Electricity Advisory Committee

TO: **Honorable Patricia Hoffman, Assistant Secretary for Electricity Delivery and Energy Reliability, U.S. Department of Energy**

FROM: **Electricity Advisory Committee (EAC)**
Richard Cowart, Chair

DATE: **September 24, 2014**

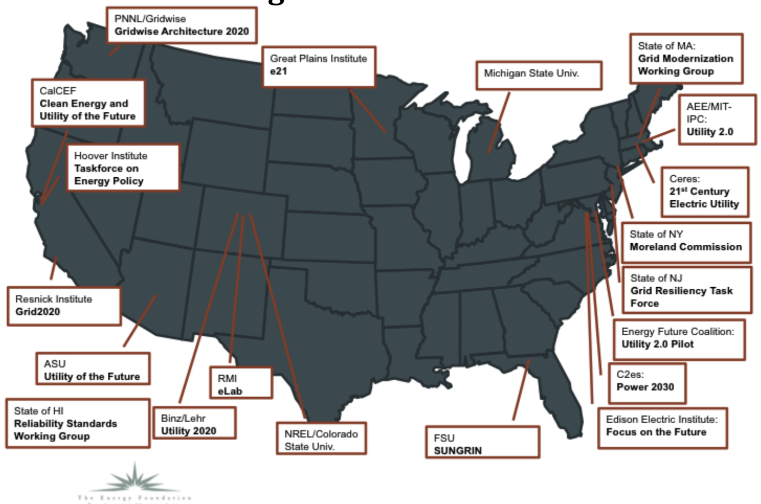
RE: **Recommendations Regarding Emerging and Alternative Regulatory Models and Modeling Tools to Assist in Analysis**

Introduction

For closely linked reasons (e.g. proliferation of distributed generation, advances in technology, desire to integrate renewable generation, customer empowerment, demand destruction, resiliency and security, etc.), state utility regulators and numerous third parties nationally (and, indeed, internationally) have, with vigor, demonstrated the inclination to devote time, energy, effort, and resources to focus on notable aspects of the utility business model.

Iterations of these explorations (e.g. *Utility of the Future, Energy 2.0, Grid Modernization, America's Power Plan, Utility 2020, Taskforce on Energy Policy, Power 2030, Hawaii Reliability Standards Working Group, the Massachusetts Grid Modernization Initiative, the New York Public Service Commission proceeding(s), and the western State-Provincial Steering Committee's New Regulatory Models and Performance Regulation studies)* have recently and forcefully entered the lexicon. These efforts are cast variously – from the breathlessly visionary to the pragmatic and plain. Some of these efforts are academic, some policy proscriptive, some exploratory – filled with ideas, ideology, and energy – these working projects are of core concern to those seeking to understand the directional trend of power provision within the United States.

Figure 1. Initiatives



The Electricity Advisory Committee (EAC) observes each of these initiatives with great interest, and broadly, proffers this paper in support of the continued exploration of the concepts to which these efforts are devoted. In addition, herein we offer our recommendations to the Department of Energy (DOE or the Department) with the intent to assist in enhancing the efficacy of these many efforts. The recommendations include suggestions for white papers and evaluations, the development or expansion of modeling tools, and the use of DOE's convening authority and financial sponsorship.

Section 1: Summary of Regulatory Model Initiatives

Contained in Figure 2 is a reference to a few of the ongoing regulatory/utility business model initiatives both nationally and internationally. The details of these initiatives are more fully described in Appendix 1 and are intended to provide DOE with a snapshot and background on how a variety of entities are looking at new ways for utilities and regulators to address emerging requirements in the electric industry sector.

Figure 2

Initiative	Reference
Utility of the Future	http://www.utilityofthefuturecenter.org
Energy 2.0	http://energyfuturecoalition.org/What-Were-Doing/Utility-20
America's Power Plan	http://americaspowerplan.com http://americaspowerplan.com/site/wp-content/uploads/2013/10/APP-UTILITIES.pdf
Utility 2020	http://resnick.caltech.edu/grid2020.php
Hawaii Reliability Standards Working Group	https://puc.hawaii.gov/wp-content/uploads/2013/04/RSWG-Facilitators-Report.pdf
Massachusetts Grid Modernization Initiative	http://www.mass.gov/eea/energy-utilities-clean-

	tech/electric-power/grid-mod/grid-modernization.html
Australian Better Regulation reform program	http://www.aer.gov.au/Better-regulation-reform-program
NY PSC Direction to Staff to Initiate a Proceeding (Case No. 07-M-0548)	http://www3.dps.ny.gov/W/PSCWeb.nsf/All/26BE8A93967E604785257CC40066B91A?OpenDocument
British Ofgem RIIO Model	https://www.ofgem.gov.uk/network-regulation-–-riio-model?utm_source=Ofgem&utm_medium=website&utm_campaign=footer_block
Bipartisan Policy Center: Capitalizing on the Evolving Power Sector	http://bipartisanpolicy.org/library/report/capitalizing-evolving-power-sector-policies-modern-and-reliable-us-electric-grid
e21	http://www.betterenergy.org/projects/e21
State-Provincial Steering Committee (SPSC): New Regulatory Models and Performance Regulation studies	http://westernenergyboard.org/wp-content/uploads/2014/03/SPSC-CREPC_NewRegulatoryModels.pdf

Section 2: Emerging Requirements

The disparate interests of each state and its electricity regulators make it difficult to generalize, and therefore communicate to the Department, about emerging requirements in reliability, resilience and adaptation. These essential components of the regulatory compact – safe and adequate service at just and reasonable prices – have always been present to a degree, but how they are dealt with has varied state by state because of differing sensitivities to the costs to address them. The definition of 'safe' has been expanded in recent years to include environmental issues through both national and local standards imposed on fixed source emitters, such as power plants.

Depending on the perspective of the observer, these standards are undergoing either evolutionary or revolutionary change. Accordingly, a contribution by DOE to the foundational elements of a benefit/cost knowledge base to be utilized by state regulators would be most welcome. This should involve a focus on renewable and other clean distributed energy resources, as well as the incorporation of technological advances. This will enable decisions regarding new power station and related transmission to be viewed through a prism that would not necessarily vary from state to state. Even the Federal Energy Regulatory Commission (FERC) could also benefit from the development of such a benefit/cost analysis in addressing these issues at the federal level.

The Electric Power Research Institute's (EPRI) study of The Integrated Grid[1], made available to the public in February 2014 included its commitment to publish a benefit/cost analysis in April of 2014,[2] but it is not yet been made available. When it

[1] Electric Power Research Institute, The Integrated Grid: Realizing the Full Potential of Central and Distributed Energy Resources, Palo Alto, CA 2014

[2] " Phase II – This six-month project [following Phase I, the publication of The Integrated Grid] will develop a framework for assessing the costs and benefits of the combinations of technology that lead to a more integrated grid. This includes recommended guidelines, analytical tools and procedures for demonstrating technologies and assessing their unique costs and benefits" Ibid, p.6.

does become available, it might provide an important ingredient of a DOE-sponsored effort.

Definitions of reliability and resilience are often in the eye of the customer base. Within all customer classes there are differing perspectives from residential, commercial and industrial customers. In many respects, the latter two groups have made their own adaptation and related investments, because lost income from missing reliability and resiliency fixes the concentration of for-profit entities. Residential customers have traditionally been more tolerant or less assertive in addressing the interruption of their needs for electricity. Complicating matters, each state has its own methodology for both determining and reporting outages to the public, so there is no national standard for comparison – interstate rivalry being a useful tool in encouraging improvements.

Within an individual state, dramatically different standards of reliability between consumers are tolerated. Recent weather events have provided the most serious examples of disruptive events at the local level. Nationally, the disruptive effects of global climate change are of increasing concern to voters in the U.S.

In New York City, for instance, in the outages of 2006 due to overloaded distribution networks as a result of inadequate planning and extreme heat, as well as the aftermath of Superstorm Sandy, people in parts of Consolidated Edison's (Con Ed) territory were not only without power in their residence, but they were also deprived of transportation to their employment by subway. Service was restored more swiftly in the underground portions of Con Ed's territory than in its radial networks both because of the number of persons and businesses impacted and the difficulty of repairs and restoration in radial networks. In upstate New York, where winter snow provides many outages annually, the ratepayers who can afford it use generators to tide them over problems with reliability and resilience. Accordingly, there are different standards based on geography, density of population and the economics involved.

Finally, adaptation of improvements by each distribution utility again depends on the willingness of its regulator to approve funding for investment in technological advances and of customers to bear the costs. These enhancements would extend to enabling distributed generation, as well as to the related customer choice about the source of the electrons they utilize. In many respects the issues are similar in states that are part of an ISO/RTO and which are not. With the advancement of distributed generation, communications and related electricity usage management tools, the precision of demand management is progressing to a level where reliability improvement is not a matter of building more large-scale generation and related long-distance transmission, but of capturing the elements at our disposal now to gain the advantages of available change.

Consumers and regulators alike are also increasingly concerned with the vulnerability to mass disconnection resulting from the anticipated increase in solar photovoltaic (PV)-driven distributed generation penetration. Such vulnerabilities include frequency variation triggered by improperly designed interconnection rules, as well as a physical or cyber security event leading to system instability and load-shedding. Combined with the reliability concerns of ratepayers that arise from increasing dependence on consistently available electrons which enable their everyday lives, voters are requiring a changed approach and a greater level of focus that the Department's involvement could facilitate.

The customer concerns are reflected in an increase in customer engagement – an enhanced awareness of the information available and how to utilize it, either alone, by aggregating with others similarly situated or by working in conjunction with electricity service companies. Present throughout any consideration of change should be an awareness of the need to give customers choices of how to procure their electric service based on their needs and means. Low income customers are more likely to be renters whose utility bills are separate from their rent bill. Accordingly, they are less likely to benefit from the rewards and subsidies for distributed energy resources available to real estate owners and to be willing to shoulder the up-front costs.

There are still decisions that are always going to be the principal province of state legislators and regulators, such as the mix of fuel utilized in generation, including the requirement that a generator be able to use natural gas and oil as security against scarcity of a specific fuel and the need to preserve nuclear generation where appropriate, even if it is not the lowest cost source of electrons. Further enabled by communication improvements being made on a regular basis, those who pay the bills, impelled by financial and/or environmental motives, are making their positions known and requiring that attention must be paid.

The single most essential tool to reflect this change in customer engagement is rate case design. It is there that regulators "put their money where their mouth is" and demonstrate the extent to which they are willing to move to the next generation of the provision of electricity service. This is by no means an easy task for either state regulatory commissions or their staff. It literally requires a change in culture: rates must not be employed to discourage innovation in an industry where risk-taking is not favored. It must be done in a manner that does not discourage innovation while subsidies at the federal and state level are phased out as distributed energy resources approach grid parity. It also cannot have an adverse impact on less affluent customers. Striking a balance among these concerns could greatly benefit from as much informed and thoughtful consideration as can be brought to bear, including through the Department's contribution.

Next among the essential tools are interconnection rules that enable newly available resources to take their appropriate place in the provision of electrons both timely and at a reasonable cost. It is asserted that certain distribution utilities have imposed delays of up to six months for interconnection of some solar PV units, despite instructions from their commission to eliminate the wait times. From a cost standpoint, a western utility, faced with a significant increase in market penetration of solar PV, asserted in the press that the estimated cost to a homeowner for adding solar PV while staying connected to its grid would be between $40 and $80 dollars a month. Its regulator ultimately decided it would be less than $5 a month. Good planning and receptivity to changes and to the wishes of the people served can help remedy these approaches.

There are two examples of foundational elements of interconnection that are worth discussion. They could provide essential components of managing a distribution analog to an ISO/RTO. These tools could be key elements of the cost/benefit analyses that will engage state commissions as they approach changes related to distributed energy resources.

First, in New York's Reforming the Energy Vision proceeding, the Public Service Commission is considering a revised approach to advance distributed energy resources involving distribution utilities becoming Distribution System Platform Providers and a results-based regulatory framework.[3] It is clear that business architecture, standards and protocols must be developed so distribution management can operate effectively and transparently. These developments would not be specific to New York; rather, they would have national application. The results could benefit other states.

The California Public Utilities Commission opened a new rulemaking with the aim of integrating large amounts of distributed energy resources into the planning and operation of utility electric distribution systems.[4]

As the issues being addressed in the New York and California proceedings have potential national implications, discussions of such issues would benefit from DOE financial sponsorship and the Department's convening stature.

A second foundational approach is to enhance the efforts currently underway at the Illinois Commerce Commission to review an "open data access network" to enhance customer value by providing clear and transparent data upon which they can make choices about electric service. This, in turn, will inform decisions about interconnection. This effort also is not state-specific and could be enhanced by DOE sponsorship.

Both rate design and interconnection must be integrated with planning processes regionally as well as at the distribution level. As improvements in energy storage are added to this equation, the need for successful integration will only increase.

Obstacles to appropriate integration of distributed generation and other renewables into the existing grid range from a perceived threat to the current utility business model to engineering concerns at the level of both transmission and distribution networks, including how much credence should be given to distributed energy resources in dispatch and reliability analyses. This has been a subject of numerous studies at the ISO/RTOs. At the distribution level, to enable this integration to occur, states are exploring different

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[3] Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, *Order Instituting Proceeding,* New York Public Service Commission Case 14-M-0101 (April 25, 2014).

[4] In the Matter of Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resource Plans Pursuant to Public Utilities Code Section 769, *Order Instituting Rulemaking,* Public Utilities Commission of California Rulemaking 14-08-013 (August 20, 2014).

constructs. For example, New York is proposing a requirement of an ISO-like structure for distribution operated initially by incumbent utilities as a way of managing the disparate sources of distributed energy resources.

There is a need for acceptance of more rapid deployment of innovation. Yet this needs to occur in a field which is dominated by the appropriate need for certainty of reliability of delivery. Many, if not most, of the senior decision makers in this field had their training and careers dominated by reliability concerns and access, sometimes difficult access, to the capital needed to effect this certainty. The capital flows in an opaque fashion through transmission and distribution charges that are, intentionally or not, difficult for the public to comprehend. Expending these funds has not been easy to account for; the degree of both engineering and policy complexity involved accounts for much of this. Utilities, as monopolies, have sometimes believed that their most important constituency is their regulator, not their customer. However, the increasing sophistication of tools to enable change, coupled with the ease of access through the internet, makes traditional approaches unsustainable. The readily understood slogan used by advocates of solar PV, "don't tax the sun," illustrates how the public can push past the complexities and, in its mind, cut to the chase.

In effecting more rapid deployment, care should be exercised through rate design that it not be too rapid. A balance needs to be struck lest some elements get ahead of the providers and the customers ability to effectively utilize new tools. This is where pilot projects, again with the participation of the Department, can help with providing a factual foundation for decision-making. Demonstration and pilot programs can be an important means of providing research and development to help define the best choices.

Finally, distributed energy resources provide an additional and highly effective approach to the environmental concerns that are now a major part of the electricity marketplace. More than 20 years ago, California, in imposing energy efficiency standards in its building codes, provides an excellent example of the efficacy of distributed energy resources in meeting clean air standards apart from fixed source emission regulation. More effective implementation of change in the industry, aided by the Department's stature as a convener and its financial contributions, can further these – either evolutionary or revolutionary, but certainly much needed -- changes.

Section 3: Current Standard and Alternative Regulatory Models

Utility regulation is intended to replicate the pressures of competitive markets for services that are provided on a monopoly basis, ensuring that utilities provide at least adequate service and do not charge unreasonable or discriminatory prices. Indeed, "the single most widely accepted rule for the governance of regulated industries is to regulate them in such a way as to produce the same results as would be produced by effective competition, if it were feasible." [5]

For many decades the regulation of monopoly utility services typically has occurred through cost-of-service regulation (COSR). Established treatises on COSR are available from a variety of sources, and will, by and large, provide depth and breadth on the topic not possible for this paper.[6]

To set cost-of-service rates, state regulatory commissions often use a quasi-judicial administrative law process to convene interested parties (e.g. investors, customers, environmentalists, the utility etc.) to coalesce (or not) and ultimately approve by commission order a utility's ***required revenues*** and resulting ***rates***. This process establishes the total of all costs prudently incurred to provide service, then sets rates necessary to provide both a ***return of*** and ***on*** invested capital. Embedded within these processes are assumptions about the real world that may or may not prove true.

This overlay of real-world circumstance – where regulated utilities collide with market forces, state and federal policy changes, or other exigent matters – is where regulation has had to adjust time and again, to meet the emergent issue. Through these myriad adjustments, States have developed unique (and periodically timely) approaches that one might refer to as "regulatory adaptation."[7]

This regulatory adaptation can rightly be stated to rest on a continuum across the states, with its foundations in evolving state law. And, whether trended toward the vertically integrated utility model still served by very traditional COSR or the highly retail/wholesale competitive; states have, time and again, demonstrated flexibility and creativity in addressing highly dynamic circumstances.

Some of the adaptations to traditional cost of service ratemaking tend to provide greater support for new investment. These approaches might involve prior regulatory review of utility plans to align plans with regulatory objectives. They also might be conditioned on utility commitments to make specific improvements. Such alternative methods include:

[5] Alfred. E. Kahn, *The Economics of Regulation, Vol. 1* (New York: John Wiley & Sons, 1970) at 17.
[6] See, for example: *Principles of Public Utility Rates, James C. Bonbright (1961); The Regulation of Public Utilities, Charles F. Phillips, Jr. (1988); The Economics of Regulation, Alfred Kahn (1971); Electricity Regulation in the United States: A Guide*, March 2011, Regulatory Assistance Project
[7] Among the range of modifications to traditional historic cost-based regulation that have been adopted in some states are "decoupling" of sales and revenues, future test years, fuel adjustment clauses, trackers, riders, formula rates, securitization, integrated resource plans, construction work in progress, and others. For additional discussion of some of these developments, see, e.g. *Decoupling Case Studies, Revenue Regulation Implementation in Six States*, July 2014, Regulatory Assistance Project; *Cost of Service Regulation in the Investor Owned Electric Utility Industry: A History of Adaptation*, June 2012, Karl McDermott on behalf of the Edison Electric Institute, *Alternative Regulation for Evolving Utility Challenges: An Updated Survey*, January 2013, Pacific Economic Group Research on behalf of the Edison Electric Institute

- ***Annual rate cases with a forecast test year:*** In some jurisdictions, the utilities forecast their investment expenditures based on prior planning reviews. By using these forecast values in annual rate proceedings, the utilities and their regulators can better match costs and revenues to the prospective level of rates. However, frequent regulatory involvement can make this approach administratively burdensome. Examples in which this approach has supported investment include the Public Service Commission of Wisconsin with its biennial Strategic Energy Assessment and annual rate cases, and the Iowa Utilities Board's pre-construction approvals of new generation.

- ***Capital expenditure trackers*****:** A tracker is a separate rate-adjustment mechanism that allows for the recovery of specific costs outside of the conventional rate case process. Historically, tracker mechanisms were reserved for significant and volatile costs, such as fuel, which are largely outside of the utility's control. More recently, several states have permitted accelerated recovery of specific capital expenditures outside of a cost-of-service rate case. For example, Pennsylvania's Distribution System Improvement Charge allows accelerated recovery of costs associated with approved long-term infrastructure plans.

- ***Formula rates:*** In this approach, a specific formula for setting rates is established in advance by statute or a prior commission order. The utility then files its cost data and the information used to determine its allowed rate of return in a standard format. While the formula sets the types of cost that may be recovered, costs may be subject to review based on whether the expenditures were prudently incurred. Examples of formula rates include FERC's transmission rates and the Illinois Energy Infrastructure Modernization Act.

These approaches can support investment, but they can involve a high level of regulatory oversight. They also offer limited incentives for the utility to reduce its costs and share any cost savings with consumers. For example, capital cost trackers have been criticized for diminishing incentives to reduce waste and cost inefficiency and for allowing rate increases for the cost of new capital additions without considering countervailing cost reductions. Similarly, some regulators have criticized formula rate statutes on grounds that they limit regulators' ability to balance the interests of utilities and consumers and discourage cost efficiency and productivity improvements.[8]

Other alternative models are designed to provide strong incentives for electric utilities to reduce costs. These include:

- ***Multi-year revenue and price caps*****:** Under these models, changes in utility revenues or rates can be indexed to inflation and adjusted for a targeted rate of productivity improvements and any extraordinary events. Alternatively, the regulator might set annual step changes or freeze revenues or rates for the duration of the rate plan. These multi-year rate plans can promote cost reduction by enabling the utility to share in any cost savings and absorb cost increases

[8] K. Costello, "How Should Regulators View Cost Trackers," National Regulatory Research Institute (September 2009).

during the years covered by the plan. However, in the absence of strong reliability standards or incentives, they have been associated with a reduction in spending on operations and maintenance and an increase in the average duration of customer outages. In addition, unless the multi-year plan is tied to a reasonable utility business plan for new investment and changes in its operations, the revenue or rate cap may not match the rate levels needed for required capital investments.

- ***Sliding scale rate plans*:** In a few states, regulators determine a target return for the utility and set rates based on cost and revenue forecasts to achieve the return target, subject to pre-determined ceiling on rate increases. The regulator also sets a range of authorized earned returns. The utility's actual earnings are later reviewed, and if the earned returns are within the authorized range, the utility may retain or must absorb all or a share of any variance between its target and actual earnings. The opportunity to retain earnings within the authorized range provides an incentive for the utility to be efficient. However, if actual earnings exceed the authorized range, the utility may be required to return excess earnings to customers. Sliding scale plans also can incorporate performance incentives based on reliability, customer satisfaction, or other metrics.

The emergence of more fundamental alternatives to traditional cost-based regulation (with its focus on cost recovery as opposed to efficiency) has begun to establish a foothold in the regulatory genre. Relying on incentive ratemaking, long-term revenue or price caps, earnings sharing mechanisms, output-based performance metrics, and other customer centric results-based approaches – these ideas have begun to enter the discussion across states (and internationally) – and while evident change will take time to demonstrate conclusory outcomes, exploring the basis and opportunities in this effort is (in our estimation) worthwhile.

In the current environment, many utilities are facing investment to provide greater reliability, resilience, and security; integrate distributed and renewable resources; facilitate customer choices; and meet environmental requirements at a time of slowing growing or in some cases declining sales. At the same time, new technologies have the potential to make fundamental changes in utility operations. These forces are impacting the ability of COSR to match the pricing, cost efficiencies, value creation, and innovation that would be produced by effective competition, were such competition possible. And, they are leading to consideration of different alternative models. Some regulators are now considering the emerging class of "results-based" regulatory models. These alternative models are designed to balance different objectives, to provide both incentives for cost savings and support investments that provide value to customers and support policy objectives.

Section 4: Emerging Regulatory Models

Regulators in the U.S. have taken note of rate setting framework being implemented by the utility regulator in the United Kingdom (U.K.), the Office of Gas and Electric

Markets (Ofgem). The New York Public Service Commission Staff commented favorably on the U.K. model in its report in the New York “Reforming the Energy Vision” (REV) proceeding.[9] Ofgem is implementing an approach for regulating transmission and distribution companies called “RIIO,” or “**R**evenue set to deliver strong **I**ncentives, **I**nnovation and **O**utputs.”[10] RIIO is an incentive-based framework that seeks to mimic the effects of competitive markets by linking revenue to output metrics, innovation, and cost savings. It encourages transmission and distribution utilities to focus on delivering net long-term value to customers. RIIO’s major components include:

- Revenues set based on a review of the utility’s business plan: The revenue that the utility will be allowed to recover is set based on a review of the utility’s plan, including benchmarking of planned operating expenses and an engineering assessment of capital expenditures.

- Multi-year revenue cap: The multi-year plan provides an incentive for the utility to pursue efficiency improvements by providing the utility an opportunity to retain a portion of any cost savings. By extending the time period during which a rate plan would be in place from five to eight years, Ofgem sought to more closely align rate plans with utilities’ long-term planning and encourage innovation that would produce cost savings for customers.

- Cost savings shared with customers: RIIO includes an earnings-sharing mechanism with large sharing factors. To the extent a utility’s actual earnings exceed its authorized return, 50% to 60% is refunded to customers. Symmetrically, if costs are higher than anticipated and earnings fall below the authorized level, the utility may have to absorb up to 50% of the loss in earnings. The precise sharing percentages can vary among utilities based on the regulator’s assessment of the utility’s cost projections.

- Clearly defined results-based metrics and output incentives: Ofgem has proposed or adopted performance incentives related to:
    - The frequency and duration of outages: Incentives are based on studies of the value different customers place on uninterrupted service.
    - Customer satisfaction: Incentives may include an up to 1% up or down adjustment in revenue based on customer surveys, and an additional incentive of up to 0.5% of revenue based on an independent panel’s assessment of the utility’s stakeholder engagement practices.
    - Environmental impacts: Incentives may be based on reductions in line losses, the visual impact of power lines (undergrounding), and reductions in greenhouse gas emissions including leakage of sulfur hexafluoride (SF6), a

[9] NYS Department of Public Service, *Reforming the Energy Vision: Staff Report and Proposal*, Case No. 14-M-0101 (April 24, 2014).
[10] For additional information on RIIO see: Ofgem, *RIIO: A New Way to Regulate Energy Networks: Final Decision* (October 2010); Ofgem, *Strategy Decision for the RIIO-ED1 Electricity Distribution Price Control: Overview* (March 4, 2013); and C. Jenkins, *RIIO Economics: Examining the Economics Underlying Ofgem’s New Regulatory Framework,* Florence School of Regulation Working Paper (June 2011).

potent greenhouse gas used in insulating transformers and other electrical equipment.
- Social obligations: Incentives address issues of fuel poverty and assisting vulnerable customers in accessing available services.
- Timing and efficiency in connecting customers: New customers purchase electric service from competitive suppliers. Incentives are based on utilities' performance in connecting customers.
- Meeting worker and public safety standards.

Incentives can be bi-directional, either increasing or decreasing earnings. The regulator may adjust output metrics and incentives during the rate plan with adjustments applied to the remaining years of the plan.

- Application of the revenue cap to total expenditures: At the start of the rate plan, the regulator fixes the percentage of revenue that will be recovered in each rate year with the residual being capitalized. Once this ratio is established at the beginning of the plan, it does not change based on the nature of the utility's actual expenditures. The utility has flexibility to take advantage of learning and modify its spending plans to meet its output objectives as efficiently as possible. An annual rate adjustment aligns revenue to authorized levels.

- Innovation programs: Ofgem is funding innovation programs for piloting large projects, small projects, and the rollout of proven solutions, which enable third parties to partner with the utility to deliver cost savings, carbon reductions, or other environmental benefits. An expert panel will disburse multiple rounds of funding.

- Limited revenue reopeners: While Ofgem's general approach is to require utilities to manage business risks, it may define circumstances in which rate plans may be reopened in order to address changes in underlying economic assumptions or unknowns such as new cyber security requirements.

- End-of-period adjustments: Ofgem will track asset health and may implement an additional positive or negative incentive at the end of the rate plan to ensure that assets have been appropriately maintained, replaced, or upgraded. Ofgem also may allow recovery near the end of the rate plan for investments designed to produce benefits during the next rate plan. Ofgem may allow utilities to carry forward into the next rate plan a share of cost savings realized near the end of the current plan.

RIIO is an example of a regulatory authority attempting to balance incentives for cost savings with performance incentives based on specific output metrics. In many respects, Ofgem was dealing with concerns comparable to those facing U.S. regulators. The U.K. power industry faces aging infrastructure, a changing generation mix with increased reliance on variable renewable generation, and limited revenue growth. In developing its reform program, Ofgem sought to engage consumers in defining desired results. It also recognized that accelerating innovation could play a key role in making power and energy affordable, as well as to meet the nation's climate objectives.

The U.K. is in the early stages of implementing RIIO with the first plans now in place.

There are important differences between the regulatory environment in the U.K. and that in the United States. RIIO builds on 20 years of U.K. experience with price cap regulation. Both the regulator and utilities had accumulated skills and tools to help them develop a long-term performance-based rate mechanism. Moreover, the regulatory process in the U.K. is more consultative and lacks a comparable history of contentious rate case litigation. For example, the regulator in the U.K. is able to offer a utility a menu of different incentive contracts designed to incent the utility to accurately disclose its expected cost for meeting performance metrics.[11]

Taking differences in their regulatory environments into consideration, U.S. regulators are considering how to adapt to their own circumstances with some core results-based concepts including:

- Revenues based upon forward-looking business or grid modernization plans;
- Multi-year revenue caps that provide an incentive for the utility to pursue efficiency improvements and retain a share of the resulting cost savings or bear a share of resulting cost overruns;
- Caps on total expenditures that provide utilities flexibility to shift spending between operating and capital expenditures to efficiently meet requirements as new information becomes available;
- Earnings-sharing mechanisms to allow customers to benefit from cost savings or bear a share of costs incurred during multi-year plans;
- Output-based, bi-directional performance incentives for reliability, energy efficiency, customer satisfaction, and other performance metrics; and
- Funding specifically set aside for research, development and other innovation projects.

Recommendation #1: DOE should develop a whitepaper on alternative regulatory models and how those models can play a role in meeting emerging requirements as discussed above.

Section 5: DOE Development of Information and Tools

The Department should provide information and analysis as well as modeling tools, as discussed in the sections below, that could enable regulators and utilities in interested

[11] This practice is known in the U.K. as an Information Quality Incentive and more generally as a Menu of Contracts approach to setting rates. For background and a description of how the approach is implemented see: R. Cossent and T. Gómez, "Implementing Incentive Compatible Menu of Contracts to Regulate Electricity Distribution Investments," *Utilities Policy,* Vol. 27 (2013); see also: Ofgem, *Handbook for Implementing the RIIO Model* (October 4, 2010) at 66.

jurisdictions to consider alternative regulatory and business models in order to address any host of emerging requirements.

5.1 Data on distribution reliability

For 2014, the Energy Information Administration (EIA) will begin gathering information on distribution reliability metrics in Form EIA-861, Schedule 3 Parts B and C. The metrics will include available utility calculations of the annual System Average Interruption Frequency Index (SAIFI) which indicates how often the average customer experiences a sustained interruption (of over five minutes), and the System Average Interruption Duration Index (SAIDI) which indicates the total duration of interruptions in minutes per year for the average customer. If available, this data would be reported both including and excluding major events. The form also asks utilities to provide information regarding how each company calculates these metrics. The requirements are new and apply only to the extent the reporting entity calculates SAIFI and SAIDI in accordance with IEEE standards in its normal business practices.[12] The changes in EIA's survey were made at the request of researchers at Lawrence Berkeley National Laboratory (LBNL) who had found inconsistencies in the reporting of outage data to state regulatory commissions. The LBNL researchers had concluded that, "differences in utility reporting practices hamper meaningful comparisons of reliability information reported by utilities to different state PUCs and, therefore, may limit the effectiveness of efforts to measure the effectiveness of efforts to improve reliability."[13] Reliability metrics provide a means of benchmarking or tracking changes in utility performance.

We note that the Council of European Energy Regulators publishes periodic reports comparing distribution reliability performance across the E.U.[14] Comparable comparisons are not generally published and available to the public for U.S. utilities.

Recommendation #2: The Department should evaluate the reporting of data under the modified EIA form and prepare a whitepaper describing the available data and how it might be useful to utilities and regulators.

5.2 Development of tools for evaluating distribution investments and distributed energy technologies and integrating distributed energy technologies into system operations

The continued deployment of distributed energy technologies and renewable energy resources creates a number of challenges at the distribution level. As the penetration of distributed energy technologies increases, so too does the need for grid modernization. At the same time, state regulatory commissions are also assessing the need and pace of capital additions that are necessary to maintain system reliability, whether due to

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[12] Energy Information Administration, *Form EIA-861 Annual Electric Power Industry Report Instructions* (May 29, 2014); see also: http://www.eia.gov/survey/changes/electricity/.
[13] J. Eto and K. H. LaCommare, *Tracking the Reliability of the U.S. Electric Power System: An Assessment of Publicly Available Information Reported to State Public Utility Commissions,* LBNL-1092E (October 2008).
[14] See for example: Council of European Energy Regulators, 5th CEER Benchmarking Report on the Quality of Electricity Supply (2011).

anticipated demand growth or simply upgrades of system components that are deteriorated or beyond the respective manufacturer's designated service lives. All of these decisions are made with an eye towards balancing the need to maintain safe and reliable service against customer affordability. Yet, regulators are also considering the demands of consumers for new services, including the services associated with supporting distributed generation on the customer side of the meter.

With the penetration of distributed energy technologies, including distributed generation, storage, and responsive demand, utilities and regulators will need to understand the impacts of distributed technologies on distribution systems. The costs and impacts of a distributed resource depend on where it is located and the characteristics of the distribution system. For example, a few distributed generators on a given circuit might reduce losses and avoid the need for upgrades, but installing additional generators on the same circuit might increase losses and require new investment. Additionally, regulators need to understand the probable impacts on distribution reliability and the benefits and costs of distribution automation, hardening, replacement of aging infrastructure, and other distribution investments. However, regulators are attempting to evaluate plans for replacing aging distribution infrastructure, upgrading distribution circuits, and modernizing systems with limited modeling tools.

DOE has supported the development of distribution planning models including GridLAB-D™, an advanced distribution system simulation and analysis tool that provides information to users who design and operate distribution systems. However, GridLAB-D™ is not widely used by regulatory commissions.

Regulators in parts of Europe and Latin America have addressed such gaps by developing Reference Network Models (RNM). A reference model is a planning tool that forecasts, using heuristics and contingency analysis, the distribution investments reasonably needed to integrate new resources, achieve desired reliability targets, and meet forecast demand in an approximately optimal fashion. Reference models can include individual substations, feeders, and customer locations and can identify the reinforcements and new facilities required to serve new load or connect distributed generation. Such models also can be used to evaluate reliability performance. A reference model can be generated for incremental changes to the existing distribution system taking into consideration street maps and other infrastructure. RNMs may differ from conventional distribution planning models in scope, covering from transmission substations to distributed generators and individual loads in large areas; by automatically generating expansion candidates from a library of standardized equipment rather than relying on a distribution planner to propose candidate investments; and in validating the feasibility of planning decisions both electrically and in terms of physical considerations when integrated with a geographic information system.[15] By enabling regulators to identify a reasonable plan that meets different distribution planning objectives, a reference model can help regulators examine

[15] C. M. Domingo, et al., "A Reference Network Model for Large-Scale Distribution Planning with Automatic Street Map Generation," *IEEE Transactions on Power Systems,* Vol. 26, No. 1 (February 2011).

the impacts of distributed energy resources, evaluate proposed utility distribution investments, and approve forward looking incentive-based revenue plans.[16]

DOE recognizes the need for massive grid modernization, and is working to provide technical assistance to states and local utilities. With the creation of the Energy Policy Systems Analysis division, DOE is prepared to assess available technologies that promote understanding of power flows across the distribution system, which in turn can help identify synergies between potentially competing grid modernization efforts. DOE also has eight national laboratories that are engaged in evaluating new technologies to facilitate grid modernization efforts. DOE is also convening a workshop to bring experts together to evaluate existing distributed energy resources valuation studies, including meta-analyses that have been conducted by RMI, Princeton, IREC and others. With the creation of the "Grid Tech Team," DOE is positioned to assist policy makers with developing economic valuation tools for evaluating distributed energy technologies. DOE's initiative can help to develop methodologies that enable policy makers and regulators to evaluate the most cost-effective utilization of distributed energy technologies. The effort should crystallize the underlying elements of the necessary cost-benefit analysis for integrating distributed energy resources, including consideration of capacity, energy, transmission and ancillary services. DOE should continue to utilize these important resources and support the development of detailed planning models, performance and cost data, and supporting information and methodologies that could help utilities and regulators evaluate specific applications of distributed energy technologies, grid modernization, and distribution investments. In supporting the development of such tools, DOE's efforts are not intended to be prescriptive, but rather will provide tailored solutions to the actual topographical specific needs of various utility systems that are in transformation.

There also is a growing need for models and management systems that can be used to support real-time integration of distributed energy technologies with the operation of the both the distribution and bulk power systems to achieve a dynamic optimization across these multiple planes. Among a number of available control technologies for maintaining system stability, there is not yet an integrated "control theory" that would facilitate the selection of the most cost-effective solutions. Such models and management systems also would be needed support the development of efficient distribution level markets. The New York Commission and its Staff are proposing that distribution utilities become Distribution System Platform Providers, operate distribution level markets, and provide an interface with the New York ISO.[17] Similarly, there are discussions in California about the development of Distribution System Operators that could operate distribution level

[16] See: R. Cossent, et al., "Distribution network costs under different penetration levels of distributed generation," European Transactions on Electrical Power, Vol. 21 (2011); T. Jamasb and M. Pollitt, "Reference models and incentive regulation of electricity distribution networks: An evaluation of Sweden's Network Performance Assessment Model (NPAM)," *Energy Policy,* Vol. 36 (2008); and
MB-O. Larsson, *The Network Performance Assessment Model: A New Framework for Regulating the Electricity Network Companies* (Royal Institute of Technology of Stockholm, Sweden: Stockholm, Sweden, 2005).
[17] NYS Department of Public Service, *Reforming the Energy Vision: Staff Report and Proposal*, Case No. 14-M-0101 (April 24, 2014).

markets federated with those of the California ISO.[18] The Department should support the development of models and management systems that may be needed to support the efficient operation of distributed energy technologies and emerging distribution level markets.

One of the most difficult and controversial issues now confronting energy policymakers and regulators is how to determine the value and cost of distributed energy technologies. This issue affects both the time- and location-specific decision of whether and where to add distributed generation to the electric system and the broader determination of how such generation should be priced. These decisions take on an added layer of complexity when the distributed generation is developed on the customer side of the meter; that is, where the traditional utility consumer becomes not just a buyer, but also a producer or seller of energy to the electricity grid.

The need for a consistent analysis of the relative costs and benefits of distributed generation was addressed in a recent review of 15 separate studies of solar photovoltaic programs across the United States. [19] As noted in that study:

> Today, the increasingly rapid adoption of distributed solar photovoltaics (DPV) in particular is driving a heated debate about whether DPV creates benefits or imposes costs to stakeholders within the electricity system. But the wide variation in analysis approaches and quantitative tools used by different parties in different jurisdictions is inconsistent, confusing, and frequently lacks transparency.
>
> Without increased understanding of the benefits and costs of DERs, there is little ability to make effective tradeoffs between investments.

Similarly, there is broad dispute over how the costs and benefits of distributed generation should be shared between utilities and consumers, and allocated among customers and customer classes. As noted in a recent analysis of distributed generation tariff and rate design issues:

> The achievements on the customer side of the meter are an economic, policy and marketing success story for many, but the reality is that this success story is not celebrated in all corners. Some utilities have expressed concern that DG adopters are undermining the financial foundation of the electric system. They argue that DG is failing to pay its fair share for its use of (and the ongoing dependence of its owners on) the electric grid. DG developers and advocates argue that the value being provided to the electric system exceeds the cost that ratepayers contribute, and so, if anything, they are being under-compensated for the services they provide.

[18] L. Kristov and P. DeMartini, *21st Century Electric Distribution System Operations* (2014); California Public Utilities Commission, *Order Instituting a Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resource Plans Pursuant to Public Utilities Code Section 769* (August 20, 2014).

[19] "Review of Solar PV Benefit & Cost Studies", Electricity Innovation Lab, Rocky Mountain Institute (September 2013) http://www.rmi.org/elab_empower

> And some consumers argue that they are unfairly subsidizing DG adopters.[20]

Among the critical cost issues under debate are the calculation of avoided energy and capacity costs resulting from the deployment of DG, including the degree to which DG coincides with utility system peak loads. With respect to retail rate design, the major controversy revolves around the recovery of a utility's fixed distribution costs that do not disappear when a customer is supplying an amount of energy equal to all (or more than) the customer's own generation needs, but which would go largely unrecovered under traditional volumetric utility rate tariffs.

It is evident today that state policies seeking to increase the penetration of low-carbon distributed energy resources can result in significant deployment. For instance, "net metering" and "virtual net metering" policies provide adequate revenue streams to incentivize construction and deployment of distributed renewable energy projects. However, many such state policies do not adequately consider the system topology in terms of demand, two-way power flows, voltage fluctuations, and most importantly, the fact that excess power often does not occur during system peaks. That leaves the utility with many engineering challenges that may lead to a higher cost distribution system for all other customers.

One lesson that can clearly be gleaned from current state policies is that (1) the time that a resource can be expected to produce power matters; and (2) the amount of excess power that a particular customer produces affects the level of system costs that all other non-participating customers must ultimately bear in the form of back-up generation as well as the ongoing economic burden of financing a distribution grid that can meet the needs of all customers during system and circuit peaks. Storage ultimately can be the "game changer" in this arena, but encouraging storage will not necessarily eliminate what otherwise may be additions of distributed resources in the wrong parts of the distribution system and in the wrong quantities.

In theory, while all of the distributed energy technology integration issues can be technically resolved at some incremental cost, state policymakers are often not fully equipped with the analytical tools needed to understand the proper intersection of engineering and economics, particularly with regard to the deployment of renewables and the potential role energy storage might play. The result may be an inefficient distribution network that will not meet the time-tested standard of "just and reasonable" rates to consumers.

Recognizing that many of these state programs are still in their infancy, DOE is positioned to play a critical role in providing states with technical assistance in understanding the engineering logistics of two-way power flows across the distribution system, along with the concomitant investment needs that flow therefrom.

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[20] C.Linvill, J.Shenot, JLazar,"Designing Distributed Generation Tariffs Well", Regulatory Assistance Project (November2013).

Recommendation #3: It is the understanding of the EAC that the DOE Grid Tech team has already begun to examine this critical set of issues. The EAC strongly supports this effort and urges the DOE to do the following for a variety of ownership models:

- Support the development of distribution planning models and tools, performance and cost data, and supporting information and methodologies that can be used by regulatory commissions and utilities to identify the likely benefits and costs of specific applications of distributed energy technologies, distribution investments, and forward-looking distribution investment plans. This should include consideration of Reference Network Models comparable to those being used in regulation outside the U.S.;
- Support the development of economic valuation and financial models that can be used by policymakers and regulators to evaluate the potential cost-benefit impacts of distributed energy technologies and related pricing and policy options;
- Support the development of models, management systems, tools, and approaches, including federated information and control architectures and market structures, that may be needed to support the efficient integration of distributed energy technologies into system operations and distribution level markets; and
- Provide technical assistance, information, tools and training to state regulatory commissions, policy-makers, and their staffs, and make such information and tools available to interested utilities to enable them to better evaluate distributed technology deployments, distribution investments, and forward looking distribution investment plans.

5.3 Updates to DOE Interruption Cost Estimation

Asking customers about and estimating the value that they place on uninterrupted electric service can have important implications for both utilities and regulators. A lack of alignment between how customers value uninterrupted electric service and utility expenditures can shift significant outage costs onto customers. Understanding the costs outages impose on customers can help provide the basis for investments needed to replace aging infrastructure, enhance the resilience of the power grid, and reduce the risk of service disruptions from cyber-security events. The value of uninterrupted service can vary significantly both within and between customer classes. There also can be important differences by region, season, timing and duration of outages.[21] DOE has developed a model that can be used to estimate the cost of outages to different classifications of customers. It has used that model to develop the Interruption Cost Estimation (ICE) calculator that can estimate outage costs for either residential or non-residential customers in different states.[22] The calculator can be used by electric reliability planners at utilities, state commissions, and other entities interested in estimating service interruption costs and/or the benefits associated with improvements in reliability metrics. At least in one case, results from the Department's model have been introduced in regulatory proceedings to support utility distribution investments.[23] However, the datasets underlying the Department's model are from surveys conducted for nine utilities over the period from 1989 to 2005. Only two of the utility datasets include any surveys conducted after the year 2000. Reliance on digital control systems, telecommunications, and devices that require reliable electric service has increased significantly in the intervening years. Moreover, none of the underlying data is from utilities in Northeastern, Mid-Atlantic, or Mountain West states. And, the data do not include estimates for the cost of extended outages lasting longer than eight hours.[24]

New surveys might well find that the value customers place on uninterrupted service has increased. Business and industry have become increasingly dependent on information, communications, and digital control technology. The U.S. population has become more urban[25] and dependent on electricity to support critical infrastructure. Moreover, major outages are happening with increased frequency, occurring at a rate more than double the historical rate.[26] Outages, such as those resulting from Superstorm Sandy, have increased the salience of outage costs to customers and potentially their willingness to pay for a more resilient power system. Moreover, modern customer segmentation methodologies could better account for what may be large differences within customer classifications in how customers value uninterrupted service.

[21] Centolella, et al., *Estimates of the Value of Uninterrupted Service for the Midwest Independent System Operator,* Midwest Independent Transmission System Operator (April 2006).
[22] See: http://www.icecalculator.com/ice/.
[23] S. Adams, E. Stinneford, & L. Brown, *Policy Panel Testimony,* Central Maine Power Company Request for New Alternative Rate Plan (ARP 2014), Maine Public Utilities Commission Docket No. 2013-00168 (May 1, 2013).
[24] LBNL (2009).
[25] U.S. Census Bureau, *Urban, Urbanized Area, Urban Cluster, and Rural Population, 2010 and 2000: United States* (March 2012).
[26] Electric Power Research Institute*, Enhancing Distribution Resiliency: Opportunities for Applying Innovative Technologies* (January 2013); S. M. Amin, "U.S. Electrical Grid Gets Less Reliable," *IEEE Spectrum* (January 2013).

A current and more granular understanding of customer outage costs could help provide a basis for distribution investments, siting for distributed energy resources, and/or potential changes in customer rate classifications.

Recommendation #4: The Department should work with the industry to develop and make available additional data on the cost of outages and power quality events to customers and improve the granularity and quality of data available for estimating differences in the cost of these events for different customer segments. Such additional data should be considered for inclusion in the Department's ICE calculator as it becomes available.

5.4 Facilitating Customer Choice Engines

Demand will increasingly participate in power markets based on smart devices that automate customer preferences. People already rely on automated customer choice technologies to perform other functions. For example, they may go to KAYAK or a similar application to locate the least expensive travel options consistent with their preferences. In just that way, a smart thermostat, allowed one or two degrees of temperature flexibility, could use power in the intervals when it is least expensive while providing desired levels of comfort. Today's communicating thermostats can access forecasts of local temperatures and humidity, sense whether anyone is at home and determine when the house is generally unoccupied, and learn the building's characteristics and the efficiency of its cooling and heating systems. Using pre-cooling and smart operating strategies, such thermostats have reduced peak residential air conditioning use by 50% in Texas's 100^{o} plus temperatures[27] and cut demand in a Nevada Power Company program by more than 3kW per household.[28]

The impact of such automation could be very large. Most uses of electricity have thermal inertia: heating and cooling buildings, heating water, and refrigeration; or flexibility in the timing of power use: most pumping loads, batch processes, and charging electric vehicles and other devices. Moreover, smart devices could respond continuously, not just during peak events, helping system operators maintain reliability and offset ramping of variable resources. Deployment of smart devices on a larger scale and in a manner integrated with efficient grid operations could make the power system more efficient and reliable, improve asset utilization, and provide bill savings for millions of customers.[29]

The barriers to a future in which smart devices implement the preferences of ordinary consumers for lower bills or greater comfort to a significant extent are regulatory. These barriers include that wholesale settlements are often based on representative hourly distribution utility load shapes, rather than the actual interval load patterns of each

[27] *Inside Nest* (Downloaded June 10, 2014 from: https://nest.com/blog/2013/07/18/our-first-rush-hour-rewards- results/.
[28] Application of Nevada Power Company d/b/a NV Energy for Approval of its 2014 Annual Demand Side Management Update Report as it relates to the Action Plan of its 2013-2032 Triennial Integrated Resource Plan, Volume 5 – Technical Appendix, available at: http://pucweb1.state.nv.us/PUC2/DktDetail.aspx. See also: Tom Kerber, Residential Savings through Data Analytics (Downloaded June 10, 2014 from: http://www.ecofactor.com/resources/

[29] The National Energy Modeling System (NEMS) plays a central role in energy forecasting and scenario analysis. The Department should review and may need to update how NEMS represents the impacts of automated customer choice technologies and other forms demand participation.

supplier's customers, and that most grid operators do not make publicly available information based on their short-term indicative forecasts of interval prices, which is information could be used to help position the energy demands of smart devices.

Recommendation #5: The Department should prepare an analysis of how best to remove market failures and barriers to enable efficient responses from smart devices. It should support development of a benefit-cost framework, a common standards-based approach for communicating with smart devices, and, where cost-effective from a systems perspective, inclusion responsive capabilities in DOE energy efficiency standards. Such steps could provide FERC and state commissions the opportunity to ensure that smart energy using devices can contribute to the reliable and efficient operation of the power system. Place attention on the correlation of the actual impacts versus the look-ahead forecast.

5.5 Benefits, costs, and impacts of Volt-VAR Optimization

As electricity loads become more variable and intermittent sources become a larger portion of the energy supply, the power grid will need to become more flexible and more efficient. Dynamic voltage and volt-ampere reactive optimization (VVO) will be increasingly essential to achieving cost-effective performance expectations. Significant benefits are forecasted in several reports. For example, a new report from Navigant Research, forecasted that worldwide revenue from these technologies would grow from $734 million in 2014 to $2.9 billion by 2023.

Much of the intelligent electronic devices, communications and information technology exists today and are being applied through pilot-scale projects on distribution systems to demonstrate congestion relief, loss reduction and to effectively free-up capacity. While many utilities have one or more pilot projects underway, few have the assessment tools and verification techniques in place to justify full-scale implementation. Furthermore, there are many techniques and methodologies that have emerged in the marketplace utilizing a wide range of control technologies in conjunction with load tap changers (LTCs), regulators, and capacitor banks. And, new solid-state power electronics located either on the distribution system or in smart inverters can provide increasingly precise control. Every inverter, from panel level to the megawatt scale, could potentially become part of the grid and have a role in stability. Smart inverter technology can be used to provide ancillary services such as low-voltage ride-through (LVRT) and support the grid in situations of low and high voltage. Control can be applied to get emergency load relief, substation voltage reduction, peak load management and customer end-use efficiency. This yields benefits of system protection during emergencies, energy savings at the substation, avoided high margin supply costs, and customer energy and demand savings. With the variability of loads, technologies, benefits, control priorities, evaluation techniques, metrics, regulatory incentives, and associated standards have been slow to develop. Often, there is relatively little means to measure results with statistic validity. As a result, compelling utility business cases and regulatory constructs are holding back potential.

Recommendation #6: DOE should pursue the following developments to facilitate improved evaluation of volt-var optimization to unleash the predicted benefits that full-scale implementation can offer.

- Business case calculator – This would help utilities evaluate the cost/benefit of enabling VVO on their system. This calculator would take into consideration regulatory incentives (e.g., federal, state, local), the cost of the system upgrades needed to enable the technology, and the estimated benefits that would be achieved (i.e., energy reduction, peak demand reduction and system loss reduction) when VVO was enabled.
- Measurement & Verification tool – This would consist of a standard, recommended measurement techniques, and metrics applied consistently to measure and verify VVO. It is difficult to measure VVO results because the variability of the actual system can shadow the gains from optimization. There is a federal guideline around measurement and verification that DOE published that was focused on customer based energy efficiency projects. Work is also needed to capture and verify the benefits realized by the delivery system with some level of accuracy.
- Planning tools – This would help utilities and regulators understand the potential benefits of applying VVO technology given a range of system conditions, technologies and optimization algorithms. A set of typical feeders could be identified that was representative of real-world load conditions. These would be used as a basis in models to design and apply VVO schemes to forecast benefits.
- A VVO data base – this would showcases the results achieved on installed system. Regulators and utilities alike could benchmark their results against others, given a set of control parameters and system conditions.

5.6 Alternative distribution rate-making models

Distribution utility costs are often recovered through volumetric rates set at uniform levels for large rate classes. This may create implicit cross subsidies. Moreover, efficient pricing for the development and operation of distributed energy resources could require new information, tools and changes in utility rates. Issues that utilities and state regulators may need to address could include:

- Enhanced reliability: All customers are assured adequate service reliability. However, given increasing reliance on digital devices and controls and the role of electricity in maintaining critical infrastructure, customers may face very different costs when service is interrupted. A growing number of customers have invested or expect to invest in customer-sited generation to meet their energy and reliability requirements.[30] If offered a choice, some customers might elect to purchase premium reliability service from their utility or to participate in a utility-operated microgrid.

[30] See for example: Generac Holdings Inc., Q3 2013 Results, press release, Oct. 24, 2013; and Cleantech Matters, Global competitiveness Global cleantech insights and trends report, Ernst & Young, 2012.

- Recovery of fixed costs in volumetric rates: This approach to rate design can result in customers with distributed generation paying a smaller share of the fixed costs for a distribution system that they may nonetheless rely upon to meet their peak requirements. It also tends to increase net metering payments to such customers. At the same time, the imposition of high fixed customer charges on customers who do not generate their own energy may reduce the incentive for those customers to conserve. High fixed customer charges may also have a negative impact on low use, low income customers. Utilities and regulators are considering alternative approaches to the recovery of fixed distribution costs given low sales growth and increasing customer sited generation.
- Distribution cost causation: Most customers pay for distribution through monthly customer and per kWh volumetric charges. These charges are not always correlated with the demand that customers place on the distribution system. Even those customers who have a demand charge may have charges based on their individual monthly demand rather than on their contribution to coincident peak demand on their distribution circuit. Peak demand on distribution circuits may occur at times that are different from both individual customer and system peak demands.
- Distributed energy resources: Distribution costs can vary significantly by time and location due to the impacts of circuit peak demands, losses, and congestion on the distribution system.[31] These differences can be significant for the siting of distributed energy resources where they can support the distribution system and to efficient integration of distributed energy resources into system operations.
- Maintenance of reasonably priced default service and understandable rates: In a section of their report on Reforming the Energy Vision titled "Maintain Commitment to Affordable Universal Service," the New York Commission Staff states that "Reliable service will continue to be available to all customers at the lowest cost achievable," and that "For those customers that do not have or desire to have DER behind the meter, default service must continue to be available on reasonable terms."[32] As new regulatory models are developed, it is important to keep these principles in mind, as well as the "practical" attributes of a sound utility rate structure identified by Bonbright as "simplicity, understandability, public acceptability, and feasibility of application."[33]

Recommendation #7: The Department should assist interested regulators and utilities in addressing these issues by preparing a whitepaper or a series of whitepapers on the following topics:

- Issues and options related to providing and pricing enhanced levels of reliability for customers who place a high value on uninterrupted service;

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[31] P. Sotkiewicz and J. Vignolo, "Nodal Pricing for Distribution Networks: Efficient Pricing for Efficiency Enhancing DG," *IEEE Transactions on Power Systems,* Vol. 21, No. 2 (May 2006); P. Sotkiewicz and J. Vignolo, "Towards a Cost Causation-Based Tariff for Distribution Networks with DG," *IEEE Transactions on Power Systems,* Vol. 22 (August 2007); see also: P. Sotkiewicz and J. Vignolo, "Allocation of Fixed Costs in Distribution Networks with Distributed Generation," *IEE.E Transactions on Power Systems,* Vol. 21, No. 2 (May 2006).

[32] NYS Department of Public Service, *Reforming the Energy Vision: Staff Report and Proposal*, Case No. 14-M-0101 (April 24, 2014) at 58-59.

[33] J. Bonbright, *Principles of Public Utility Rates* (1961) at 291.

- Alternative approaches for recovery of fixed distribution costs;
- Alternative methodologies and the development of distribution models that could facilitate efficient pricing for distributed energy resources, including approaches designed to incent the efficient siting and operation of distributed generation.
- Methodologies for depreciation that can be applied to new smart grid technology such as software, inverter-based technology, micro-processors and communications that have a shorter life-cycle than traditional transmission and distribution units of property. Often the new technologies with shorter lives are integrated into devices that have been depreciated over 20 years or longer.
- Develop methodologies to monetize the value of technologies to integrate renewables and the like and incorporate them into the integrated planning process.

5.7 Social costs[34]

The Department should monitor where it may be useful to develop information or methods for valuing social cost impacts and make such information and tools available to utilities and states interested in considering these factors in planning or in alternative regulatory models. We note here a few potential examples where the provision of a synthesis of objective information might be useful to utilities and regulators:

- Methodologies for measuring and verifying end use, distribution, and power plant energy efficiency improvements to document compliance with proposed EPA rules on greenhouse gas emissions from existing power plants under Section 111(d) of the Clean Air Act;
- Valuation of public health impacts from criteria pollutants, e.g. fine particulates, that can be substantial, may be important in utility resource planning, and are not by priced by a market based system of environmental regulation;35 and
- Information on the load profiles and price elasticity of low-income customers, who in some cases may tend to experience lower bills under time varying pricing than under flat rates.

Recommendation #8: The Department, where practicable, should seek to make available to utilities, state commissions and their staffs objective information on social costs that otherwise might not be presented in a standard cost of service framework and that could help utilities and regulators evaluate performance metrics and alternative regulatory or business models. For example, the Department should work with U.S. EPA and the states to develop tools that would enable states to evaluate options and verify compliance with proposed EPA rules regulating greenhouse gas emissions from power plants under Section 111(d) of the Clean Air Act.

5.8 Support for innovation

Regulators in California, New York, and Massachusetts are setting aside ratepayer funds for research, development, or other innovation projects. The expansion of public and

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[34] *The term "social costs" is should be interpreted in very broad terms and not limited to just the examples included.*
[35] National Academy of Sciences, *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use* (2010).

private funding for energy innovation, including among other sources funding through utility rates, may reflect recognition of:

- The use of new technologies in grid modernization and to meet new expectations and requirements for grid reliability and resilience, cyber and physical security, and the integration of variable and distributed resources;
- Anticipation of a transformation to a low carbon economy that could fundamentally change the power sector;
- The limitations of learning by doing from deployment of clean energy technologies, which may be insufficient to make these technologies cost competitive with conventional generation;[36] and
- Utility research and development spending, approximately 0.2% of revenue,[37] being a fraction of what is spent on research and development in most other industries.[38]

States and regions could play an important role in strengthening the energy innovation system.[39]

Recommendation #9: The Department should prepare a whitepaper on options for advancing energy innovation, including through state and regionally based institutions. The whitepaper should address the option that funding through utility rates could be one of several potential sources of support for energy innovation initiatives. Additionally, the Department should continue to foster coordination and partnerships between federal and state energy research, development, and demonstration programs.

Section 6: DOE Convening Authority

As highlighted in this paper, there is a growing interest across the country in new utility regulatory models designed to address the challenges of the energy sector. While the regulation of utilities varies across the country, regulators, policymakers, utilities and stakeholders are seeking mechanisms to fulfill a wide variety of objectives including, but not limited to, reliability, resiliency, the integration of variable and/or distributed resources, asset optimization, sustainability, customer choice, and innovation. Regulators in California, Illinois and New York have already begun exploring different options to meet emerging requirements. The work conducted in these states has broad applicability and could be useful for other states contemplating solutions to similar challenges.

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[36] See for example: G. F. Nemet, "Beyond the learning curve: factors influencing cost reductions in photovoltaics," *Energy Policy*, Vol. 34, No. 17 (2006); T. Jamasb, "Technical Change Theory and Learning Curves: Patterns of Progress in Electricity Generation Technologies," *The Energy Journal*, Vol. 28, No.3 (2007); C. Fischer, et al., *Environmental and Technology Policy Options in the Electricity Sector: Interactions and Outcomes*, Resources for the Future (2013) available at: http://www.rff.org/Publications/Pages/PublicationDetails.aspx?PublicationID=22362; and W. Nordhaus, 'The perils of the learning model for modeling endogenous technological change,' *The Energy Journal*, Vol. 35, No. 1 (2014).

[37] R. Lester and D. Hart, *Unlocking Energy Innovation: How America Can Build a Low-cost, Low-carbon Energy System* (2012) (hereafter Lester and Hart); Battelle Memorial Institute and R&D Magazine, 2012 Global R&D Funding Forecast (December 2011) at 21.

[38] L. Diaz Anadon, et al., *Transforming U.S. Energy Innovation* (November 2011) at 222; American Energy Innovation Council, *A Business Plan for America's Energy Future: Technical Appendices* (2010).

[39] See for example: Lester and Hart; J. Duderstadt, et al., *Energy Discovery-Innovation Institutes: A Step Toward America's Energy Sustainability* (2009); and M. Porter, *Clusters of Innovation Initiative: Regional Foundations of U.S. Competitiveness*, Harvard Business School (October 2001).

DOE can assist regulators, policymakers, utilities and stakeholders by utilizing existing national, regional and state organizations and events to facilitate discussions on emerging requirements (resiliency, reliability, etc) and how those emerging requirements could be addressed by alternative regulation and emerging regulatory models. Additionally, DOE could help align these entities with DOE-developed tools and also build upon the lessons learned from state technical assistance programs and from the national labs.

Due to the wide variety of topics and interests of state regulators and policymakers, DOE could convene a series of regional workshops that address key emerging requirements/challenges for that region. These workshops could coincide with the annual regional meetings of state energy regulators (e.g. Western Conference of State Public Service Commissioners) and policy-makers (e.g. Council of State Governments West). Other avenues of outreach could include panels at national meetings for broader discussions and webinars designed for specific topics, solutions and tools.

In addition to fostering conversations within stakeholder groups (e.g., regulators, legislators), DOE should initiate conversations between stakeholder groups. The initial conversations can identify interests by stakeholder group and the second round of discussions can develop consensus policy recommendations. According to a survey of state regulators and legislators conducted by the Energy Storage Association and provided the EAC in 2013, both sectors believe DOE is the most trusted source for information. The proposed facilitated discussions and consensus building efforts suggested above would be well received by the state interests.

Recommendation #10: Assist regulators, policymakers, utilities and stakeholders by convening/funding discussions on identifying emerging requirements and how those requirements could be addressed by alternative/emerging regulatory models and evaluated by using DOE-developed tools.

Appendix 1

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Appendix 2

Example Summary Descriptions of State Proceedings and 3rd Party Activities

Massachusetts Grid Modernization Working Group and Related Proceedings

Key Milestones:

- October 2012 – Department Issued Notice of Investigation into Modernization of the Electric Grid.
- November 2012 – June 2013 Stakeholders discussed grid and customer facing issues related to modernization.
- July 2, 2013 – Stakeholder final report
- December 23, 2013 – Mass DPU final report.
- Jun 12, 2014 – Mass DPU Final Order
- Distribution utilities have 9 months to file Grid Modernization Plans from date of Mass DPU Order on Time Varying Rates or its issuance of further directives on the filing of business cases for modernization investments.

Summary

DPU set out four overarching objectives that included modernization for the purposes of:

(1) To reduce the effects of outages;
(2) To optimize demand, which includes reducing system and customer costs;
(3) To integrate distributed resources; and
(4) To improve workforce and asset management.

Key Proposal Elements

Distribution utilities to submit 10-year grid modernization plans (GMP) consistent with the key noted objectives. Components of GMP include notably: "a marketing, education, and outreach plan with a component that is common to all the companies, as well as a company-specific, local component; a research, development, and deployment plan; and proposed infrastructure and performance metrics to measure progress in achieving grid modernization objectives, including common statewide and also company-specific metrics."[40]

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[40]MA Department of Public Utilities, *Massachusetts Electric Grid Modernization Stakeholder Working Group Final Report*, DPU 12-76 (July 2, 2013).

Targeted cost recovery is available for incremental (technologies or levels of) investments to achieve grid modernization under a Short Term Implementation Plan that "addresses Advanced Metering Functionality." Throughout the proceeding the DPU has distinguished Advanced Metering Functionality from AMI. However, it is not clear the extent to which the characteristics defined as Advanced Metering Functionality can be addressed without deployment of AMI. This is likely to be an issue when the Commission reviews utility plans. Targeted cost recovery allows pre-authorization of investment and a cost tracker to facilitate "more timely cost recovery" than would typically occur. GMP would include schedule and prioritization of investments, but not a detailed budget.

Time variable rates, data access, EV, cybersecurity and privacy are being addressed other proceedings.

Rather than a fundamental regulatory shift, Grid Modernization becomes part of the normal course of planning and ratemaking activity. The DPU declined to adopt a future test year as included in the ratemaking framework supported by a majority of stakeholders.

Includes a requirement that distribution utilities also file as part of GMP a framework for metrics.

NY PSC Reforming the Energy Vision Proceeding

On April 25, 2014 the New York Public Service Commission (PSC) issued an order opening a proceeding -- the Reforming Energy Vision (REV) Initiative (Case No. 14-M-0101) -- to examine how current regulatory practices should be modified to enable electric utilities to manage and coordinate distributed energy resources and enable customers to optimize their energy priorities, provide system benefits, and be compensated for providing such benefits.

Topics to be addressed:

The Commission intends to consider incentives to promote energy efficiency, renewable energy, least-cost energy supply, fuel diversity, system adequacy and reliability, demand elasticity, and "customer empowerment." The PSC stated "the existing ratemaking structure falls far short of the pace of technology development that defines many parts of our economy. By fundamentally restructuring the way utilities and energy companies sell electricity, New York can maximize the utilization of resources, and reduce the need for new infrastructure through expanded demand management, energy efficiency, renewable energy, distributed generation, and energy storage programs."

The initiative is to be conducted in two tracks. Track 1 is to address the functions of the "distribution system platform provider" (DSPP), with these functions to include: undertaking an integrated approach of considering energy resources (including energy efficiency, demand reduction and distributed generation) in utility planning and operations (as opposed to a silo approach of evaluating these resources) to help optimize resource deployment to meet customer reliability needs and reduce overall costs to customers; upgrading distribution management systems and communications infrastructure and providing a platform to accommodate distributed energy resources (DER) to offer new energy products and services; and, creating pricing mechanisms to buy/sell products/services from DER resources to provide value to the utility system and thus to customers. Track 1 will also address factors that may affect customer participation.

The key issues in Track 1 are to include: whether the DSPP should be the incumbent utility or an independent entity; the products and services that the DSPPs will purchase from DER providers; whether the utilities should be permitted to own/control DER; and, maximizing customer engagement. It is contemplated that the utilities would file implementation plans in 2015, in the context of rate case filings.

Track 2 is to address the ratemaking approaches that will support the vision and models that result from Track 1. The key issues in Track 2 are to include: the appropriateness of longer-term distribution rate plans (current rate plans tend to be three-years in length); the need to revise existing performance mechanisms (penalty only vs. symmetrical incentives); the need for additional incentive mechanisms; rate design modifications; impacts on captive customers; the definition of default service; and, the financial stability of the utilities, bond ratings, and the ability to raise capital.

Schedule

The schedule for this process has been modified since the commencement of the proceeding; the current schedule is set forth below:

Track 1

August 22 - Staff straw proposal on Track 1

October 24 - Public comments due on Track 1

November 4 - Track 1 technical conference

Early 2015 - PSC order on track 1 issues

Track 2

October 3, 2014 - Staff options paper

October 20, 2014 and December 15, 2014 -- Roundtable meetings with stakeholders to gain feedback on specific topic areas identified in Staff options paper.

January 30, 2015 - Staff straw proposal due

March 20, 2015 - Party Comments due on Staff straw proposal

Benefits to date

The proceeding's greatest contribution to the anticipated reforms –so far-- is the collection of careful and thoughtful comments and suggestions from not only an experienced and sophisticated Staff, but also dozens of interested parties from every aspect of the generation and delivery of electricity and, to a more limited extent, the delivery of natural gas.

Hawaii Reliability Standards Working Group and Commission's Inclination's on the Future of Hawaii's Electric Utilities

Key Milestones

- July, 2011 – RSWG initiates work under Docket No. 2008-0273 (later spun out into 2011-0206)
- March 13, 2013 – Final Facilitators Report
- April 28, 2014 – Rejection of HECO IRP, and publication of Commission Inclination's

Objective
Increase Hawaii's utilization of renewable energy while ensuring grid reliability is maintained.

Summary:
Final filing of RSWG work product included some 80 attached documents that emerged on a general consensus basis, but dissenting input and analysis was also offered.

Crosscutting issues of the RSWG included reliability standards, new generation interconnection, and system operational flexibility and renewable generation curtailment.[41]

Key Proposal Elements

[41] Public Utilities Commission Reliability Standards Working Group Facilitators, *Final Report*, Docket No. 2011-0206 (March 25, 2013).

Key recommendations of the report are summarized in table form on page 25-31. An important aspect of the project is process related – that is the HPUC set up an informal, forward looking, docketed proceeding to examine issues and make recommendations outside of the rulemaking and contested case format. Process was consensus based, allowed for dissent – but included balloting of measures.

HPUC Inclinations Document

The HPUC rejected HECO's filed IRP, and in doing so, published a set of guidelines. Within this document, HPUC summarizes three directional goals for HECO that include HPUC's thoughts on: *Creating a 21st Century Generation System, Creating Modern Transmission and Distribution Systems,* and sets out *Policy and Regulatory Reforms to Achieve Hawaii's Clean Energy Future.* These observations acknowledge that the proper regulatory incentives may not currently exist and propose a series of alternatives for consideration by policy makers within Hawaii.

Energy Future Coalition – Maryland Utility 2.0

Maryland Governor Martin O'Malley charged this non-profit with "scoping out a Utility 2.0 pilot proposal and reporting back…on a viable method to explore the contours of the utility of the future." The pilot proposes: (1) testing the application of new tech, strategies, and practices in the day-to-day functioning of electric utility service in the pilot project area, and (2) matching changes in utility business practices and reward structures as well as the regulatory scheme under which utilities operate.[42]

Proposal Elements

Key tenets of the EFC Utility 2.0 proposal included categories related to reliability and resiliency, residential and larger customer optionality, utility system upgrades, utility business model changes, and regulatory model adjustments.

Although Utility 2.0 includes 29 recommendations across this spectrum of categories, most relevant to this summary are those proposals related to the utility business model and regulation. Of particular note, are the following:[43]

- Utility 2.0 proposal includes performance-based criteria for compensation with a two percent band on ROR on equity for superior/inferior performance.
- Allow customers to individually rate the criteria around performance factors – and pay differentiated rates based on those selected factors.

[42] See Energy Future Coalition, Piloting the Future for Maryland's Electric Utilities and their Customers, MD Utility 2.0 Pilot, Page 1, (October, 2012). http://energyfuturecoalition.org/What-Were-Doing/Utility-20.
[43] See Energy Future Coalition, Piloting the Future for Maryland's Electric Utilities and their Customers, MD Utility 2.0 Pilot, Page 19, (October, 2012). http://energyfuturecoalition.org/What-Were-Doing/Utility-20.

- Sets a baseline system management cost of service, allowing utility to retain 1/3 of savings below baseline from reductions attributed to integrating customer equipment for 2 years.
- Permit utility to make validated customer-side investments geared toward smart grid, energy efficiency at customer's cost, with on-bill repayment that survives real estate transaction, obtaining credit for savings.
- Permit utility on-bill repayment of customer-side utility investments, conveying obligation to new owners of premises with permanent investments.

A major point of emphasis for this proposal is to align how utilities are paid with the actual current needs of their customer.[44]

The Maryland Public Service Commission Staff has subsequently issued a report on performance-based regulation and the Commission is soliciting comments on that report.[45]

Bipartisan Policy Center: Capitalizing on the Evolving Power Sector: Policies For a Modern and Reliable Electric Grid

On Feb. 7th, 2013 the Bipartisan Policy Center released Capitalizing on the Evolving Power Sector: Policies for a Modern and Reliable Electric Grid. While the report is prescriptive in a number of areas, a number of the recommendations fall outside of the scope of this white paper.

Key Proposal Elements

The Bipartisan policy center recommends the following:

- The US DOE fund an effort to identify best practice policies for state public utility commissions to encourage modifications of distribution infrastructure for the integration of advanced grid technologies.
- The National Association of Regulatory Utility Commissioners (NARUC) should work with state PUCs to identify suitable, output-based distribution system performance metrics that could be used in incentive- based regulatory proceedings. In addition, DOE should fund NARUC or state efforts to develop model language for incentive-based regulation.
- Utilities and state PUCs should offer dynamic retail pricing of electricity as an option where advanced metering infrastructure exists. States regulators should also ensure that customers are able to make their usage information available to third-party demand response aggregators or other service

[44] See Energy Future Coalition, Piloting the Future for Maryland's Electric Utilities and their Customers, MD Utility 2.0 Pilot, Page 120, (October, 2012). http://energyfuturecoalition.org/What-Were-Doing/Utility-20.
[45] Staff of the Maryland Public Service Commission, Report on Performance Based Ratemaking Principles and Methods for Maryland Electricity Distribution Utilities, *In the Matter of the Electric Service Interruptions in the State of Maryland Due to the June 29, 2013 Derecho Storm* (July 1, 2014); See also: *Notice of Hearing and Opportunity to Comment* (July 11, 2014).

providers in a secure and privacy-protected format. Finally, where utilities have installed or plan to install advanced metering infrastructure, state PUCs should require that they conduct the necessary consumer education and outreach.

- Market operators and regulators should permit demand response resources that are capable of performing in a manner comparable to conventional generation to participate in electricity markets and auctions on the same terms as generation resources.

Western Interstate Energy Board (WIEB)/Committee on Regional Electric Power Cooperation (CREPC)/State-Provincial Steering Committee (SPSC)[46]

CREPC and SPSC began exploring the concepts of new utility models by convening a panel entitled "New utility model for a low load growth / high DG future" as part of a joint meeting held in April 2013. Subsequently, SPSC approved a consulting project to explore possible changes in utility business models to address the challenges and opportunities facing the industry, including performance based ratemaking measures. The final report for Phase 1 of the project, entitled "New Regulatory Models," ((http://westernenergyboard.org/wp-content/uploads/2014/03/SPSC-CREPC_NewRegulatoryModels.pdf) provides a current assessment of PBR developments being considered or implemented. The report was prepared by Sonia Aggarwal from Energy Innovation and Eddie Burgess from the Utility of the Future Center at Arizona State University. Carl Linvill (RAP), Andy Satchwell (LBNL) and Ron Lehr (Western Grid Group/APP) served on the project review committee.

Key Proposal Elements Related to State Regulatory Innovation

The New Regulatory Models report published in March 2014, avers that we may be slowly reaching a tipping point for the electric utility sector that requires a re-examination of the traditional utility model.

The white paper offers a potential solution in the form of performance-based ratemaking, offering six examples from 5 US states and the UK.

It lays out a premise for a theoretically ideal PBR mechanism and compares the examples it cites to that ideal.

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[46] WIEB is an organization of 12 western states and three western Canadian provinces. The Board's legal basis is derived from the Western Interstate Nuclear Compact. CREPC is a committee of WIEB, which consists of public utility commissioners, energy agencies and facility siting agencies and has been working to improve the efficiency of the western electric power systems. SPSC consists of appointees from each state and province in the Western Interconnection and was created to provide input from representatives of governors, premiers and utility commissioners to regional transmission planning and analysis in the interconnection.

Case Study	Is revenue tied to a clear performance goal? If yes, what is the goal?	Is there an upside opportunity for exceeding goal?	Is there a downside risk for failing to meet the goal?
1. Ft. St. Vrain	Yes. Operate plant at >50% capacity factor.	Yes	Yes
2. Xcel REC sales	Somewhat. Related to RES, but incentive tied to over-performance.	Yes, from REC sales.	Somewhat. Out of RES compliance if insufficient RECs.
3. Mass EE Performance Incentive	Yes. Multiple targets for savings, value & performance.	Yes	No
4. MidAmerican IA off-system sales	No. But subject to Advanced Ratemaking Principles and rate freeze.	Somewhat. Not specific goal, but utility can earn more from efficient performance.	Somewhat. No specific goal, but lower sales means lower margins. May necessitate rate case.
5. Illinois EIMA	Yes. Multiple performance goals (e.g. SAIDI improvement).	Yes. The ability to opt out of the current structure.	Yes. ROE reduced for goals not met in each year.
6. UK RIIO	Yes. Scorecard system for performance outputs.	Yes	Yes
7. PacifiCorp internal Metrics	Yes (in short run). Internal targets for unit costs.	Somewhat. Larger operating cost savings between rate cases.	Somewhat. Smaller operating cost savings between rate cases.

Table D. Case study performance on the first principle of effective PBR design

The WIEB and SPSC issued an RFP to conduct a Phase 2 study exploring new regulatory models and performance regulation. Synapse was selected as the contractor. A draft of the study will be presented at a joint meeting of WIEB/CREPC/SPSC in late October and the final study is expected by the end of the year.

America's Power Plan

This set of documents, produced by over 150 energy experts from industry, academic institutions and non-profits, proffers a series of recommendations around 7 key areas. These include: power markets, utility business models, finance policy, distributed energy resources, distributed generation policy, transmission policy and siting of new power infrastructure. For further information, see: http://americaspowerplan.com; and Ron Lehr, *Utility and Regulatory Models for the Modern Era*, available at: http://americaspowerplan.com/the-plan/utility-business-models/.

Grid 2020, Toward's a Policy of Renewable and Distributed Energy Resources

Issued in September 2012, this report argues that"market participation and policy support will be essential to open opportunities for business investment and innovation, yet issues of pricing schemes and market designs that properly align with grid controls, who pays and how much for critical research, infrastructure and technology are only beginning to be examined."[47]

Lawrence Berkeley National Lab

LBNL is focused, in part, on providing technical assistance relative to the impacts of energy efficiency on utility costs, revenues and customer bills. This work is funded by DOE Office of Electricity Delivery and Energy Reliability for state regulatory commissions, state energy offices, investor-owned utilities and the State Energy Efficiency Action Network.

In addition, LBNL is currently working on a project entitled: "Quantifying the Financial Impact of Distributed Solar on Utility Rates and Profitability". Technical report forthcoming. Link to Power Point presentation outlining scope of work: http://westernenergyboard.org/wp-content/uploads/2014/03/03-25-14-CREPC-SPSC-satchwell.pdf

Utility of the Future Center at Arizona State University

According to its website, the Utility of the Future Center is designed to assist utilities, regulators and consumers in making the move to a clean energy future. Former Arizona Corporation Commissioner, Kris Mayes, is the acting Director of the Center.

Utility of the Future Center Energy Innovation Policy and Technology, LLC (http://energyinnovation.org/), in partnership with America's Power Plan drafted the report "New Regulatory Models" (discussed above) for the State Provincial Steering Committee/Western Interstate Energy Board

Australian Energy Regulator – Better Regulation Program

In August 2013 the Australia Energy Regulator released its Reform Package Update that summarizes its efforts. 7 draft guidelines have been published with the goal of alter the mechanism for receiving and evaluating network/distribution company expenditure proposals and determining revenues and prices.

Implicit in the Better Regulation Program are incentive sharing mechanism for savings on Opex and Capex, a requirement to consider non-network alternatives on par with network alternatives, an increased role for economic forecasting and assessment as tools in the regulatory process, and encouraging and assisting customers with participation in decisions about the network.

[47] California Institute of Technology Resnick Institute, Grid 2020, Toward a Policy Renewable & Distributed Energy Resources, Page 2, (September, 2012). http://resnick.caltech.edu/docs/R_Grid.pdf.

Specific tests (e.g. RIT-D) have been developed by AER to force a cost/benefit analysis in reviewing the economic efficiency of network investment. Under this process, distribution companies follow a consistent national process annually for planning, reporting and project assessment.

For a full treatment of the AER/BRR refer to the following:
http://www.aer.gov.au/node/19146

E21 Initiative

The Great Plains Institute has recently partnered with Xcel Energy, Minnesota Power, the Center for the Energy and Environment, George Washington University Law School and other stakeholders to review regulatory model in Minnesota. This effort is represented as attempting to address the following:

- Stabilizing rate impacts and providing competitive, equitable, and transparent rates.
- Aligning utility and customer interests with the pursuit of Minnesota's goal of an 80% reduction in GHGs by 2050 and the transition to a sustainable, carbon-neutral energy system.
- Providing for economically viable utility business model(s) that supports energy efficiency, renewable energy, distributed generation, and advanced energy technologies.
- Providing for a reasonable rate of return for utilities and other energy producers and a fair allocation of costs for all customer classes, with as few stranded assets as possible during the transition.
- Better aligning state and federal authority in light of the changing nature of the electric energy system and the increasing interstate character of utilities.
- Better coordinating processes and markets for infrastructure development across transmission, generation, distribution and storage technologies.
- Reducing regulatory administration costs and resources (e.g., results in fewer rate cases or otherwise reduces the burden of the regulatory process).

For a full treatment of the e21 Initiative see:
http://www.betterenergy.org/projects/e21.