Utility Sector Incentives and Disincentives for Renewable Energy

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POLICY NAME AND DESCRIPTION

This paper addresses utility sector economic incentives and disincentives and their impact on the deployment of renewable energy.[3]

No matter what the regulatory approach, regulation necessarily presents utility managers with a set of economic incentives or disincentives which may favor or disfavor the deployment of renewable energy. Regulators should be attuned to these incentives in their decision making and strive to align them with public policy objectives.

RECOMMENDATION

Traditional regulatory approaches should be modified to provide appropriate incentive structures to encourage regulated utilities to acquire renewable energy resources. The Arizona Corporation Commission should assess the incentives which utilities face, with respect to renewable energy resources, mitigate or eliminate incentives structures which run counter to the deployment of renewable resources, and adopt incentive structures which encourage renewable resources.

The Arizona Corporation Commission should directly address incentives mechanisms either in the context of rate proceedings, special proceedings or rules. Ultimately, regulatory policies should support a sustainable business model that allows utilities to earn a fair return to its investors while furthering public policies which favor renewable energy. In short, utilities should be able to build a viable business plan around renewable energy and which replaces the existing traditional business model.

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[2] The Regulatory Assistance Project is a grant funded not-for-profit organization of former utility regulators which provides technical and policy support to government agencies and legislatures.

[3] While this discussion focuses on renewable energy, many of the incentive issues involving renewable energy are equally applicable to energy efficiency and demand-side management. These similarities are noted in the discussion where applicable.

BACKGROUND: HOW TRADITIONAL REGULATION WORKS

Traditional regulation is premised on two primary tenets: 1) a utility is required to provide reasonable, adequate and efficient service to its customers and 2) a utility is entitled to a reasonable opportunity to recover the costs of providing service to customers[4], including an allowance for a reasonable return on its investments incurred to provide service.[5] Contrary to popular perceptions, the utility's actual profits are neither limited nor guaranteed.

Historically, the business model of a regulated utility is very similar to that of other businesses – increases in sales and reductions in expenses will increases profits. The principal difference between regulated utilities and other businesses is the fact that utility prices are administratively determined by the regulators in periodic rate proceedings. In theory, prices are set at level intended to provide the utility an opportunity to recover the costs associated with providing service to customers, including an allowance for a reasonable return to investors – the utility's profits. As a general rule, prices are changed only at the conclusion of a rate proceeding and remain in place until the conclusion of the next rate proceeding. In simplified terms, traditional regulation uses the following two-step formula to set prices:

$$\text{Test Year Revenues} = \text{Test Year Expenses} + (\text{Test Year Invested Capital X Fair Rate of Return})$$
$$\text{Price} = \text{Test Year Revenues} \div \text{Test Year Unit Sales}$$

Each of these "inputs" is determined on the basis of a "test year" which is either a "historical" snapshot of the utility's financial condition or an estimation of its "future" or expected financial condition. Ironically, while rate proceedings are often highly contentious and include an allowance for profits, once prices are set, the actual profits earned by a utility have little to do with the test year values used by regulators to set prices. Instead, after prices are determined, actual profits for a utility are a function of the following two-step formula generally applicable to all businesses:

$$\text{Actual Revenues} = \text{Actual Sales X Price}$$
$$\text{Actual Profit} = \text{Actual Revenues} - \text{Actual Expenses}$$

Within this framework, a utility has two principal leverage points to increase its profits. First, in the rate case context, a utility's profits will be driven in large part by the total capital invested. Between rate cases, increases in capitalization will actually decrease a utility's rate of return, but in the next rate case it will have the effect of increasing the total revenues allowed and therefore the price set by regulators. For utilities with increasing sales, the lag between the time of capital investments and the conclusion of the next rate case is partially or wholly offset by increased revenues, so

[4] This general notion is sometimes referred to as the "regulatory compact." However, the term compact suggests something more akin to an enforceable contract, which it definitely is not. In fact, these tenets of regulation only provide a framework for decision making, including the setting of prices. This is especially on point with respect to the actual profits earned by utilities, which rarely, if ever, reflect the administratively determined "allowed" returns determined by regulators.

[5] In regulatory terms, the utility's profits are considered "costs" to consumers. Hence, the use of the term "cost of equity" to represent the fair returns to stockholders of a utility. This overall approach to regulation is often termed "cost of service" regulation.

profits can actually continue to rise between rate cases. Over time, ever increasing investments in rate base will drive up total profits, even if the allowed rate of return is held constant.

Second, in the post-rate case context, a utility will seek to either increase sales or decrease expenses in order to increase profits. If it is successful in doing one or both of these, its profits will rise even to levels above those contemplated when prices are set. To the contrary, if sales decline or expenses increase, profits will decline to levels below that assumed in the rate case. In either case, the utility is allowed to keep the increased profits or made to suffer the decreased profits – there is no accounting of differences between the allowed return from the rate case and the utility's actual financial experience.

For the most part, a utility has a limited ability to control expenses as a means to increase profits. The vast majority of expenses are largely fixed (at least in the time horizon between rate cases) and reduction of those expenses that are variable (mostly fuel and purchased power expenses) are flowed through to customers if sales are reduced. As a practical matter, this leaves increased sales between rate cases as *the* prime mechanism for increasing profits. This phenomenon is often characterized as the utility's throughput incentive – because of the utility's financial structure, this is quite a powerful incentive.

The impact of an increase or reduction in sales can be quite extraordinary because of two financial characteristics of a utility. First, a utility's cost structure is, in the short-term, relatively fixed, so reduced sales are not generally offset with reduced expenses. Likewise, increased sales are generally not accompanied by increased costs. Even where expenses change with sales (typically in the form of increased or reduced fuel costs), there is no associated impact on profits because these expense changes are typically passed through to customers via the fuel and purchased power adjustment. This means that virtually every dollar gained from increased sales translates into a dollar of increased profits and virtually every dollar lost to reduced sales translates into a dollar of reduced profits.[6]

Second, because utilities are typically highly leveraged and have large fixed expenses, profits make up only a small portion of the total revenues collected, often on the order of just 5% of total revenues. Thus, a utility with $1 billion in revenues may have only a few tens of millions dollars of profits in the $50 million range. A seemingly small 1% change in total revenues ($10 million) may represent as much as a 20% change in profits. This large sensitivity of profits to small changes in revenues can make the utility highly averse to increased non-utility-owned renewable resources, although not all non-utility-owned renewable are the same.

In traditional regulation a utility makes an expenditure to purchase or build a generation asset then recovers the cost of that asset, after the fact, in a rate proceeding. In rate proceedings these assets must pass a "use and useful" test and be judged to be a prudent expenditure for the utility to receive cost recovery. If the expense for a generation resources is deemed to be imprudent then

[6] In theory, each increase or decrease in profits results in an associated increase or decrease in income taxes which muffles the effects described here. Whether and to what extent this actually happens, depends largely on the individual utility's tax situation – that is, whether it is actually paying taxes on incremental income.

cost recovery may be disallowed. Because renewable energy resources may have higher up-front or initial costs there is a possibility that the expenditure could be viewed as imprudent and cost recovery disallowed. As expenditures for renewable energy resources grow utilities will face a strong disincentive to purchase these resources unless pre-approval of the expenditure is received or the ACC clearly establishes, as a matter of policy, that the reasonable cost of renewable energy will not be the basis for disallowance, as was done in the Solana concentrating solar project case.[7]

Within this policy and regulatory setting, renewable energy may present a number of profit issues for utilities which may translate, at worst, into the erection of barriers to renewable resources or, at best, a lack of enthusiasm on the part of the utility to encourage renewable energy. For our purposes, renewable energy comes in two economic forms – utility-owned resources and non-utility-owned resources. Each type relates to the regulatory incentive structure in a different way. The policy objective should be to formulate a business model for the utility which overcomes these barriers.

Utility-Owned Renewable Resources

Utilities may directly own and operate renewable resources just as they own traditional power plants such as nuclear, coal or natural gas generators. These renewable resources may come in the form of large central station power plants or in the form of so-called distributed generation which is deployed strategically or tactically on different parts of the utility's transmission or distribution grid to address specific needs. In either case, these utility-owned assets are, for ratemaking purposes, virtually the same as traditional power supplies. In this case, there is a direct opportunity for the utility to earn a profit, because the investment will be reflected in rate base and become part of the "profit" calculation used in the rate setting formula. In this respect, utility-owned renewable energy is not much different from traditional resources.

Utility-owned renewable resources, however, may present a regulatory risk for the utility because of their potentially higher initial costs. Because renewable energy is often more expensive than the embedded average cost of a utility's existing power supply, it will have the effect of increasing prices in the short term. This, in turn, is likely to cause increased opposition from consumer advocates who generally focus on rate impacts. This risk may be exaggerated where new technologies are involved and the potential for cost overruns or poor operational performance may be high.

Non-Utility-Owned Renewable Resources

Non-utility-owned renewable resources are typically owned by the utility's customers (or by third parties who sell and then operate resources on behalf of customers) or by merchant developers who intend to sell the output on a wholesale basis to utilities. Customer-owned facilities are typically small and are usually sized to meet all or less than all of a customer's energy needs. A significant portion of Arizona's renewable energy portfolio standard is required to be distributed

[7] *In the Matter of the Application of Arizona Public Service Company for Approval of Concentrating Solar Power Contract*, Docket No. E-01345A-08-0106, Decision No. 70531.

renewable generation.[8] Merchant facilities are more likely to be large utility-scale facilities, such as large wind or solar farms. From an incentive standpoint, however, both customer-owned and merchant facilities present similar, though not identical, profit issues for the utility.

In the case of customer-owned renewable resources, especially under a net-metering regime, every kilowatt-hour (kWh) of energy produced by the renewable resource represents a kWh of sales reduction for the utility. In this case, the full impact of the throughput incentive is in play – every dollar of lost sales represents a dollar of lost profits.

Merchant renewable resources have a slightly different impact on profits. Here, the output of the facility is typically sold at wholesale to the utility, which then uses the power to serve the needs of its customers. There are no associated reductions in retail sales associated these facilities and so there is no sales-related impact on profits. However, when a utility purchases power at wholesale for resale, it has no means for earning a profit on the "generation" portion of the sale. Treated as a purchased power "expense," the wholesale cost of the power will simply be flowed through to customers on a dollar for dollar basis (either in a fuel clause adjustment or as part of the utility's allowed expenses in the next rate proceeding). On the retail sale side, there will continue to be a small profit component in the rates charged for distribution and transmission services. Thus, merchant facilities deprive the utility of a potential profit opportunity, but do not have the direct profit reduction impacts of customer-owned generation.

POLICY APPROACHES TO ALIGNING INCENTIVES WITH PUBLIC POLICY

There are two basic policy mechanisms which policymakers and regulators should consider to align utility incentives with pro-renewable public policies:

- Address the throughput disincentive
- Create utility profit opportunities for renewable energy and tie them to performance

ADDRESSING THE THROUGHPUT DISINCENTIVE

Decoupling Revenues from Sales

The current state of the art approach to addressing the throughput issue is by decoupling revenues from sales ("decoupling"). As noted earlier, like most other businesses, a utility's profits rise or fall with increased or decreased sales of its product – unit electricity sales. Unlike other businesses, utility's costs are not very sensitive to changes in sales. Moreover, the basic approach in traditional regulation is to set prices at a level which will collect the utility's total cost of service. Even so, traditional regulation has taken the approach of setting prices once at the end of each rate case and not changing them again until the next rate case. Hence, the formula (from above):

$$\text{Actual Revenues} = \text{Actual Sales X Price}$$
$$\text{Actual Profit} = \text{Actual Revenues} - \text{Actual Expenses}$$

[8] 13 A.A.R. 2389 R14-2-1805

In its simplest form, decoupling is accomplished through a simple algebraic transformation. Instead of holding prices constant and allowing revenues to change with changes in sales, one determines the allowed revenue and then allows prices to change with changes in sales. Thus:

Price = Allowed Revenues ÷ Actual Unit Sales
Actual Profit = Allowed Revenues – Actual Expenses

Here, *Actual* Revenues will always equal *Allowed* Revenues.[9] While it can be implemented in a number of different procedural formats, in its simplest form, prices would be adjusted on customers' bills on a monthly basis, reflecting actual sales for that billing period. Table 1 has a sample decoupling calculation for a utility experiencing a 1% decrease in sales relative to its test year sales:

Table 1
Periodic Decoupling Calculation

From the Rate Case	
Allowed Revenues	$10,000,000
Test Year Unit Sales	100,000,000
Price	$0.10/Unit
Post Rate Case Calculation	
Actual Unit Sales	99,000,000
Allowed Revenues (from above)	$10,000,000
Required Total Price	$0.10101/Unit
Decoupling Price "Adjustment"	$0.00101/Unit

The effect of decoupling is to make the utility indifferent to reductions in sales associated with customer-owned renewable resources.[10] No matter the magnitude of energy production from customer-owned renewable resources, the utility's profits will not be adversely affected.

Positive Incentives for Renewable Energy Performance

While decoupling addresses disincentives for renewable energy, it does not, in and of itself, create a positive incentive or profit opportunity for the utility. In the case of utility-owned generation, a profit opportunity exists in the same manner as other generation – the investment is added to rate base which is multiplied the allowed rate of return to derive an expected profit. Customer-owned and merchant facilities do not share this attribute. Under traditional regulation, the only opportunity for profits is through investments in plant or by enjoying sales above those assumed in the rate case – the latter being addressed by decoupling.

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[9] For an in-depth discussion of decoupling, including its mechanics, how it is implemented and administered and related benefits and issues associated with its use see: Shirley, *et al*, *Revenue Decoupling: Standards and Criteria, Report to the Minnesota Public Utilities Commission*, (June 2008), available at: http://www.raponline.org/showpdf.asp?PDF_URL=%22Pubs/MN-RAP_Decoupling_Rpt_6-2008.pdf%22.

[10] Although beyond the scope of this discussion, it should be noted that unless it is modified in some way, basic decoupling will also eliminate some customer and utility risks associated with weather and will have other benefits associated with reducing the utility's risk profile and, therefore, its required rate of return.

Energy Efficiency Approaches to Incentives

This is not to say that rate base investments are the only mechanism by which utility can earn profits. To the contrary, for some time regulators in different states have formulated profit incentive mechanisms for energy efficiency initiatives based on measurable performance metrics. State regulators have used some variation of one of three incentive mechanisms to reward utilities for meeting energy efficiency performance goals termed here as: Shared Net Benefits, Cost Capitalization and Performance Target.[11] Only the latter two might be used as a model for renewable energy incentives.

Cost Capitalization

In the Cost Capitalization approach, expenses incurred in the energy efficiency programs is put into rate base, just like expenditures on traditional supply-side investments. In at least one application (Nevada), the utility is allowed a bonus rate of return, above the administratively determined rate case rate of return.[12] In application, the rate base entry should be amortized over the life of the efficiency investments, which may be as short as 5-10 years. This is the ratemaking equivalent to depreciation of supply-side investments, which accounts for the "return of" investors' capital investments. The actually amount of the return reward could be tied to a sliding performance scale, as in the case of the Shared Net Benefits approach.

Performance Target[13]

In the Performance Target approach, the utility's entitlement to recover an incentive is determined on the basis of meeting some objective energy savings target, while the amount of the reward is calculated as a share of the budget or of a pre-determined dollar amount. The amount of the award can be based on a sliding scale based on the level of performance as a percent of the stated goal.

Application of Energy Efficiency Incentive Approaches to Renewable Energy

Both of the incentive options described above share two distinct characteristics. They both have a metric for computing the amount of an incentive. They also have a metric for performance (expressed in terms of energy). When designing incentives for renewable energy, some comparable metrics would be appropriate as well.

The Cost Capitalization approach to incentives could be easily applied to utility-owned renewable resources, which can be included in the utility's rate base just like traditional generating resources. However, this approach has no comparable application for non-utility-owned resources, where the utility has no investment. If separate performance standards are set for non-utility-owned and

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[11] A recent paper by Lawrence Berkeley National Laboratory and other authors (this author included) used these labels. See *Quantitative Financial Analysis of Alternative Energy Efficiency Shareholder Incentive Mechanisms*, Cappers *et al*., Lawrence Berkeley National Laboratory (2008).

[12] In Nevada, the bonus rate of return is applied to a number of different "critical facilities" investments, Critical facilities include investments made for such needs as reliability, in addition to energy efficiency.

[13] This approach might well have been called the *Percent of Budget* approach.

utility-owned resources, then the Cost Capitalization method could be easily applied to the utility-owned resources.

The Performance Target approach is likely the most flexible for application to renewable energy. In this approach, regulators would likely adopt an energy production goal for renewable energy from all sources. An energy goal could for be set for an amount of energy in excess of the requirements of the existing Renewable Energy Standard to encourage performance above and beyond renewable portfolio requirements. If separate goals are set for non-utility-owned and utility-owned renewable energy production, the Performance Target approach might be applied to the non-utility-owned renewable resources. Alternatively, this approach might be applied to all types of renewable resources with no distinction or preference between non-utility-owned and utility-owned resources.

Incentive Design Considerations

Keep it Simple

As a general rule, simplicity should be favored over complexity. Regulators, utilities and other stakeholders should be able to easily determine what goals are being set, how performance is measured and how incentives are computed. As incentives schemes become more complex, the likelihood of controversy or litigation increases greatly.

Stretch goals

Incentives should be designed to reward exceptional performance, not business-as-usual. This is accomplished by using stretch goals for performance. While some reward may be allowed as performance nears the goal, the utility should not be rewarded for achieving what is easily (or already) accomplished.

Consider Incentive Caps and Exit Ramps

Unlike energy efficiency which immediately lowers the total cost of service, some forms of renewable energy resources may cause an immediate increase in the total cost of service, which is offset by the absence of future costs (mostly fuel) over time. From both a political and economic standpoint, it may be appropriate to consider a cap on the incentive reward if the rate impacts of these choices are, from a political standpoint are too front-loaded. This may be less important for the Cost Capitalization approach which is a more traditional ratemaking tool.

In addition to capping incentives, policymakers and regulators may want to consider exit ramps or limitations to avoid rate shock or other adverse consequences. These would likely be tied to triggers on total costs or to a maximum rate of deployment of renewable resources.

Be Aware of Unintended Incentives or Disincentives

While the overall objective of providing incentives for renewable energy is to reward the utility for embracing and deployment clean resources, the incentive schemes themselves may present the utility with unintended collateral incentives. For example, the Cost Capitalization method may encourage inefficient spending – the more you spend, the more you get to put into rate base.

Assured Cost Recovery

Significant capital commitments are necessary for renewable energy projects. Historically utilities in Arizona seek cost recovery after the purchase or building of a generation facility. Because most renewable energy, especially solar, has a higher cost than a utility's embedded average cost and a higher cost than other available new sources of supply, utilities may be reluctant to deploy these technologies for fear of having the costs disallowed from rates. This risk can, in turn, increase the cost of capital for the utility – both debt and equity.[14] In a rate case setting, challenges to cost recovery are typically framed as either a "prudence" issue or as a "used and useful" issue. The former has to do with a management decision to build resources and the management of their construction.[15] The latter has to with whether the facilities are actually needed to serve customers.

When compelled to build these resources by a renewable portfolio standard, these issues are not usually in play. However, in order for a utility to embark on a more aggressive renewable program beyond required purchases of renewable energy, these issues should be dealt with in advance. This can be done through the use of broad stakeholder collaborative in which consumer advocates and other have a voice, as well as through orders entered by regulators which make clear findings ratifying the decision to build or purchase renewable resources.[16] Increased cost recovery certainty should reduce the utility's risk profile and, therefore, its cost of capital. It should also help make the utility a strong partner in pursuing clean resources going forward, rather than being a reluctant if not resistant participant. The ACC recognized this challenge when it allowed, in the Renewable Energy Standard rule, the ability of utilities to seek preapproval for energy purchases.[17]

Another benefit of assured cost recovery relates to a utility's debt ratio and financial rating of the institution. Financial credit rating agencies impute a debt value to a utility's balance sheet for long-term purchase power agreements (PPA) that are used to purchase renewable energy resources. This debt equivalence is assigned to monetize the financial risk associated with cost recovery of expenditures for a PPA. PPAs are viewed as debt because they obligate a utility to future payments, affecting cash flow. In simple terms the greater the uncertainty of cost recovery for utilities the

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[14] In ratemaking parlance, a utility's "profit" is represented by its "cost of equity" because from a customer's viewpoint, it is an additional cost incurred to provide service. Interest on debt is termed "cost of debt" and the weighted average of the two is usually referred to collectively as the utility's "cost of capital." Increases in cost of capital, therefore, translate directly into higher prices for consumers.

[15] Management's decisions and performance during construction of plant may also be subject to a prudence review; however, regulators rarely, if ever, pre-approve the prudence of future decisions.

[16] Regulators often distinguish between the prudence of a decision to build utility facilities and the prudence of the actual construction of those facilities. In this case, it is the build decision that is of concern.

[17] Arizona Administrative Rule R14-2-1804-G states An Affected Utility may ask the Commission to pre-approve agreements to purchase energy or Renewable Energy Credits from Eligible Renewable Energy Resources.

greater the imputed debt assigned. Increased debt ratios have an effect on the financial rating of a utility which can affect its costs of capital and reduce a utility's ability to borrow capital.[18]

An assured cost recovery policy can be applied on a project by project basis. As is allowed in the Renewable Energy Standard, utilities are allowed to seek preapproval for renewable energy purchases. For the 280 MW Solana concentrating solar power project APS sought approval to proceed with the project. ACC Decision70531 did not directly approve of the PPA but did provide sufficient certainty for the utility to proceed with the project.

CLEAR POLICY LEADERSHIP

Perhaps the most important ingredient for successfully deploying renewable energy is clear and unequivocal public policy leadership. Regulators and legislators should make clear the overall public policy objectives.

Depending on how regulators view their obligation and their authority to support renewable energy, legislation may be required to explicitly require regulators to act or to provide them with the requisite authority to act. That said, utility regulation is increasingly a stakeholder oriented process that includes not just the regulator and the utility but various consumer, environmental and other advocates, as well as the general public. The best incentive mechanisms are likely to come from a process that encourages and considers input from all interested parties and then crafts a solution that addresses their concerns to the extent possible, drawing on the considerations outlined in this discussion.

[18] Increased debt in the capital structure of a utility is not, in and of itself a detriment to consumers because debt is generally lower in cost than equity and more debt would decrease the overall weighted cost of capital which reflects the proportional costs of debt and equity. The difficulty arises from the fact that, at some level of debt, the utility's financial risk increases, which drives up the interest rates on new debt (and possibly on existing debt), as well as the required return to shareholders – the cost of equity.