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**BEFORE THE ARIZONA CORPORATION COMMISSION**

Arizona Corporation Commission
DOCKETED

NOV 18 2011

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COMMISSIONERS

GARY PIERCE – Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.

Docket No. E-01345A-11-0224

**NRDC's NOTICE OF DIRECT TESTIMONY**

Natural Resources Defense Council ("NRDC") by and through its attorney hereby files the Direct Testimony of its Witness Ralph Cavanagh in the above-referenced matter.

RESPECTFULLY SUBMITTED this 17th day of November, 2011.

By _____
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ORIGINAL and 13 COPIES of the foregoing filed this 17th day of November, 2011 to:

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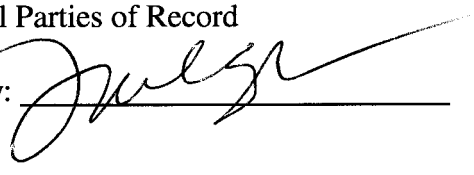
By: 

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BEFORE THE ARIZONA CORPORATION COMMISSION

DIRECT TESTIMONY

OF

RALPH CAVANAGH

**SECTION I - Introduction**

Q. Please state your name, address, and employment.

A. My name is Ralph Cavanagh. I am the Energy Program Co-Director for the Natural Resources Defense Council ("NRDC"), 111 Sutter Street, 20th Floor, San Francisco, CA 94104.

Q. Please outline your educational background and professional experience.

A. I am a graduate of Yale College and Yale Law School, and I joined NRDC in 1979. I am a member of the faculty of the University of Idaho's Utility Executive Course, and I have been a Visiting Professor of Law at Stanford and the University of California. From 1993-2003, I served as a member of the U.S. Secretary of Energy's Advisory Board, and I am now a member of the Department of Energy's Electricity Advisory Board. My current board memberships include the Bipartisan Policy Center, the Bonneville Environmental Foundation, the Center for Energy Efficiency and Renewable Technologies, the Renewable Northwest Project, and the Northwest Energy Coalition. I have received the Mary Kilmarx Award from the National Association of Regulatory Utility Commissioners (2007), the Heinz Award for Public Policy (1996) and the Bonneville Power Administration's Award for Exceptional Public Service

(1986). Prior to 2011, I had not testified before the Arizona Corporation Commission in at least two decades, but I was an invited participant in the workshops that preceded the Commission's adoption last December of its Final Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures ("Final Policy Statement"). I also filed testimony for NRDC in support of the Southwest Gas Company's "energy efficiency enabling provision," a revenue-per-customer decoupling mechanism that was included in an application now pending before the Commission.

Q. On whose behalf are you testifying?

A. I am testifying for the Natural Resources Defense Council (NRDC).

Q. What is the purpose of your testimony in this proceeding?

A. My testimony supports the Arizona Public Service Company's ("APS") proposal for an Efficiency and Infrastructure Account ("EIA") mechanism.

**SECTION II - Summary of Testimony**

Q. Summarize your conclusions and recommendations.

A. I agree with APS that its proposed EIA "is necessary given the [Commission's] ambitious Energy

Efficiency Standard and increasing DG requirements," because "without [the EIA], successful energy efficiency programs - even at levels below that set by the Commission in the EES - create a significant disincentive for the utility with serious adverse financial impacts."[1] The company's General Rate Case Application appropriately links the EIA to "the Commission's recently approved decoupling policy statement," and indicates that the EIA would "address the loss in fixed cost recovery that occurs when the historical volumetric pricing structure is used in combination with increasing energy efficiency and distributed generation requirements."[2] To underscore the EIA's importance and urgency, APS notes that in its 2010 Test Year it collected more than two-thirds of the fixed costs of serving its residential and commercial through volumetric charges.[3]

I conclude that the proposed EIA is entirely consistent with the Commission's decoupling policy statement, and I recommend its approval. My testimony summarizes experience with comparable revenue decoupling

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[1] See Testimony of Leland R. Snook on behalf of APS, p. 2:17-28.
[2] Arizona Public Service Commission, Docket No. E-01345A-11-0224, Application (June 1, 2011), p. 6.
[3] See Testimony of Leland R. Snook, p. 3 (noting that APS collected 73% of residential sector fixed costs and 66% of commercial sector fixed costs, respectively, through kWh charges).

mechanisms and responds to concerns commonly raised about them. APS's proposal would remove a potent disincentive to the company's engagement with all forms of progress in energy efficiency and distributed generation, by ensuring that the Company recovers the fixed costs previously authorized by the Commission (but no more than that amount), notwithstanding any short-term fluctuations in metered electricity use. My testimony also shows that efforts to link rate adjustments specifically to energy efficiency program impacts would have perverse consequences and impede statewide progress in achieving cost-effective savings.

My testimony anticipates and rebuts claims that approval of APS's proposal should be linked to reductions in its return on equity. I am aware of no evidence that decoupling mechanisms have reduced any utility's cost of capital, and customer benefits from the proposed mechanism are illustrated by the specific reference in the Commission's policy statement to opportunities for "direct bill savings to [APS] ratepayers on the order of $4.6 billion between 2011 and 2030", which "were principally driven by utility plant deferrals and by reductions in utility fuel and purchased power budgets" associated with the enhanced energy efficiency efforts required to comply

with the Commission's Energy Efficiency Standard.[4] Reducing the Company's authorized return on equity ("ROE") would undercut a principal rationale for the Commission's Final Policy Statement, which was to "encourage and enable 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."[5]

**SECTION III - Energy Efficiency Benefits to APS Customers**

Q. What is the source of that estimate of $4.6 billion in net energy-efficiency benefits to APS customers[6], and why is it different from the $8.9 billion figure that appears in Mr. Leland Snook's testimony for APS (p. 12:1 & n. 3)?

A. Both numbers appear in a comprehensive analysis by the Lawrence Berkeley National Laboratory, which was initially presented during the Commission's workshops and later published in a document that is attached as an exhibit to this testimony (A. Satchwell, P. Cappers & C. Goldman, Carrots and Sticks: A Comprehensive Business Model for the Successful Achievement of Energy

[4] See Final ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures, Docket Nos. E-00000J-08-0314 and G-00000C-08-0314,(Dec. 29, 2010), p. 20 (comparing "high efficiency scenario" to "the business as usual case").
[5] Id. at p. 30.
[6] See this testimony, p. 4:20-21.

Efficiency Resource Standards (March 2011) [EXHIBIT NRDC-1]. The period covered by the estimates runs from 2011 through 2030; the higher ($8.9 billion) number reflects the difference between achieving the state's EES targets and a "business as usual" case involving no utility intervention to promote energy efficiency. The lower ($4.6 billion) number is the difference between reaching the EES targets and maintaining the current level of savings from utility programs. Both numbers "are net of the costs of energy efficiency programs (e.g., the costs of administering the program, incentives to customers)." Id. at p. 10.

**SECTION IV - The APS Proposal is Consistent with the Commission's Statement on Energy Efficiency and Decoupling**

Q. What is the basis for your conclusion that APS's proposal is consistent with the Commission's Final Policy Statement?

A. APS has proposed a revenue per-customer decoupling mechanism, which includes an annual adjustment to reconcile actual and allowed fixed cost recovery,[7] enhanced bill stability "by mitigating the impact of

[7] In the EIA proposal, "fixed costs" appropriately include "virtually all base rate costs, except for fuel and transmission costs, which are determined to be fixed cost in the most recent cost of service study," which itself is based on the NARUC Electric Utility Cost Allocation Manual. "Other costs that vary in the short-term with sales levels are also excluded from the mechanism, primarily generation maintenance costs." See Testimony of Leland R. Snook, p. 15:16-23 & n. 6.

weather for customers," broad inclusion of customer classes (except for those with non-metered accounts and large gas-fired plants not included in energy efficiency programs), and a three percent limit on potential surcharges associated with the mechanism (but no limit on potential rate reductions).[8] APS also "proposes to aggregate all of the differences between authorized and actual fixed cost recovery for each customer class," and to allocate the "total amount of over or under-recovery of fixed costs … to each customer class on an equal percentage basis," in order "to provide customers with greater rate stability."[9]

The Commission anticipated and encouraged all of these decoupling elements in its Final Policy Statement:

- "Revenue decoupling may offer significant advantages over alternative mechanisms for addressing utility financial disincentives to energy efficiency . . ." [p. 30, item 3]

- "[N]on-fuel 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." [p. 30, item 4]

- "Adoption of decoupling . . . should not occur as a pilot, as this insufficiently supports demand side management efforts, discourages beneficial

[8] See Testimony of Leland R. Snook, including Attachment LRS-1, which illustrates the operation of the proposed EIA. "If in any year the cap is exceeded APS proposes to defer that amount with interest until such time as it can be included in the annual adjustment without reaching the cap." Id., p. 21:6-9.

[9] Id. at p. 19:9-16.

changes in rate design and is unlikely to encourage financial ratings improvements." [p. 30, item 5]

- "Full decoupling is preferable to partial decoupling ..." [p. 31, item 8]

- "Decoupling adjustments should occur at least on an annual basis; however, parties may propose more current adjustments as this may provide ratepayers with weather related relief following extreme events." [p. 31, item 10]

- "Broad participation in decoupling is preferred; however, the unique characteristics of each utility may merit different treatment of some customer classes." [p. 31, item 11]

- "Decoupling adjustments should be blended and applied across customer classes to discourage dramatic changes experienced by any one class." [p. 31, item 12]

**SECTION V - Experience with Revenue Decoupling in Other States**

Q. Describe experience with revenue decoupling elsewhere in the country.

A. Nationally, the count of states with decoupling for at least one utility stands at 14 for electricity and 22 for natural gas. In the West, Hawaii, California, Idaho and Oregon have adopted decoupling for at least one electric utility; Washington's Commission is now considering such mechanisms for its two largest electric utilities, Avista and Puget Power. California, Utah, Oregon, Washington and Wyoming have adopted natural gas decoupling mechanisms. New Mexico's Public Service Commission has left open "the determination of whether a

decoupling mechanism should be approved or required for any utility," and the New Mexico Legislature has acknowledged the need to "identify regulatory disincentives or barriers for public utility expenditures on energy efficiency and load management measures and ensure that they are removed in a manner that balances the public interest, consumers' interests and investors' interests."[10]

**SECTION VI - Rate Impacts of APS's Proposal**

Q. What about rate impacts of revenue decoupling?

A. Neither revenue decoupling in general nor the APS proposal in particular add any additional costs to utility bills; they simply ensure that previously approved fixed costs are neither over- nor under-recovered. In terms of rate adjustments to achieve this objective, industry experience shows that effects are minimal in practice, with adjustments that go in both directions. A comprehensive industry-wide assessment found that, of 88 gas and electric rate adjustments from 2000-2009 under decoupling mechanisms, less than one-seventh involved increases exceeding 3 percent. (Refunds accounted for a much larger fraction.) Typical adjustments in utility bills "amount[ed] to less than $1.50 per month in higher or lower charges for residential gas customers and less than

[10] See Case No. 08-00024-UT, Final Order Repealing and Replacing 17.7.2 NMAC (2010), p. 10; Efficient Use of Energy Act, Section 62-17-5.F.

$2.00 per month . . . for residential electric customers."[11] For electric bills, that represents less than seven cents a day in annual variations for the average household, which hardly seems like dangerous rate volatility, particularly since it sometimes comes in the form of a rebate - and serves only to ensure that the utility recovers no more and no less than the fixed costs of service that regulators have reviewed and approved.

**SECTION VII - Revenue Decoupling Does Not Reduce the Incentive to Save Energy**

Q. What do you say to those who are concerned that revenue decoupling reduces incentives to save energy, by raising rates and depriving customers of rewards from consumption reductions?

A. Experience proves the opposite: revenue decoupling results in trivial rate adjustments that go both ways, and do not materially affect rewards for saving electricity and natural gas. As the Oregon Public Utility Commission found when it adopted a decoupling mechanism for Portland General Electric in January 2009, responding to analogous claims that decoupling would rob customers of the rewards of conservation: "We believe the opposite is true: an individual customer's action to reduce usage will have

[11] See Pamela Lesh, Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review, Electricity Journal (October 2009), p. 67.

no perceptible effect on the decoupling adjustment, and the prospect of a higher rate because of actions by others may actually provide more incentive for an individual customer to become more energy efficient." Oregon PUC Order No. 09-020, p. 28 (Jan. 2009).

Finally, note that unlike so-called "fixed-variable rate designs" that load fixed costs into monthly customer charges, APS's proposal does not establish a high fixed minimum bill that would greatly reduce customers' rewards for saving electricity; if all its fixed costs were recovered in that way, APS would need to raise the basic service charge for residential service "to over $90 per month," and "General Service customers would experience even larger increases."[12]

**SECTION VIII - Approving APS's Proposal Should Not Result in an Adjustment in Its Authorized Return on Equity**

Q. Explain your conclusion that approving APS's proposal should not result in an adjustment in its authorized return on equity.

A. In this I am of course echoing the Commission's conclusion in the Final Policy Statement: "Commitment to and early implementation of decoupling should precede significant decoupling-specific adjustments to cost of capital if a revenue per customer decoupling

[12] Testimony of Leland R. Snook, p. 8:14-17.

mechanism is approved for a utility."[13] The data summarized earlier from Pamela Lesh's Electricity Journal study provide additional support for my recommendation: rate impacts this modest (typically averaging less than seven cents per household per day) simply do not imply appreciable consequences for company-wide cost of capital, and I have seen no empirical evidence to the contrary. Indeed, in the specific context of natural gas utility decoupling, a March 2011 investigation by the Brattle Group reached the opposite conclusion:

> The findings of our analysis do not support the belief that utilities with decoupling have a lower cost of capital than utilities without decoupling. Contrary to what some might expect to find, at least on the basis of the opinions of certain intervenors and the (minority set of) judgments where commissions reduced allowed rates of return because of decoupling, we found that the estimated cost of capital for decoupled utilities was higher by a small but statistically significant amount (emphasis in original).[14]

**SECTION IX - Adjustments Keyed Solely to Adjudicated Savings Would Mean Automatic Annual Rate Increases**

Q. Why shouldn't the Commission amend the proposal so that adjustments track only electricity savings attributable to the Company's energy efficiency programs?

[13] Final ACC Policy Statement, note 4 above, p. 31 [item 6].
[14] J. Wharton, M. Vilbert, R. Goldberg & T. Brown, The Impact of Decoupling on the Cost of Capital (Discussion Paper, The Brattle Group, March 2011), p. 2.

A. This would undercut the whole purpose of the mechanism, while introducing a whole new set of perverse incentives. It would reintroduce automatic penalties, in the form of reduced fixed-cost recovery, for all cost-effective electricity savings not directly associated with APS's programs, even when the Company by action or inaction could make a material difference in prospects for those savings. It would create a reason for the Company to promote programs that looked good on paper but delivered little or no savings in practice. And it would ensure adversarial discord over every savings calculation, since significant financial stakes would then hinge on the results. Finally, and most tellingly, adjustments keyed solely to adjudicated savings would mean automatic annual rate increases (unless the company was wholly ineffective), whereas decoupling adjustments can be either positive or negative (Southwest Gas notes as part of its own pending decoupling proposal, for example, that its most recent Nevada decoupling adjustment "will return approximately $2 million to its customers."[15])

Q. But doesn't your recommendation mean paying APS for savings that it didn't help achieve?

[15] In the Matter of Southwest Gas Corporation, Docket No. G-01551A-10-0458, Prepared Direct Testimony of Edward B. Gieseking, p. 9:5 (Nov. 12, 2010).

A. No, because the proposed EIA doesn't "pay" APS any incremental amount for anything; it is simply a mechanism that allows the company to receive no more and no less than the fixed-cost revenue requirement per customer that the Commission has reviewed and approved.

**SECTION X - The APS Proposal Reduces Risk to Customers**

Q. Revenue decoupling has been criticized as "use less, pay more" and shifting risk to customers; do you believe those are valid concerns regarding APS's proposal?

A. No. As indicated earlier in my testimony, customers who find ways to use significantly less energy will not be appreciably affected by decoupling-induced rate adjustments, and of course a principal justification for the Commission's Energy Efficiency Standards is to reduce the costs of providing reliable energy services, with long-term multi-billion dollar savings to APS customers (in the form of reductions in the company's revenue requirements and fuel purchases) that revenue decoupling will not affect. As regards risk shifting, an appealing feature of APS's proposal is that it reduces risks for *both* customers and the company; customers get relief from cost increases driven by extreme weather events, and APS avoids downside risk on recovery of its authorized fixed costs (although, as noted earlier, I do not view this as justification for a

reduction in the company's ROE). Risk reduction is not a zero sum enterprise here.

**SECTION XI - Conclusion: Revenue Decoupling Removes a Powerful Disincentive for APS to Increase Its Energy Efficiency Investment**

Q. Does revenue decoupling remove the rationale for the Commission to provide energy-efficiency-related incentives for APS, in order to spur utility effort and achievement?

A. No. Revenue decoupling eliminates a potent disincentive for utility engagement in energy efficiency, but it does not supply an upside analogous to that accompanying utility-owned generation or grid assets. Meeting Arizona's appropriately aggressive energy efficiency targets requires more than institutional neutrality, and although it would certainly help to avoid automatic utility shareholder losses from cost-effective energy efficiency improvements, it would be even better to combine decoupling with shareholder rewards for utilities' success in delivering cost-effective savings. From the standpoint of motivating utility management and maximizing benefits to utility customers, my view is that both revenue decoupling and earnings opportunities are ultimately necessary and appropriate to ensuring that cost-effective energy efficiency remains a core element of the APS business model.

Q. Does this conclude your testimony?

A. Yes.

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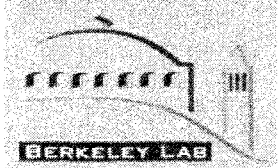


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# Carrots and Sticks: A Comprehensive Business Model for the Successful Achievement of Energy Efficiency Resource Standards

Andrew Satchwell, Peter Cappers, and Charles Goldman

***Preprint version of paper for conference proceedings, ECEEE Summer Study, Giens, France, June 6-11, 2011***

Environmental Energy Technologies Division

**March 2011**

The work described in this report was funded by the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability (OE) - Permitting, Siting and Analysis Division under Contract No. DE-AC02-05CH11231.

## Disclaimer

## Acknowledgements

The work described in this report was funded by the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability (OE) - Permitting, Siting and Analysis Division under Contract No. DE-AC02-05CH11231.

The authors would like to thank Larry Mansueti (DOE OE) for his support of this project. The authors would also like to thank Jeff Schlegel for his comments and feedback on this paper.

# Carrots and Sticks:
# A Comprehensive Business Model for the Successful Achievement of Energy Efficiency Resource Standards

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March 2011

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**Abstract**

Energy efficiency resource standards (EERS) are a prominent strategy to potentially achieve rapid and aggressive energy savings goals in the U.S. As of December 2010, twenty-six U.S. states had some form of an EERS with savings goals applicable to energy efficiency (EE) programs paid for by utility customers. The European Union has initiated a similar type of savings goal, the Energy End-use Efficiency and Energy Services Directive, where it is being implemented in some countries through direct partnership with regulated electric utilities.

U.S. utilities face significant financial disincentives under traditional regulation which affects the interest of shareholders and managers in aggressively pursuing cost-effective energy efficiency. Regulators are considering some combination of mandated goals ("sticks") and alternative utility business model components ("carrots" such as performance incentives) to align the utility's business and financial interests with state and federal energy efficiency public policy goals. European countries that have directed their utilities to administer EE programs have generally relied on non-binding mandates and targets. In the U.S., most state regulators have increasingly viewed "carrots" as a necessary condition for successful achievement of energy efficiency goals and targets.

In this paper, we analyze the financial impacts of an EERS on a large electric utility in the State of Arizona using a pro-forma utility financial model, including impacts on utility earnings, customer bills and rates. We demonstrate how a viable business model can be designed to improve the business case while retaining sizable ratepayer benefits. Quantifying these concerns and identifying ways they can be addressed are crucial steps in gaining the support of major stakeholder groups - lessons that can apply to other countries looking to significantly increase savings targets that can be achieved from their own utility-administered EE programs.

## Common Acronyms and Definitions

- ACC *Arizona Corporation Commission* – Arizona state regulatory body with authority over public utilities, incorporation of businesses and organizations, securities regulation, and railroad/pipeline safety. The ACC is composed of five publicly elected Commissioners.
- APS *Arizona Public Service* – Arizona investor-owned utility that is the subject of this analysis.
- BAU *Business-As-Usual* – Used in this analysis as a scenario representing the pre-existing path of energy savings for a particular utility and assuming no new energy efficiency or demand response programs.
- DSM *Demand Side Management* – Strategies designed to encourage consumers to modify patterns of electricity usage, including reducing usage in many hours (i.e., energy efficiency) and reducing usage in peak periods (i.e., load management and demand response programs).
- EE *Energy Efficiency* – Programs intended to reduce the overall amount of energy used, while providing the same level of service to consumers.
- EERS *Energy Efficiency Resource Standard* – Molina et al. (2010) defines an EERS as "a quantitative, long-term energy savings target for utilities." Utilities may administer their own programs or use an authorized program administrator to achieve energy savings.
- EES *Energy Efficiency Standard* – The same long-term energy savings target as an EERS and implemented in some states, including Arizona.
- FERC *Federal Energy Regulatory Commission* – U.S. Federal regulatory agency with jurisdiction over interstate electricity sales and wholesale electric rates, among other things.
- O&M *Operations and Maintenance* – Category of utility costs pertaining to the ongoing maintenance of a utility power system which may be fixed or variable in nature.
- ROE *Return on Equity* – The level of earnings on utility equity determined by regulators in a utility rate case proceeding, expressed as a percentage. The utility may not exceed this established level (i.e., authorized ROE) and the utility often earns less than this authorized level as a function of declining sales due to energy savings or weather, regulatory lag, and/or business cycle fluctuations
- RPC *Revenue-Per-Customer* – A form of decoupling, whereby a utility's total revenues needed to provide safe, adequate, and reliable service are determined for a set amount of time and only allowed to change as the number of customers changes. This is the most common form of decoupling in the U.S.
- RPS *Renewable Portfolio Standard* – Regulation requiring a certain percentage of energy from renewable energy sources.

## 1. Introduction

U.S. regulators and legislators are utilizing energy savings goals in the form of energy efficiency resource standards (EERS) as a means to mandate aggressive energy efficiency (EE) savings (Barbose et al. 2009). As of December 2010, twenty-six U.S. states had some form of an EERS. Policy drivers for such mandates include offsetting potentially higher costs and environmental impacts associated with the construction of new generation resources and providing additional options for customers to control their energy costs. In the U.S., ratepayer-funded EE programs are a common means of delivering these savings.

U.S. utilities face significant financial disincentives under traditional regulation in pursuing aggressive energy efficiency goals which limits the interest of shareholders and managers. Both are concerned that the pursuit of aggressive EE savings will result in reduced utility revenues, affecting the utility's ability to fully recover its fixed costs and ultimately increasing the likelihood that the utility under-achieves its authorized return on equity (ROE), and limited opportunities to expand rate base thereby foregoing earnings-generating investments. Regulators and policymakers are considering or have adopted more comprehensive business models (e.g., shareholder incentives, and/or lost revenue recovery mechanisms) to align the utility's business and financial interests with a state's public policy goals for the electricity sector (e.g., increased efficiency, reduced emissions).

In establishing energy efficiency goals and targets, policymakers and legislators in both Europe and the U.S. can utilize varying combinations of "sticks" and "carrots". At one extreme is a "stick-only" approach, whereby utilities must meet mandated energy savings targets or face financial penalties. This approach is common in many U.S. states that have adopted a Renewable Portfolio Standards (RPS) with an alternative compliance payment provision if a utility does not achieve renewable energy goals. However, this "stick-only" approach (i.e., mandate with penalties) is much less common in the U.S. for energy efficiency.[1] As a practical matter though, because of financial disincentives, some/many U.S. utilities would characterize an energy savings mandate (i.e., EERS) absent the ability to recover fixed costs as a "sticks only" approach. In the U.S., utility energy efficiency programs have been most successful in those states that utilize a "sticks-and-carrots" approach, combining a mandated savings goal or target with a comprehensive business model.

This study examines (1) the customer bill and rate impacts, and (2) the shareholder earnings and return on equity (ROE) impacts when a utility achieves aggressive energy savings from an EERS. Our analysis will compare a "stick-only" approach of mandated energy savings goals to a "sticks-and-carrots" approach that includes a comprehensive business model. We model our analysis based on the Arizona Energy Efficiency Standard (EES), which directs Arizona investor-owned utilities to achieve 22% cumulative energy savings by 2020.[2] We provide a long-term assessment of impacts on ratepayers and shareholders from energy efficiency programs that achieve these savings reduction targets (about 2% per year) through 2020 with

[1] Pennsylvania is an example of a state with an EERS with a financial penalty provision and no ability for the utility to earn an incentive for successful achievement of energy efficiency targets or to recover lost revenues.

[2] Arizona Corporation Commission. *In the Matter of the Notice of Proposed Rulemaking on Electric Energy Efficiency*. Decision No. 71819. Docket No. RE-09-0427. August 10, 2010. An Energy Efficiency Standard (EES) is the same as an Energy Efficiency Resource Standard (EERS).

impacts over a 20-year time-horizon (2011-2030) to fully capture the benefits over the installed measures' useful lifetimes.

We characterize and model Arizona Public Service (APS), which is the largest investor-owned utility in Arizona, and analyze two EE portfolios: (1) a "business-as-usual" (BAU) EE scenario as if the EES was not enacted and APS continues on its pre-existing EE savings path of approximately 1% annual savings; and (2) an EES scenario as if APS meets the EES savings targets of about 2% annual savings.[3] We examine issues from a customer perspective – impacts of the EES on aggregate customer bills and rates compared to the "business as usual" case. We also analyze issues from the perspective of utility shareholders and managers and assess the effects on earnings and ROE of the EES compared to the "business as usual" case with and without a comprehensive business model (e.g., a revenue-per-customer decoupling mechanism and a shareholder incentive mechanism).

The remainder of the paper describes the comprehensive business model, discusses the study approach (including the utility financial characterization, EE portfolios, and ratepayer and shareholder impact scenarios), presents analysis results, and concludes with key findings and policy discussion.

[3] The specific provisions of the Arizona EES allow utilities to take some credit for energy efficiency measures installed prior to 2011 (starting in 2016), demand response programs, and the effects of improved building codes as part of complying with their savings target.

## 2. Comprehensive Business Model

The traditional electric utility business model in the U.S. provides a financial incentive for increasing electricity sales and making investment in supply-side generation. Regulators in the U.S. establish a utility's tariff (i.e., rates), based on forecasted sales and its existing and forecasted costs, including a return on investment, in a rate case proceeding. Once rates are established, the utility may improve its financial performance between rate cases by either increasing sales above those forecasted and/or managing its costs. This financial incentive comes in the form of increased revenues and/or lower costs, respectively, and hence larger profits (if revenues grow faster than costs), as well as a guaranteed return on supply-side investments that are utilized to serve increasing demand.

Conversely, a utility may experience financial harm when sales decrease between rate cases. Because a utility's revenues are a function of the regulated price for energy and its sales to customers, any downward change in sales from the forecasted level results in reduced utility revenues. The pursuit of energy savings exists then as a disincentive to the investor-owned utility as it directly impacts and reduces the utility's collected revenue and hence profitability between rate cases (again if revenue reductions outpace cost savings) through decreased sales while deferring investment in supply-side generation. Despite the clear benefits of EE to ratepayers and society as a whole, there is a bias among U.S. investor-owned utilities against the pursuit of energy savings.

The traditional utility business model is further challenged by regulatory or legislative energy savings mandates (e.g., EERS), which alone may function as a "stick" for the utility. A regulated utility prefers a viable business model when faced with energy savings mandates; a viable business model encourages or incents the utility to capture the societal benefits of energy efficiency, delivering benefits to customers, while ensuring that profitability can in fact come from EE investment.

There are three components of a comprehensive EE business model, from the utility perspective: recovery of prudently-incurred program costs, collection of lost revenues associated with EE savings (the portion of lost revenues that would be used to recover authorized fixed costs), and the development of a shareholder incentive. If a regulator approves only a subset of the three components, the effectiveness of any component may be undermined (Hayes et al. 2011).

1. Ensure cost recovery. The recovery of program costs is intended to allow the utility to fully offset the costs of implementing and administering EE programs. In the U.S., when energy efficiency programs were first offered by utilities in the late 1980s and 1990s, a few utilities were unable to recover all of their costs for administering EE programs in subsequent regulatory proceedings because cost recovery mechanisms were not in place. Since then, utilities request and regulatory authorities often provide guidance on the cost recovery mechanism that utilities can use to recover program costs associated with administering energy efficiency programs. In many cases, regulatory authorities allow and authorize utilities to expense their program costs incurred in situations where the regulatory authority has reviewed and approved an EE plan; this approach is designed to mitigate the risk that the utility will not fully recover prudently incurred EE program expenses in a timely fashion.

2. Reduce the disincentive. The utility must have sufficient revenues to cover its system costs. A utility's past investments in their generation, transmission, and distribution systems are recovered through current and, to some degree, future retail rates based on a forecast of energy sales, among other things. As discussed earlier, any decrease in forecasted sales between rate cases because of energy savings from energy efficiency programs may result in a reduction in utility revenues. Regulators may approve the collection of those revenues lost to the decline in sales in order to insulate the company from not being able to recover its fixed, non-fuel costs, thereby making the utility "financially indifferent" to a change in sales from EE. Decoupling is a common form of lost revenue recovery mechanism and is designed to remove the link between sales and revenues by establishing a determined amount of revenues the utility may collect for a set period of time, regardless of sales levels.

3. Provide a shareholder incentive. The intent of a shareholder incentive is to provide a utility with an opportunity for additional earnings if it is successful in achieving aggressive savings goals and to make energy efficiency a potential business "profit center" for the utility. Supply-side investments are often much larger than dollars spent on EE and utilities can account for the investment in its ratebase, or value of utility property, and earn a return on the investment. This presents a potential bias towards such investments, as utilities may find the supply-side investment more attractive when compared to energy efficiency investments that typically are not part of ratebase. If a utility does not receive regulatory approval to implement a shareholder incentive but has a pre-existing incentive to make investments in supply-side generation, the utility will tend to prefer supply-side investments that provide greater earnings opportunities.

Shareholder incentives and lost revenue recovery mechanisms have seen increased attention in recent years at the federal and state levels. The American Recovery and Reinvestment Act of 2009 (ARRA), passed in February 2009, included additional state energy grant opportunities if the state regulator has sought to implement a policy that aligns financial incentives for electric utilities. At the state-level, 31 states have enacted some sort of lost revenue recovery and/or shareholder incentive mechanism. Of those states who lead the U.S. in energy efficiency program spending, eight of the top ten have implemented a combined shareholder incentive and lost revenue recovery mechanism (Molina et al 2010).

## 3. Approach

We used a pro-forma, spreadsheet-based financial model adapted from a tool (Benefits Calculator) constructed to support the National Action Plan for Energy Efficiency (Cappers et al. 2009a). This model builds on previous LBNL work on shareholder incentives (Cappers et al. 2009b, 2009c, 2010) by characterizing the effects of an EERS. The major steps in our analysis are depicted in Figure 1.

The first step is to identify the main inputs ("Model Inputs"): (1) a characterization of the utility which includes its initial financial and physical market position, a forecast of the utility's future sales, peak demand, and resource strategy and estimated costs to meet projected growth; and (2) a characterization of the demand side management (DSM) portfolio – projected electricity and demand savings, costs and useful lifetime of a portfolio of energy efficiency and demand response programs that the utility is planning or considering implementing during the analysis period.

The second step is to identify the scenarios of interest for the analysis ("Scenario Analysis"). These scenarios include a base case that maintains the current portfolio of DSM programs ("Business-As-Usual (BAU)") as well as alternative scenarios that include different energy efficiency and demand response resource savings levels and alternative business models ("With DSM").

The third step is to define the characteristics of the DSM business model of interest ("DSM Business Model"), determining what components will be included (e.g., DSM program cost recovery, lost fixed cost recovery and/or shareholder incentives).

The model provides outputs in the form of common stakeholder metrics ("Model Outputs"): (1) shareholder metrics include ROE and total earnings; and (2) ratepayer metrics include estimated retail rates and total customer bills for each year of the study period. Model outputs from various scenarios that differ by the level of achieved DSM savings and costs, application of alternative DSM business models, etc. can be compared to assess changes in utility earnings, ROE, average retail rates, and customer bills. The Benefits Calculator model also estimates total DSM resource costs and benefits of the DSM portfolio ("DSM Resource Costs & Benefits") using a forecast of avoided capacity and energy costs.

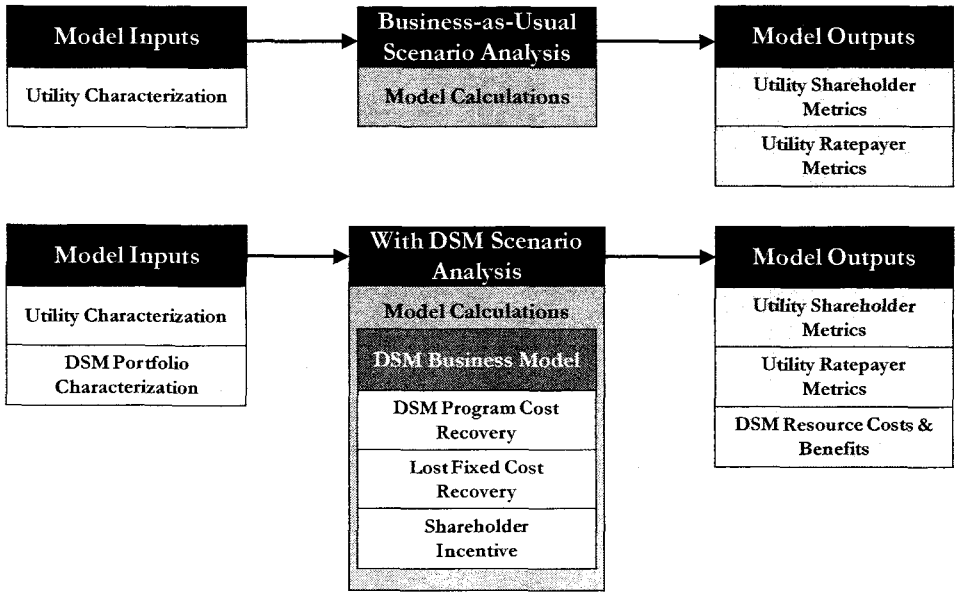


*Figure 1. Flowchart for analyzing impacts of portfolio of energy efficiency programs on stakeholders*

## 4. Modeling Characteristics

### *4.1 Utility Characterization*

We developed a long-range cost and load forecast for APS (2011 to 2030), using historic information from the US Federal Energy Regulatory Commission (FERC) Form 1 as well as the utility's most recent general rate case data. This information was used to construct an expected relationship between growth in peak demand and growth in costs, which was reviewed by APS staff and served as the basis for our analysis.

In 2011, APS has retail sales of ~30,000 GWh and a peak demand of ~6,470 MW, which are forecasted to grow at a compound annual rate of 2.9% and 3.1% per year, respectively over a 20-year time horizon (excluding energy efficiency programs). The utility has ~1.1 million customers in 2011 and expects significant customer account growth of 2.7% per year. With such fast growing electricity requirements, the utility projects that its non-fuel expenses, inclusive of return of and on capital expenditures and operations and maintenance (O&M) expenses associated with new generation assets will increase in excess of 5% per year. Increases in non-fuel expenses are reflected in retail rates after the Arizona Corporation Commission (ACC) has issued an order in a general rate case or other regulatory filing.[4] However, revenue growth between rate cases is not anticipated to keep pace with the ~5% annual growth in non-fuel expenses.[5] Thus, APS would be unable to achieve its authorized ROE of 11%. This is a case of significant utility under-earning prior to the achievement of aggressive EE savings. Without a decoupling mechanism to mitigate the revenue erosion between rate cases, we assume that the utility would file a rate case triennially (i.e., every third year) to reduce the detrimental impact on shareholder returns.[6]

### *4.2 Demand Side Management (DSM) Portfolio Characterization*

In 2008, Arizona's utilities achieved electricity savings of ~0.53% of retail sales, which places Arizona near the national average among U.S. utilities in pursuing energy efficiency (Molina et al. 2010). However, in 2010, the state's policymakers established energy savings goals that are among the most ambitious in the United States. The Arizona EES was established by ACC rulemaking in July 2010 requiring electric utilities to achieve 22% cumulative savings in 2020.[7] Under the EES, annual savings targets are set at 1.25% in 2011 and accelerate to 2.5% per year in 2016-2020.[8] We have constructed two EE portfolios that capture the pre-existing level of energy efficiency activity and savings (i.e., BAU with EE) and a second scenario that includes the required energy efficiency program savings goals under the new EES (see Figure 2).

The first energy efficiency portfolio represents a BAU with EE case as if Arizona had not passed the EES but simply continued on its pre-existing path of capturing energy efficiency savings of

[4] Fuel and purchased power costs are passed through to APS customers annually through a fuel adjustment clause (FAC) and so are modeled as if they are completely collected in the year they are incurred.

[5] APS receives additional base revenues as the number of customer accounts increase each year (2.7% per year) and/or as customers increase their electricity usage; although revenues from retail rates increase at a slower rate than expected non-fuel costs.

[6] APS is assumed to use a historic test year in their rate case filings. Generally there is a two-year lag between the time a general rate case is filed and the time the ACC issues an order setting retail rates.

[7] Arizona Corporation Commission. In the Matter of the Notice of Proposed Rulemaking on Electric Energy Efficiency. Decision No. 71819. Docket No. RE-09-0427. August 10, 2010.

[8] There are several provisions in the regulation that allow credits for pre-standard energy savings beginning in 2016, a credit for improvements in building codes, and a credit for demand response savings.

~1% annually on a nominal 2010 budget of $43M.[9] In this scenario, the utility achieves 43,581 GWh of electricity savings over the 2011-2030 period,[10] which provides ~$946M[11] in net resource benefits between 2011 and 2030 (see Table 1).[12] Program administration and measure costs are assumed to grow at a nominal annual rate of 4.3% for residential EE programs and 4.8% for non-residential programs.

The EES portfolio represents savings and expenditure levels based on utility compliance with the Arizona EES. Under this aggressive scenario, cumulative annual electricity savings exceed 7,000 GWh in the year 2020 when accounting for EES requirements and credits (see Figure 3). The utility achieves 95,002 GWh of electricity savings over the 2011-2030 period. The EES portfolio has a total resource cost of ~$2.2B and produces $3.6B in resource benefits, thus providing $1.4B in net resource benefits (see Table 1).

We constructed the portfolios based on typical program costs to achieve the established savings levels. In the BAU with EE portfolio, average EE costs were estimated at ~1.9 cents/lifetime-kWh. Given the increase in savings levels in the EES portfolio, we estimated that average EE costs would increase to ~2.8 cents/lifetime-kWh.[13] The costs associated with the EES portfolio is quite attractive compared to supply-side alternatives. In both portfolios, 50% of electric savings comes from residential programs in 2011 and the share decreases as we assume more savings will have to come from commercial and industrial EE programs over time. In Arizona, savings from residential lighting programs are projected to decrease due in large part to federal lighting standards set to change in 2012.[14]

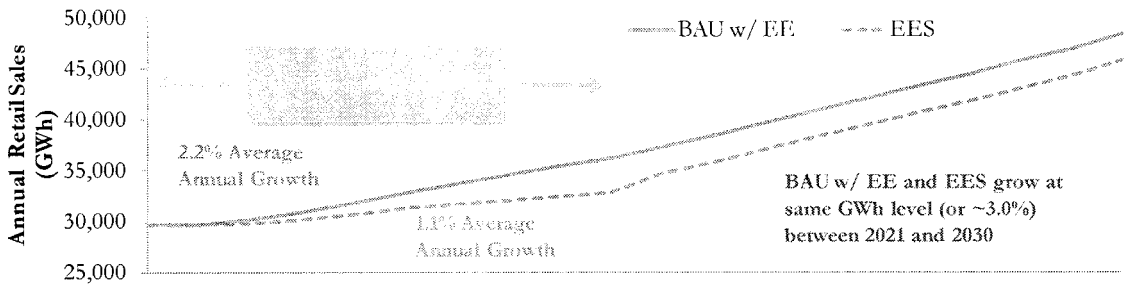


***Figure 2. Effect of energy efficiency portfolios on Arizona utility load forecast***

[9] APS had an existing level of EE savings determined as part of a settlement agreement in its most recent rate case, which established an annual savings goal of 1.0%, 1.25%, and 1.5% in 2010, 2011, and 2012, respectively. We assumed APS returned to 1.0% annual savings level in 2013-2020.

[10] A decision was made to implement energy efficiency programs for a ten year period (2011-2020) but allow the analysis period to extend out twenty years (2011-2030). This was done so the benefits derived from expenditures on energy efficiency measures implemented could be fully captured in the model time horizon.

[11] All dollar figures are reported on a present value basis using a societal discount rate of 4.0%.

[12] In the calculation of resource benefits, we include the avoided cost of energy, avoided cost of generation capacity, and avoided cost of T&D capacity and exclude non-electric benefits (e.g., water savings, avoided alternative fuel savings). We also do not include the shareholder incentive or the lost fixed cost recovery mechanism in estimating resource costs.

[13] The estimated program cost per lifetime kWh saved is averaged over the 2011-2020 period. EE program costs increase from ~1.5 cents/lifetime-kWh in 2011 to 4.0 cents/lifetime-kWh in 2020.

[14] Our EE portfolio savings and costs were reviewed and vetted by APS and are consistent with the utility's typical program offerings.

**Table 1. Lifetime savings, resource costs and benefits of alternative energy efficiency portfolios (2011-2020)**

| | Portfolio Lifetime Savings | | | | Total Resource ($M, PV) | | |
|---|---|---|---|---|---|---|---|
| Case | Peak Energy (GWH) | Off-Peak Energy (GWh) | Total Energy (GWh) | Peak Demand (MW) | Benefits | Costs | Net Benefits |
| BAU w/ EE | 30,507 | 13,074 | 43,581 | 602 | 1,675 | 729 | 946 |
| EES | 75,664 | 19,338 | 95,002 | 1,520 | 3,616 | 2,208 | 1,408 |

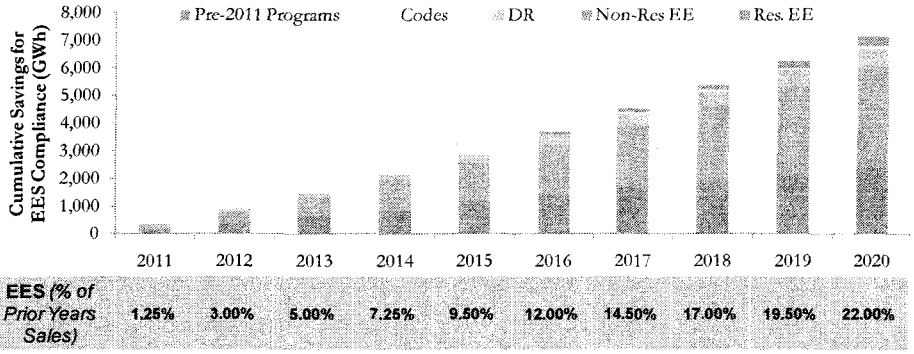


*Figure 3. Cumulative savings from Energy Efficiency Standard for Arizona Public Service Company*

### *4.3 Business Model Construction*

Arizona has historically allowed the recovery of prudently incurred EE program costs, and thus, we modeled program costs as a component of the utility revenue requirement. The ACC has also previously approved a shareholder incentive for APS for the successful achievement of target EE savings. The incentive is capped at 14% of program costs, on a pre-tax basis. We modeled the shareholder incentive at the approved amount and assumed the utility would achieve 100% of its targeted energy savings. We included both the program cost recovery and shareholder incentive business model components in the initial analysis of the BAU with EE and EES portfolios. Given the magnitude of the mandated energy efficiency savings in Arizona, revenue erosion will likely become a major concern for utilities in the achievement of the EES. At the time of our analysis, the ACC was considering allowing utilities to implement a decoupling mechanism to support recovery of authorized fixed costs.

Based on conversations with the ACC, we decided to apply a revenue-per-customer (RPC) decoupling mechanism. An RPC decoupling mechanism is designed to recover the utility's required revenues on a per-customer basis. The decoupling mechanism was applied only in the EES case to make the utility financially indifferent between the pursuit of the EES goals or lack thereof (relative to the BAU with EE).[15] When coupled with a shareholder incentive mechanism, this comprehensive business model may provide an opportunity for the utility to realize additional earnings and/or a higher ROE from the successful achievement of the aggressive energy efficiency savings goals.

[15] We did not include a decoupling or lost revenue recovery mechanism in the BAU with EE case based on discussions with ACC and Arizona utilities.

## 5. Analysis Results

We assess the impacts of implementing an EES portfolio on customers' bills and rates and on utility earnings and ROE compared to a "business as usual" case that includes current energy efficiency programs (BAU with EE). We then focused on developing a more robust EE business model by applying a RPC decoupling mechanism when the utility achieves the EES savings goals to assess the degree to which it will improve the financial outlook for shareholders and at what cost to ratepayers.

The EES portfolio provides substantial ratepayer bill savings at relatively modest rate increases.[16] If APS achieves the savings targets in the EES, then ratepayers would realize about $4.6B of customer bill savings between 2011 and 2030 (see Figure 4). These incremental bill savings are in addition to the bill savings that customers realize from participating in the existing energy efficiency programs offered by the utility in the BAU case (~$4.3B) and are also net of the costs of energy efficiency programs (e.g. costs of administering the program, incentives to customers). It is important to note that ratepayers, as a whole, begin to see bill savings starting in 2016 as new generation plants begin to be deferred and fuel costs are reduced (see Figure 4). This trend in aggregate bill savings occurs for two reasons. First, the utility cost savings associated with these energy efficiency portfolios (e.g. reduced fuel costs and lower capital and O&M requirements for new generation) take time to develop and inure to ratepayers (based on the timing of general rate case filings) sufficient to offset the annual EE program expenditures. Second, the costs of the energy efficiency programs are expensed during each program year, while the energy savings and other benefits accrue over the lifetimes of the measures.[17] Thus, in this situation, a short-term analysis might not full y capture the bill reductions that would occur over time and inure to consumers as a whole, depending upon the time horizon chosen.

Customer rate impacts from energy efficiency increase as savings levels rise. This is primarily a function of the decline in sales being higher than the reduction in revenue requirement from the achieved EE savings.[18] In the EES portfolio, annual rates are ~1.0 cents/kWh higher, on average, than in the BAU with EE portfolio (see Figure 5). There is an observed increase in retail rates while DSM programs are being offered (2011-2020) and a decrease in retail rates when DSM programs costs are no longer incurred and the savings from EE accrue to ratepayers.

[16] The Benefits Calculator model used to perform this analysis only provides aggregate ratepayer effects; thus rate and bill impacts can not be broken out separately for participants in the EE program or non-participating customers.
[17] Bill savings also increase after 2020 because DSM program costs are no longer incurred while savings from measures installed continue to yield savings over their economic lifetime (assumed to be 10 years for the entire portfolio of measures) and reduce customer bills.
[18] All-in retail rates are a function of the utility's revenue requirement in the numerator and sales in the denominator. Mathematically, a unit decrease in the numerator will decrease the fraction while a unit decrease in the denominator will increase the fraction, ceteris paribus. In this case, both the numerator and denominator are being reduced. In percentage terms, electricity sales (denominator) are dropping much faster than the revenue requirement (numerator), so retail rates (the fraction) will increase.

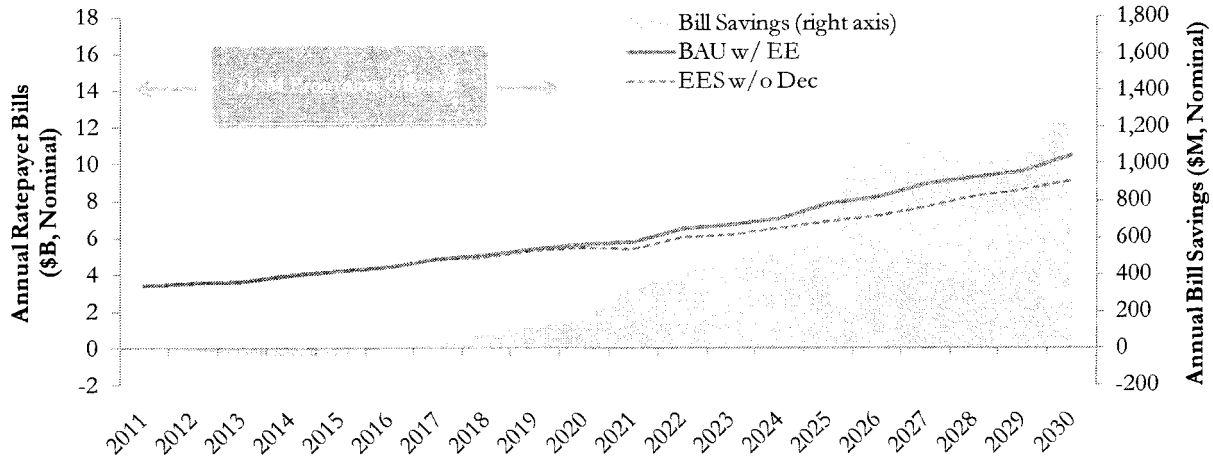


***Figure 4. Ratepayer bills and bill savings of Arizona Public Service Company customers***

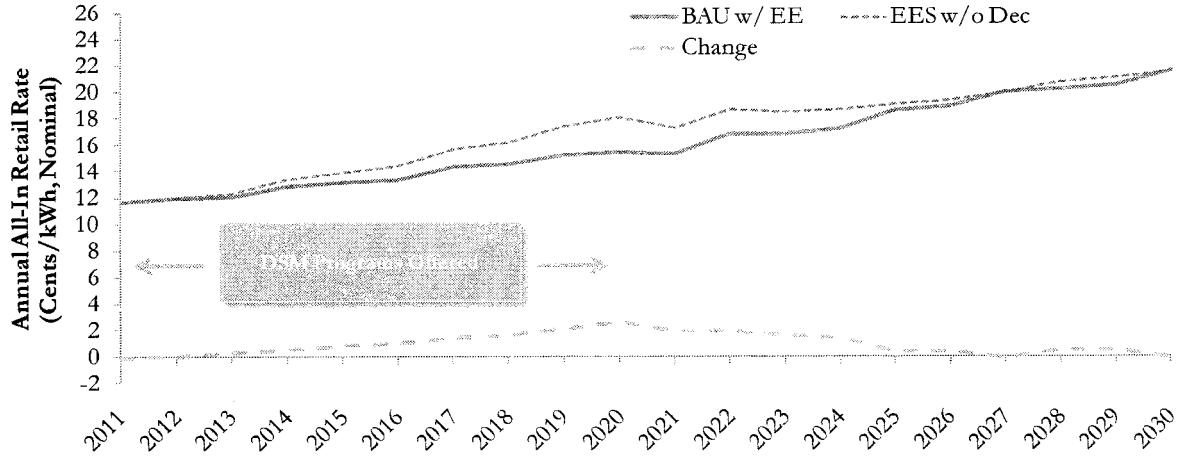


***Figure 5. Impact of EES portfolio on all-in retail rates of Arizona Public Service Company customers***

If the regulators adopt a "stick-only" approach, they would establish energy savings goals that the utility must achieve and only provide for recovery of energy efficiency program costs. The utility's base earnings for each scenario in Figure 6 and Figure 7 reflect this "stick only" approach in which the utility is only allowed to recover the costs of energy efficiency programs, but is not allowed to recover "lost revenues" associated with energy efficiency or provided an opportunity for additional earnings due to achieving energy efficiency savings targets (i.e. a case without a comprehensive business model). In the "business as usual" case (that includes the current level of energy efficiency programs), utility base earnings are about $2.52B between 2010 and 2030 (see Figure 6). In the EES scenario, the utility achieves base earnings of $2.23B, which is ~$290M lower than the BAU with EE case. This illustrates the point that a utility that achieves aggressive EES goals will end up with lower earnings compared to a BAU case. A similar trend is observed with respect to the impacts on the utility's return on equity (ROE). The achieved ROE for APS is much lower (~7%) than its authorized ROE (11%); APS is under-

earning the authorized ROE by ~400 basis points based on our analysis.[19] The utility is experiencing significant under-earnings as a result of the lag in years between when a request for rate change is filed with regulators and when the regulators approve the rate increase (i.e., regulatory lag), as well as non-fuel costs are increasing at a faster rate than revenue collections. In addition to these pre-existing impacts on utility earnings, aggressive EES goals exacerbate the impact on the utility's ROE in the absence of a comprehensive business model. The utility's base ROE is 75 basis points lower if it achieves the EES savings goals compared to the BAU case, 6.73% vs. 7.48% (see Figure 7).

Utility shareholders are concerned about the impact of aggressive EE programs on their earnings and ROE, especially considering the degree to which the utility is already under-earning relative to authorized levels. We consider a "stick-and-carrots" approach by implementing a comprehensive business model to address shareholder concerns. Under the EES portfolio, the utility's returns are reduced even further, by 75 basis points and $290M in earnings, but the shareholder incentive mechanism only adds back 34 basis points and $110M in earnings. Without the introduction of some sort of decoupling or lost revenue recovery mechanism as part of a more comprehensive utility EE business model, it is unlikely the utility would voluntarily attempt to achieve the EES savings goals.

The implementation of an RPC decoupling mechanism, designed as part of a comprehensive business model for the achievement of the EES, would allow the utility to achieve nearly comparable shareholder returns to the BAU with EE case. The decoupling mechanism would increase earnings by ~$150M and ROE by 45 basis points, which is a more lucrative component of the comprehensive business model than the performance incentive.

The incremental cost of the RPC decoupling mechanism to ratepayers would be ~$320M, or a 0.9% increase in customer bills, between 2011 and 2020, and would raise all-in retail rates on average by ~1.5 mills/kWh (or 1.0%). Even with this additional recovery by the utility, ratepayers as a whole would still realize significant incremental bill savings under the EES portfolio of $4.6B in aggregate.

[19] Basis points are used to denote the change in a financial metric. For example, a 100 basis points drop in ROE is equal to a 1% reduction in return on equity.

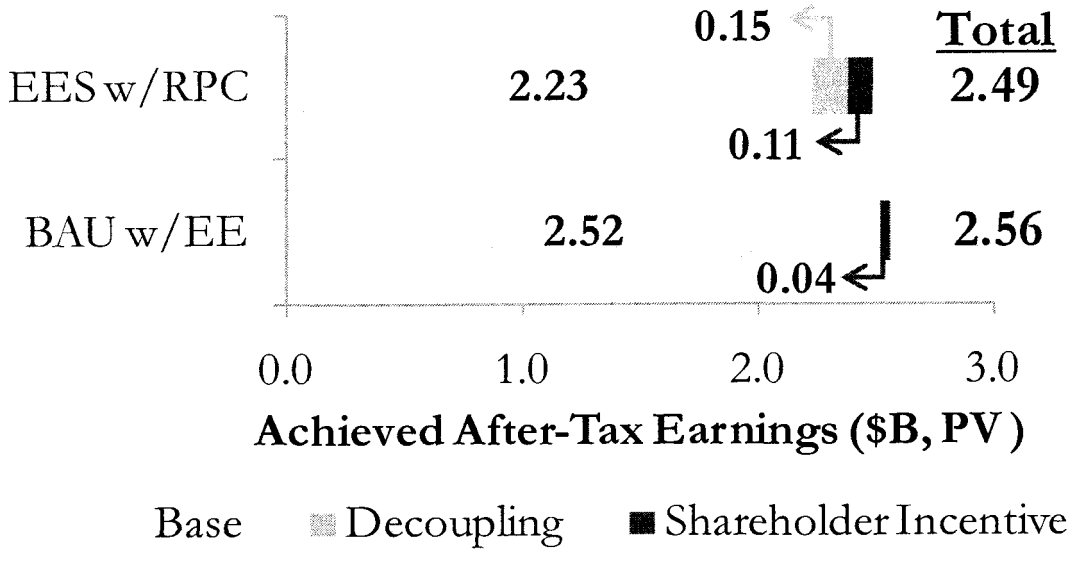


*Figure 6. Impact of a comprehensive energy efficiency business model on utility earnings*

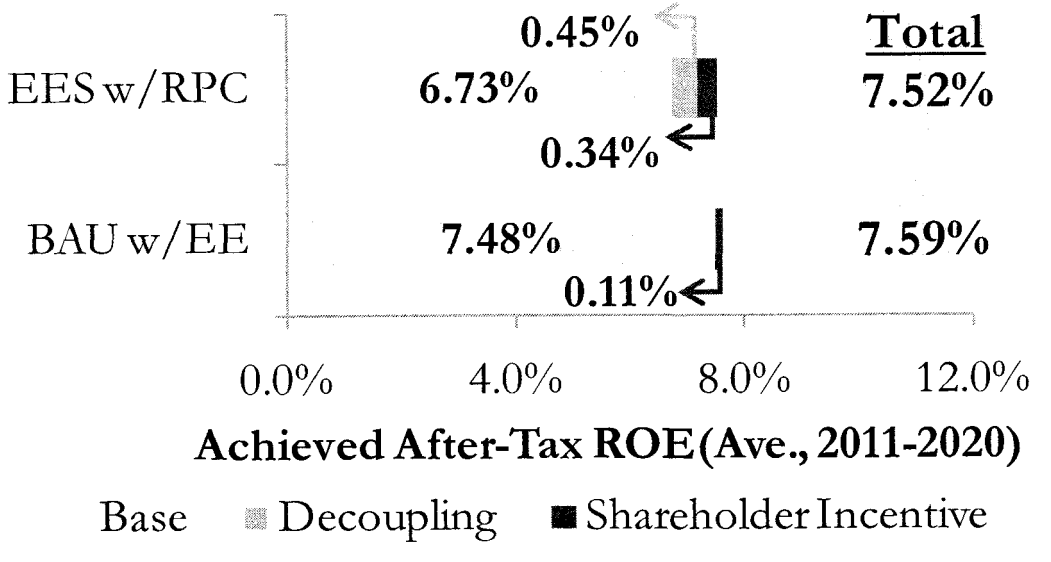


*Figure 7. Impact of a comprehensive energy efficiency business model on utility ROE*

## 6. Conclusion

This analysis quantifies the impacts on ratepayers and shareholders when a state like Arizona mandates aggressive energy efficiency goals: ~2.0% savings as percent of annual retail sales through ratepayer-funded programs offered by its electric utilities. We focus on the ability of a comprehensive business model, including program cost recovery, decoupling to support fixed cost recovery, and a shareholder incentive, to align the interests of utility shareholders and managers with the state's public policy goals (i.e., achieving aggressive EE savings targets).

The portfolio of energy efficiency programs included in the EES is an attractive, relatively low-cost resource for Arizona utility customers. We estimate that the portfolio of EE programs that meets EES goals would provide ~$1.4B in net resource benefits over the analysis period (2011-2030). Customer bills would be about $4.6B lower (or 5.9%) over the lifetime of installed measures (2011-2030) compared to the "business as usual" case that includes the pre-existing path of EE savings.[20] These bill savings account for and are net of any rate increases necessary to fund the increased energy efficiency efforts. Rates are modestly increased by ~1.0 cents/kWh higher, on average, than in the pre-existing case.

Our analysis also suggests that the utility faces significant erosion in earnings and a lower ROE as more aggressive energy efficiency programs are implemented. Without the effect of an RPC decoupling mechanism, utility earnings are ~$220M lower under the EES scenario compared to the BAU with EE scenario. Our analysis, however, shows that it is possible to design an RPC decoupling mechanism that allows the utility to effectively remove the impacts on the utility's achieved ROE from the lower sales and thus reduced recovery of fixed costs. With the implementation of an RPC decoupling mechanism designed in this fashion along with a shareholder incentive that provides the Arizona utility with 14% of program costs on a pre-tax basis, shareholder returns (i.e., ROE) would be comparable to the BAU with EE scenario. The implementation of this type of decoupling mechanism would only slightly increase average all-in retail rates by ~1.0%.

This study provides some insights for policymakers and regulators interested in pursuing aggressive EE goals. While this analysis was specific to a U.S. regulatory context, utilities that operate under a similar regulatory structure in which earnings (and the utility's profitability) increases as energy sales increase would have a bias against energy efficiency (because of the impact of energy savings on revenues from sales). As nations around the world begin to consider and/or mandate aggressive EE policy goals, it becomes vitally important for policymakers to consider comprehensive business models in order to mitigate potential utility financial impacts. Our case study of a large Arizona utility suggests that an aggressive EE portfolio can provide significant benefits to ratepayers and also demonstrates that regulators, utilities, and other stakeholders can align the financial interests of utilities with broader governmental energy policy goals.[21]

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[20] Net resource benefits are a metric of societal benefits from the DSM portfolio. The BC model calculates net resource benefits as the administratively determined avoided energy and avoided capacity benefits minus the utility program costs and installed costs of the energy efficiency measures. Customer bill savings are a metric for the impact on customers when a utility achieves aggressive energy savings. The BC model calculates customer bill savings as the actual benefits of avoided energy and capacity expenditures net of any rate increases to customers to pay for the increased energy efficiency.

[21] The ACC unanimously approved a decoupling policy statement on December 15, 2010 establishing guidelines for an electric utility's decoupling mechanism based in large part on the results of this analysis. See ACC Docket No. E-J-08-0314.

We presented a comprehensive business model to achieve aggressive energy savings that assumes that utilities administer energy efficiency programs funded by their customers. It is important to note that a number of U.S. states, and other countries, have chosen other types of entities and organizations besides utilities to administer ratepayer-funded energy efficiency programs. There are two other types of administrative models that have emerged. First, some states have chosen an existing state agency to act as the program administrator (e.g., New York Energy Research and Development Authority) or have created a new agency or non-profit corporation (e.g., Energy Trust of Oregon). In these states, the state agency administering the energy efficiency programs has signed a Memorandum of Understanding (MOU) with the state regulatory commission which establishes a multi-year contract and performance period. If the state agency fails to effectively administer and deliver ratepayer-funded EE programs, the regulatory commission has the option of terminating and/or not renewing the MOU with the state agency. Second, other states have selected and signed multi-year contracts with third-parties, either non-profit or for-profit companies, that have been selected through competitive solicitations to administer ratepayer-funded EE programs. In the states that have utilized this approach (e.g., Vermont, Hawaii, Wisconsin, New Jersey), the third party program administrator typically has the opportunity to earn a performance incentive included as part of their contract (typically at levels that are between 1-4% of program costs) for successfully meeting program goals or targets It should be noted, however, that non-utility administration does not address the financial impacts of energy efficiency on the utility from declining sales and it fails to fully address the supply-side investment incentives obstructing energy efficiency policy objectives.[22] It is vital, therefore, that a successful business model for energy efficiency must take into account and balance the interests of all stakeholders.

[22] Cappers et al. (2009a) discussed the conceptual framework of the energy efficiency business model in further detail.

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