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**Financial Impact of Energy Efficiency
under a Federal Renewable Electricity
Standard: Case Study of a Kansas
“super-utility”**

Peter Cappers and Charles Goldman

**Environmental Energy
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Principal Authors

Peter Cappers and Charles Goldman

Ernest Orlando Lawrence Berkeley National Laboratory
1 Cyclotron Road, MS 90R4000
Berkeley CA 94720-8136

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Acronyms and Abbreviations

ACES	American Clean Energy and Security Act
BAU	Business-as-usual
BP	Basis Points
CERES	Combined Efficiency and Renewable Electricity Standard
DSR	Demand Side Resource
EE	Energy Efficiency
EERS	Energy Efficiency Resource Standard
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
GWh	Gigawatt-hour
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent Power Producer
KCC	Kansas Corporation Commission
kV	Kilovolt
kWh	Kilowatt-hour
MACRS	Modified Accelerated Cost Recovery System
MW	Megawatt
MWh	Megawatt-hour
O&M	Operations and Maintenance
PPA	Purchased Power Agreement
PTC	Production Tax Credit
PV	Present value
RES	Renewable Electricity Standard
ROE	Return-on-equity
RPS	Renewable Portfolio Standard
SNB	Shared Net Benefits incentive mechanism
\$M	Million dollars
\$B	Billion dollars

Abstract

Local, state and federal policies that jointly promote the generation of electricity from renewable technologies and the pursuit of energy efficiency are expected to help mitigate the detrimental effects of global climate change and foster energy independence. We examine the financial impacts on various stakeholders from alternative compliance strategies with a Combined Efficiency and Renewable Electricity Standard (CERES) using a case study approach for utilities in Kansas. If only supply-side options are considered, our analysis suggests that a Kansas “super-utility” would prefer to build its own renewable energy resources, while ratepayers would favor a procurement strategy that relies on long-term renewable power purchase agreements. Introducing energy efficiency under varying levels as a CERES resource will, under our analysis, reduce ratepayer bills by ~\$400M to ~\$1.0B between 2009 and 2028, but commensurately erode shareholder returns by ~10 to ~100 basis points. If a business model for energy efficiency inclusive of both a lost fixed cost recovery mechanism and a shareholder incentive mechanism is implemented, our results illustrate how shareholder returns can be improved through the pursuit of energy efficiency, by at most ~20 basis points if certain conditions apply, while ratepayers continue to save between \$10M and ~\$840M over 20 years.

1. Introduction

Reduced reliance on fossil fuels through the generation of electricity from renewable technologies and increased energy efficiency are expected to help mitigate the detrimental effects of global climate change (IPCC 2007) and promote energy independence. Policies and programs that implement this strategic approach are under consideration and/or being pursued at every level of government, as there is a growing sense of urgency.

For example, many states in the U.S. have developed policies to promote renewable energy production. Currently, 29 states and the District of Columbia have adopted Renewable Portfolio (or Electricity) Standards (RPS or RES) that require electric suppliers to meet a fraction of their consumer's electricity demands with power generated from renewable resources (USDOE 2008).¹ These state-based renewable energy policies have significantly expanded the renewable generation sector; over ~16,500 MW, or roughly 60%, of the non-hydro renewable capacity additions between 1998 and 2008 occurred in states with an RPS program (Wiser and Barbose Forthcoming 2009).

Regulatory commissions in many states have also supported ratepayer-funded energy efficiency programs in order to reduce consumer costs and environmental impacts associated with electricity generation. Currently 31 states have legislative or regulatory policies in place that identifies the need to pursue energy efficiency programs; although as of 2007, reductions in electricity sales were modest (less or equal to 0.1%) in 11 of these states (Eldridge et al. 2009). There are ample business reasons why a regulated utility would eschew energy efficiency efforts (Jensen 2007). Thus, states are increasingly adopting policies that set explicit savings goals for utilities through legislative or regulatory requirements and/or attempt to align the utility's business and financial interests with broader public policy objectives that support energy efficiency. For example, eleven states have adopted an energy efficiency resource standard (EERS) within the last three years (Barbose et al. 2009).

Environment and efficiency advocates and experts (e.g., Sovacool 2009; Brown, York and Kushler 2007) have promoted a more coordinated and comprehensive energy policy; one that focuses on increased reliance on renewable electricity supply resources and reduced overall consumption of electricity. The American Clean Energy and Security Act (ACES), which was passed by the United States House of Representatives in June of 2009, included a Combined Efficiency and Renewable Electricity Standard (CERES) provision starting in 2012, which ramps up to 20% by 2020 and allows utilities to meet up to 25% of their RES requirement by implementing energy efficiency programs, or up to 40% by petition of the state governor (USHOR 2009). Furthermore, energy efficiency also reduces the utility's overall sales, thereby reducing their CERES energy targets and associated financial compliance obligation. Thus, the value proposition of energy efficiency to utility ratepayers may change significantly if this federal CERES is enacted.

A federal RES also poses challenges and opportunities for utility managers and state regulators as utilities will have to assess the impacts of alternative compliance strategies. For example,

¹ Five other states have set voluntary goals, instead of binding targets, to pursue renewable electricity.

utilities may prefer to comply with a RES by developing renewable energy projects under traditional cost-of-service regulation, which provides opportunities to increase earnings. Utilities may not aggressively pursue RES compliance strategies that rely on energy efficiency or signing long-term contracts with private sector developers of renewable projects if they are perceived to be less profitable. Thus, regulators may need to consider policies that improve the utility's business case for energy efficiency (or at least make the utility indifferent financially) or adopt regulatory or statutory directives to require the pursuit of alternative options that have lower costs and risks for ratepayers.

Few studies have empirically examined the financial impacts of alternative RES compliance strategies on key stakeholders (i.e., ratepayers, utility shareholders and managers). Chen et al. (2007) reviewed RPS cost-impact studies from 18 different states, all of which provided some form of a rate or bill impact. However, the studies did not appear to address likely cost differences based on alternative compliance strategies. Cita et al (2008) examined the potential rate and bill impacts of Kansas' proposed 2015 Wind Challenge, although shareholders' perspective and the potential effects of energy efficiency as a compliance strategy were not analyzed. Mahone et al. (2009) assessed how the avoided cost of energy will change as the California RPS target is increased, thereby raising the cost-effective level of energy efficiency investment, but does not examine how the pursuit of this increased investment might impact stakeholders. At a national level, Mancisidor et al. (2009) explore the evolution of the European Union's comprehensive energy strategy (i.e., RES and EE) and how these policies have influenced Spain's energy policy, but provide very little quantitative analysis of how such policies have impacted different Spanish electricity stakeholders. The U.S. Energy Information Administration (EIA) assessed the national impact of a March 2009 discussion draft version of the American Clean Energy and Security Act (EIA 2009a) and found that fully incorporating energy efficiency into the RES can lower electricity rates.

This study examines the financial impacts on various stakeholders of alternative strategies that a utility can use to comply with a proposed federal RES (as described in ACES): building and operating the requisite amount of renewable resources under cost-of-service regulation, entering into long-term power purchase agreements with independent power producers (IPPs) or relying on energy efficiency to meet a fraction of the proposed federal RES. We analyze various ratemaking and incentive mechanisms that regulators can implement to remove disincentives to energy efficiency and also provide a positive incentive for the utility to maximize acquisition of cost-effective energy efficiency resources as part of its RES compliance strategy. We adopt a case study approach and focus on a Kansas "super-utility" that reflects the aggregate characteristics of the three major investor-owned utilities in that state.

The remainder of the paper is organized as follows. Section 2 provides a high-level overview of the framework for this analysis and discusses key inputs (e.g., utility characterization, the utility's proposed resource plan to meet its RES requirements, and alternative energy efficiency portfolios). In Section 3, we present the results of our analysis of the financial impacts on shareholders and ratepayers of different approaches to complying with the proposed federal RES (e.g., purchased power vs. utility-owned renewable generation vs. energy efficiency) and alternative business models to promote energy efficiency. Section 4 summarizes key findings, including discussion of the policy significance of the results.

2. Quantitative Analysis of Utility Compliance with a Renewable Electricity Standard

2.1 Overview of Analysis Method

We utilized and enhanced a spreadsheet-based financial model, (i.e., Benefits Calculator) that was initially constructed to support the National Action Plan for Energy Efficiency (Cappers et al. 2009). The major steps in our analysis are displayed graphically in Figure 1. Two main inputs are required: (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 Resource (DSR) portfolio – projected electricity and demand savings, costs and useful lifetime of a portfolio of energy efficiency programs that the utility is planning or considering to implement during the analysis period. The Benefits Calculator also estimates total resource costs and benefits of the DSR portfolio using a forecast of avoided capacity and energy costs. The Benefits Calculator uses inputs provided in the Utility Characterization to produce a “business-as usual” (BAU) case as well as alternative scenarios that include energy efficiency resources. If a business model comprised of program cost recovery, lost fixed cost recovery and/or shareholder incentive mechanisms are instituted, the Benefits Calculator model readjusts the utility’s revenue requirement and retail rates accordingly based on the design and earnings basis of these mechanisms. Finally, for each scenario, the Benefits Calculator produces several metrics that provide insights on how energy efficiency resources and proposed ratemaking and incentive mechanisms impacts utility shareholders (e.g. overall earnings, return on equity), ratepayers (e.g., customer bills, all-in rates) and society (e.g. net resource benefits).

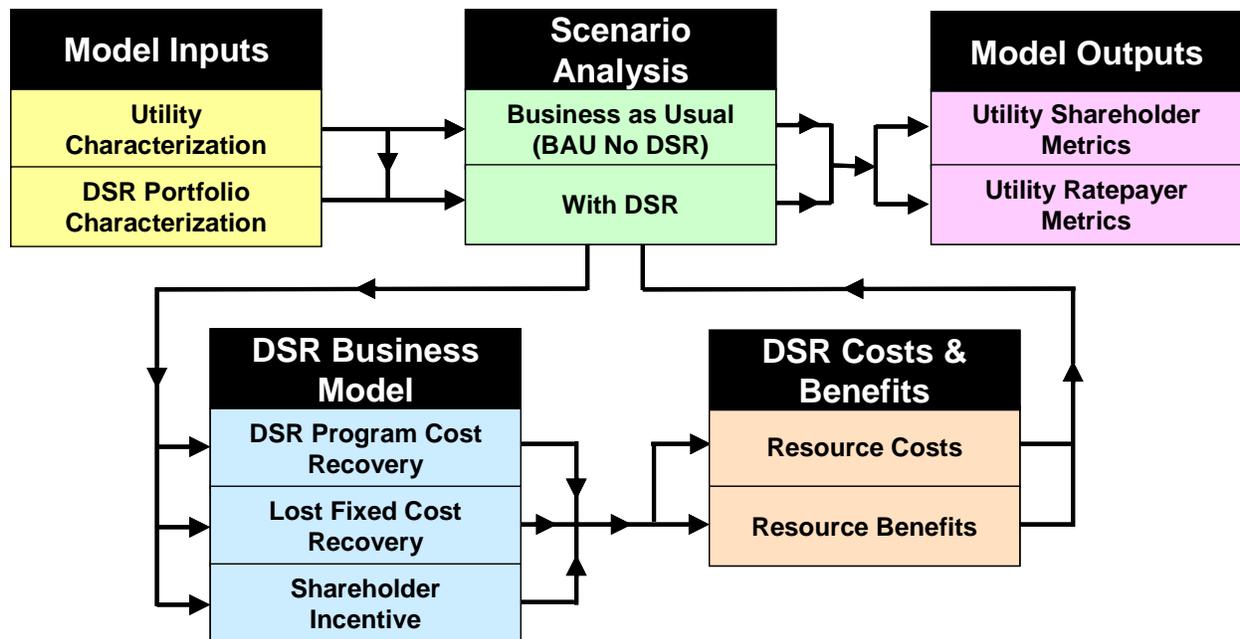


Figure 1. Flowchart for quantitative analysis of energy efficiency incentive mechanisms

2.2 Utility Characterization

We reviewed the physical and financial characteristics of the three largest investor-owned electric utilities in Kansas (Kansas Gas and Electric, Westar Energy, and Kansas City Power and Light) and combined the individual utility characteristics to construct a single “super-utility” for this study. This approach facilitated a statewide assessment of the likely impacts of federal RES and energy efficiency policy goals for Kansas², rather than examining impacts on each utility in isolation.³

The Kansas super-utility has first-year (2009) annual retail sales of ~37,000 GWh and an initial peak demand of ~6,600 MW, which equates to a 65% load factor. Sales are forecasted to grow at a compound annual rate of 1.6%, while peak demand is expected to increase at a slightly faster rate of 1.7% per year. The super-utility has ~1.2 million customers in 2009 and expects customer account growth of ~1.0% per year. These load, peak demand, and customer account forecasts represent our “business-as-usual” scenario if energy efficiency is not implemented

In order to comply with the proposed federal CERES, the super-utility may sign long-term purchased power agreements (PPA) with commercially-developed renewable resources or alternatively build and operate its own fleet of renewable generation units under traditional, cost-of-service regulation. Kansas appears to have ample wind and biofuel (i.e., agricultural byproducts) potential to meet a federal CERES (UCS 1999). If the utility chose to build and operate the facilities starting in 2012 (first year of ACES) and seek cost recovery under cost-of-service regulation, the overnight nominal capital cost⁴ for a 150 MW wind facility⁵ (with an assumed 38% capacity factor) is estimated at \$217M and \$137M for a 50 MW biofuel facility (with a capacity factor of 85%), both growing at a rate of 1.9% annually. Fixed and variable operations and maintenance (O&M) costs for utility-sponsored wind and biofuel projects start out in 2012 at \$4.9M (Wiser and Bolinger 2009) and \$20.2M (EIA 2009b) respectively, but are expected to grow rapidly to \$8.8M and \$45.6M by 2020 (EIA, 2009b) because of expected system integration costs, \$5/MWh by 2020 (USDOE 2008), associated with introducing more of

² The state of Kansas adopted a RES in 2009. For purposes of this analysis, we are ignoring the requirement and focusing instead on a federal mandate.

³ This approach differed from Cappers et al. (2008), where a prototypical utility was constructed based on attributes taken from several utilities in the Southwestern U.S. but did not explicitly represent these utilities in aggregate.

⁴ The Benefits Calculator model is unable to directly handle the Modified Accelerated Cost Recovery System (MACRS) and Production Tax Credit (PTC) that the utility is likely to apply and receive. For this reason, the actual overnight capital cost of the wind facility and the biofuel facility are each reduced by ~34% as a proxy to capture the impacts of these two effects (~22% from the present value of the PTC and ~12% from the present value of the 5-year MACRS vs. 20-year straight line depreciation schedule). Without the effect of this adjustment, the “unadjusted” overnight nominal capital cost (in 2012) for the wind and biofuel facilities would be \$328M and \$207M, respectively (EIA, 2009b).

⁵ As the market penetration of wind resources ramps up in response to the increasing federal RES, the transmission system will need to be expanded in order to move wind power from remote areas to load centers, which will increase capital costs. However, an extra high capacity 765 kV merchant transmission line running west from Wichita to Spearville and then south to the Oklahoma/Kansas border has been approved by the Kansas Corporation Commission, which will produce benefits not just for wind development in western Kansas but also for consumers across the Southwest Power Pool and Midwest ISO footprints (Prairie Wind Transmission 2009). For this reason, we have chosen to not directly apply this expense to the capital cost nor the PPA costs of the wind facilities proposed to be built under ACES in Kansas.

these variable generation resources.⁶ When combined, the levelized nominal cost for a wind project in 2012 is estimated to be ~\$60/MWh and about \$108/MWh for a biofuel facility, but grows to \$77/MWh and \$131/MWh, respectively, in 2020. Alternatively, the super-utility estimates that the all-in, first-year 2012 cost for wind energy under a power purchase agreement would be ~\$54/MWh (Wiser and Bolinger 2009) and ~\$116/MWh (Olcott 2009) for biomass and would rise to \$70/MWh and \$146/MWh, respectively, in 2020, assuming the utility and merchant power producers would see identical growth in costs.⁷ Because of differences in overall resource costs, we assumed that the super-utility had a preference for wind energy. To meet the CERES requirement, the utility would first apply the output from existing and newly built or contracted wind resources and fill the remaining requirement with electricity generated from biofuel in the same manner (i.e., utility- built or PPA).

We developed a “business-as-usual” generation expansion plan, inclusive of 3,368 GWh of existing renewable resources (as of 2008), that allows the Kansas super-utility to meet its forecasted load growth and the proposed federal CERES requirement, which increases over time, and does not include any energy efficiency resources (see Figure 2).⁸ Renewable energy projects in the utility’s resource plan are assumed to come on line in the year they are needed to meet or exceed the proposed federal CERES requirement.⁹

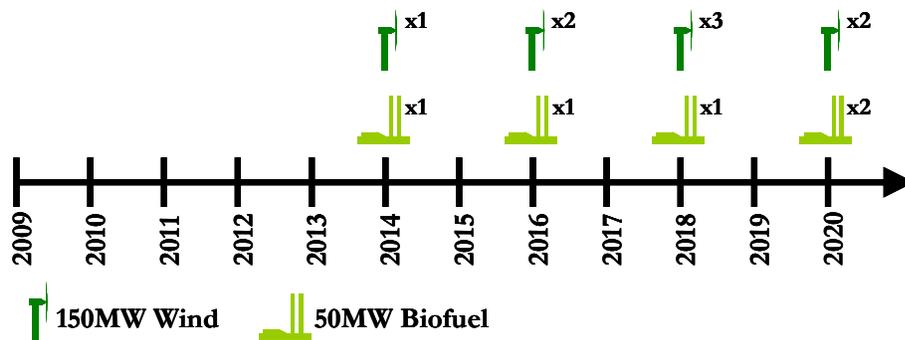


Figure 2. Renewable generation expansion plan: Business-as-usual (BAU) No EE Case

⁶ Biofuel plants are not expected to dramatically increase system integration costs. However, the model is only able to apply a single growth factor to each cost category (i.e., capital expenditures and O&M) that does not differ by the renewable technology. Since wind resources comprise such a large proportion of the renewable resource portfolio (~60-75%), the loss in accuracy associated with applying a more rapid growth in O&M expenses (1.9% without system integration vs. 7.68% with them included) is expected to have modest effect on the analysis.

⁷ Cita et al. (2008) reach a similar conclusion that the utility’s ratepayers would be better off if compliance with the state’s 2015 Wind Challenge was met through purchased power agreements with wind resource providers rather than through the utility’s own fleet of wind generation assets financed under cost-of-service regulation. Furthermore, FPL Energy (now Nextera Energy Resource, LLC) filed testimony with the Iowa Utilities Board claiming that it could sell wind energy to MidAmerican Energy Company cheaper than the utility could produce it (O’Sullivan 2009).

⁸ We did not explicitly model the impact of a carbon cap and trade regime on the utility in this study, in part because we implicitly assumed that the level of carbon adder would be relatively low during our time horizon and would not lead to retirement of existing coal units. Furthermore, Kansas allows its investor-owned utilities to sell excess generating capacity off-system where 100% of the net after-tax proceeds are returned to consumers. Thus, we assumed that the utility would not alter the dispatch of existing units as new renewable projects come on-line; rather, the additional capacity would allow the utility to increase its off-system sales.

⁹ The timing of renewable resource additions is driven by load growth and provisions of the federal ACES bill, which increases the RES requirement over time. The utility chooses to bring new plants on-line so that it meets these requirements but minimizes excess capacity, given unit size constraints.

2.3 Energy Efficiency Portfolio Characterization

The super-utility can also utilize energy efficiency to meet a portion of its CERES obligation (under the proposed ACES bill). We developed cost and savings estimates for two alternative energy efficiency portfolios (i.e., Moderate and Aggressive EE portfolios) based on program data from other utilities in the region (i.e., Iowa) that have significant experience administering energy efficiency programs. The Moderate EE portfolio was designed such that the utility can apply the maximum amount of energy efficiency towards compliance with the CERES requirement allowed under the ACES bill (i.e., 25% of the CERES requirement), which equates to ~0.5% a year incremental reduction in sales, at an average cost of ~3.1¢/lifetime kWh.¹⁰ The Aggressive EE portfolio exceeds the amount of energy efficiency that can be directly applied to satisfy the CERES requirement and was designed to reduce overall sales by 2% a year (after a 5 year ramp up), at an average cost of ~3.2 ¢/lifetime kWh. The Aggressive EE portfolio completely offsets projected load and peak demand growth starting in 2012 and reduces them by 31% and 44%, respectively, by 2020.

The total resource costs and benefits of the Moderate EE portfolio are about one-fourth of the Aggressive EE portfolio (see Table 1, columns 5 and 3). This close symmetry between costs and benefits of these two energy efficiency portfolios produces a roughly comparable benefit cost ratio (column 7 of Table 1), 1.36 vs. 1.28 for Moderate and Aggressive EE portfolios respectively.

Table 1. Lifetime savings, resource costs and benefits of alternative energy efficiency portfolios (2009-2028)

	Lifetime Energy Savings (GWh)	Lifetime Pk. Demand Savings (MW)	Total Resource Benefits (\$M, PV)	Utility Program Costs (\$M, PV)	Total Resource Costs (\$M, PV)	Net Resource Benefits (\$M, PV)	Benefit Cost Ratio
	(1)	(2)	(3)	(4)	(5)	(6) = (3) - (5)	(7) = (3)/(5)
Mod. EE	50,848	1,053	\$1,154	\$530	\$848	\$306	1.36
Agg. EE	195,683	4,014	\$4,261	\$2,298	\$3,339	\$922	1.28

¹⁰ Technically, ACES allows a state to petition to the Federal Energy Regulatory Commission (FERC) to increase the maximum proportion of energy efficiency savings credited as a compliance resource to 40% from 25%. It is unclear how FERC will consider such requests; thus, we chose to cap energy efficiency at 25% as a CERES compliance strategy, consistent with the statute in the proposed legislation.

2.4 “Business Models” for Ratepayer-funded Energy Efficiency

As the National Action Plan for Energy Efficiency (Jensen 2007) points out, many utilities continue to shy away from aggressively expanding their energy efficiency efforts when their shareholders’ fundamental financial interests may be placed at risk by doing so. Thus, effective ratemaking and incentive mechanisms that address utility disincentives must likely be developed in order to promote significant energy efficiency efforts by utilities. A viable business model for ratepayer-funded energy efficiency should address the following issues: recovery of prudently incurred program costs, under-recovery of fixed cost revenues between rate cases due to reduced sales from energy efficiency, and development of a shareholder incentive that provides an opportunity for energy efficiency to become a “profit center” for the utility administrator.

In terms of program cost recovery, we are interested in seeing how different methods for recovering authorized energy efficiency program expenditures impact the different stakeholders’ financial interests. Thus, we examine two alternative program cost recovery mechanisms: expensing and amortization of program costs.¹¹

We subsequently augment the analysis by expanding the business model to be more comprehensive in nature. First, we consider mechanisms for removing the disincentive associated with under-recovery of fixed costs between rate cases due to a reduction in sales by analyzing a lost base revenue recovery mechanism and a decoupling mechanism with an inflation adjustment (1.9%) to account for cost growth between rate cases.¹² Second, we analyze the impact of a shared net benefits incentive mechanism, which is designed to provide the utility with a reasonable opportunity to increase its after-tax returns to shareholders.¹³

The design criteria and package of ratemaking and incentive mechanisms varies somewhat across the two energy efficiency portfolios. This is done in part to address equity and fairness issues typically raised by ratepayer and consumer advocates (e.g., appropriate sharing of benefits between ratepayers and shareholders, rate impacts). For either energy efficiency portfolio, the utility is able to fully recover all authorized program costs either through expensing or amortization. For illustrative purposes, we assume that consumer advocates will likely only support the implementation of a decoupling mechanism if the utility pursues the Aggressive EE

¹¹ All program administration and measure incentive costs were funded through the issuance of short-term debt, amortized over a five year period, where the un-depreciated balance had a carrying charge applied at the utility’s weighted average cost of capital. Given that energy efficiency programs are offered in every year of our 20-year analysis period, program costs in the latter years will not be fully collected under an amortization recovery mechanism within the framework of our analysis. However, the effects of discounting that occur when present-valuing a stream of payments (or costs) is expected to offset this loss of accuracy in our financial results.

¹² This is commonly referred to as a utility’s “throughput” incentive. The vast majority of fixed costs are collected volumetrically in rates, predominantly on a \$/kWh basis, from ratepayers. If sales are reduced because of energy efficiency efforts, the utility collects less revenue between rate cases which results in an under-recovery of fixed costs. Alternatively, if sales increase more than forecast (e.g. due to a booming economy), the utility collects more revenue, which completely offsets fixed costs and adds to utility profits. A lost fixed cost recovery mechanism attempts to directly reimburse the utility for the reduced revenue associated exclusively with energy efficiency program savings. A decoupling mechanism, on the other hand, attempts to reduce the fluctuation in collected revenue between rate cases due any factor that would influence sales (e.g., energy efficiency programs, weather).

¹³ A shared net benefits incentive mechanism is designed to give the utility a fraction of the total resource benefits minus the costs to acquire them that inure from ratepayer-funded energy efficiency programs.

portfolio, but would be willing to support a more narrowly targeted lost base revenue mechanism under the Moderate EE portfolio.¹⁴ For the Moderate EE portfolio, we analyze the combined effect of a lost base revenue mechanism and shared net benefits incentive mechanism (designed to provide the utility with an opportunity to increase its average ROE by 10 basis points). For the Aggressive EE portfolio, we combine a decoupling mechanism with a shared net benefits incentive mechanism designed to provide the utility with an opportunity to increase its average ROE by 15 basis points. Table 2 shows the elements of the business model for each energy efficiency portfolio.

Table 2. Energy efficiency business models analyzed for Kansas super-utility

	Mod. EE	Agg. EE
Program Cost Recovery	Expensing or Amortization	
Lost Fixed Cost Recovery	Lost Base Revenue	Decoupling
Shareholder Incentive	SNB (+10 Basis Points to ROE)	SNB (+15 Basis Points to ROE)

¹⁴ A decoupling mechanism deals with potential erosion in utility earnings from sources other than just energy efficiency (e.g. mild weather) and typically is implemented initially as part of a general rate case. A Lost Base Revenue mechanism does not typically require a general rate case to implement. Because the savings goals in the Moderate EE scenario are modest, we assume that consumer advocates would be more reluctant to support the more far-reaching decoupling mechanism in this context. In contrast, the savings goals in the Aggressive EE portfolio (2% of retail sales) exceed current practice of utilities in leading states. For illustrative purposes, we assume that stakeholders from consumer and environmental groups may be more willing to consider and support a decoupling mechanism if this is the *quid pro quo* for achieving this level of savings.

3. Results

3.1 Financial implications of alternative renewable procurement strategies: “Build” vs. “Buy”

The Kansas super-utility’s strategy for complying with the proposed federal CERES requirement could have a significant financial impact on both ratepayers and shareholders (see Table 3). If the utility enters into long-term power purchase agreements to buy renewable energy to meet the entirety of the federal RES, average rates are 0.15 cents/kWh lower between 2009 and 2028 compared to meeting the entire standard by building renewable projects under cost-of-service regulation. This translates into ~\$520M in aggregate customer bill savings over the 20 year analysis horizon. In contrast, the utility’s shareholders are worse off under the Buy RES scenario as earnings and ROE erode (by ~\$450M and 5 basis points respectively) since fewer resources are added to the utility’s rate base. These results are driven in part by our assumptions regarding differences in the levelized cost of renewable energy under the “build” vs. “buy” scenario.¹⁵

Table 3. Stakeholder financial metrics for BAU No EE case (2009 – 2028)

	Build RES Scenario	Buy RES Scenario	Difference
Avg. Retail Rates (¢/kWh)	8.37	8.22	0.15
Collected Revenue (\$B, PV)	\$32.96	\$32.44	\$0.52
Achieved After-Tax Earnings (\$B, PV)	\$3.52	\$3.07	\$0.450
Achieved After-Tax ROE (Avg.)	10.37%	10.31%	0.05%

3.2 Energy efficiency with program cost recovery: Impact on stakeholders under federal CERES

The super-utility is also considering implementing several energy efficiency portfolios in 2009 under existing regulations that authorize recovery of program costs in advance of the CERES requirement (2012). This deployment schedule allows the utility to ramp up energy efficiency efforts to meet the resource contribution for energy efficiency allowed under the ACES bill. The portfolio of energy efficiency programs will continue through 2028, which is the end of the analysis period.¹⁶ Both portfolios reduce the basis upon which the CERES requirement is

¹⁵ The rate and bill impacts will converge if the super-utility’s levelized cost of building renewable supply resources approaches that of a merchant project, ceteris paribus. However, bond rating agencies are beginning to consider sizable long-term PPAs equivalent to debt, which will increase the super-utility’s cost of capital and thus cost ratepayers more in the long-run. This impact has not been modeled due to the uncertainty such an approach to a federal RES compliance would have on the bond rating and subsequently on the utility’s weighted average cost of capital.

¹⁶ Treatment of end effects somewhat influence the results and are an inherent concern in this type of analysis. Our decision to model a 20-year period where EE programs are annually implemented produces results that do not fully capture all benefits provided by investments in energy efficiency. The same is true for any investment (e.g. generation, transmission, distribution) that has a longer lifetime than the analysis period; the initial costs are included within the analysis period but the benefits from that investment are not fully captured in the results. Due to the length of the analysis period coupled with using present value calculations to report results, the detrimental

derived. Moreover, the Aggressive EE portfolio also completely offsets incremental load growth starting in 2012 (see line chart in Figure 3) and effectively bends the forecasted load curve downwards. Despite the fact that lifetime electricity savings are almost four times greater in the Aggressive vs. Moderate scenario (~196,000 vs. ~51,000 GWh), the impact of the Aggressive EE portfolio on the utility’s renewable resource requirement is rather muted, only reducing the requisite amount of new renewable resources for compliance with the federal CERES in 2028 by 54% relative to the Moderate EE case (~3,500 vs. 1,900 GWh).¹⁷

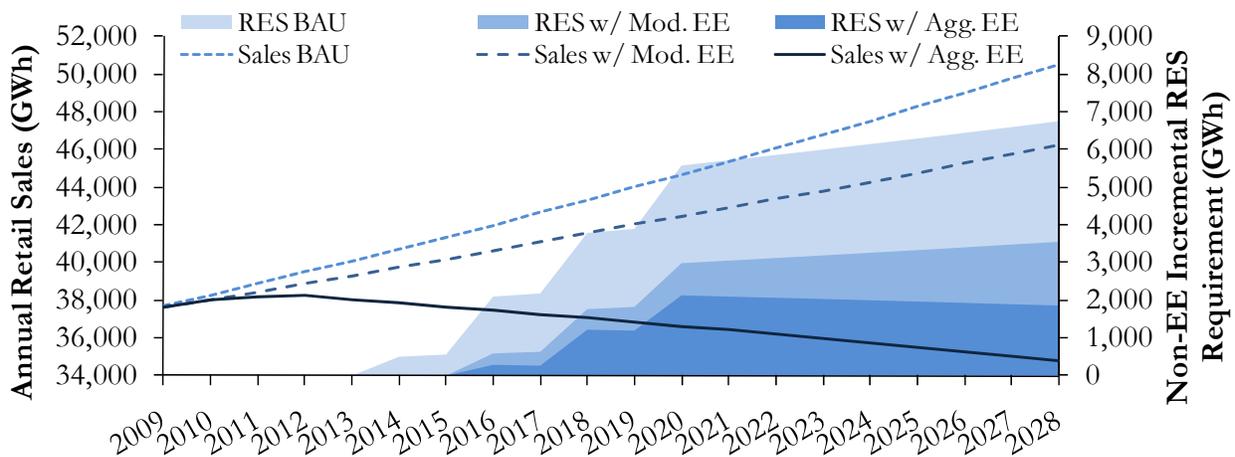


Figure 3. Effect of energy efficiency on load growth and annual RES requirement

The Kansas super-utility’s overall cost to comply with the CERES obligation is reduced if energy efficiency programs are pursued both because of lower load growth and because of lower procurement costs.¹⁸ Specifically, the capital budget for the Kansas super-utility’s new renewable projects would be ~\$1.5B (on a PV basis) between 2012 and 2028 in the business-as-usual No EE case. The capital budget is reduced by ~\$820M if the utility successfully implements the Moderate EE portfolio and is ~\$1.0B lower under the Aggressive EE portfolio compared to solely constructing renewable projects under the RES Build scenario (see Figure 4).¹⁹ Alternatively, if the utility meets its federal CERES obligation by relying completely on

effect caused by our inability to capture benefits beyond 2028 is substantially mitigated by the discounting of these benefits over such a long time period.

¹⁷ A utility must procure at most 20% of its annual sales from renewable resources under the ACES bill after 2020. Thus, after the utility has exhausted the ability for energy efficiency to serve as a RES resource, every 10 units of electricity that are reduced from energy efficiency produces only a 2 unit reduction in the RES requirement. For this reason, even though load growth is negative under the Aggressive EE scenario, this results in a relatively modest incremental impact on the RES obligation.

¹⁸ In the Build RES Scenario, the super-utility will defer the need for incremental renewable resources due to the implementation of energy efficiency programs. The deferral value of these resources would be captured in the capital expenditure budgets of the utility. Likewise, in the Buy RES Scenario, the utility’s purchased power budget would be reduced as less electricity generated from renewable sources must be procured to meet the federal RES requirement.

¹⁹ This illustrates how energy efficiency can reduce the near-term compliance costs with a federal RES, but does not take into account how these costs are recovered from ratepayers. Power purchase agreement costs simply flow through directly to ratepayers annually due to the super-utility’s fuel adjustment clause. In contrast, reductions in

purchases from independent renewable power producers, purchased power costs are ~\$1.8B between 2012 and 2028. Under this RES Buy scenario, the utility’s cost to comply with the proposed federal CERES is reduced by ~\$870M and ~\$1.2B respectively if the Moderate or Aggressive EE portfolios are implemented. However, in order to fully assess compliance costs under different renewable procurement strategies and alternative EE scenarios, a more comprehensive approach is required which examines changes in the utility’s revenue requirement so that all costs and benefits are considered.

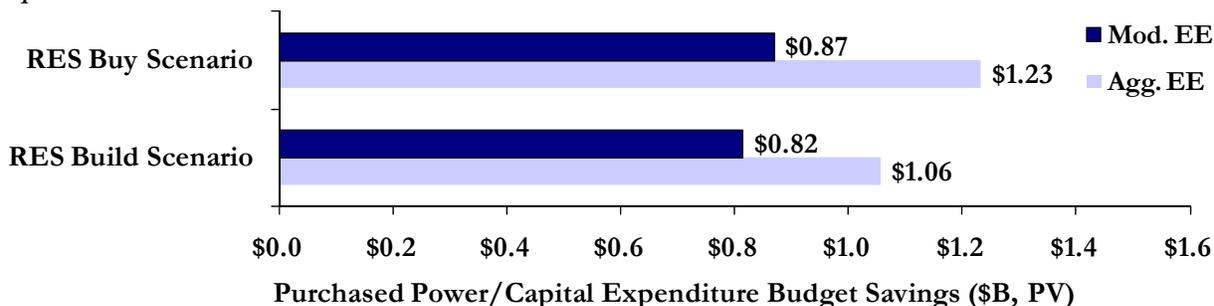


Figure 4. Direct RES compliance cost savings from energy efficiency

Customers of the Kansas super-utility would realize aggregate bill savings under either EE portfolio. However, aggregate bill savings (as reflected in a lower revenue requirement) do not exceed program costs until 2014 in the Moderate EE case and until 2017 in the Aggressive EE scenario, when program costs are expensed and recovered from ratepayers at the end of each program year (see Figure 5). Energy efficiency does drive down supply costs and will defer plant investment, which can be seen by comparing the Base Revenue component in the No EE case with the Moderate or Aggressive EE case in any year (see Figure 5). However, the accumulated impact of these savings due to energy efficiency takes time before it is reflected in a lower overall revenue requirement. The pace at which these cost savings are realized and factored into average customer bills must be compared to the cost to acquire “new” energy efficiency resources and the cost recovery strategy employed by the utility. One way to shorten the length of time it takes for ratepayers to begin seeing bill savings is to amortize energy efficiency program costs. Amortizing energy efficiency program costs over a multi-year period improves the alignment in the timing of the benefits and costs of energy efficiency that are reflected in changes in the utility’s overall revenue requirement. From a ratepayer’s perspective, this may result in broader support for energy efficiency from consumer advocates, although most utilities have preferred expensing of energy efficiency program costs in order to minimize perceived regulatory risk.

capital expenditure budgets only flow through to ratepayers during each general rate case, which are assumed to be filed every other year.

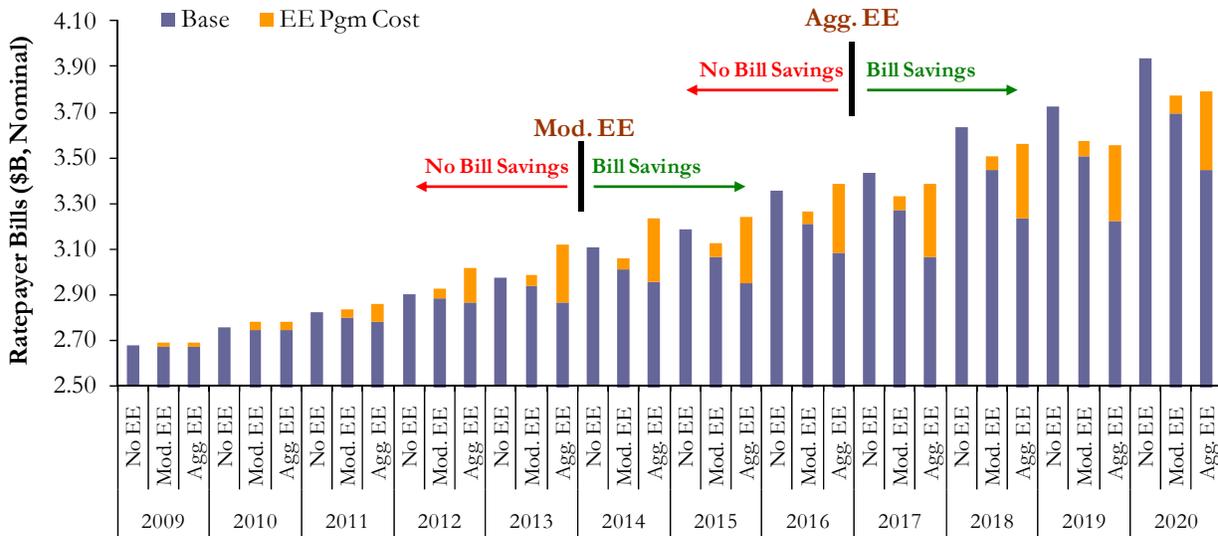


Figure 5. Aggregate ratepayer bills with and without energy efficiency (expensing of program costs and RES Build scenario)

From a longer-term perspective, the utility’s choice to even pursue energy efficiency has at least as big an impact on ratepayers as its approach to recovering energy efficiency program costs or its preferred renewable procurement strategy to comply with a federal CERES. If program costs are expensed, customer bills in aggregate are reduced by ~\$400 to ~\$800M over the 20 year time horizon (see Figure 6). If the utility amortizes energy efficiency program costs, ratepayers see aggregate bills reduced further by ~\$100-\$400M (or ~\$700M-\$1B in total savings) as cost recovery is pushed out into the future where discounting to the present makes it less costly. In contrast, if the utility eschews energy efficiency and relies exclusively on purchase power agreements to meet its RES requirements, ratepayers save at most \$600M.

The implementation of the Moderate EE portfolio increases rates by only 1-2 mills/kWh while rates would increase by ~1.3 cents/kWh under the Aggressive EE portfolio (see Figure 6). The approach used to recover energy efficiency program costs, either expensing or amortization, has little effect on rates (i.e. <1 mill/kWh difference in rates under alternative EE scenario or utility renewable procurement strategy). Thus, from a ratepayer perspective, the procurement strategy (build vs. buy) chosen by the Kansas super-utility to comply with the federal CERES is not nearly as important as the level of achieved energy efficiency savings or, to a lesser degree, the treatment of EE program cost recovery to both bills and rates.

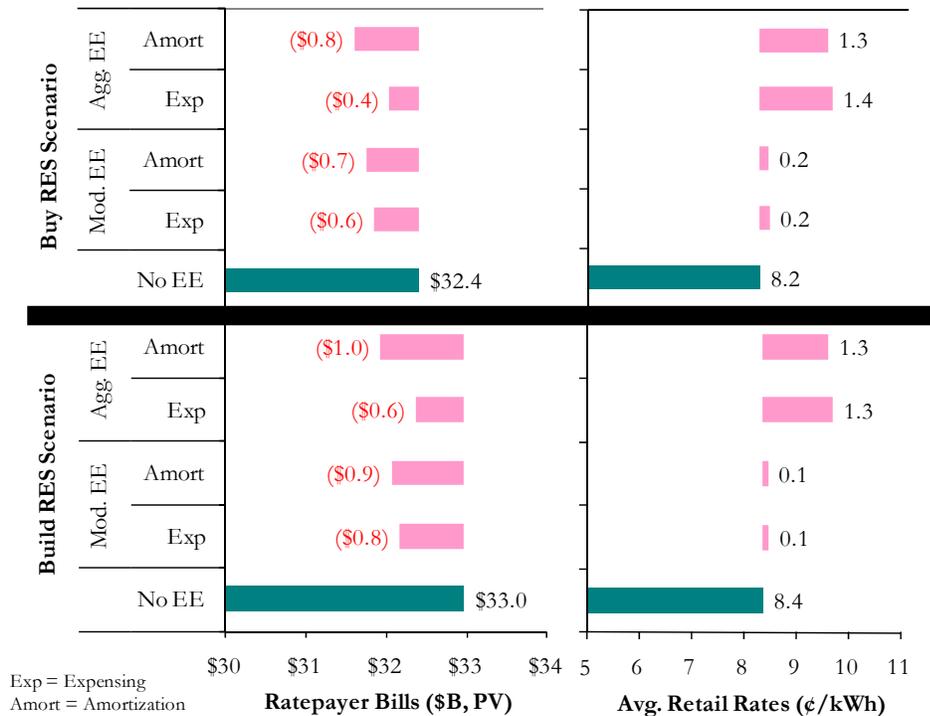


Figure 6. Direct impact of energy efficiency: Ratepayer perspective

From the perspective of utility shareholders, the preferred compliance strategy is contrary to the financial interests of ratepayers. As noted earlier, the utility’s rate base is larger under the “business as usual” scenario that relies exclusively on renewable energy projects compared to scenarios that include energy efficiency resources, as EE program costs are not ratebased and new plant is deferred. Having a larger rate base generates larger earnings opportunities for investors. Utility reliance on energy efficiency to meet a portion of the proposed federal RES reduces earnings by ~\$300-\$700M over the 20-year time horizon compared to a scenario in which the utility is allowed to add renewable generation under cost-of-service regulation (Build RES Scenario in Figure 7). In contrast, utility earnings are eroded by at most \$400M with energy efficiency in the case where in which the utility acquires renewables through power purchase agreements with independent power producers (Buy RES Scenario in Figure 7). However, a larger rate base does not always translate into a higher achieved ROE; there is relatively little difference (6 basis points) in the super-utility’s average return on equity when comparing the results of the decision to “build versus buy.”²⁰ The super-utility’s approach to recovering energy efficiency program costs has a larger impact on its ROE than its RES procurement choice (see Figure 7). If the utility is allowed to amortize energy efficiency program expenditures, its average ROE decreases by ~25 to ~104 basis points compared to the BAU No EE scenario. Alternatively, if the utility expenses energy efficiency program costs, its ROE decreases by about half that amount (i.e., ~12 to ~51 basis points) in the Moderate or Aggressive EE scenario, respectively compared to the BAU No EE scenario. In contrast, the RES procurement choice impacts ROE by 6 basis points.

²⁰ The utility must issue additional equity to cover the cost of the renewable generation resources in the Build RES Scenario which is not required in the Buy RES Scenario.

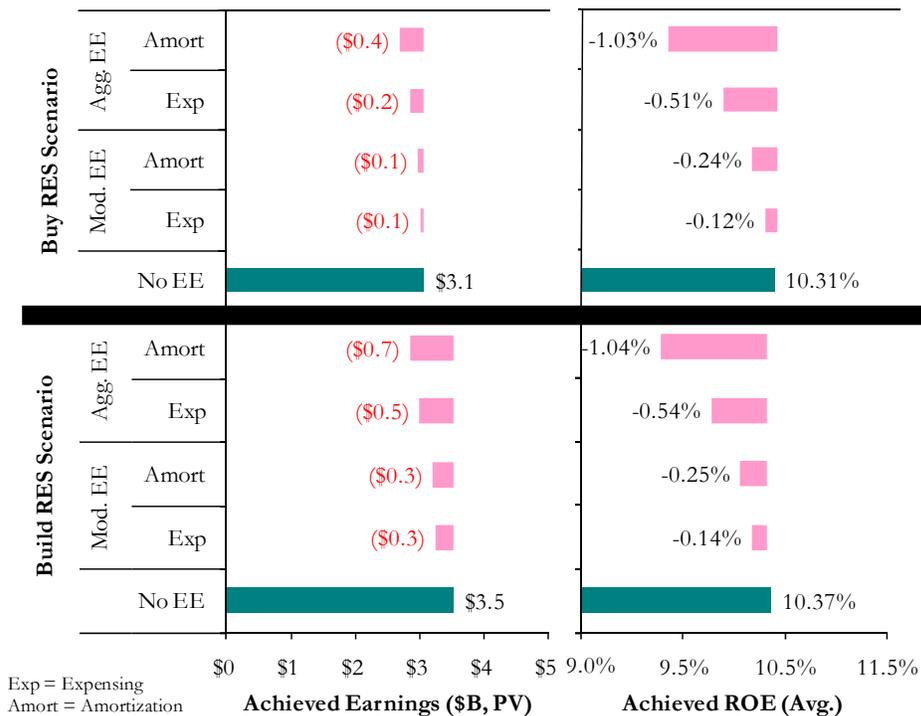


Figure 7. Direct impact of energy efficiency: Shareholder Perspective

Regardless of whether utility managers focus primarily on absolute level of earnings or ROE, our analysis suggests that the Kansas “super-utility” would prefer to build its own renewable generation resources and would be unlikely to aggressively pursue energy efficiency. The utility also faces even deeper erosion in total earnings under the “RES Buy Scenario” with energy efficiency. Given the erosion in earnings and reduced ROE when energy efficiency is implemented, it is likely that regulators will have to implement policies that establish a more attractive business model for energy efficiency in order to motivate the Kansas “super-utility” to pursue the least cost strategy from ratepayers’ perspective (i.e., inclusion of energy efficiency resources as part of an RES compliance strategy).

3.3 Energy efficiency with a comprehensive business model: Impact on stakeholders under federal CERES

To explore this issue, we analyzed the financial impact of alternative ratemaking and policy options that mitigate disincentives to energy efficiency for our Kansas “super-utility.” For illustrative purposes, we assume that the regulatory commission is willing to establish a shared net benefit incentive mechanism that provides shareholders with an upside earnings opportunity of 10 and 15 basis points if the utility achieves the savings goals in the Moderate or Aggressive EE portfolio, respectively.

The earnings basis of a shared net benefits incentive mechanism can be designed so that the utility has an opportunity to achieve these specific earnings targets, but would differ depending

upon the level of savings achieved by the EE portfolios (Moderate and Aggressive) and the renewable procurement strategy (Build vs. Buy). Under the Moderate EE savings scenario, the incentive mechanism would provide utility shareholders with 8.0% of the net resource benefits if the utility pursued purchased power agreements to comply with the federal RES or 10.4% if the utility built its own renewable resources under cost-of-service regulation. The earnings basis of the shared net benefits would be 4.1% and 5.0% in the RES Buy and Build cases respectively if the utility achieved the savings targets in the Aggressive EE portfolio, because there is a larger amount of net resource benefits to share. This analysis suggests that it is possible to provide utility shareholders with a modest boost to earnings (e.g. 10-15 basis points) while still ensuring that ratepayers receive at least 90% of the net resource benefits if utilities successfully implement a portfolio of energy efficiency programs.

The decoupling mechanism, which is provided upon the utility's commitment to achieve the Aggressive EE portfolio, is far more valuable to our Kansas super-utility than the combined effect of the shareholder incentive and lost base revenue mechanisms that are given if the super-utility achieves the Moderate EE savings goals (see Figure 8). From an earnings perspective, decoupling adds ~\$175M to the super-utility's earnings in comparison to the ~\$40M the utility receives from the lost base revenue and shareholder incentive mechanism. The impact on the utility's achieved ROE is also quite significant; 59 basis point improvement with decoupling vs. a 13 basis point increase with the joint application of the shared net benefits and lost base revenue mechanisms.

However, it is unclear if the PUC's proposed shareholder incentive mechanism (i.e., an opportunity to increase ROE by 10 or 15 basis points) is sufficient to motivate the utility to pursue energy efficiency compared to supply-side alternatives. As Table 4 shows, if the utility expenses program costs, then the shared net benefits mechanism allows the utility to achieve a comparable ROE in the Moderate EE case, and a higher ROE in the Aggressive EE case compared to the business-as-usual No EE case (19 to 24 basis points), irrespective of the utility's renewable procurement strategy. If the utility amortizes EE program expenses, its actual ROE is still somewhat lower (by 10-30 basis points) in the Moderate and Aggressive EE scenarios even with the EE business model compared to the business-as-usual No EE case. In terms of impact on achieved earnings, if the utility's supply-side procurement strategy is limited to buying renewables through purchased power agreements, then the EE incentive mechanism produces earnings that are roughly comparable. In contrast, if the utility has the option to build its own renewable generation under cost-of-service regulation, then the EE incentive mechanism offered by the PUC is still less attractive, as achieved earnings would be around \$270 to 450M lower under the Moderate and Aggressive EE scenario compared to the business-as-usual No EE case (even though ROE is comparable or higher).

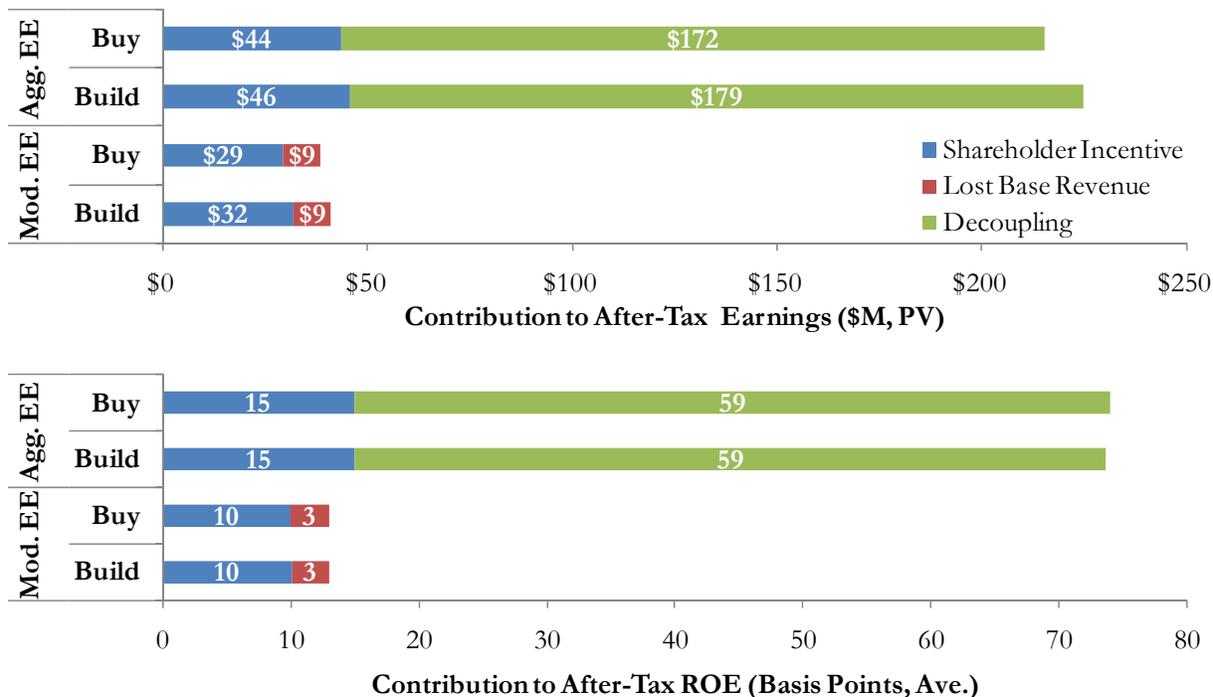


Figure 8. Contribution of energy efficiency business models to after-tax earnings and ROE

From a ratepayer perspective, the implementation of these proposed business models for the utility requires that they “share” some of the benefits of energy efficiency with shareholders. The proposed EE business models do increase rates somewhat and reduce aggregate bill savings (see Table 4). Retail rates are 0.1 to 0.2 cents/kWh higher in the Moderate EE scenario compared to the business-as-usual No EE case and are about 1.3 cents/kWh higher in the Aggressive EE business case, with the decoupling and shareholder incentive mechanisms. However, the incremental impact of the EE business model is quite modest (e.g., 0.1 cents/kWh in the Aggressive EE case) because rate increases are driven primarily by the reduced sales base from implementing energy efficiency rather than the EE business model.

In aggregate, customer bills are \$500-800 million lower in the Moderate EE scenario with the EE business model compared to the business-as-usual No EE case. In aggregate, customer bills are still \$240-660M lower in the Aggressive EE scenario with the EE business model, except for the case in which the utility buys renewables through power purchase agreements and expenses EE program costs (bills are reduced by only \$10M).

Table 4. Financial impact of various energy efficiency business models on utility shareholders and ratepayers

	Build RES Scenario					Buy RES Scenario				
	No EE	Mod. EE		Agg. EE		No EE	Mod. EE		Agg. EE	
	BAU	Exp	Amort.	Exp	Amort.	BAU	Exp	Amort.	Exp	Amort.
Achieved Earnings (\$MM, PV)	\$3.52	\$3.28	\$3.25	\$3.22	\$3.07	\$3.07	\$3.05	\$3.02	\$3.07	\$2.92
Achieved ROE (Avg.)	10.37%	10.36%	10.25%	10.56%	10.07%	10.31%	10.33%	10.21%	10.55%	10.03%
Avg. Retail Rates (¢/kWh)	8.37	8.51	8.49	9.84	9.75	8.22	8.42	8.40	9.70	9.61
Total Ratepayer Bills (\$B, PV)	\$32.96	\$32.23	\$32.13	\$32.74	\$32.29	\$32.44	\$31.95	\$31.84	\$32.43	\$31.99

4. Conclusions

This type of quantitative analysis provides insights into the impact that energy efficiency can have on the different financial positions of stakeholders, and is a crucial step in educating them on the tradeoffs of different compliance approaches to a federal (or state) RES mandate. We found that the method to comply with a federal renewable electricity standard does indeed impact both ratepayers and shareholders, but in very different ways and is an important but not primary determining factor when assessing the impact energy efficiency can have on compliance costs.

If energy efficiency is not an option, our analysis suggests that the utility clearly would prefer to build its own renewable energy resources, rather than buy renewable electricity from independent power producers to comply with a federal RES requirement, while ratepayers would tend to favor a procurement strategy that relies solely on long-term power purchase agreements with private power producers.

Our analysis also indicates that introducing energy efficiency as a contributing resource in meeting the federal RES requirement complicates stakeholders' preferences. For example, from an earnings standpoint, utility shareholders would be better off pursuing the Moderate EE portfolio while preserving the right to build renewable resources compared to a situation where the private power market is relied on exclusively to meet all of the super-utility's federal RES requirement (see Figure 7). Utility managers focusing on ROE, however, would instead eschew energy efficiency and purchased power agreements with renewable resources altogether. On the other hand, consumers prefer any approach to RES compliance that includes both energy efficiency and a renewable "buy" strategy, especially if the Aggressive savings targets are pursued (see Figure 6). Stakeholders may also have somewhat differing interests on approaches to cost recovery of energy efficiency program costs. The energy efficiency savings target level (i.e., Moderate or Aggressive) and choice of energy efficiency program cost recovery mechanism (expensing vs. amortization) substantially drives the length of time it takes for ratepayers to begin seeing bill savings (see Figure 5). We found that amortizing EE program costs becomes increasingly important as savings targets become more aggressive because it helps align the timing of program costs and benefits and mitigate short-term rate impacts. Yet, the utility's financial metrics suggest that the utility would prefer to expense EE program costs, even if there is a belief that the risk of future cost disallowance is low over a modest amortization period (see Figure 7).

This lack of alignment in preferred approaches to the achievement of energy efficiency goals may necessitate the development and implementation of a viable business model. We found that if the introduction of a viable business model for energy efficiency induces the utility to meet the savings goals, ratepayers as a whole are better off in all cases in terms of aggregate customer bills, regardless of the utility's renewable procurement strategy (e.g. Build or Buy) under the RES compared to the business-as-usual No EE case (see Table 4). The introduction of a decoupling mechanism coupled with the more lucrative shareholder incentive mechanism may be sufficient to induce the super-utility to achieve the Aggressive EE savings targets while relying on long-term contracts with merchant renewable generation providers to fill the remainder of its federal RES obligation.

Kansas has a somewhat unique set of circumstances with respect to the cost of service for its regulated utilities and the abundance of relatively inexpensive renewable resources such that our results may not be directly transferable to other jurisdictions across the United States. However, given the clear difference between ratepayers' and shareholders' preference for compliance strategies under a federal RES in this study, it will be very important for state regulators to conduct this type of quantitative financial analysis as part of a review process for proposed utility compliance strategies to meet federal (or state) RES requirements in order to assess whether they are in the best interests of ratepayers and facilitate a sustainable business model for the utility.

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