSM activity accelerates in Arizona the need exists to review existing regulatory review practices and interpretations of key required calculations. Fine tuning the regulatory framework and benefit/cost protocols used in Arizona, by themselves, will not help utilities achieve these aggressive goals. Arizona utilities will need to rise to the occasion, and design comprehensive and robust energy efficiency portfolios at a scale never seen before. Given the context of an unprecedented increase in DSM activity in Arizona, the primary purpose of this paper is focus on several discrete and technical issues that will facilitate utility and regulator DSM portfolio development and review. This paper is prepared in the spirit of identifying current benefit-cost test issues and areas of regulatory uncertainty that delay or reduce the likelihood for Arizona utilities to develop aggressive and cost-effective DSM programs. While this paper is focused primarily on issues in Arizona, items identified in this paper, especially a proposed revision to a key interpretation of the societal cost test as currently detailed in the 2002 California Standard Practice Manual, will be of interest to the broader DSM community.

A discussion is underway in the DSM community with respect to what cost-effectiveness test is the most appropriate today in the context of aggressive DSM goals and regulatory and legislative mandates for acquiring all cost-effective energy efficiency. Some DSM experts are starting to propose that the utility cost test (UCT), also known as the program administrator cost test (PACT), is the most appropriate test as it values DSM costs and benefits with the same inputs and weighting as used by utilities for assessing the benefit-cost of supply side decisions (Neme & Kushler, 2010). Currently, as part of the Arizona EER standard docket, utilities are directed to screen measures and programs consistent with the societal cost test (SCT). The authors of this paper believe that the ACC should review comprehensively the required benefit-cost test calculations, and the associated complexities of each test, including metrics whether monetized or not, to assess which test is the most appropriate given the changing DSM landscape in Arizona. The PACT may be a more accurate and straightforward test for utilities to use when evaluating DSM versus supply side alternatives. Furthermore, the application of the PACT would simplify calculations and expand the range of DSM measures eligible for program promotion.

However, given that the ACC currently requires the SCT, this paper addresses some incremental issues with the current ACC staff interpretation of the SCT, in the spirit of making the test more accurate and viable as currently required. The remainder of this paper reviews five overarching topic areas that, with an agreed upon statewide utility/regulator DSM consensus, will help to expedite program planning and portfolio development.

Topic Area #1: Societal Cost Test and Issue of Exclusion of Interest Expense Associated with Building New Power Plants

The SCT, as opposed to the total resource cost (TRC) test, attempts to value DSM investment decisions from the perspective of the broader society. While the directive of the regulator to require utilities to utilize the societal cost test is reasonable and currently a common practice across the DSM industry, the ACC has not defined exactly how the SCT is to be conducted. In the absence of a clear definition, Arizona utilities such as Tucson Electric Power (TEP) and Arizona Public Service (APS), have often defaulted to the definitions published in the 2002 California Standard Practice Manual (CA SPM). Given the range of options with respect to what attributes are included in the societal cost test, differences exist with respect to how the same test is calculated for TEP and APS. Essentially, according to the 2002 SPM, the societal cost test is structurally similar to the total resource cost (TRC) test except for the following factors:

- The utility may apply higher marginal costs than used with the TRC test if the utility has lower marginal costs than other utilities in-state or out-of-state suppliers.
- Tax credits are treated as a transfer payment (unlike in the TRC), and as such, are excluded from any calculations.
- For capital expenditures, such as building a new power plant, interest payments are considered a transfer payment and are thus excluded from avoided cost calculations. According to the SPM, "in the case of capital expenditures, interest payments are considered a transfer payment since society actually expends the resources in the first year. Therefore, capital costs enter the calculations in the year in which they occur."
- Societal discount rate should be applied.
- Marginal costs also can include additional externalities not valued in the TRC test.

Currently, the ACC staff applies a very literal interpretation of the 2002 CA SPM definition, particularly with respect to the exclusion of interest payments associated with building a new power plant. Power plants are large investments, with financing terms typically lasting decades, which represent large interest payments. The effect of the ACC's interpretation of the CA SPM makes DSM measures and programs more difficult to pass cost-effectiveness screening because the benefit of avoided capacity costs are greatly reduced when the cost of the interest on investments is excluded. A short survey by Navigant Consulting of a small group of industry professionals in California and across the United States familiar with the intricacies of benefit-cost tests revealed agreement that interest payments should be included as an avoided cost, and not as a transfer payment as implied by the CA SPM. The exclusion of the cost of interest is particularly penalizing on utilities facing significant investments in generation, transmission, and distribution assets.

Currently, California does not use the societal cost test, as such, this issue, to our knowledge, has not been scrutinized in any formal California docket proceedings, and if it were, we believe, the CA SPM would be revised to allow incorporation of the interest expense associated with the carrying costs of capital, as without this change, cost-effectiveness of comprehensive and deep energy efficiency portfolios is more difficult.

To address this concern and others like it, public utility commissions around the country have various state-specific interpretations of benefit cost tests used for DSM program analysis. Typically, these take the form of allowing for variations or "modifications" of either the total resource cost test or the societal cost test as described in the California Standard Practice Manual. As such, the authors of this paper believe a new interpretation of the societal cost test is required in Arizona to allow for the incorporation of interest expenses.

Topic Area #2: Establishing a Societal Discount Rate

The SCT utilizes a societal discount rate as a mechanism for valuing demand and energy savings from a broader societal perspective. The selection of an appropriate societal discount rate value is a matter of some debate. Economists are at odds over what is considered an appropriate societal discount rate (SDR). Some will argue that from a societal perspective, the SDR should be zero, as this is the best way not to underestimate the unknown value of an item to future generations. Other economists argue that some form of discount rate is necessary to make more informed and comparative investment decisions. Typically, based on our experience, SDRs for DSM benefit-cost screening have ranged from 2% to 5% and are established based simply on utility proposed levels and Commission approval. Currently in Arizona, utilities have no guidance with respect to setting the SDR and this has led to multiple rates being used, with none of the rates being defined or tied to any metric, such as the discount rate used in an IRP for investment decisions, or to the broader credit markets. As such, SDRs tend to remain static and irrelevant to the utility business model or changes in market rates experienced by broader society. For example, a 7% SDR may have been reasonable when ten year treasuries yielded 7% or more during the early 1990's, but using this rate may not be appropriate during today's economic environment, where this same treasury yield is under 4%. Currently, the ACC uses a societal discount rate of 7% in their benefit-cost screening tool, which may or may not align with the discount rates used by utilities in their own measure level screening.

The lower the discount rate, the more favorable the calculations will be in support of passing cost-effectiveness thresholds. Therefore, establishing a reasonable method to calculate a societal discount rate will promote consistency across Arizona utilities that are relative to the current business environment. One option is that the ACC could mandate a DSM industry "consensus" SDR to use, such as 4%, and direct all utilities to use the same rate until further notice. An alternative approach would be to allow utilities to calculate their own utility-specific societal discount rate using one of several options currently under review. Each of these proposed methodologies subscribes to the following design principles:

- The SDR should be defined as an interest rate that represents lower risk to society than the discount rate used in capital investment decisions made by an investor-owned utility (IOU), preferably as noted in the IOU's most recent integrated resource plan (IRP).

- The SDR should be based on market indexes that can be updated to account for the interest rate environment relevant to the period in which the DSM investment is being considered.

The first alternative option allows the SDR to be calculated by multiplying the discount rate used in a utility's business plan, such as the discount rate found in an IRP, by a multiplier that reflects how the current credit market discounts for risk, or a risk discount multiplier. For example, this multiplier could simply be the yield on a treasury bond divided by the yield corporate bond. Here is an example of how the SDR could be calculated under this option:

$SDR = DR_{IRP} \times RDM$

Where

DR_{IRP} = Discount rate used in capital investment decisions made by the utility in the most recent IRP

RDM = Risk discount multiplier which is calculated by dividing the yield for the U.S. Treasuries by the average yield for investment grade U.S. corporate bonds.

Here's an example using U.S. Department of the Treasury data and an average yield data for corporate bonds presented by Moody's could be used to calculate the RDM:

Moody's Baa Corporate bond average yield for 2009 = 7.29%

Market yield on U.S. Treasury securities at 20-year constant maturity in 2009 = 4.11%

RDM = 4.11% / 7.29% = 0.56

In this example, a utility using a 7% discount rate in its IRP business case would have 3.9% SDR (7% x 0.56 = 3.9%)

The second alternative approach being considered simply would be to allow utilities to use current Treasury yields as their SDR. This may be determined as the yield on a specific bond, such as a 20-year T-bond, or as an average value of the current yield curve for all Treasury instruments.

Each of these options has various benefits, but adopting either approach would remove the current uncertainty that exists for utilities when deciding what SDR to use. Applying a set methodology for determining the societal discount rate will reduce confusion among the utilities and regulators as to the appropriate rate to apply, thereby allowing both parties to focus on other topics in support of achieving the overall goals. However, one key thing to note is that, in a DSM environment of legislatively-mandated and aggressive DSM savings goals, the authors propose that regulators establish a "maximum" level societal discount rate (e.g., 4%), while allowing utilities to utilize a lower discount rate through an alternative calculation method as identified above when the product generated is less than the deemed maximum societal discount rates. The justification for this allowance is based on the numerous non-energy externality benefits that are applicable for the SCT. Currently, only carbon is monetized, which leaves other non-energy benefits such as job creation, health and safety, worker productivity, etc., un-monetized.

Topic Area #3: Program Administration Costs

Program administrative costs are all non-incentive costs incurred by the utility in the process of operating and delivering DSM programs. These costs include management, administration, marketing, training, implementation services, and measurement and evaluation. Currently, upon ACC directive, the utilities follow a practice that in the opinion of the authors, imprecisely applies estimated per measure program administrative costs as part of the measure level benefit-cost screening. The process for assigning program administrative costs at the measure level varies by utility in Arizona, as well as in the specific methodological form, ranging from methods that assign administrative costs based on either the percentage of unit incentive, or unit savings, or unit incremental cost. The methodological approaches currently vary between TEP and APS, which leads to confusion and expense each time the topic is addressed in regulatory plan development, and it likely leads to confusion by the ACC when reviewing plans with different methodologies for assigning program administrative costs.

Therefore, for the purposes of cost-effectiveness analysis of DSM programs and measures, the utilities should simplify the current practice, with ACC approval, and allow administrative costs to be applied at the level of <u>program</u> cost-effectiveness analysis (i.e., across the suite of measures promoted by the program) and not at the individual measure level. Costs included in the screening of individual DSM measures would be limited to customer incremental or installed costs, and this would become the first threshold for evaluating measure cost-effectiveness. Applying administrative costs at the overall program level, as opposed to a pro-rated measure level basis, removes the artificial application of program administrative costs and makes this calculation consistent with the methodology recommended by the National Action Plan for Energy Efficiency (2007) and used by leading DSM programs around the country (e.g., Efficiency Vermont).

Topic Area #4: Incremental Costs and Incentive Levels

Customer incremental costs are those costs incurred by the customer in the process of installing the DSM measure. Incremental costs are typically defined as the added costs of an energy efficient technology compared to its standard efficiency alternative at the time of burnout or failure of the existing equipment. For discretionary early retirement of working equipment, incremental costs represent the added cost for the efficient technology and labor compared to the baseline technology, and the associated labor to install the technology. When estimating incremental costs for early retirement measures, we believe it also is appropriate to estimate the added expense associated with forecasted additional maintenance and repairs of the old equipment if it was to remain in service until projected retirement, and to discount this additional amount from the incremental cost calculation for the new efficient technology.

Another area related to incremental costs is a current ACC requirement that DSM measure level incentives are not to exceed 75% of incremental costs. While it is understandable that the ACC desires to balance achievement of aggressive DSM goals with safeguards on ratepayer expenditures via the 75% of incremental cost limit, the authors believe that as the percentage of annual savings from retail electric sales is increased, utilities will be forced to offer programs that are less known and which include more expensive measures. Limiting incentives to only 75% of incremental costs may not provide enough stimulus to potential customers, especially for relatively new technologies or lower income customers, and will make utility achievement of regulated goals more difficult. As such, the authors believe utility incentives should be allowed to cover up to 100% of incremental costs, with the caveat that market activities be monitored closely and if participation is high and markets are starting to transform, incentive levels should be reduced accordingly and re-invested in the promotion of other new and emerging cost-effective technologies.

Topic Area #5: Avoided Capacity

The current ACC screening tool calculation does not provide any present value for avoided capacity until the year that planned capacity is online. For example, if TEP forecasts that it will need additional supply-side capacity in 2012, then the avoided capacity benefits of a DSM measure installed in 2010, would not be factored into DSM screening calculations until 2012. In an era of regulated requirements for achieving DSM savings, the reality of whether a utility is avoiding the need for new supply or not should not be a punitive issue in evaluating the cost-effectiveness of potential DSM measures and programs. The authors believe a utility should be able to include the estimated capacity costs ($/kW value) from purchase power agreements as forecasted in the most recent IRP, or updated annually, as a proxy value until planned new generation is on-line, at which time the estimated cost for this new additional generation would be used as the avoided capacity benefit value. Again, costs for new generation will be based on values reported in a utility's most recent IRP, or updated on an annual basis, as necessary.

Additionally, utilities are currently using avoided cost estimates based on estimated costs associated with building a new natural gas fired combustion turbine plant. Given Arizona has an aggressive renewable portfolio standard, any new in-state capacity is likely to be from renewable resources in the near future. As such, the authors suggest that avoided costs associated with the development of utility-scale renewable projects would be an even more accurate representation of the avoided capacity benefits of DSM. This would be even more appropriate if Arizona modified the existing renewable portfolio standard (RPS) to allow all cost-effective energy efficiency that is less expensive than new renewable supply, to meet all or a portion of the RPS requirements. Valuing DSM investments consistent with significantly higher avoided costs associated with utility-scale or distributed generation renewable power plants would significantly improve the economics for screening more expensive energy efficiency DSM measures.

Conclusion

With more aggressive energy efficiency goals, the challenge for utilities and regulators will be to develop, approve, and deliver cost-effective DSM programs that meet regulatory targets. The DSM landscape in Arizona is changing rapidly. Along with higher savings goals comes the need to re-visit established calculations to ensure utilities have the best opportunity to develop robust DSM portfolios. The authors believe the suggested changes in approaches, interpretations, and methodologies proposed in this paper will reduce some of the uncertainties associated with current DSM plan development and allow utilities to apply more favorable DSM calculations in the interest of reaching regulatory goals. In addition, the authors believe that further steps to develop uniform and statewide methodologies, e.g., an Arizona statewide cost-effectiveness screening tool, and a statewide deemed savings database (i.e., technical reference manual), will further the goal of minimizing confusion and expedite the development of robust DSM plans, with a minimum amount of confusion and delay for both plan development and regulatory review. While the proposed DSM calculation changes discussed in this paper will be helpful, an even greater need will be to draw from the lessons learned in other high-DSM saving states (e.g., CA,VT, MA) to significantly ramp-up DSM spending and introduction of new measures and tactics to achieve Arizona's aggressive energy efficiency resource standard.

References

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