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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Distributed Energy Resources.	Rulemaking 14-10-003 (Filed October 2, 2014)

ASSIGNED COMMISSIONER'S RULING INTRODUCING A DRAFT REGULATORY INCENTIVES PROPOSAL FOR DISCUSSION AND COMMENT

Summary

This assigned Commissioner Ruling introduces a regulatory incentive proposal addressing issues related to the issues of "utility role, business models and financial interest with respect to distributed energy resources deployment," as reflected in the February 26, 2016 Joint Assigned Commissioner and Administrative Law Judge Ruling and Amended Scoping Memo (Amended Scoping Memo). Parties are invited to comment on the proposal and respond to several questions provided below. Comments and responses to the questions shall be filed no later than May 2, 2016. Reply comments may be filed not later than May 16, 2016.

Discussion

During the course of this proceeding a number of parties have requested that the Commission address concerns regarding the current regulatory framework and utility business model as they relate to the expanded deployment of distributed energy resources (DERs). Reflecting these party positions, the

Amended Scoping Memo included issues related to the "Utility role, business models, and financial interest with respect to DER deployment." This ruling begins formal consideration of these issues with the intent to begin limited deployment of solutions starting as soon as practical.

I note that concerns regarding the current regulatory framework and utility business model as they relate to the expanded deployment of DERs have also been identified as an issue within the scope of Rulemaking (R.) 14-08-013, the Distribution Resource Plan (DRP) proceeding. Indeed these concerns are integral to the success of both the DRP this and the proceedings. As such, this effort will be closely coordinated with the Assigned Commissioner and Administrative Law Judge of that proceeding.

Consistent with our "walk, jog, run" approach to these complex issues, I do not intend for this phase to consider or adopt an entirely new regulatory framework or business model for the California electric utilities. Rather, I hope to develop a pilot program that can test a revised framework that may assist us in our efforts to promote the cost-effective deployment of DERs in California. At the same time, the critical efforts to further our understanding of distribution planning and the potential value of DERs in R.14-08-013 and to improve the sourcing of DERs in R.14-10-003 must continue on pace.

This ruling represents a first step, wherein I offer a conceptual outline of the utilities' financial interests as they concern DER and a proposed interim regulatory process by which to pilot the effect of incentives on utility sourcing of DER. For now, I will focus on developing a general methodology for calculating incentives. Determining actual incentives earned will require additional steps, including input from stakeholders.

A. Need for Considering Utility Incentives to Deploy DERs

Any regulatory effort that considers displacing or deferring utility investments in distribution infrastructure via the deployment of DERs raises fundamental questions about the current regulatory framework and utility business model. Under the current framework, Investor-Owned Utilities (IOUs) earn a rate of return on investments in utility infrastructure, and distribution infrastructure in particular is a major source of investment opportunity for the utilities today. If the utility displaces or defers such investments by instead procuring DER services from others, it earns no return on the associated expenditures -- such operating expenses are merely a pass-through in rates.[1] Thus, asking the IOUs to identify opportunities for such displacements or deferrals, as we are doing in this proceeding and the DRP, sets up a potential conflict with the company's fundamental financial objectives. If we hope to create a truly successful model for future distribution infrastructure planning and DER deployment, we cannot reasonably proceed without acknowledging and attempting to address the conflict between the Commission's policy objectives and the utilities' financial imperatives. This Ruling sets forth a proposal for a pilot regulatory incentive structure and process designed to harmonize the utility's financial objectives with the Commission's desire to foster the cost-effective deployment of DERs. I seek party comment on this proposed pilot through this Ruling. Before laying out the framework of the proposal, however, I first discuss with more specificity the nature of the utility's current

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[1] "Pass-through" may not technically be the correct term if such expenditures are adopted as forecasts in a General Rate Case (GRC). In that case the utility may or may not recover its actual expenses dollar-for-dollar, depending upon how actual costs compare to the adopted forecast.

financial incentive structure, because a thorough understanding of the status quo is essential to any successful proposal for change.

B. The Driver of Increased Shareholder Value:
Return on Equity minus the Cost of Capital, or "*r minus k*"

Attached to this Ruling as Appendices A and B are two articles that discuss in detail the current utility business model with respect to the creation of increased shareholder value. I will not repeat that entire discussion here, but ask for parties to carefully review and comment on whether the observations therein are correct, and if they are not, then why not? The following excerpts from Appendices A and B capture the key messages that I derive from my own review of these articles. This begins by acknowledging roadblocks, in concept, to understanding utility financial value:[2]

> There are two roadblocks . . . to understanding financial value. Many in the regulatory community believe that: (1) the utility's return on equity is the sole value driver; and (2) regulators set returns on equity at a rate equal to the cost of equity. Neither of these perceptions is correct, and understanding why is key to developing effective utility incentive mechanisms.
>
> **THE VALUE ENGINE: *(r-k)***
>
> Many regulatory reform discussions focus on the utility's return on equity as the sole driver of financial value, but that does not align with the concept of investor value creation. **It is not the *absolute* level of a company's return on equity (*r*), but rather the *difference* between *r* and its cost of equity (*k*), that creates the value opportunity that drives the stock price.**
> (Appendix B, p.6)

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[2] All footnotes and references have been deleted for ease of reading.

This discussion leads to the following correction to the investment incentive proposition espoused by many:

> INCORRECT: $r > 0$ utilities have an incentive to expand
> CORRECT: $r > k$ utilities have an incentive to expand
> $r = k$ utilities are indifferent as to whether they expand
> $r < k$ utilities have a disincentive to expand
> Capital, like any other input to a production process, is not free. This should have intuitive appeal. Does it seem likely that utilities would rush to expand their facilities if regulators allow them to earn, for example, a 2 percent return on such investment? Clearly there is some minimum acceptable level of return. The cost of capital, by definition, is that minimum return hurdle.
>
> This corrected incentive structure should give some readers pause. Many, if not most, regulators say that they set utility rates of return equal to the cost of capital. If that condition held, utility management focused on creating value should not care whether it ever makes any plant investment. Just as buying apples for 50 cents and selling them for 50 cents creates no value for the grocery store owner, raising capital at a cost of 10 percent to invest in assets that earn 10 percent is similarly a financial wash—no matter how large the investment, it creates no investor value. (Appendix A, p.3)
>
> If markets or regulators consistently drove the return on equity down to the cost of equity, there would be no financial reason for value-oriented firms to make investments. For a utility, they would have no incentive to invest in new plant.
>
> When return on invested capital is lower than the company's cost of capital, faster growth necessarily destroys value, making the point where return on invested capital equals the cost of capital the dividing line between creating and destroying value through growth. On the line, value is neither created nor destroyed, regardless of how fast the company grows.
>
> The key question for investors then is not whether the utility earns a return on equity on its new plant investment, but whether

> that return exceeds the cost of equity, and by how much. (Appendix B, p.7)
>
> Currently, utilities are typically assigned returns on equity around ten percent, while market evidence and investment analysts suggest that the *cost* of equity for electric utilities today is closer to seven or eight percent. Standard stock valuation models, the ones used by Wall Street investment analysts, demonstrate that today's typical electric utility stock market-to-book ratio of 1.7 is consistent with a cost of equity of 7.5 percent.
>
> To be clear, we are not suggesting in principle it is inappropriate for a utility to be allowed to earn an equity return in excess of the cost of equity—to the contrary, the return on equity *should* exceed the cost of equity, just as it does for the typical non-regulated company. In fact, that is the only way that firms can create value for their investors. Our recommendation is that utility regulators connect this engine of shareholder-value creation more closely to customer- and societal-value creation. A utility earning a rate of return in the ten percent range is earning noticeably more than its cost of equity on every investment. The implications here are important. This system of compensation is predicated on the assumption that nearly all, if not all, **utilities are creating investor value every time they make capital investments**. (Appendix B, pp.4-5)

In short, the utility's incentive to invest is determined by *r* minus *k*. Since in recent years *r* has consistently exceeded *k* by roughly 2.5 to 3.5 percentage points[3] in California as well as nationally, the incentive to invest additional capital in the utility business has been strong. If this Commission desires to incent the IOUs to displace some of that investment by procuring DERs, it should

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[3] The 2.5% number comes from the figures quoted from the Appendices: $r = 10\%$ and $k = 7.5\%$. The 3.5% is included for conservatism and to reflect California-specific conditions.

offer utility shareholders the opportunity to achieve equal or greater value by so doing. This suggests that IOUs could be incented to pursue DERs if they could achieve shareholder returns equal to, say, 3.5% when they choose DERs over more traditional rate base investments.[4]

The goal of this ruling is NOT to determine the precise value of the incentive; rather, my objective at this point is to determine whether the concept is correct and, if so, how it could be utilized to develop an interim pilot program encouraging the IOUs to pursue cost-effective DERs. If the concept is adopted, the next step would be to establish a methodology to determine k and the appropriate incentive rate relative to the difference between r and k.

C. The Need for and Structure of the Incentive

One might ask: why provide the IOUs with any incentive at all? Why not just *direct* the utilities to choose DERs whenever they are less costly than traditional distribution investments? The problem is that, given the complexity of the distribution system, this Commission is ill-equipped, at least at present, to determine with the necessary specificity exactly when and where such DER deployment opportunities may exist. Further, the regulatory process necessary to make such determinations may be so lengthy, detailed and contentious that the underlying data would become stale before any decision could be reached. Practically speaking, command-and-control regulation faces major challenges in this context. Instead, if our objectives are to be achieved, we should create the

[4] Since utility equity returns on rate base are grossed up to cover the associated state and federal income taxes, an incentive such as that suggested here would also have to be grossed up for taxes.

appropriate utility incentives, such that the IOUs will affirmatively seek opportunities to deploy DERs in the pursuit of their own shareholders' interests.

The offering of shareholder incentives for utility deployment of cost-effective DERs should not come at the expense of ratepayers – as long as the amount paid to the DER provider[5], plus the cost of the utility incentive, is less than the cost of the avoided or deferred utility capital investment, ratepayers should always be better off paying the incentive than if the utility had just gone ahead with the planned investment. The development of the Locational Net Benefit Analysis (LNBA), currently within the scope of the DRP, is central to this effort, limiting the active deployment of DER to locations where the benefits exceed the cost. I propose to establish such a limitation for purposes of this pilot, in order to ensure that consumers are not disadvantaged in the process of encouraging increased deployment of DERs.

Regulatory incentives in such situations have often taken the form of "split-the-savings" structures, in which both ratepayers and shareholders receive a portion of the savings achieved by the selection of a lower cost option. But a difficulty arises when the amount of the savings is uncertain and subject to dispute. Such determinations necessarily involve the creation of a counter-factual: what would have happened, for example, if the DER option had not been pursued? Would the utility actually have proceeded with a different course of action, such as a capital investment? And if so, how much would that alternative have cost? Our experience with shareholder incentives for energy efficiency has been fraught with controversies over such issues, and the situation

[5] The DR provider could be either an aggregator of DER services, and individual vendor, or perhaps even a single large customer.

here is even more complex. While such a determination may still be necessary under the proposed approach in order to set a cost cap on the sum of the utility's DER procurement costs and associated incentives, the exact dollar amount of the foregone capital investment will have far less importance. I do not wish to create a pilot structure that will promote extensive litigation over the amount of the incentives to be awarded. Indeed, uncertainty over the amount of any eventual award may act as a contrary incentive, potentially leading the utility to choose the relative certainty of earning a return on a traditional capital investment, rather than take on the risk that a regulatory incentive might (or might not) eventually be awarded.[6]

For this reason the proposed pilot would offer a shareholder incentive for the deployment of cost-effective DERs that displace or defer a utility expenditure, based on a fixed percentage of the payment made to the DER provider (customer or vendor).[7] The percentage would be set at the high end of the range of the estimated value of *r* minus *k* for the California IOUs, such as 3.5% in the above example. Again, I reiterate that the next step, following the pilot, would be to determine a methodology whereby *r* and *k* could be determined iteratively and, to the extent feasible, automatically. Further, I propose that the exact amount of the incentive be determined in a subsequent ratesetting proceeding. That proceeding may be an extension of this rulemaking,

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[6] If a party believes that an alternative incentive approach such as split-the-savings is indeed preferable and feasible to implement in the context of this interim pilot, they are welcome to provide comments describing and justifying that alternative.

[7] If the particular DER selected is already subject to a shareholder incentive mechanism (*e.g.*, energy efficiency), the incentive proposed here would prevail over the resource-specific incentive. A utility would not be allowed to collect a double incentive.

an addition to a related rulemaking (*e.g.*, DRP), or part of a utility request for cost recovery following the execution of DER sourcing. The proposed interim process, outlined below, suggests the latter.

Further, the provision of a regulatory incentive need not be limited to situations where the "avoided cost" for the utility is always a capital expenditure. In some situations the deployment of DERs may lead to the avoidance of higher operations and maintenance expenses or other non-capital costs for the IOU. While in these situations the potential for savings may be more challenging to quantify, I do not wish to exclude such possibilities *a priori*. If the cost of the payment to one or more DER providers, plus the incentive, is less than the cost of the expenses that the utility would otherwise have incurred, ratepayers will still be better off if the utility chooses the DER option.

D. Proposed Interim Pilot Program of Regulatory Incentives for Deployment of Cost-Effective DERs

I propose to establish, on a pilot basis, an interim program offering regulatory incentives to the three large IOUs for the deployment of cost-effective DERs. In this context, "cost-effective" means that the DERs plus the incentive cost less, in terms of present value of revenue requirements, than what the utility would have recovered if it had not deployed the DERs. In appropriate circumstances, this may also include system level costs for the procurement of energy, capacity and ancillary services, as well as the cost of Greenhouse Gas emissions avoided by the choice of the DERs. For purposes of discussion, please assume that the incentive would take the form of an additional payment to the utility of 3.5% (grossed up for taxes) of the payments made to the DER provider(s). The exact figure will be determined later if this proposal or a similar alternative is adopted by this Commission.

The regulatory process for identifying opportunities for cost-effective DER deployment, selecting, deploying and verifying them, and awarding incentives must also be determined. What follows is my suggested process structure, which may be modified or replaced based on the comments received. Much of the process here should eventually be displaced by the DRP process, which I broadly envision to include: a) application of the Integrated Capacity Analysis and LNBA methodologies at regular intervals, b) approval of resulting determinations of distribution service needs and opportunities, and c) approval of authority to source incremental DERs to meet distribution service needs and opportunities. However, to achieve progress in piloting potential incentive mechanisms, I propose a pilot in this proceeding in order to test incentives in parallel with the DRP Demonstration projects.

The proposed pilot process would function as follows: First, the utilities would begin to identify opportunities for the cost-effective deployment of DERs on their systems. Once the utility has identified one or more such opportunities, it would convene a meeting of its Distribution Planning Review Group (DPRG), a new entity similar to the existing Procurement Review Group (PRG) but with differing membership,[8] to describe and discuss the proposed DER procurement.

Second, following this consultation, the utility would submit a Tier 3 advice letter proposing to procure DERs. This advice letter would identify in detail the location in question and the system issue that the proposed procurement was intended to address, specifically including the electrical

[8] The DPRG would be open to interested non-market participant stakeholders that are willing to enter into an appropriate non-disclosure agreement, and would include Office of Ratepayer Advocates (ORA) and Energy Division.

products and/or services that would be sought. A cost estimate for the action that the utility would propose to take in the absence of a DER solution would also be provided to the DPRG and the Commission on a confidential basis. The utility would describe its plan for soliciting DER solutions to the identified problem. At this stage, all-source RFOs for DERs consistent with the solicitation framework being developed in this proceeding would be our preferred procurement vehicle. The goal should be to achieve the best, most cost-effective DER packages that can be obtained, at the right locations.

The utility would also describe in its advice letter a proposal for notifying end-use customers in the affected area of the electrical products and/or services the utility was seeking to obtain. Affected customers could propose their own DER projects or, more likely, various vendors and aggregators could offer packages of DERs in the defined area. Customers in the affected area could also indicate that they would like to have their names and contact information placed on a public list that vendors could use to solicit participants in a DER project. Absent such affirmative consent, the identities of individual customers in the affected area would not be disclosed.

Third, a public workshop would be held before any comments or protests to the advice letter were due (in other words, the standard protest period would be extended), and in that workshop the utility would explain the proposed solicitation in sufficient detail for attendees to understand what products and/or services the company was seeking, where, and for what purpose. Proposed performance requirements for any selected DERs would also be presented for discussion. Parties would be invited (and encouraged) to suggest alternative approaches.

Fourth, after the workshop(s), a deadline of a certain number of days would be set for the submission of comments or protests to the advice letter. (The deadline could be determined by the Commission or could be flexibly determined by Energy Division.) Energy Division would then prepare a resolution for Commission consideration, addressing any issues raised in comments.

Fifth, if the advice letter is approved (with or without modifications) the utility would then undertake the approved procurement process, in consultation with its DPRG and an independent evaluator.

Sixth, any resulting contracts would be submitted for Commission approval via an application, in which the utility would justify the chosen DERs and propose an appropriate incentive, consistent with the Commission's prior guidance. If a DER solution is chosen and approved, the utility would be authorized to record the approved shareholder incentive in a balancing account at the same time as payments were made to the DER provider, and entries to the account would be subject to review in a designated subsequent formal proceeding. The presumption would be that the utility would be able to collect the incentive as long as a potential distribution capital investment or expenditure was, in fact, deferred at a cost less than that of the avoided utility expenditure. I anticipate that ORA and other traditional GRC intervenors would be involved in ensuring consistency among DRP results, GRC requests, and claims for successful deferrals.

During the interim period, while this process proceeds in parallel with the DRP Demonstration projects, I envision that a utility could submit the initial Tier 3 advice letters as often as necessary, hopefully grouping several identified projects together to avoid multiple, overlapping requests. A potential minimum requirement of at least one proposed project every six months could be established to ensure that the program is actually implemented, but I would hope and expect that the utilities would be more aggressive in seeking out DER deployment opportunities.

I offer this proposed process as a straw man for discussion and comment, and am open to suggestions for how to improve and/or expedite the process of proposing, reviewing and approving of potential DER deployment opportunities, consistent with the need for adequate review and comment by both market and non-market participants.

At this time I foresee this pilot opportunity lasting for no more than two years from initial approval through the date of the last advice letter proposal, although actual project development may take longer. The Commission will actively monitor any approved pilot and make mid-course corrections as necessary. Once the DRP process for determining distribution service needs and opportunities is up and running, this program could potentially be made permanent (with or without modification) if it proves to be successful.

E. Request for Comment

Comments on all aspects of this proposal, including the Appendices, are invited, to be filed no later than May 2, 2016. Suggestions for modification or entire alternative proposals are welcome. Reply comments may be filed no later than May 16, 2016. One or more public workshops may be scheduled once the initial comments have been submitted and reviewed, and will provide for at least one round of post-workshop comments, if not more. The assigned commissioner and/or assigned Administrative Law Judge will modify the schedule as necessary.

Specific questions that I would like parties to address in their comments include the following:

1) Is the description of the source of utility shareholder value summarized above and discussed in the Appendices accurate? If not, why not?
2) Would an incentive program such as that described above achieve the objective of promoting the cost-effective deployment of DERs? If not, why not?
3) What alternative approaches should the Commission consider at this time?
4) Is the proposed incentive, in the range of 3.5% grossed up for taxes, approximately correct?
5) Are there other disincentives to the deployment of DERs that this proposal does not address that should be considered at the same time? If so, please explain.
6) Is the suggested process for identifying and approving DER projects that would generate an incentive reasonable and appropriate? How could the process be improved?
7) Is there need for a limit on the number of projects or the amount of dollars that a utility could propose during this pilot program? If so, what should it be?
8) Would participation in a DER solicitation by a utility affiliate require any changes to the Affiliate Transaction Rules, or any changes to the process for review and approval of proposed DER solutions?
9) What would be the appropriate role of the IOUs themselves in the deployment of cost-effective DERs? Should direct IOU participation in DER deployment be encouraged, foreclosed, or allowed with certain caveats? Please fully explain your answer.

IT IS RULED that parties may file comments to the proposal presented in this assigned Commissioner's Ruling and may respond to the questions posed. The comments and responses shall be filed no later than May 2, 2016. Reply comments may be filed no later than May 16, 2016.

Dated April 4, 2016, at San Francisco, California.

/s/ MICHEL PETER FLORIO
Michel Peter Florio
Assigned Commissioner

Designing a New Utility Business Model? Better Understand the Traditional One First

Steve Kihm, Energy Center of Wisconsin
Jim Barrett and Casey J. Bell, American Council for an Energy-Efficient Economy

ABSTRACT

There appears to be a consensus among energy efficiency advocates that traditional utility regulation rewards sales growth and penalizes efficiency. Economic history, however, appears to tell a more-nuanced story. While we cannot isolate the impacts of energy efficiency per se, we can see that gas utilities stocks have outperformed their electric utility counterparts over the long haul, despite selling less product today than they did forty years ago. (Moody's, 2000)

Stock prices are influenced in part by changing expectations about the economic value-added created (or destroyed) when utilities build assets. This metric is influenced not only by internal factors, but also by macroeconomic cycles. Historically, periods in which utility asset expansion adds value precede periods in which it diminishes value. The ratemaking model stays the same but the inputs to it change, and as a result the incentives that model creates for utilities change substantially. Focusing on the incentives that the traditional ratemaking model provided in the recent past tells us little about the incentives those same mechanics will likely provide over the next several decades.

The purposes of this paper are: (1) to describe the existing utility business model at its most fundamental level; (2) to show that this simplified expression can successfully explain past utility financial performance and behavior; and (3) to draw inferences from the model about how current and potential future market conditions are likely to impact utilities' performance and behavior going forward.

Introduction

There is near universal agreement among energy efficiency and renewable energy advocates that the existing structure of utility regulation, the system that defines the utility business model, creates disincentives for investor-owned utilities to promote energy efficiency and customer-owned distributed generation, such as solar photovoltaic (PV) systems (SEIA 2014). When energy resources are realized on the customer-side of the meter, not only do utility sales decline, but over the long run they also deprive utilities of opportunities to grow their profits because increased use of non-utility resources by customers reduces future utility demand and diminishes the utilities' need to add supply-side assets. Because past utility growth and profit strategies have often been based on adding supply assets, there is a concern that reducing the need for adding these assets will endanger the financial viability of utilities under their current business model.

With this issue looming large, there is widespread support for a new utility business model, one that aligns utilities' financial interests in such a way that they can promote increased use of more socially desirable energy resources (Weedall 2013). Looking for a better utility business model is undoubtedly a worthy activity, and such efforts should proceed. But we should enter that discussion with full knowledge of the incentives and disincentives associated with the traditional model. There is more to these incentives and disincentives than meets the eye, and they are not static, but rather change over time. It is a fact that increasing penetration of customer-owned resources and increase use of energy efficiency measures will limit the ability of utilities to make profitable investments in supply-side assets (LaMonica 2013). The assumption that this will necessarily be financially harmful to utility investors requires further exploration.

When analyzing incentives and disincentives for utilities to expand we must use the proper metric. If we are interested in measuring shareholder value, neither the aggregate profit level nor the rate of return is the variable of interest. The finance literature is unequivocal in that the objective of management should be to maximize shareholder value, which is not fully represented by profit or corporate rate of return, but is better represented by stock prices, which reflect future expectations about risk-adjusted cash flows (Damodaran 2012). That is to say we do not find the ultimate information about investor value on a firm's financial statements; we find it in the financial markets. And under certain circumstances, conditions that have held for long periods in the utility industry in the past, taking actions that increase profits, specifically investing in new facilities, have caused utility investor value to decline. That is, while investing in new plants increased profits, it also led to loss of investor value—substantial loss, for that matter.

Rate of Return, Cost of Capital, And Investor Value

Several decades ago utility executives en masse issued statements that they were going to avoid large-scale plant investment whenever possible, even if load continued to grow. Their statements were grounded in the financial concepts we discuss here. At that time the Congressional Budget Office feared that the disincentive for utilities to make plant investment could lead to a more-expensive power supply.

> *The nation's electricity supply could become less cost-effective if regulatory incentives continue to bias utilities away from capital investments* (CBO 1986).

What model were utilities operating under that created a disincentive, not an incentive, to invest in plants? The same one in place today.

The key to creating value for investors is not whether utilities can earn positive returns on plant investment, but rather whether those returns exceed the cost of obtaining the funds to make the investment. When a project can offer a return that lies above the cost of capital, plowing money into such projects creates value for investors. Conversely, even though any positive return on a plant would make for a profitable investment from an accounting perspective, if the rate of return lies below the cost of obtaining the funds for that investment, every dollar invested diminishes rather than creates investor value. This is a basic tenet of corporate finance:

> *The bigger the positive spread between a company's return [r] and the cost of capital [k], the more it will gain in relative market value from growth. When returns fall below the cost of capital, higher growth leads to lower valuations* (Koller et al. 2010).

The profit-maximization strategy calls for investing in a plant whenever r is positive, but the correct metric for evaluating this decision is optimizing shareholder value, not profit. To find the threshold return that must be met to create value we need to compare r to the cost of raising the funds to make that investment, which is the cost of capital k. In other words, the condition necessary to create investor value by building a power plant is that r must be greater than k. That is a much more difficult condition to meet than simply making a profit on the investment, and utilities have not always been able to meet that critical threshold. When they have not, the investment utilities made destroyed billions of dollars of investor value, even though utility profits increased substantially as a result of that plant expansion.

This discussion leads to the following correction to the investment incentive proposition espoused by many:

INCORRECT	$r > 0$	utilities have an incentive to expand
CORRECT	$r > k$	utilities have an incentive to expand
	$r = k$	utilities are indifferent as to whether they expand
	$r < k$	utilities have a disincentive to expand

Capital, like any other input to a production process, is not free. This should have intuitive appeal. Does it seem likely that utilities would rush to expand their facilities if regulators allow them to earn, for example, a 2 percent return on such investment? Clearly there is some minimum acceptable level of return. The cost of capital, by definition, is that minimum return hurdle (Phillips 1988).

This corrected incentive structure should give some readers pause. Many, if not most, regulators say that they set utility rates of return equal to the cost of capital. If that condition held, utility management focused on creating value should not care whether it ever makes any plant investment. Just as buying apples for 50 cents and selling them for 50 cents creates no value for the grocery store owner, raising capital at a cost of 10 percent to invest in assets that earn 10 percent is similarly a financial wash—no matter how large the investment, it creates no investor value.

The utility regulation literature makes it clear that if r equals k on a consistent basis, the utility would be stuck on a metaphorical value-creation treadmill. Running faster (investing more in plants) gets the utility nowhere in terms of creating investor value. A utility operating under this condition would be equally valuable to investors whether it continued to operate or ceased operations and sold off its assets (Train 1991). Under such circumstances, value-oriented utility managers would not be troubled by loss of investment opportunities to competitors, such as distributed generators, because while those lost opportunities would deprive the utility of the ability to increase accounting asset values and profits, they would have no effect on its stock price. The fact that in long periods of time utility managers have wanted to make plant investment while in other long periods they have wanted to avoid that investment suggests that, as a rule, r generally does not equal k for regulated utilities (Myers and Borucki 1994; Kahn 1988; Kihm 2011).

Empirical Evidence from the Utility Industry

With the proper corporate finance framework established, let's next explore an extremely interesting, but financially painful, time in the history of utility regulation. From 1965 to 1980, the cost of capital increased for all firms. Figure 1 shows utility bond yields increasing noticeably over this period.

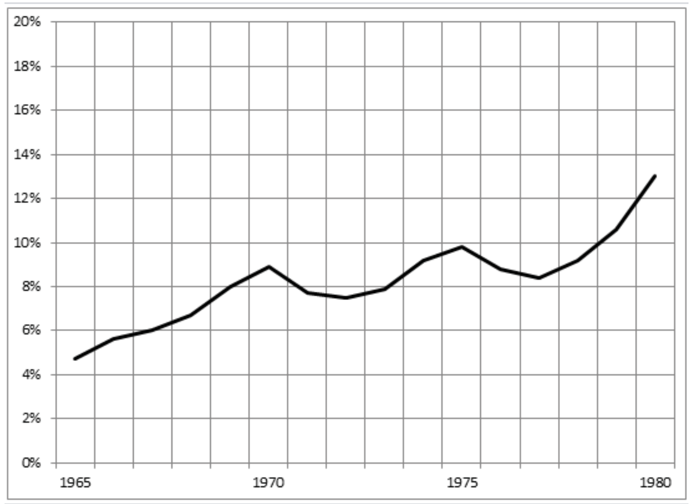

Figure 1. Utility Bond Yields (1965-1980). Source: *Moody's Public Utility Manual*.

We see that in 1965 utilities could borrow funds at a cost of less than 5 percent per year. By 1980, that cost had more than doubled to 13 percent. But the cost of debt is not the ultimate variable of interest here. Stock prices depend on returns on equity and costs of equity. Even though we know the cost of equity exists, we can never observe it directly. As an opportunity cost, it represents a foregone return, the one investors could have earned if they had invested in other similar-risk firms instead of in the utility. Since equity is more risky than debt, and since the cost of capital increases with risk, the cost of equity must lie above the cost of debt. A reasonable rule of thumb espoused by stock analysts is that the cost of equity for a utility is about 3 to 4 percentage points above the cost of corporate bonds (Childs, 1993; Damodaran 2012). We will assume for purposes of this exposition that that the cost of equity is 3 percentage points above the cost of utility debt. See Figure 2.

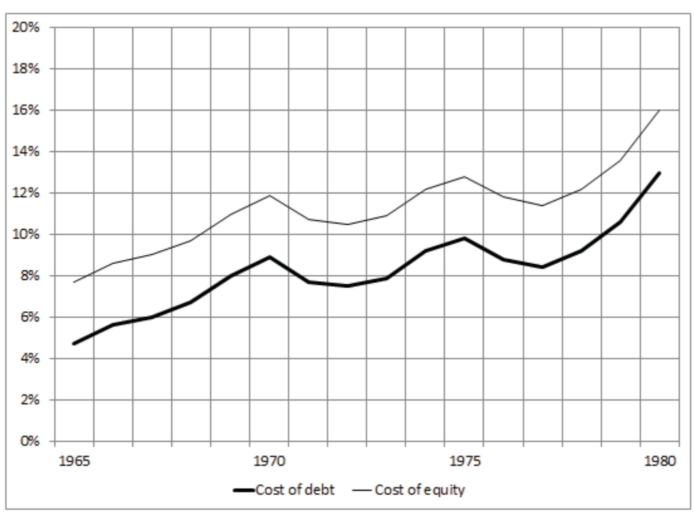

Figure 2. Utility Bond Yields and Estimated Cost of Equity for Moody's Electric Utility Stock Index (1965-1980). Source: *Moody's Public Utility Manual*.

Whether utility plant investment made over this period would increase investor value depended on investor expectations as to whether the traditional regulatory model would allow utilities to earn equity returns in excess of the cost of equity. An important reference point is the returns on equity that utilities, in our case electric utilities, were actually earning at the time. We see those returns added to the image in Figure 3.

This painted a bleak picture for utility investors. However, it is important to take a closer look at other factors that impacted the true cause and effect. It was not that all regulators refused to increase authorized returns on equity in times of increasing costs of capital, for many actually did increase them. Nevertheless, the increased returns often lagged increases in the cost of capital and it became increasingly difficult for utilities to actually earn those authorized returns. Increasing inflation rates (see Figure 4) coupled with increasing interest rates presented the utilities with a particularly difficult environment.

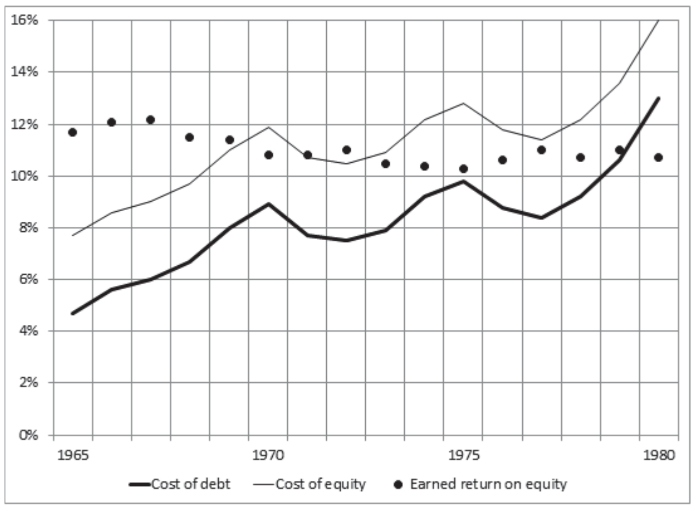

Figure 3. Utility Bond Yields, Estimated Cost of Equity (1965-1980) and Earned Returns on Equity for Moody's Electric Utility Stock Index. Source: *Moody's Public Utility Manual*.

The rapid year-to-year increase in the cost of providing service weighed heavily on the utilities. Even though many regulators were increasing authorized returns on equity over this period, their adjustments often failed to keep pace with the rapid increase in the cost of capital. Even if they did set a return that at least matched the cost of equity, once the regulators set utility rates those prices remained largely static until the next rate case. Rising interest rates and inflation rates pushed costs above those used to set rates, making it almost impossible for utilities to earn their authorized returns. Referring back to Figure 3 we see that by 1980 not only were utilities failing to earn the cost of equity, at that point they were actually earning less than it cost them to raise debt.

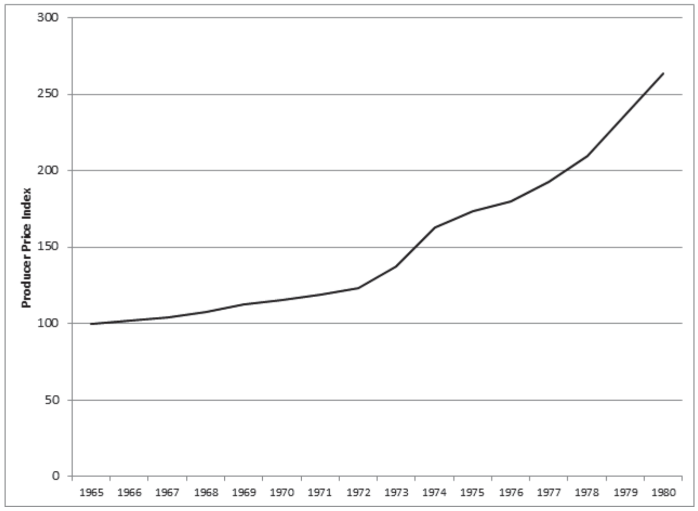

Figure 4. Producer Price Index (1965 = 100). Source: Bureau of Labor Statistics.

So did utilities expand during this period? Unfortunately for their investors, the answer is yes. Figure 5 provides the final piece of the perfect storm that led to massive value destruction for utilities, which we will document in a moment. In 1965, when electric utilities earned returns on equity that exceeded the cost of equity by +4.0 percentage points, the industry spent less than $2 billion on new plant construction. By 1980, when the spread between the earned return and the cost of equity had declined to -5.3 percentage points, the industry was spending about $9 billion on new plant, much of it nuclear generation capacity.

So how did all of this affect utility *profitability* (not investor value)? Even though the earned rates of return on equity generally did not increase over the period in question, electric utility earnings per share grew by 51 percent. The only way a largely stable rate of return on equity can produce earnings per share growth is if the underlying accounting book value per share grew over time. (Book value is the accounting convention that includes the equity portion of plant investment, as well as any retained earnings.) It did, as we see in Figure 6. From an *accounting perspective*, this plant investment was making utilities more valuable.

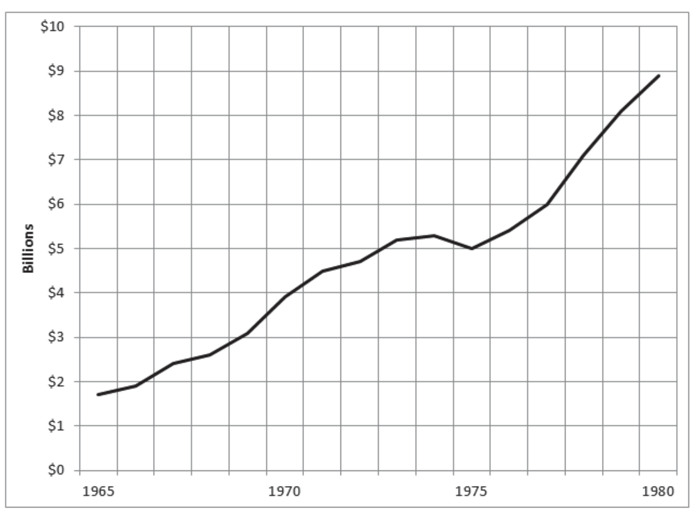

Figure 5. Annual electric utility construction expenditures (1965-1980). Source: *Moody's Public Utility Manual*.

All of the things that many think would be viewed as positive developments for utilities—growth in book value, earnings and dividends—were manifest over the 1965-1980 period. To put this in the commonly used construct all this plant investment substantially increased utility profits. If profit-maximization was the goal, this was a period of great utility success.

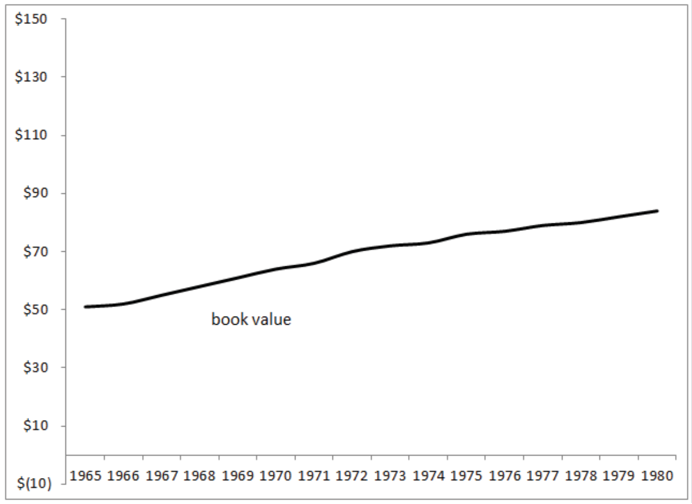

Figure 6. Moody's Electric Utility Index book value per share (1965-1980). Source: *Moody's Public Utility Manual*.

But if finance theory is correct, since the industry was making this capital investment while earning returns below the cost of equity, we should find that utility expansion of this scale took a huge toll on investor value. We do. Figure 7 shows that electric utility stocks lost about half of their value over this period. Some might suggest that the significant loss of market value was due to disallowances of plant investment. That argument fails to recognize that total disallowances of utility plant investment during this construction boom ultimately amounted to only 7 percent of total investment, not enough to explain a 50 percent loss in market value. (Lyon, 2005)

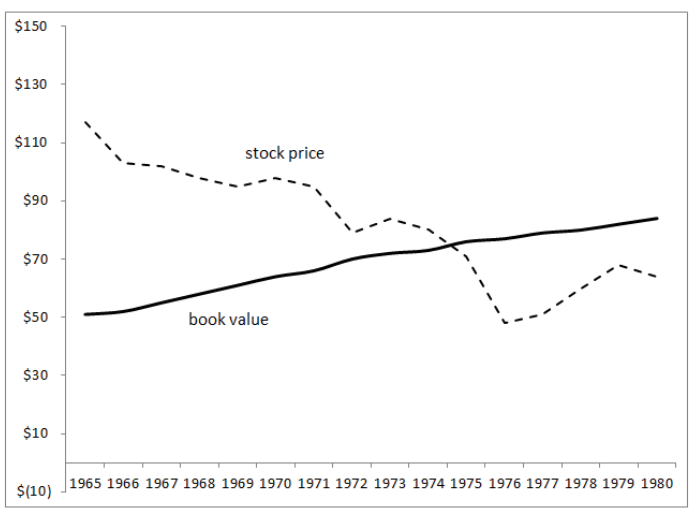

Figure 7. Moody's Electric Utility Index book value per share and stock price per share (1965-1980). Source: Moody's Public Utility Manual.

Furthermore, gas utilities, which faced no major plant disallowances, saw their stocks decline by 22 percent over this period, suggesting that the regulatory model in general was failing to protect investor value over this period. (Moody's, 2000) In contrast, the overall stock market, as represented by the S&P 500, increased by 50 percent over this period.

Electric utility stocks sold at over twice book value in 1965, which was a reasonable valuation given the degree to which utility returns exceeded the cost of capital. By the late 1970s and early 1980s they were trading at about 80 percent of book, which again was rational given the reversal of the important relationship between the company's earned return (*r*) and its cost of capital (*k*). This historical analysis therefore verifies that the essence of the financial value creation model is on track.

Note, however, that while deteriorating macroeconomic conditions could pose such problems in the future, that is not the key point we are making. The important takeaway is that anything that can close the gap between the earned return and the cost of capital affects the incentive for utilities to expand. If the gap disappears, so does the incentive. If the gap goes negative, expansion destroys utility investor value. If that outcome is likely then utilities should welcome actions that allow them to avoid future plant investment. All of these incentives and disincentives can occur and have occurred under the traditional utility business model. Structural shifts have occurred throughout the course of history, and future states of the world are highly uncertain. Today utilities generally earn returns in excess of the cost of capital. We know that because they trade at a noticeable premium to book value.

> *If the return on equity [r] exceeds the cost of equity [k], the price will exceed the book value of equity; if the return on equity is lower than the cost of equity, the price will be lower than the book value of equity* (Damodaran 2012).

The point, though, is not whether investors today expect returns to exceed the cost of capital, but rather whether we can count on that continuing in the long-run future. Investors in 1965 who were willing to pay more than twice book value for utilities assets had likely been lulled into a sense of complacency due to the supportive regulatory environment they had found themselves in since World War II. While it was difficult to see it coming, at that point gentle tail winds were about to turn into hurricane-force head winds which turned utility plant investment from a value-creating to a value-destroying activity. The question to all of us then is: what does the financial weather forecast look like for utilities as we peer into the future? That is what will determine whether utilities truly have an incentive to invest in their systems.

Implications for the Utility Industry in the Near Future

The finance theory presented here is not new nor is it unique to the utility industry. While utility finances can get a great deal more complicated than the stripped-down version outlined here, the simple core of principles of finance remain. Any entity that wishes to increase investor value must pay less for its investment capital than it earns when it puts that capital to work. Faced with this immutable reality and the vagaries of electricity markets, what does this mean for the future of the utility business and its business model?

To this point, this discussion has been mainly retrospective and deterministic. In discussing future investment decisions, risk and uncertainty play a critical role. In addition to the riskier nature of equity investment relative to debt as mentioned above, the issue of risk is already inherent in this discussion: The riskier an investment is, the higher the rate of return that it must offer to attract capital without causing a loss in investor value (Morin 2006). Note that firms can and do issue stock when expected returns lie below the cost of capital, but they do so at the expense of their existing investors who see the stock price decline, which is precisely what happened for utilities in the 1965-1980 period.

> *When expected earnings [r] are less than investors' requirements [k] and a sale of stock occurs, new shareholders can expect to gain their return requirement at the expense of the old shareholders* (Morin, 2006).

In this context, the cost of capital that utilities face, *k*, is a critical component in the decision of whether or not to build new generating assets, or any assets for that matter. If potential investors see the utility business as inherently more risky than other investments, they will demand a higher minimum rate of return, a higher *k*. This increases the threshold that utilities' return on investment must reach for a project to be financially sound.

Generally speaking, anything that makes the return on generation projects more risky, the higher the rate of return on those projects must be to justify them. In one of the injustices of utility financing, investors get to price their uncertainties into the cost of capital, *k*, in advance. Utilities, on the other hand, with retail prices subject to PUC decisions, do not get the same privilege with respect to *r*.

To see why this creates a problem for utilities, imagine the following simplified situation: A utility is considering building a power plant with prices regulated by a PUC that quickly and accurately adjusts electricity rates in reaction to changes in the utilities' costs. Imagine that the utility is considering building a new power plant but also faces some uncertain future that could impact its profitability, such as a carbon tax. If a carbon tax is implemented, the PUC will act swiftly to ensure that it is fully passed on to the utility's customers. This way the utility knows that it will be held harmless if the tax is enacted, and if *r* is currently 9%, the PUC will maintain *r* at 9% whether or not the tax is implemented.

Imagine further that equity investors had previously had a *k* of 8%, so that before the carbon tax became a possibility, the new plant would have been a financially sound investment (i.e., 9% > 8%). Now that the carbon tax is a possibility, however, investors may become more wary of the profitability of the new plant. They may doubt that the PUC will act swiftly to adjust utility rates; they may believe that the proposed carbon tax is just the beginning of a new era of regulation and that the PUC may not be able to fully pass on the costs associated with a new suite of regulations. Whatever the rationale, investors perceive increased risk and increase their *k* to 10%, for example, and the plant is no longer financially viable and does not get built. (Assume the utility then purchases power from a neighboring utility or independent power producers.)

If the carbon tax does not get enacted, or if it does and the PUC would have moved as swiftly and completely as it promised, then, ex-post, the plant would have been a value-creating use of investor funds. But because the possibility of the carbon tax increased the ex-ante risk associated with the project, it did not get built, and investors missed out on the opportunity. In practice, of course, PUC's don't necessarily move instantly to exactly adjust prices to maintain a given *r*. Utilities must therefore make a build vs. power purchase decision based on their expected rate of return, E(*r*). The basic rule needs to be modified to reflect this uncertainty: If the utility believes that its returns on a project will exceed the known costs of capital, i.e. if E(*r*) > *k*, then a project is financially sound, ex-ante.

Returning to the carbon tax example above, imagine now that the carbon tax is a certainty fully expected by both the utility and equity investors. Imagine further that both the utility and investors believe that the PUC will act to raise electricity rates once the carbon tax is enacted, but that there will be a delay between the enactment of the tax and when the PUC raises rates. This belief reduces the risk somewhat, and k increases from 8% to 9%. However, if uncertainty about the speed and completeness of the PUC's actions lowers the expected return, E(r), at all, the plant again fails the build/no-build test and the utility does not make the investment.

In the scenarios above, the introduction of uncertainty and risk turned a financially sound project into an unsound one at the time that the build/no-build decision had to be made. Generally speaking, anything that raises the perceived risk of investing in plant construction or that increases the uncertainty of utility returns will raise k or lower E(r), or both, reducing, or perhaps even eliminating, the incentive to build new generating plants. Looking forward, there are several such factors that serve to make building new generating assets less financially attractive. The same financial construct applies to transmission and distribution assets, although the risks associated with those assets differ from those associated with generation assets, which is the asset type we focus on here.

Greenhouse gas regulation. Though seemingly less likely now than it was a few years ago, the potential for direct regulation of emissions of carbon and other greenhouse gases introduces a number of risks to electricity generating projects. The Environmental Protection Agency is in the process of writing and enacting regulations pursuant to the Clean Air Act. These amendments would regulate the emission of carbon from new and existing power plants. These regulations may reduce electricity demand, raise generating costs, and necessitate capital investments that otherwise would not occur. Any of these impacts could raise k and lower E(r), reducing the incentive to build new power plants.

Rising interest rates. In the aftermath of the financial crisis of 2008 and the recession that followed, interest rates remain at historically low levels. These low rates have resulted in very low capital costs for utilities, a situation which is unlikely to persist indefinitely. The U.S. Energy Information Administration projects noticeable increases in yields on Treasury bonds and corporate bonds over the remainder of the decade (EIA 2014). As interest rates start to rise, the cost of capital will rise with it, making new generating assets more expensive to finance. To the extent that investors recognize that interest rates are likely to rise in the future, capital costs may already be reflecting this expectation, though the effect may become much more pronounced once rates start to increase. The key question is whether utilities can earn returns in excess of the cost of capital in an era in which the cost of capital is rising. This is by no means a sure thing, as history reveals.

Inflationary pressures. One of the policy responses to the financial crises and recession was a rapid expansion of the money supply. Under normal economic conditions, such an expansion would normally result in inflation. In the current slack economy, inflationary fears have gone largely unrealized. However, as the economy continues to expand, the monetary expansion may begin to exhibit its side effects in the form of higher inflation. As in the past, PUC's and other regulators may not respond to inflation by rising electricity rates quickly enough, and may be unwilling or unable to raise them in concordance with rapidly rising inflation.

Falling electricity demand. The annual growth rate of electricity consumption has fallen significantly over the past 50 years, from near 10-12% per year in the 1950s to below 2% since the mid 2000s. If the trend continues, either due to continued economic uncertainty, structural shifts in the economy, increased use of distributed generation, or the prevalence of successful energy efficiency programs, weak electricity demand could reduce the expected return on power plant investments, and reduce the need and incentives for new generating assets.[1]

Fuel price volatility. There are many economic, political, and environmental factors that can influence the supply and demand of fuel, causing volatility in prices. In some states, regulators have limited the extent to which these costs can be passed along to customers, lowering E(r) for utilities.

Sunk or stranded costs. Decision makers in the utility industry cannot act with perfect foresight. The perceived risk to revenues caused by mandatory Demand Side Management (DSM) and energy efficiency programs also play a role in determining E(r). In addition, there is a risk that investments in programs that reduce the demand for new generation could result in stranded costs from recent investment in new generation, or even from not so recent investments given the long depreciation schedules attached to capital investments.

Competition from new products or markets. The growing market penetration of DSM and Distributed Energy Resources (DER) can lead to decreased revenues which, coupled with long depreciation lives for power plant investments, can hinder a utility's ability to recover costs through ratemaking. There is an added risk as the burden of these costs are passed along to consumers, that consumers will adopt alternative products or participate in new markets to supply energy demand, perhaps by installing solar PV-gas turbine hybrid systems that allow them to disconnect from the grid (Graffy-Kihm 2014). Such "disruptive forces" are not yet readily available or widely affordable, and the timeline for the availability of these products and markets can be hard to predict. However, forward-thinking utility decision makers are likely aware of this risk, and it may be factored in to expected rate of return (Kind 2013).

Conclusions

Redesigning utility business models cannot be done in a vacuum, one that considers only energy efficiency or renewable energy issues. A macro perspective based on corporate finance principles provides the proper view regarding utility incentives and disincentives. A good business model will be founded on providing incentives for utilities to increase shareholder value. The factors we just discussed demonstrate the degree of uncertainty that can influence the outcomes of utility executives' decisions. Utility rates of return are not guaranteed, especially over the long-term. Furthermore, there is no guarantee that utilities will be able to recover the costs of new plant investments over the next 30 years, let alone earn returns on those costs. The industry is aware of these potential threats to their retail business (Kind 2013).

As industry searches for new ways to increase or at least maintain investor value and other stakeholders look for new business models that reward investments in energy efficiency and clean energy production, it is important to keep the impact of uncertainty on E(*r*) in mind.

[1] Note that since revenue decoupling tends to push E(*r*) to the authorized *r*, and not to *k*, decoupling does nothing to address incentives or disincentives created when authorized *r* differs from *k*.

We have demonstrated the existing business model is based on relatively simple financial principles that are likely to continue to apply whether the market grows or shrinks, and regardless of the types of investments being made. The point not to be missed is that this value-creation construct is the one the financial markets will apply even under new utility business models.

As we seek a framework for a new utility business model, it is critical that we measure success in terms of optimizing shareholder value, rather than simply maximizing profits, and that we recognize that shareholder value is not tied uni-directionally to supply asset investment. Just as past investments in supply assets helped destroy shareholder value under the current business model, so too can reducing investments enhance shareholder value, under the right circumstances. Furthermore, we need to broaden our paradigm of what influences decision-makers' ability to meet this condition to account for uncertain future states of the world.

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(END OF APPENDIX A)

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YOU GET WHAT YOU PAY FOR:

Moving Toward Value in Utility Compensation

PART ONE – REVENUE AND PROFIT

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June 2015

EXECUTIVE SUMMARY

U.S. utilities—and the power systems they manage—are in the midst of a vast transformation fueled by rapid advances in power system software and hardware, combined with fundamental changes in customer expectations. To accommodate these changes, the electric utility system and its associated institutional arrangements will have to take on a new look. Under the current regulatory structure, utilities are feeling increasing pressure from efficiency gains that reduce electricity sales, requirements to reduce pollution from their fleets, and a growing share of their market being absorbed by new technologies they do not own. At the same time, more and more customers expect utilities to respond to these challenges with innovation and flexibility—to compete with offerings from nimble third-parties. Against this backdrop of industry upheaval, regulators are asking whether this is the moment to refine the way regulated utilities make money in order to better manage this change, reward innovation, and provide more value for customers' money.

Executives of investor-owned utilities are motivated by the opportunity to create value for their shareholders. In principle, rewards to shareholders are warranted in exchange for making capital available to provide a valued service to the public. But today's rate of return model often offers the same return on all approved capital investments—offering utilities the same opportunity to create value for shareholders without testing whether investments are creating the most value possible for customers or society.

Many in the regulatory community believe that the utility's rate of return is the sole value driver, and that rates of return are set at the cost of equity. Neither of these perceptions is correct. Instead, the financial "value engine"—the difference between a utility's return on investment and its cost of capital—drives shareholder returns. Regulators should use this value engine to align utilities' financial motivations with delivering value to customers and society. They can offer utilities opportunities to earn increased revenues when they provide value-based products and services. Regulators can also influence utilities' cost of capital by taking actions that increase the predictability of returns on valuable investments.

Regulators have options for how to use the financial value engine to increase value for customers and society; via performance-based regulation, incentive rates of return, and standards. To start down this path, regulators should consider which customer- and societal-values are most important in their region. They should then seek input from many stakeholders to drive toward quantitative metrics for performance in each category of values. They can apply more realistic estimates of utilities' cost of equity to the equity portion of investments, and use that as the lower bound on associated revenue. Regulators can also offer utilities opportunities to earn above that lower bound when they perform against the defined quantitative metrics. Estimates of the financial benefits of performance in each value category can then be used as upper bounds for earnings. Utilities can be offered opportunities to earn performance portions of their revenue outside traditional rate-of-return on investment, to break their implicit financial incentive to deploy capital indiscriminately.

CONTENTS

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I. INTRODUCTION

The electric grid is essential to our modern economy—the National Academy of Engineering named electrification of the country as the greatest engineering achievement of the 20th century.[1] Electric service today is generally reliable, affordable to most, and electric generation is typically environmentally cleaner than it was in the past. Utilities tend to receive above-average customer satisfaction scores.[2]

Yet, few utility managers or regulators today are complacent, nor should they be. America's utilities—and the power systems they manage—are in the midst of a vast transformation fueled by rapid advances in power systems software and hardware, combined with fundamental changes in customer expectations. With the Public Utility Regulatory Policies Act of 1978 (PURPA), competition began to seep into the cracks of the once-monolithic utility monopolies.[3] As the ecosystem of electricity service providers has grown, it has become clear that last century's utility business models and regulatory approaches can no longer contend with the rate of change on the ground. We have reached a turning point in American history: it is time to revisit the very principles we use to regulate and compensate utilities.

Given changes that have been building over the past quarter century, the regulators' task -- to simulate market competition via regulated compensation -- has become increasingly complex. In the face of increasing complexity, we believe two fundamental questions can be used to guide the regulator's task for investor-owned utilities:

- What values and services do we want our electric system to provide?
- How can we improve the incentives currently provided by regulation to get more of what we want from electric utilities?

Traditional regulatory approaches focus primarily on historic cost of service rather than future value delivered. This paper intends to shed light on some ways regulators can encourage utilities to deliver more value to customers, "more value for money." In this two-paper series we:

Part 1: Analyze how utilities respond to either create or destroy value for their shareholders, customers, and society large.

Part 2: Identify ways to create or modify these incentives to encourage utilities to maximize value for customers.

Ultimately, our aim is to provide some ideas for how to update utility regulation and the incentives it provides to ensure that the lights stay on, system-wide costs remain as low as possible, and the environmental impact of our energy system shrinks considerably.

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[1] National Academy of Engineering, http://www.greatachievements.org/
[2] American Customer Satisfaction Index, http://theacsi.org/
[3] Pub.L. 95–617, 92 Stat. 3117, enacted November 9, 1978.

WHAT ARE WE PAYING FOR TODAY?

Any discussion of moving towards a new incentive scheme for the "utility of the future" must begin with a thorough understanding of how the "utility of the present" is compensated for providing its services. Today's cost of service model for utility compensation is based on a system of accounting. First, utilities make investments and operate their system to keep the lights on, keeping careful track of each of their costs. Second, regulators comb through utility costs line-by-line to determine whether each investment and expenditure was appropriate, usually given a "least-cost" rule of thumb.[4] Differences of opinion as to what counts as "least cost" underlie the adversarial nature of the ratemaking process. Once a set of decisions about projects and investments, kinds and levels of expenses, and their booked costs are accepted, regulators allow utilities to recover operating expenses in full, as well as capital costs plus an opportunity to earn a commission approved "rate of return" on invested equity.[5]

The rate of return is made up of a return on debt (bonds) and a return on equity (stocks), weighted to reflect the proportional shares of total capital each type of security provides. In abstract economic theory, the rate of return is intended to compensate the utility only for its cost of capital. Since utility bond holders are secured by utility assets, equity holders are taking on the lion's share the utility's investment and operating risks, making an up-front investment in infrastructure that they will be compensated for over time.[6] Currently, utilities are typically assigned returns on equity around ten percent, while market evidence and investment analysts suggest that the *cost* of equity[7] for electric utilities today is closer to seven or eight percent.[8] Standard stock valuation models, the ones used by Wall Street investment analysts,[9] demonstrate that today's typical electric utility stock market-to-book ratio of 1.7 is consistent with a cost of equity of 7.5 percent.[10]

To be clear, we are not suggesting in principle it is inappropriate for a utility to be allowed to earn an equity return in excess of the cost of equity—to the contrary, the return on equity *should* exceed the cost of equity, just as it does for the typical non-regulated

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[4] If the regulator uses a forward test year, they perform this assessment on a prospective basis.

[5] The U.S. Supreme Court has made it clear that the Constitutional right afforded utilities under regulation comes in the form of a reasonable opportunity to earn a fair rate of return, not a guarantee that the utility will earn such a return. *See Southwestern Bell Tel. Co. v. Public Svc. Comm'n, 262 U.S. 276 (1923).*

[6] Equity investors can substantially diminish their exposure to many of these risks by combining stocks in a portfolio.

[7] The cost of equity represents the cost of money provided by shareholder investments. This is usually higher than the cost of debt, which is the cost of borrowing money to be repaid. The cost of capital is a blend of the cost of equity and the cost of debt.

[8] See Andrew Bischof, "Attractive transmission and Illinois growth opportunities are set to drive earnings," *Morningstar*, March 3, 2015.; and Steve Kihm, "Rethinking ROE," *Public Utilities Fortni*ghtly, August 2011.

[9] See Steven Kihm, "The Proper Role of the Cost-of-Equity Concept in Pragmatic Utility Regulation," *The Electricity Journal*, December 2007.

[10] Actual utility market-to-book ratios were calculated with data from *The Value Line Investment Survey*. Using a cost of equity (k) of 7.5 percent, a return on equity (r) of 10.0 percent, and an earnings retention rate (b) of 40 percent, we can apply the discounted cash flow model to estimate the associated market-to-book ratio (M/B) as flows: $M/B = (r \times (1-b))/(k - b \times r)$, therefore $M/B = (0.100 \times (1 - 0.40)) / (0.075 - 0.40 \times 0.100) = 1.7$

company. In fact, that is the only way that firms can create value for their investors. Our recommendation is that utility regulators connect this engine of shareholder-value creation more closely to customer- and societal-value creation. A utility earning a rate of return in the ten percent range is earning noticeably more than its cost of equity on every investment. The implications here are important. This system of compensation is predicated on the assumption that nearly all, if not all, **utilities are creating investor value every time they make capital investments**. That may have been appropriate when the primary social goal of the utility sector was to grow enough to provide universal service, and economies of scale were clear. Assuming that system build-out is no longer the primary objective several questions follow:

- Do returns on equity higher than utility costs of equity provide utilities with incentives to spend money?
- Do returns on equity higher than utility costs of equity continue to be in the public interest?
- Could utility investment capital be better directed toward projects and services that would create more value for consumers' money?
- Are external utility industry costs largely overlooked?
- Could investment analysis be made more transparent and effective, if utility incentives were better targeted and less contentious?

Subsequent sections of this paper explore how we might redefine value in the utility context, and how compensation structures might be rationalized to match utility compensation with societal value creation.

II. HOW UTILITY MANAGERS CREATE SHAREHOLDER VALUE

As with any investor-owned company, it is the job of investor-owned utility management to maximize shareholder value. Utility managers pay attention to Wall Street, and more can be learned about utilities' top priorities by listening to shareholder earnings calls than regulatory proceedings. To capture the attention of utility management, regulators can consider how to tie shareholder value creation to societal and customer value creation. Utility managers' primary obligation is to the owners of the firm, not its creditors.[11] As such, in establishing incentives for managers to take actions that create investor value, regulators should focus on shareholders. Understanding the factors driving stock price formation sets the stage for identifying regulatory mechanisms to align investor value creation with consumer and societal goals.

Even if the utility does not have an observable stock price, which is the case if it operates as a subsidiary in a holding company (public or private), we can still use the concept of

[11] Myron Gordon, *The Cost of Capital to a Public Utility*, Michigan State University (1974), p. 3.

shareholder value creation to develop incentive mechanisms. The same factors that drive stock prices create investor value wherever they occur within the organization.[12]

There are two roadblocks, though, to understanding financial value. Many in the regulatory community believe that: (1) the utility's return on equity is the sole value driver; and (2) regulators set returns on equity at a rate equal to the cost of equity. **Neither of these perceptions is correct**, and understanding why is key to developing effective utility incentive mechanisms.

THE VALUE ENGINE: *(r-k)*

Many regulatory reform discussions focus on the utility's return on equity as the sole driver of financial value, but that does not align with the concept of investor value creation. **It is not the *absolute* level of a company's return on equity (*r*), but rather the *difference* between *r* and its cost of equity (*k*), that creates the value opportunity that drives the stock price.** [13] This statement requires some definition.

The return on equity is what the company earns on its books; the cost of equity is the return that prospective shareholders would forego by investing in the utility's stock instead of those of other similar-risk firms.[14] The market sets prices for securities of similar-risk firms so that they produce the same expected return.

While the return on equity and the cost of equity could take on the same numerical value, there is no conceptual relationship between them. The return on equity is an ***accounting-based*** return for a ***firm***; the cost of equity is a ***market-based*** return for its ***investors***.

Let's put this in perspective by examining these returns in a broad market context. Most investment advisors today suggest that the cost of equity (the long-run expected return) for stocks in general is eight to nine percent.[15] In stark contrast, the return on equity for the S&P 500 is currently 16 percent.[16] In the electric utility sector, investment advisors suggest

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[12] Utilities that are not investor-owned, such as municipals and cooperatives, do not have shareholders in the sense we consider here. The value creation principles we set forth here may have some bearing on the decisions of managers leading those entities, but understanding the overarching objectives of those entities requires additional analysis. Ironically, the fact that these utilities do not have shareholders makes it more difficult to determine what motivates managers.
[13] The term "rate of return" generally refers to the weighted average return on all of the firm's securities, which includes both debt and equity issuances; its market analog is the cost of capital. The term "return on equity" refers to the rate that applies only to the equity balance; its market analog is the cost of equity. The value proposition is qualitatively the same for both perspectives. If the firm earns a rate of return that exceeds the cost of capital it can create value for investors. Similarly, if it earns a return on equity that exceeds the cost of equity it again creates investor value.
[14] Ezra Solomon, "Alternative Rate of Return Concepts and Their Implications for Utility Regulation," *Bell Journal of Economics & Management Science*, Spring 1970.
[15] Michael E. Lind, *Estimating Long-Term Market Returns*, Charles Schwab, May 22,2014; Morningstar.
[16] See www.multpl.com

that the cost of equity (the long-run expected return) on utility stocks is about seven to eight percent;[17] the typical return on equity for electric utilities is ten percent.[18]

These figures should not be surprising. In a world where firms have the opportunity to create value for investors by making investments, the return on equity and the cost of equity cannot take on the same numeric value. McKinsey & Co valuation experts describe the fundamental principle that describes this relationship.

> The guiding principal of value creation is that companies create value by investing capital they raise from investors to generate future cash flows at rates of return ***exceeding*** the cost of capital.[19]

If markets or regulators consistently drove the return on equity down to the cost of equity, there would be no financial reason for value-oriented firms to make investments. For a utility, they would have no incentive to invest in new plant.

> When return on invested capital is lower than the company's cost of capital, faster growth necessarily destroys value, making the point where return on invested capital equals the cost of capital the dividing line between creating and destroying value through growth. On the line, value is neither created nor destroyed, regardless of how fast the company grows.

The key question for investors then is not whether the utility earns a return on equity on its new plant investment, but whether that return exceeds the cost of equity, and by how much.

STOCK PRICE FORMATION

Value flows from the gap between the return on equity r and the cost of equity k expressed explicitly in stock pricing formulas, such as this one[20]:

$$P = BV + \frac{(r-k)BV}{k-g}$$

In this model, P represents the stock price, BV is the accounting book value, and g is the long-run growth in residual earnings.[21] It is the difference between the return on equity and the cost of equity ($r - k$) that we focus on here. **The larger the gap between *r* and *k*, the greater the value opportunity per dollar of capital invested.**

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[17] Source: Morningstar.
[18] Source: Analysis of data from *The Value Line Investment Survey*.
[19] Tim Koller, Marc Goedhart and David Wessels, *Valuation: Measuring and Managing the Value of Companies*, John Wiley & Sons (2010), p. 4.
[20] This is the residual income model, a particularly-revealing form of the standard discounted cash-flow model. From Stephen Penman, *Accounting for Value*, Columbia Business School Press (2010).
[21] Residual earnings are those in excess of the return required by investors, i.e., in excess of the cost of equity.

The cost of equity is the most elusive variable in the value equation. While we cannot observe it directly, we can see its shadow. We can determine whether a firm is earning more or less than its cost of equity by observing the relationship between its stock price and its book value.

> If the return on (book) equity is pushed back toward the cost of capital, then the stock price will be pushed back to book value.[22]

We see this important foundational principle embedded in financial valuation models. If we set the return on equity equal to the cost of equity ($r = k$), the stock price converges to book value, just as the theory suggests must be the case.

$$P = BV + \frac{(k - k)BV}{k - g} = BV + 0 = BV$$

Finance theory tells us then that if the cost of equity for the S&P 500 index were actually equal to its 16 percent return on equity, and not the eight to nine percent that investment advisors suggest, the index would trade at its underlying book value of $733. Today it trades at about $2,100, which is consistent with the advisors' cost of equity estimates.[23]

Similarly, if the cost of equity for utilities were actually equal to the typical ten percent return, and not the seven to eight percent that investment advisors suggest, electric utility stocks on average would trade at book value. The typical utility stock today trades at 1.7 times book value. No major investor-owned electric utility stock today trades at or below book value. Again this suggests that the advisors' cost of equity estimates are on track.

The finding that utility returns on equity exceed the cost of equity is not a new one. Over the past several decades financial experts have repeatedly rejected the notion that regulators set the return on equity at the cost of equity. Those who believe that regulators should set returns in this manner must conclude that regulators have failed to achieve that objective. In a study completed for the New York Commission in the 1990s Myers and Borucki found:

> There is no way to square these numbers with the standard view of the objectives of rate of return regulation…This does not allow an expectation of long-run profitability exceeding the cost of equity or market-to-book ratios substantially above one for virtually all utilities.[24]

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[22] Stewart C. Myers and Lynda S. Borucki, "Discounted Cash Flow Estimates of the Cost of Equity Capital: A Case Study," *Financial Markets, Institutions & Instruments*, 1994.

[23] The current book value for the S&P 500 is $736 and estimated earnings per share are $119. The return on equity is then 16.2 percent ($119/$736). Combining that information with a long-term growth rate matching GDP growth of 4.5 percent (in the long-run, corporate growth for non-regulated firms keeps pace with the economy) and a cost of equity of 8.5 percent, and applying the residual income model, we obtain the following value estimate for the S&P 500: $736 + [(0.162 – 0.085) x $736]/(0.085 – 0.045) = $2,152. The S&P 500 trades today at $2,122.

[24] Myers and Borucki, *supra*.

The last time average electric utility stocks traded at or below book value was during the Reagan administration.[25] That means that over the past 30 years or so, utility returns on equity have generally exceeded their associated costs of equity. Much of that gap is attributable to the significant decline in interest rates over that period. The empirical evidence reveals that for every 100 basis point drop in interest rates, regulators reduce the return on equity by only about 50 basis points.[26] This is a recipe for financial prosperity for utilities, one that has made investment not only profitable, but more important, value-creating for shareholders.

CONSIDERATIONS FOR SETTING THE RETURN ON EQUITY

Despite popular claims to the contrary, the preceding discussion reveals that regulators have not typically set the return on equity at the cost of equity for utilities. That means that utility growth, and related investment, has created value for shareholders. Is that an undesirable result?

The fact is that if regulators want to incent utilities to make investments, they cannot set the return on equity at the cost of equity.

> In fact, even if that were feasible, there is one very good reason for not following the standard: it seeks to equate book and market investment value. Should one succeed in doing this, the firm would have no incentive to increase efficiency.[27]

In his classic text *The Economics of Regulation*, Alfred Kahn argues that the cost of equity is the starting point, not the end goal, in setting the rate of return.[28] Kahn also suggests that regulatory policies should create incentives for utilities to innovate, which aligns well with the goal of linking shareholder and societal value.

> The provision of incentives and the wherewithal for dynamic improvement in efficiency and innovations in service may require allowing returns to exceed that level [the cost of equity]…The rate of return must fulfill an institutional function: it somehow must provide the incentives to private management that competition and profit-maximization are supposed to provide in the nonregulated private economy generally.[29]

Setting the return on equity equal to the cost of equity for all investments is a prescription for stagnation.

We saw that the typical firm as represented by the S&P 500 earns returns on equity noticeably above its cost of equity. If regulation is to mirror competitive market results then there should be some gap between the return on equity and the cost of equity, at least

[25] Congressional Budget Office, *Financial Condition of the U.S. Electric Utility Industry*, March 1986.
[26] Roger Morin, *The New Regulatory Finance*, Public Utility Reports, 2006.
[27] Stephen Breyer, *Regulation and Its Reform*, Harvard University Press (1982), p. 47.
[28] Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, John Wiley & Sons (1970), p. 44.
[29] Kahn, *supra*.

for well-managed utilities and especially for those who meet societal and consumer objectives[30] –paramount for enterprises that ostensibly exist to serve the public interest.

The key is to understand that this gap represents a policy choice—whether explicit or implicit—about whether and how much to incent utility investments.

But there should not be a gap between *r* and *k* for *all* utilities regardless of performance. As Kahn suggests:

> Merely permitting all regulated companies as a matter of course to earn rates of return in excess of the cost of capital does not supply the answer; there has to be some means of seeing to it that those supernormal returns are earned, some means, for example, of identifying the companies that have been unusually enterprising or efficient and offering higher profits to them while denying them to others.

Kahn sets forth a pragmatic, institutional framework here. Investor rewards (increased value) should go to the firms that achieve desirable goals. Those that do not achieve desirable goals deserve no special compensation.

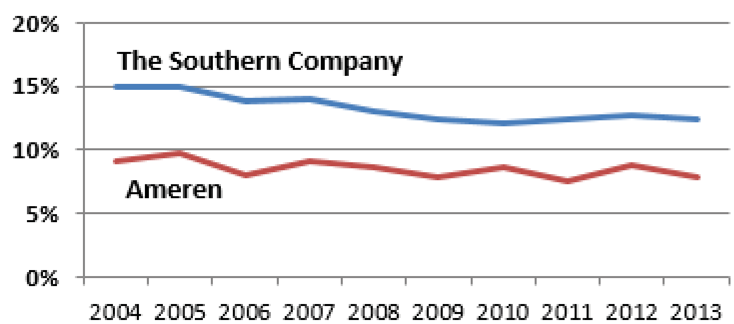
Cost of equity for utilities: an illustrative example

To set the stage for a discussion of the cost of equity, we start with a reference to the return on equity. Figure 1, below, shows the returns on equity for two utilities: Ameren, a Midwest utility, and the Southern Company, a holding company consisting of several major Southeast utilities.

Figure 1. Earned Rates of Return

(Returns on Equity)

Source: The Value Line Investment Survey



Over this period, the Southern Company earned on average 13.1 percent; Ameren earned on average 8.5 percent, or 460 basis points less than the Southern Company. So which company is expected to produce higher returns for its ***investors*** going forward?

Even though their returns on equity are noticeably different, since the risks associated with investing in the Southern Company's stock and Ameren's stock are about the same (both

[30] Steven Kihm, "Rethinking ROE," *Public Utilities Fortnightly*, August 2011.

are electric utilities with a *Value Line* safety rank of two),[31] the market will price their securities using the same cost of equity, which will in turn drive long-run expected stock returns to the same level.

That market result is illustrated by a comparison of the utility stock prices to their corresponding book values. The Southern Company trades at 1.9 times book value; Ameren trades at 1.4 times book value.[32] That is to say if you want to own a share of the Southern Company's stock, you have to pay $1.90 for every $1.00 of book value. In simple terms, this dilutes that 13 percent book return to about 7 percent.[33] Ameren's lower return is diluted less ($1.40 for every $1.00 of book value) than is the Southern Company's. This market action makes the expected returns (dividends plus capital gains) on the Southern Company's stock and on Ameren's stock are essentially the same. Put another way, new investors looking to buy utility stocks shouldn't expect to make more money by investing in companies with high returns on equity than they can by investing in companies with low returns on equity. The market will price the stocks to eliminate such easy pickings.

The investment advisory firm Morningstar provides estimates of the cost of equity in line with finance principles. When looking at Ameren's regulated operations in Illinois and Missouri it notes:

> At the regulated utilities, we forecast their $8.3 billion capital investment program will lead to 6% rate base growth through 2018. ***We use a 7.5% cost of equity*** and a 5.8% weighted average cost of capital in our discounted cash flow valuation.[34]

With respect to the Southern Company Morningstar notes:

> We are raising our fair value estimate to $47 per share from $46 after recalibrating our capital cost assumptions to better align with the returns equity and debt investors are likely to demand over the long run. ***We now assume a 7.5% cost of equity****, down from 8%*. This is lower than the 9% rate of return we expect investors will demand of a diversified equity portfolio, reflecting Southern's lesser sensitivity to the economic cycle, and lower degree of operating leverage.[35]

As expected, the cost of equity is the same for the two similar-risk stocks. In a world where the S&P 500 is expected to produce long-run returns of eight to nine percent, and where corporate bonds yield four to five percent, a cost of equity estimate of 7.5 percent for utilities makes perfect sense. The fact that it is well below the typical authorized return for utilities is not necessarily a problem. In fact, such a relationship is required if the aim is to incent utilities to make investments.

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[31] The *Value Line* safety ranks range from 1 (lowest risk) to 5 (highest risk).

[32] Source: *The Value Line Investment Survey*.

[33] The actual effect of the market price on the expected stock return is a bit more complicated, but this simple division makes the principal point.

[34] Andrew Bischof, "Attractive transmission and Illinois growth opportunities are set to drive earnings," *Morningstar*, March 3, 2015.

[35] Mark Barnett, "Southern's regulatory environment remains the envy of many peers despite current regulatory risks," *Morningstar*, February 23, 2015.

Figure 1 shows historical returns on equity for the Southern Company and Ameren. But financial markets look forward. *Value Line* projects that over the next three to five years the Southern Company will earn 12.5 percent on equity and Ameren will earn 9.5 percent. Combining these estimates with Morningstar's cost of equity estimates, we see the value engines for both utilities:

- The Southern Company $(r - k) = (12.5\% - 7.5\%) = 5.0\%$
- Ameren $(r - k) = (9.5\% - 7.5\%) = 2.0\%$

Both utilities will create investor value when they make plant investment because investors expect those investments to earn more than the cost of equity. The Southern Company creates more value per unit of investment, but Ameren's two percentage point net gain on investment is still quite attractive to investors.

It costs Ameren 7.5 percent to raise equity capital from new investors; it earns 9.5 percent by investing that capital. The excess return above the cost of equity inures to the benefit of existing investors, even though they provide no new capital. That is, the existing investors skim two percentage points of value off the new investors' capital.

The mechanism transferring returns from the new investors to the existing investors occurs not through the accounting statements, but through the bidding up of the stock price associated with the opportunity to invest in projects with returns in excess of the cost of equity. The fact is that Ameren, or any other utility that earns a return in excess of its cost of equity, doesn't even have to start construction to generate these windfall gains to its existing investors. Once the opportunity appears, long before the utility raises new capital, the existing investors capture the net benefit though a capital gain on the stock.

> An *opportunity* to invest in a project offering more than the cost of capital generates an immediate capital gain for investors. This is a windfall gain, since it is realized *ex ante*.[36]

When new investors provide capital to the utility they must pay that higher stock price. The existing investors have already benefitted from that stock price change. That is how firms create value for their investors. The value goes to the existing investors, not the new ones.

VALUE DESTRUCTION

While utilities today have incentives to invest, such was not always the case. In the early 1980s authorized rates of return for utilities were in the 13 to 15 percent range, with earned returns being closer to 10 to 12 percent.[37] The cost of debt (which is lower than the

[36] Stewart C. Myers, "The application of finance theory to public utility rate cases," *Bell Journal of Economics and Management Science*, Spring 1972.
[37] *Moody's Public Utility Manual*.

cost of equity) reached levels in excess of 16 percent.[38] Utility stock prices traded as low as half of their underlying book values.[39]

Clearly, the return on equity was less than the cost of equity during this period, creating a disincentive for utilities to make investments. Under these conditions, every dollar the utilities invested tended to increase profits (which depends only on having a positive *r*), but it also caused their stock prices to decline (because *r* was less than *k*). At the time, this raised concerns that rose all the way to Congress about a bias *against* utility investment and led to debate about the possibility of Federal intervention to remedy the problem.

> The nation's electricity supply could become less cost-effective if regulatory incentives continue to <u>bias utilities away from capital investments</u> regardless of their technical or economic merit. Although state regulators have the primary responsibility for the financial incentives of the electric utility industry, the Congress might consider several options to move the electric system toward greater economic efficiency.[40] (Emphasis added.)

This reinforces the notion that the inputs to the value engine are not fixed, but rather change over time. In some periods, utilities had an incentive to invest (which is the case today) while in others they had a disincentive to do so (as in the late 1970s and early 1980s). They key question that utility managers must face when making long-term investment decisions today is what will the *r* – *k* relationship look like over the next several decades.[41]

III. HOW REGULATORS CAN USE THE SHAREHOLDER VALUE ENGINE TO CREATE VALUE FOR CUSTOMERS AND SOCIETY

Regulators can provide opportunities for higher returns on desirable investments, which will increase *r*, or make it less risky for utilities to make desirable investments, which will tend to reduce *k.* Conversely, if utilities take actions that produce results that are contrary to society's values, regulators can take actions that reduce *r* or increase *k*, narrowing or even eliminating the value creation opportunity. Thus the financial construct provides a simple but powerful means of using value-based principles as a regulatory tool to promote desirable outcomes and discourage unattractive ones.

Example: Incentive rates of return

Assume that regulators want a vertically-integrated utility to invest in clean energy resources and to shy away from pollution-intensive generation. The regulator issues the following policy:

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[38] U.S. Federal Reserve Board http://www.federalreserve.gov/releases/h15/data.htm

[39] A. Lawrence Kolbe, James A. Read, Jr. and George R. Hall, *The Cost of Capital: Estimating the Rate of Return for Public Utilities*, MIT Press (1984).

[40] Congressional Budget Office, *Financial Condition of the U.S. Electric Utility Industry*, March 1986.

[41] Steve Kihm, Jim Barrett and Casey Bell, "Designing a New Utility Business Model? Better Understand the Traditional One First," American Council for an Energy Efficient Economy Summer Study, August 2014.

- Fossil fuel-based resources will receive a return on equity of ten percent.
- The regulator will allow an 11 percent return on clean energy resources.

Does that create an incentive to add clean energy resources? We can't be sure without further investigation. The first question we must answer is what is the cost of equity? For simplicity's sake, we start with the assumption that the market views both resources as having the same risk. We estimate the cost of equity to be eight percent. Now have we created an incentive for the utility to procure renewable resources rather than fossil fuel resources?

The analysis starts to get complicated because a central station wind facility may not be a perfect substitute for a coal plant. We may need to assemble a portfolio of resources to offset the services provided by the coal plant. Assume the coal plant requires $500 million of investment.[42] The utility would earn ten percent on that investment. We can displace that resource with a combination of a wind farm and a combined cycle gas plant (or another source of flexibility, such as price-responsive demand). The cost will be $200 million for the wind farm, which will earn 11 percent and $150 million for the combined cycle unit, which will earn ten percent (it too is a fossil fuel plant).

Rather than calculate the full cash flow stream, let's examine the basic problem conceptually by looking at the first year returns under an *r* – *k* framework.[43]

Investment Type	***Initial Cost***	***x***	***(r – k)***	***=***	***First year returns***
Coal	$500,000,000	x	(0.10 – 0.08)	=	**$10,000,000**
Alternative:					
Wind	$200,000,000	x	(0.11 – 0.08)	=	$6,000,000
Gas	$150,000,000	x	(0.10 – 0.08)	=	$3,000,000
Total				=	**$9,000,000**

Even though the utility earns a higher return on the renewable portion of the alternative proposal, the utility creates more value ($10 million is bigger than $9 million) for its existing investors if it builds the coal plant *for one reason alone*—the coal plant is more capital intensive.

Note that investment decisions designed to increase value depend on comparison of absolute ***dollar figures*** not ***rates of return***. Viewing rates of return in isolation ignores the other critical driver of value—the size of the investment.[44] Many in regulatory circles focus solely on rates of return as the value driver, suggesting that investors would prefer that the utility invest in a smaller plant that earns an 11 percent return rather than building a larger

[42] In these examples we assume 100 percent equity financing.
[43] Note: the investment provides a stream of revenue over a number of years. This differs from other types of performance incentives that might only be provided for a single year.
[44] See Robert C. Higgins, *Analysis for Financial Management*, McGraw-Hill (2011).

plant that earns a ten percent return. That is simply incorrect and we must reject that notion if we are to create effective incentives for utility management.[45]

Under the original formulation, the utility still has the financial incentive to build the coal plant. The regulator could remedy this situation in one of two ways. The first, more obvious way, is to raise the return on the renewable asset. If the incentive rate of return was raised to 12 percent, we would have:

Investment Type	***Initial Cost***	***x***	***(r – k)***	***=***	***First year returns***
Coal	$500,000,000	x	(0.10 – 0.08)	=	**$10,000,000**
Alternative:					
Wind	$200,000,000	x	(0.12 – 0.08)	=	$8,000,000
Gas	$150,000,000	x	(0.10 – 0.08)	=	$3,000,000
Total				=	**$11,000,000**

Because $11 million is greater than $10 million, the alternative proposal creates more value for the existing investors. Still, it is useful to note that the difference in the rates of return will need to grow in order to overcome larger differences in cost between different resource types. For example, if the wind plant scenario could rely on price-responsive demand rather than natural gas for balancing, the total cost in the clean energy scenario might be even lower—say $200 million for the wind facility plus $50 million for the demand management program. If the utility earned the same amount on the demand program as it did on the wind investment, there would be no material difference between investing in coal or clean energy for the utility. Thus, the incentive rate of return would need to climb past 12 percent in order to tip the scales in favor of the clean energy portfolio.

There is yet another policy lever here. The regulator cannot set the cost of equity (the market sets it), but the regulator can affect it. For example, it could pre-approve recovery of the wind plant, perhaps allowing for full cost recovery within a pre-determined range of deviations from the initial cost estimate, while keeping the potential recovery of the fossil plants subject to prudence reviews. This decreases risk for the wind plant investment relative to the coal plant.

Assume that the market reacts favorably to such a move, reducing the cost of equity for the wind plant from eight to seven percent. The fossil plants are subject to the traditional approach so the cost of equity for those resources remains the same. We see that we don't need to increase the return on equity to 12 percent under this scenario, but rather can keep it at the original 11 percent level, and the utility will already prefer the wind alternative.

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[45] This is especially relevant when considering investments in demand-side management, which often offer comparable service to supply side investments, but cost several times less.

Investment Type	***Initial Cost***	***x***	***(r – k)***	***=***	***First year returns***
Coal	$500,000,000	x	(0.10 – 0.08)	=	**$10,000,000**
Alternative:					
Wind	$200,000,000	x	(0.11 – 0.07)	=	$8,000,000
Gas	$150,000,000	x	(0.10 – 0.08)	=	$3,000,000
Total				=	**$11,000,000**

This example demonstrates that the cost of equity depends on the risk of the ***asset***, not the average risk of the ***firm***. Therefore in this case, not only do we have different returns on equity for the same company, we also have different costs of equity.

While investors must be compensated for risk, not every action must be rewarded. The regulator could lower the return on fossil fuel plants to the eight percent cost of equity. That return is still compensatory—it reflects the risk of the investment. But there is neither an incentive nor a disincentive to add the asset.

Investment Type	***Initial Cost***	***x***	***(r – k)***	***=***	***First year returns***
Coal	$500,000,000	x	(0.08 – 0.08)	=	**$0**
Alternative:					
Wind	$200,000,000	x	(0.11 – 0.07)	=	$8,000,000
Gas	$150,000,000	x	(0.08 – 0.08)	=	$0
Total				=	**$8,000,000**

Now the clean energy resource portfolio is clearly preferred.

Note that if we set the return on equity equal to the respective costs of equity for all assets, the utility cannot create investor value with any of them.

Investment Type	***Initial Cost***	***x***	***(r – k)***	***=***	***First year returns***
Coal	$500,000,000	x	(0.08 – 0.08)	=	**$0**
Alternative:					
Wind	$200,000,000	x	(0.07 – 0.07)	=	$0
Gas	$150,000,000	x	(0.08 – 0.08)	=	$0
Total				=	**$0**

If regulators set the rate of return at the cost of equity, writ large, utilities would be indifferent as to whether they ever built another asset. They would not object if competitors captured all future asset growth opportunities. Does that reflect the reality of utility markets today? If it doesn't, then regulators must be setting returns on equity above the cost of equity, just as Morningstar, and a host of other financial experts, suggest must be the case.

In the example where the coal plant investment creates no value, making the investment would increase profits by $40 million per year ($500 million x 8.0%). That's a lot of money. But investors could have made that same $40 million investing in securities of other companies. The utility is therefore no more attractive to investors than it would be if it did not make the investment. Its stock price therefore does not change based on whether or not the utility makes the investment.

For investors, it's all about value, not profit. If utilities can create shareholder value by investing in certain assets, but can only tread water in a financial sense if they invest in others, utilities will seek out the value-creating resources. This takes us back to Kahn. It is not appropriate that ***all utilities*** earn returns in excess of the cost of equity on ***all investments***. Our goal should be to allow such returns **only on investments that help to deliver value to customers and achieve public policy objectives**.

Example: Performance-based ratemaking

Another approach to value creation involves moving away to some extent from rate base regulation towards a performance-based approach. Performance—not investment alone—is the way that most other industries achieve profitability. There is substantial literature on this subject and a full discussion of it is beyond the scope of this paper,[46] but we describe some of the major features here.

The regulator sets a base revenue amount that the utility can collect. It also sets performance targets, such as reducing air emissions from power plants to levels below a threshold figure. If the utility achieves the pre-determined goal, it can collect more revenue from customers. The upper bound of this incentive is set by an estimate of the value of these outcomes to society. To the extent that the extra revenue exceeds the cost of meeting the target (including the cost of any equity raised), the utility would create value for its existing investors. This performance revenue should not come in the form of basis point adjustments to the utility's overall rate of return – the revenues should be paid to the utility separately upon achievement of the performance objectives.

If the performance incentives are *not* in the form of an adjustment in the utility's rate of return, this approach makes no distinction as to whether the utility achieves the target by investing capital or by taking some other course of action. For example, if the utility switches vendors to obtain a cleaner fuel supply, as many utilities in the 1980s and 1990s

[46] See e.g., Mark Newton Lowry, Matthew Makos and Gretchen Waschbusch, *Alternative Regulation for Alternative Utility Challenges*, Edison Electric Institute, January 2013. Sonia Aggarwal and Eddie Burgess, *New Regulatory Models*, Western Interstate Energy Board, March 2014. Melissa Whited, Tim Woolf, and Alice Napoleon, *Utility Performance Incentive Mechanisms*, Synapse, March 2015.

did by moving from high-sulfur eastern coal to low-sulfur western coal to reduce SO_2 emissions. Under traditional rate base regulation, if there is no capital investment, then such actions do not benefit the utility investors because all direct rewards flow from rates of return on capital investments.[47] Expenses are pass-throughs.

But under the performance-based approach, the utility can create value for investors with either capital expenditures or other actions. The financial reward depends on the outcome, not the means of achieving it. The extra revenue earned for successful implementation flows to the bottom line, effectively increasing *r*. ***If the cost of equity remains the same as does the investment scale***, the higher profit creates investor value. Note again, though, that looking solely at the profit does not determine whether value is created or management is motivated. It's all about the joint effect of risk (*k*), return (*r*), and scale (the size of the investment).

Example: Setting a standard as a legal requirement

Incentive rates of return and performance-based rates lend themselves to providing positive financial rewards to utility shareholders in exchange for valued service. In some cases positive rewards ("carrots") may not be sufficient to fully align utility actions with societal interests, and a "stick" approach may be needed to complement positive incentives.

This becomes readily apparent when considering investments in demand-side energy efficiency. Energy efficiency (EE) investments frequently cost several times less than supply-side investments and thus can yield significant value to customers and society when used as an alternative to those supply-side resources. However, these investments provide little to no value for utility investors.

To overcome this, regulators have tried offering performance incentives for achieving energy efficiency goals or (less often) allowing EE investments to be rate-based.[48] The following example illustrates a comparison between an investment in a 550 MW coal power plant and 550 MW of energy efficiency.[49] In this case we assume that the energy efficiency is allowed to be rate-based at an incentive rate of return (r) equal to 11% and we also assume that the risk profile of the two investments (which determines k) is identical.

Investment Type	***Initial Cost***	***x***	***(r – k)***	***=***	***First year returns***
Coal	$500,000,000	x	(0.10 – 0.08)	=	**$10,000,000**
Efficiency	$100,000,000	x	(0.11 – 0.08)	=	**$3,000,000**

[47] Non-capital-related activities could provide indirect benefits—and they could be substantial—if they reduce investors risk.

[48] Since energy efficiency investments are not physically owned by the utility they offer no collateral value, and must be treated as a "regulatory asset." From an accounting perspective, this introduces certain limitations on the ability to capitalize energy efficiency, typically restricting the lifetime of such assets to less than five years.

[49] This assumes new coal plant costs ~$130/MWh at a capacity factor of 80%, and energy efficiency has a first year cost of saved energy equal to $103/MWh.

It's readily apparent from this example that energy efficiency does not provide comparable earnings to investors as a coal plant. Thus, despite its significant societal value, energy efficiency may not be embraced by utility managers due to the smaller scale of the investment opportunity.

As an alternative to incentive rates of return, performance incentives can be linked to the level of energy efficiency investment or the related benefits in a given year. However, performance incentives that are offered on an annual basis do not provide a long-term stream of revenues over the life of the asset in the same way that a capital investment would. Incentives also need to be considered in context – a small performance incentive might matter more to a slowly growing utility with little investment opportunity whereas even a large incentive may be unattractive to a quickly growing utility with lots of investment opportunity.

Given all of this, what are the options for regulators to capture the societal value that EE can provide? They could attempt to raise the EE performance incentive (or ROE if rate-based)—however it may need to be raised very significantly to achieve comparable earnings. Raising the value of the incentive will also tend to diminish the value to customers. In the example above, the rate of return could be significantly increased to 18 percent to make it comparable, however, that represents a significant transfer of wealth from ratepayers to utility shareholders that is unlikely to be accepted by many regulators or ratepayer interest groups. An alternative solution (that has been adopted in many states) is to set a standard—a legal requirement that establishes the minimum level of energy efficiency a utility is required to achieve (e.g. an "Energy Efficiency Resource Standard").

In the case of a standard, the connection to the r-k value engine can be readily understood if failure to meet the standard leads to a financial penalty. However, even in cases where there is no explicit penalty, a failure to meet the standard might introduce additional regulatory risk that would tend to increase k across utility investments.

THE INCENTIVE PLAYBOOK

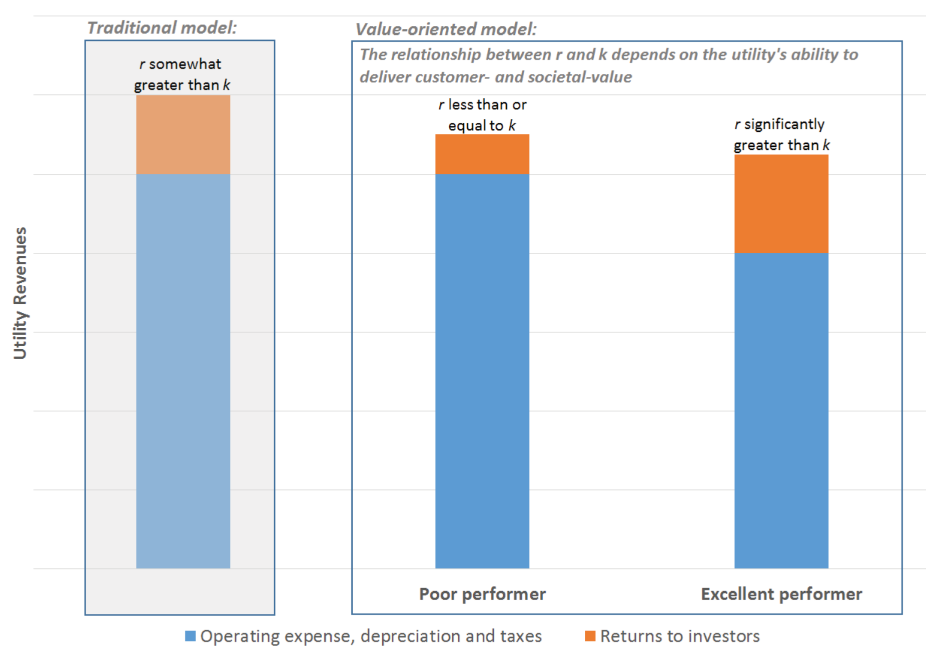
When regulators set *r* greater than *k*, they create incentives for utilities to generate value for existing investors, and the smart utility makes investments to take advantage of that gap. When the gap between *r* and *k* is positive, shareholder returns can be increased via all investments under traditional rate of return regulation, or via customer- and value-creating investments under performance-based approaches. Policies that change utility risk profiles, which in turn affect the cost of equity,[50] can affect value as well. But regulators must also be cognizant of scale differences between resources when setting incentive rates of return or establishing other utility performance incentives. In some cases, the difference in scale between traditional investments and value-creating investments may be too great

[50] Not all risks that a company faces affect the cost of capital. See Koller, *et al.*, p. 34.

to overcome simply through performance incentives tied to a variable rate of return. In these cases, as noted in the examples above, it will be especially important to explore offering cash incentives or setting a standard.

Incentives should cut both ways. While utilities that perform well in terms of meeting social objectives should receive rewards (returns in excess of the cost of equity), conversely those that fail should face consequences (returns either at or below the cost of equity). Figure 2 provides an illustrative example of the difference between utility earnings under the traditional regulatory framework (left-most bar) and utility earnings under a new value-oriented framework that connects the difference between *r* and *k* to the utility's ability to deliver customer- and societal-value. The poor performing utility under the value-oriented framework (middle bar) is assumed to create less value for customers and society, thus it earns less overall and also has smaller shareholder returns. The utility that performs excellently (right-most bar) creates substantial value for customers and society—partially through organizational efficiency, which saves money overall. In this illustrative example, we assume that savings are shared between shareholders and customers, so the excellent performer's total earnings are still less. But more important, the larger gap between *r* and *k* means that more value is created for the shareholders of the excellent performer than either the poor performer or the traditional utility.

Figure 2. Investor Value Should Depend on Performance



Firms that repeatedly fail might encounter financial difficulty under such a value-oriented model, but that would invite more successful firms to acquire the poor performers. Acquisitions that alter the management structure of a utility will not necessarily impact the day-to-day activities of its operations in a way that would jeopardize safety or reliability, so we should also not fear the consequences of the failure of some underperforming utilities.

Instead, we should expect such occurrences, i.e., winners and losers, under a more value-focused approach.

Shareholders and their agents—utility managers—need to see that the financial value engine can work to support adequate returns on investments as the electricity system, the regulatory model, and utility incentives evolve. Risks and rewards of any new system for compensating utilities must be ascertainable, and not radically more difficult to comprehend than current approaches for investment analysts. The good news: current approaches set a relatively low bar. Today's system determines utility compensation via rate cases that typically happen after the utility has already made its investment decisions, meaning that the investment is completely at risk until a rate case order is issued. New approaches to compensation under consideration in New York and elsewhere suggest that these investment risks can be managed better, and possibly more transparently from an investment analytical perspective—and that risk can be used as a tool to guide utility investment toward assets that customers and society value. By identifying customer values, planning up front, and fostering more stakeholder buy-in, utilities can meet society's goals and give customers more value for their money. If this results in more supportive regulators and better satisfied customers, it's possible that risks to capital could even decrease.

The New York Commission's recent REV order lays out the potential for new compensation systems to respond to the tough situation in which utilities find themselves now:

> Under REV, utilities will respond to disruptive trends by adding value to various activities in the evolved power economy, with the concomitant opportunity to earn revenues from new service offerings and the ability to raise capital on reasonable terms.[51]

But how should new regulatory models address the difference in scale between the investments of the past and the new products and services of the future? If the advice of analysts at Synapse Energy Economics is followed, utility incentives will start small and grow over time as they prove themselves.[52] This suggests that—at least for a time—the scale of incentives from the old construct will be larger than the incentives associated with "new utility services." In part, this additional opportunity for earnings could be explained by the utility industry being in transition—times of transition are more risky than times of stability. Change brings new risks.

Since staying with the existing system of compensation seems unlikely given the accelerating motivations for change in the utility sector, investors must begin to analyze new risks and accommodate them in their required returns. Will the logic that supports these small, but growing, new incentives, provide enough support for utilities and their investors to offer "reasonable" or low cost capital to fund investments in the innovations

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[51] State of New York Public Service Commission. Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. *Order Adopting Regulatory Policy Framework and Implementation Plan.* February 2015. <http://www.askpsc.com/askpsc/file/rev_order_feb_26_2015>

[52] Whited, Melissa, Tim Woolf and Alice Napoleon. *Utility Performance Incentive Mechanisms: A Handbook for Regulators.* Prepared by Synapse Energy Economics for the Western Interstate Energy Board. March 2015. <http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf>

that are promised? Will investment under circumstances of change and new risks be sufficient to maintain or improve utility capital flows until the new incentives scale? Only time will tell. There is no justification for equity returns in a risk free environment. The alternative to change for utility managers and shareholders is not appealing— regulatory panic induced by the threat of an industry death spiral and endless zero sum game disputes.

Today's context suggests that new utility revenue sources can eventually scale up to match and surpass current sources. Industry changes are an occasion for investment risks taken to be rewarded with commensurate returns. For example, customer uptake of rooftop solar typically exceeds even optimistic projections, and with falling costs and new financing mechanisms like leasing in play, there is ample evidence that many customers want access to these new technologies. At the same time, utility energy efficiency programs have produced enough energy savings to have lowered or eliminated growth for many regions, providing space to retire old generators and less pressure to invest in new ones. In some circumstances, bulk power renewable energy is available at prices below system average generation costs. Most states' renewable energy standards are being met, or exceeded, at reasonable costs, and sometimes at a savings to consumers, so there is hope that new, clean generation technologies like solar and wind can be implemented to meet goals of diversity, environmental performance, and freedom from fuel costs, risks, and liabilities. Clean energy technologies have attracted very substantial investment interest and some of them, like wind, solar, and efficiency, are scaling up quickly. These new and improving technologies, which support lower costs and system efficiencies, can bring more value to shareholders if utilities can find and play their appropriate roles in providing these new products and services.

These important elements of the system we see emerging today suggest that the promise of new utility incentives can be attained, adding both new utility revenues and potentially more and more reasonably priced investments as regulators and state policy makers adjust utility incentives to align with societal values. Any new system for utility incentives must respect the utility value engine: r must exceed k. But a new system of utility compensation need not be perfect at the start, it only needs to improve upon the current flawed one.

IV. CONCLUSIONS FOR REGULATORS

Based on the ideas laid out in this paper, here are five steps that can transform regulation from a backward-looking accounting exercise that incents capital investment into a forward-looking system that creates more societal value:

1) Consider which societal values are most important for the regulated electric sector in your region. Seek input from many stakeholders and drive toward quantitative metrics for performance in each category. Common examples of societal values include:
   - Resilience: how often do customers lose power? How many people are affected? Are critical services (hospitals, fire stations, etc.) able to stay up and running in emergencies? How quickly does the system recover from extreme events?
   - Affordability: can customers obtain electricity service at a reasonable cost?
   - Environmental performance: how much pollution is the electric system emitting?
   - Safety: does the electric system deliver high quality service while keeping its workers and citizens safe?
2) Improve estimates of the utility's cost of equity so that they reflect the necessary markup on money they receive from shareholders. This should set the *lower bound* for the return on equity allowed to utilities.
3) Research the benefits in each of the value categories – estimating total benefits can set an upper bound for the incentives offered to utilities that deliver these values.
4) Consider the difference between the cost of equity and the current return on equity – this is the money that motivates shareholders and utility management. It may be appropriate for part of that difference between earnings and cost of equity to be tied to capital investment, but regulators may also choose to use part of it to tie earnings to performance in the value categories identified in step one.
5) Consider alternative ways to deliver the performance portion of utility revenues, aside from adjustments to rate of return. Adjustments to return on equity maintain the underlying incentive to expend capital, but direct shareholder incentives (or, better yet, "shared savings" programs where some of the incentive goes to the shareholder and some flows back to the customer) may provide a more direct connection to performance in the value category intended for the policy to achieve.

Utility shareholders and their agents—utility executives—need to see that the financial value engine can work to support adequate returns on investments as the electricity system, the regulatory model, and utility incentives evolve. If regulators follow these steps, they can give utilities that assurance, and put the power system on track to begin delivering more value to customers and society.

(END OF APPENDIX B)