**Memorandum**
**From:** Seth Handy
**To:** Jonathan Schragg
**Date:** May 2017
**Regarding:** Rhode Island Division of Public Utilities and Carriers & Office of Energy Resources Power Sector Transformation Q&A

I respond on behalf of Handy Law. We are not representing NERI with regard to these proceedings as of this time. We also, admittedly, do not have the expertise of others on these matters so have mostly relied on other sources (that we've accumulated over years of work on reform efforts) to gather what seemed to be pertinent and possibly helpful input. The exercise of hunting and gathering took considerable time so please forgive us if some content isn't directly responsive or perfectly organized.

*Questions for stakeholders on utility functions*

*1) Which of the functions described here are integral to the future electric utility?*

**Reply:** All of the functions listed on Page 3 of the Inquiry are integral pieces of an Electric Utility Business Model. The question is, how are those services structured, who provides the services, are they cost effective for the end user and do they move Rhode Island toward its renewable energy goals? The Grid of the Future will be bi-directional, flexible and designed to encourage renewables, co-generation, storage systems and other on-site generation. It will be efficient and cost effective. It will match generation with point of use loads, reducing transmission, fuel conversion and standby generator losses, as well as the need for new transmission and distribution capacity. It will utilize multi-directional open access information and communication technology to maximize market forces driving efficiency, load management, peak shaving, dispatchable generation and storage. It will be interactive, encouraging user conservation, power use scheduling and changes in consumer use based on clear market signals. This redesigned grid will enable new opportunities in technology, finance, contracting and other critical areas of innovation. With thousands of dispersed generators and microgrids, it will be more resilient and less subject to failure. It will capture input energy efficiently through combined heat and power and similar solutions, significantly reducing fuel needs relative to energy demands. It will be safer and more environmentally sound, increasingly powered by renewable energy generators. As our existing stock of power plants ages and heads towards decommissioning, new realities are emerging that will shift the traditional utility model from overdependence on inefficient centralized monopolies to an open participatory model, with distributed generation, distributed storage and micro-grids first supplementing and eventually replacing most of the traditional generators we now depend on. Sensible public policies are needed to enable and accelerate the transition to robust, reliable, resilient and affordable energy delivery systems of the future. [Source - Unger & Meyers, "Rethinking the Grid"]

So how do we plan for the Grid of the Future? Planning must integrate local and regional level resources. In other words, ensuring that when planning for new power plants or power lines, utilities (or grid managers) consider how needs can be met with local solutions including rooftop solar, energy storage, electric vehicles, and even non-capital measures like controllable, smart appliances.

There must be independent, neutral operation of the distribution system. In other words, removing the conflict of interest that causes incumbent utilities to prefer building new infrastructure to conservation, efficiency, or local power from competitors or even utility customers. Proactive system planning is the key. Hawaii and New York are good examples of states that are implementing energy plans that incorporate the integration of local and regional resources. New York's Reforming the Energy Vision also proposes the independent operation of the distribution system. [Farrell – "Beyond Utility 2.0 to Energy Democracy"]

Decoupling is the first step toward the independent operation of the distribution system, having already been adopted in 7 states (with a dozen other states either piloting decoupling or using alternative policies with similar outcomes). This policy breaks the connection between electricity sales and utility revenue, to remove the disincentive for energy efficiency. Some ten states have gone further, completely moving energy efficiency program responsibility from the utilities to a third party. However, regulators in New York warn that while decoupling makes utilities indifferent to sales losses from energy efficiency and distributed generation, it does not shield ratepayers from the risk of widespread revenue loss should distributed generation grow substantially. The other substantial policy change is shifting from shareholder returns based on infrastructure investments to performance-based returns; returns based on a flexible, low-carbon, efficient electricity system. Some states, like New York, have layered financial penalties for non- attainment on top of the existing return on equity formula. In other words, for-profit utilities can lose money when they fail to accomplish objectives related to clean energy. [Farrell – "Beyond Utility 2.0 to Energy Democracy"]

The structural center of a democratized electricity system is grid management that cannot discriminate against its users, similar to management of roads. Road networks don't differentiate between the Postal Service or UPS, and the distribution grid should be similarly open to resources from any provider. The grid manager should not have a financial interest in building new wires or power plants at the expense of its competitors. The rules of the grid should also enable peer-to-peer transactions via equal access and transparent pricing (for energy, voltage and frequency response, ramping, etc). This would mean that a wind farm on a Native American reservation can sell power to a solar-dominated microgrid in Minneapolis, and vice versa. [Farrell – "Beyond Utility 2.0 to Energy Democracy"]

We cannot plan for the future until we figure out how to fully value DERs. Historically, the electricity system has not fully valued DERs in distribution system planning and investment, despite potential benefits of DERs to the grid. While some utilities have employed DERs to modify peak loads and reduce wholesale peak costs, DERs can provide other services that may not been fully accounted for in existing tariffs. In fairness, utility companies may not have fully leveraged DERs in part because the regulatory framework guiding utilities' business model did not explicitly orient the utility to recognize that value. Now that is changing. Due to cost reductions and accelerating adoption curves, DERs matter, and states and utilities are taking DERs more seriously in business model development and planning. [Source – Crosby & Call, "NY & CA Are Building Grid of Future"]

Pursuant to the regulatory compact, utilities have long maintained a monopoly control of the distribution network. This allows for reliable system planning, but has also resulted in a "black box" around distribution system planning and costs. We have the opportunity to shed light into the distribution system planning processes and costs. One way to achieve this would be for utilities to file resource plans to make public where grid constraints exist and investments required, and to shift planning and investments toward integration of DERs. [Source – Crosby & Call, "NY & CA Are Building Grid of Future"]

In New York, the NYDPS Staff Straw Proposal proposes that utilities should file near-term "distributed system implementation plans" (DSIPs), in which utilities will describe how they plan to transition to being a DSP provider, and how they will recognize DER contributions that might otherwise compete against traditional infrastructure investments. [Source – Crosby & Call, "NY & CA Are Building Grid of Future"]

In California, AB 327 requires IOUs to file DRPs that include scenario-based planning as well as integration analyses. Scenario-based planning accounts for different DER adoption scenarios, as well as other factors that might impact the need for DERs, such as retirement of large power plants. The CA IOUs are required to define the criteria for determining what constitutes an optimal location for DER deployment, and then identify values for the deployment via online mapping tools. The IOUs are also required to conduct integration analyses to measure the threshold integration of DERs, based on assumptions related to DER impacts on electric system reliability and safety. [Source – Crosby & Call, "NY & CA Are Building Grid of Future"]

The proposed CA approach is different from the NY approach because the utility, rather than the market, is in an active position to define the DER valuation and criteria for determining how much DERs can safely be added to the system (although both analyses are subject to public processes). [Source – Crosby & Call, "NY & CA Are Building Grid of Future"]

States have an opportunity to open the DER market to providers that have direct access to customers, with new products and services that attract and excite customers to adopt DERs and actively manage them. New York has clearly stated its intent to change the utility's role from commodity service provider (kWh) into a platform for an untold number of new energy services and service providers. [Source – Crosby & Call, "NY & CA Are Building Grid of Future"]

*2) Are there additional functions not described here that should be included as a strategic focus of the electric utility?*

**Reply**: The approach to distributed resources should be reevaluated to determine how demand management can be used not as a last resort but rather as a cost effective, primary tool to manage distribution system flows, shape system load, and enable customers to choose cleaner, more resilient power options. It is technically feasible to integrate energy-consuming equipment, as well as distributed generation and storage, fully into the management architecture of the electric grid. The purpose of this inquiry is to examine how the distributed grid architecture that is now technically feasible can be achieved on a wide scale. Such architecture offers the potential of increased efficiency and reduced volatility in system management at both bulk and distribution levels, as well as reduced total consumption and greater penetration of clean and efficient technologies, with ensuring benefits in overall system costs, reliability, and emissions. It also offers the potential for customers to optimize their individual priorities with respect to resilience, power quality, cost, and sustainability. It is not intended to replace central generation, but rather to complement it in the most efficient manner, and to provide new business opportunities to owners of generation and other energy service providers. Distribution utilities will play a pivotal role, representing both the interface among individual customers and the interface between customers and the bulk power system. The utility as Distributed System Platform Provider (DSPP) will actively coordinate customer activities so that the utility's service area as a whole places more efficient demands on the bulk system, while reducing the need for expensive investments in the distribution system as well. The function of the DSPP will be complemented by competitive energy service providers; both generators of electricity and retailers of commodity will expand their business models to participate in Distributed Energy Resources (DER) markets coordinated by the DSPP. [Source - NY REV]

Transition to a DSPP model should occur through incremental steps that are guided by a clear set of long-term goals and objectives. Emphasis should be placed on developing the regulatory and system platforms that support innovation while providing the appropriate level of protections to consumers. Because technology as well as service and product innovation are at the heart of the distributed grid, it will be important for the Commission to remain focused on framing the vision and the regulatory incentives. The Commission should enable the risk and reward mechanisms that enable innovation without trying to select the winning technology or products. At the same time, it will be critical to take the first tangible steps that will drive change and long-term value. Thus, in addition to establishing regulatory and incentive platforms that will support long term market based transformations, this proceeding should allow participants to identify the technologies and programs that serve as a base for supporting the transformation. These technologies and programs should have immediate consumer benefit and be scalable to support systemic change. [Source - NY REV]

The DSPP will identify, plan, design, construct, operate, and maintain the needed modifications to existing distribution facilities to allow wide deployment of distributed energy resources. The DSPP will therefore be responsible for transforming existing distribution systems into a platform not only for DER, but also for a range of products and services that will enable greater efficiencies in the generation, management, and consumption of electric energy. To achieve this, the DSPP will also have to control, manage and balance distribution-system-level DER in real time, and promote new products and services to meet customers' evolving needs. [Source - NY REV]

The incumbent distribution utilities are best situated to perform these functions and tasks. As the entities that planned, designed, built, and have operated existing distribution systems, they are uniquely positioned. Just as importantly, they know how existing distribution systems are operated under real world conditions, and engage in frequent contact with the ISO related to system reliability issues. They also know the specific needs of many customers served by such systems. In many instances, the upgrades needed to facilitate two-way power flows, automated controls, instantaneous communications and dynamic management of energy sources and loads can and will be designed and engineered to work with existing facilities. The incumbent utilities are best positioned to carry out this work. In taking on the role of DSPP, the distribution utility expands its function from being a physical conduit for delivery of electricity, to also being a transactional platform for a distribution-level market. The relationship between utilities and regulators has long been shaped by the fact that physical delivery of electricity across a service territory has been a natural monopoly. The introduction of widespread distributed resources can be perceived as challenging the natural monopoly model of utilities. But even if the sources of power are distributed, the need for a single entity to be responsible for reliability of the overall system remains. The vision does not eliminate the natural monopoly of the distribution system operator; rather the locus of the natural monopoly is shifted from sheer physical delivery to management of a complex system of inputs and outputs while maintaining reliability. [Source NY REV]

An integrated utility service (IUS) model is being explored by Ft. Collins Utilities with the help of Rocky Mountain Institute and other collaborators (some other U.S. utilities are also experimenting with various aspects of the model). With an IUS, the utility would offer a suite of DERs, such as energy conservation and/or solar offerings to its customers through third-party contractors. Although the utility would likely see less revenue from electricity use (since grid demand in homes and buildings would be reduced), the utility could expand its offerings by managing additional value-added energy services. Customers would pay for the energy measures over time on their electricity bill, likely with net bill savings. This model benefits from streamlined adoption and reduced hassle factor as well, in a similar manner to PACE, OBR, and OBF programs. For a municipal utility, this particular initiative could be entirely led by and accountable to the community. [Source – RMI, Community Energy Resource Guide]

Discuss with electric distribution planning staff at National Grid ways to address a gap in stakeholder engagement. Start by confirming the set of interested stakeholders (e.g. OER, the EERMC, and the DG Board), then identify or create opportunities outside of PUC dockets for these stakeholders to engage with the utility on distribution investments pertaining to load growth. Concurrently, determine if and how distribution planning/SRP can be coordinated with net metering to offer enhanced incentives above what is currently available to promote the development of DG where it is most needed, if determined to be cost-effective. Work with National Grid distribution planning to determine how and to what extent forecasted DG from REG, net metering, and any other applicable renewable energy promotion processes can be incorporated into distribution planning. Also consider how this can be done for other forms of DER and for strategic electrification in the longer term. Ensure that any resulting information from above is coordinated with Grid's current "long-range capacity plan" and future distribution planning where appropriate. Gain an understanding of how the long-range capacity plan and ISR could be used to merge traditional "poles and wires" approaches with new technologies in a multi-year, strategic approach. Explore the role that robust measurement and verification processes have in distribution planning to enable planners to better understand the costs and benefits of capital investments and technology deployment, ultimately as a basis for informing future decision-making. Work with National Grid to better understand the overlap between "asset condition" and "load relief" projects as identified in distribution planning and proposed in the ISR. understanding the dynamic between asset condition and load relief projects is necessary information for the future update of the Standards to potentially open up more projects to NWA eligibility. [Source – SIRI]

The planning and investment policies that govern our power grid were developed in an earlier era, when large fossil-fueled power plants were constructed to energize population centers. Longstanding policies skew decisions in favor of legacy power grid investments over newer, often less expensive and more advanced solutions. For example, the costs of paying for transmission projects are "socialized" in many regions of the country. This approach spreads the cost of transmission projects to ratepayers in all states in the power pool, while lower cost local options are rarely considered and are not eligible for this type of socialized cost recovery. These rules need to change so that viable, often lower-cost alternatives to large-scale trans- mission projects—such as energy efficiency, clean distributed generation, energy storage, and demand response—are not excluded when considering investments to maintain and improve power reliability. Such alternatives can replace or defer the need to construct more grid infrastructure, immediately delivering economic and environmental benefits. [Source – ENE, Energy Vision Framework]

The traditional ratemaking methodology that guides distribution utilities' decision-making focuses on certainty: allowing a utility to recover its investment plus a rate of return set by regulators. This practice was established decades ago and premised on investments in a largely stable and proven infrastructure of power plants, substations, poles and wires. Currently, there is a lack of clarity as to how new technologies and grid modernization strategies, which do not fit neatly into the old rate of return model, will be treated by utility and grid regulators. This uncertainty can discourage utilities from deploying advancements like time varying rates, load control, or voltage regulation and limits utility approaches to smarter grid options. New technologies can deliver substantial benefits, including increased reliability and efficiency, lower costs and bills, increased consumer control and choices, and lower greenhouse gas emissions. Reformed regulatory models are needed to remove current uncertainties and align utilities' financial incentives with the states' clean energy, carbon reduction, and economic goals. [Source – ENE, Energy Vision Framework]

Utilities should account for carbon emission costs in resource planning, and align those costs and risks with likely carbon-reduction scenarios. Failing to effectively mitigate carbon risk will lead to higher shareholder and lender risks, as well as unreasonably burdening ratepayers with higher costs. Investors and utility commissions will be scrutinizing electricity supply portfolios more closely to evaluate impacts associated with new climate regulations. Even though the details of legislation could significantly influence the ultimate carbon price, accounting for a range of potential carbon costs will lead to more prudent decision-making. The results of a Lawrence Berkeley National Laboratory study of utility practices for quantifying carbon financial risks indicate that the best-equipped utilities will have planning scenarios that include:

- the most likely future regulatory outcomes;
- a wide range of possible carbon prices; a diverse set of low-carbon portfolios capitalizing on energy ef ciency and renewable resources;
- 10–20 year time horizons;
- potential indirect effects of carbon regulation;
- accounting for risks attributable to uncertainty in future technology costs; and
- the value of emissions avoided through EE and reduced carbon regulatory risk.

To achieve the conditions that will produce meaningful increases in clean energy resources and significant reductions in GHG emissions, utilities must be actively involved in the transformation. To ensure that this happens, utilities need to clearly understand the rules of the game, and receive strong signals from regulators on how to best deploy resources.

A key component of successfully implementing a clean energy strategy is to reduce or eliminate the regulatory risk associated with these programs. Utility management will be hesitant to embrace what some might consider non-core activities if they feel they are putting shareholders at risk. A solution could be to create targeted incentives that give premium returns on the "right" investments. In such cases, policy makers:

- decide what the right investment choices are (e.g., generation with low carbon emissions, or energy ef ciency);

- determine the value of the externality that is derived by selecting the right investment (e.g., the cost of a ton of $CO_2$); and

- build a portion of the value into the rate that the utility uses with its customers (e.g., 25 percent of the value of $CO_2$ avoided). An important advantage to a targeted incentive is that it be crafted to reward specific choices, and is relatively simple to implement.

While auction markets can arguably provide better incentives for power plant owners than the regulators who preceded the marketplace, the actual results depend less on the theory than on the practice. An essential characteristic of a successful ISO is that its governance is active, representative of stakeholders and transparent in its decision-making. State regulators should insist that ISO/RTO governance meets these expectations. Commissioners must be engaged with the ISO, participating wherever possible on advisory bodies or in forums where policy is decided. This includes participation in dockets at the Federal Energy Regulatory commission (FERC) when ISO tariffs are considered.

[Ceres – 21st Century Utility Business Model]

*3) Are there functions described here that should be provided by an unregulated third party, or through a market-based approach?*

**Reply**: The DSPP will modernize its distribution system to create a flexible platform for new energy products and services, to improve overall system efficiency and to better serve customer needs. The DSPP will incorporate DER into planning and operations to achieve the optimal means for meeting customer reliability needs. The factors to be considered in such planning will be grounded in the State's policy initiatives, such as policies promoting clean generating technologies, reducing costs, and making the electric grid more resilient and secure. [Source NY REV]

The DSPP will create markets, tariffs, and operational systems to enable behind the meter resource providers to monetize products and services that will provide value to the utility system and thus to all customers. Resources provided could include energy efficiency, predictive demand management, demand response, distributed generation, building management systems, microgrids, and more. This framework will provide customers and resource providers with an improved electricity pricing structure and vibrant market to create new value opportunities. The DSPP will enable the adoption of information technology and real-time information flow among market participants, and establish a platform to support demand-side markets and technology innovation. DSPP products and pricing structures will allow for large scale deployment of clean DER, including energy storage that complements renewables, into the electric system. The DSPP should serve simultaneously as the interface among retail customers in distribution-level markets, and the interface between retail customers as a whole and the ISO. At present, a utility generally bids its load into the market as a price taker. Taking advantage of more responsive distributed energy resources, it could bid load in a more predictive fashion that saves money for customers and creates greater system wide efficiencies. The DSPP could function as the aggregator of aggregators and interface with the ISO in this manner. In addition, just as we have seen in the bulk power markets, as technology evolves the DSPP can introduce new markets and products at the distribution level that will yield further benefits to consumers. This will require the DSPP to use localized, automated systems to balance production and load in real time while integrating a variety of DER, such as intermittent generation resources, and energy storage technologies. The DSPP would manage DER products and services in real time, using technologies that allow the flexible and instantaneous use of generation or demand response to meet customer and system needs. Such applications could potentially maximize the operational and economic efficiency of DER and distribution systems. Implementation of DSPP functionalities will need to be carefully staged, taking into account cost-effectiveness, customer participation, local system needs, and the scalability of near-term measures toward long-term implementation of a fully integrated grid. Resolution of pricing issues in a DSPP model could affect the long-term role of net metering for solar and other clean energy projects. Net metering acts as an incentive to promote desirable technologies, and also serves as compensation for the system contribution made by customer-sited generation that feeds into the grid. If DSPP markets are developed correctly and aligned with the Commissions policy objectives, in time they should serve as a replacement for net metering that serves both functions -- incentive and compensation – via market mechanisms that more properly value both environmental benefits and system contributions. [Source NY REV]

Rather than a specific program funded through a surcharge, efficiency will be one of the DER tools at the utility's disposal. The DSPP will integrate energy efficiency into its system planning, targeting efficiency where it will produce maximum system value, and thus optimizing the economic value of energy efficiency expenditures for all customers. Efficiency programs may also be implemented on a territory-wide basis by enhancing customers' ability to manage bills and other objectives of the Commission. The existing DMS infrastructure must be upgraded as a part of the anticipated transformation of the electric grid. The DSPP must procure and employ advanced distribution management systems that will be needed to enable distribution systems to serve as the platform for integrating DER technologies. Such advanced systems will be essential to allow wider deployment of DER, including renewable generation resources such as solar and wind. To the extent the DSPP manages a market, an independent operator is arguably preferable. [Source NY REV]

Although competitive processes are more likely to stimulate innovation in DER products for consumers, there may be products that are so closely tied to critical reliability interests that direct utility engagement is needed. At a minimum, the public interest will require that utilities be available to provide essential services that are not provided through competitive markets. Where a utility has imminent operational and planning needs and/or can provide resources that are not available in the commercial market, a pragmatic approach may be preferable to a theoretical approach to the optimal operation of markets in an as-yet-unrealized system. [Source NY REV]

If interconnecting at the distribution level, an interconnection agreement must be made between the microgrid facility and the local distribution utility. Distributed resources including microgrids must meet the technical requirements that allow for parallel operation with the utility system. During a utility grid outage, the microgrid can intentionally island itself to maintain critical loads. In such a configuration, equipment must be employed to ensure the safe and appropriate disconnection of the microgrid from the rest of the grid. It is critical that the islanding is intentional as it ensures the surrounding grid will not be unintentionally energized (backfed) by the energy resources contained with the microgrid. Isolating from the grid to provide service in the event of widespread outages can be a considerable benefit for customers. In addition to ensuring safe operations, reliability and resiliency concerns must also be addressed. Infrastructure must be employed within the microgrid to ensure good power quality, such as generation and load management (balancing) systems, and black start capability, which ensures that the microgrid can come online in the event of a utility grid outage. [Source NY REV]

This initiative will establish new markets for demand management services and tools, as well as cleaner and more resilient power options. Products of this nature are already offered by energy services companies (ESCOs), utilities and other vendors, primarily designed for larger electricity users. One objective of this proceeding is to explore whether, and how, a broadly expanded portfolio of these products and services can be developed and made available to all electricity consumers. ESCOs, utilities and other vendors will have a key role in developing and selling these innovative services. ESCOs should become providers of bill management services. The vision in which retail suppliers, demand management companies and others develop and provide innovative products and services may be achieved through a wide range of business models. [Source NY REV]

Small commercial and residential customers in New York and other states are beginning to benefit, to a limited extent, from metering retrofit services, wireless HVAC control and diagnostic sensors, single open protocol software platforms, controllable Wi-Fi thermostats, energy advisory support, mobile applications, desktop dashboard alerts, and financial business incentives. ESCOs and other vendors are generally just beginning to offer these products and services to mass-market customers. In addition, the cable television industry is beginning to offer energy commodity service as well as home energy management tools to residential customers. Products designed to change customers' behavior regarding their energy use have been developed by companies that are partnering with utilities and ESCOs to promote behavior change primarily for residential customers. [Source NY REV]

Other business models include community aggregation programs (e.g., municipal, community, commercial, non-profit), community and multi-family building based renewal energy projects, regional "Main Street" venues which might include the sponsorship of micro grid projects or community based DER/generation projects, and "buy local" green power initiatives. New technologies are being developed by a wide array of companies, some very large and well-established, others start-up, that will invariably lead to additional innovative products and services if markets are established that enable customers to have access to these products. [Source NY REV]

Arlington County, Virginia, and St. Paul, Minnesota, are both recognized as champion cities in the U.S. for their district-energy cooling and/or heating systems. Cities without these systems may consider commissioning new ones for areas with large loads and density such as downtowns, hospital and business districts (and they can also be used successfully in high-density residential areas). A recent United Nations Environment Program (UNEP) district energy report notes that one of the most cost-effective means for reducing greenhouse gas emissions and primary energy demand is a modern district-energy system, especially one that incorporates combined heat and power (CHP, or co-generation). The analysis finds that modernizing district-energy systems can reduce heating and cooling primary-energy consumption by up to 50%. Since many systems are developed and/or operated by private-sector companies for communities, this opportunity also represents a unique public/private partnership. Co-benefits include cost savings from avoided and/or deferred investment in power- generation infrastructure, peak-load reduction, local investment and tax revenue, and local employment. [Source – RMI, Community Energy Resource Guide]

Communities may wish to assess large portfolios of public buildings for efficiency improvements, and may wish to collaborate with the private sector entities interested in the same. There are several ways to analyze and plan the phasing of retrofit measures across large portfolios of buildings. First, relative performance comparisons can be made across the portfolio, and packages of improvements can be applied broadly to groups of similar buildings. As part of this process, right-timed deep retrofits which coincide with capital improvement projects can be considered to increase return on investment. Further, a select few buildings might be considered for innovative pilot projects. [Source – RMI, Community Energy Resource Guide]

The emergence of new analytical software tools is helping to make portfolio-scale energy assessments easier and more cost effective, both for cities and for other large portfolio owners. RMI examined the use of these software tools to support the portfolio-assessment process and concluded that these new analytical software tools are helping to make portfolio-scale energy assessments easier, although the process does present challenges as well. Private-sector companies selling such tools include First Fuel, Retroficiency, and others. Communities considering portfolio analytics for public buildings may wish to interview a select few providers and conduct a pilot to assess cost effectiveness and potential before committing to a larger portfolio. [Source – RMI, Community Energy Resource Guide]

Multiple levers are available to communities interested in increasing efficiency and renewables. Potential solutions include both utility and non-utility levers. Utility levers include efficiency rebates, green tariffs, community solar, net metering, and competitive retail supply. Non-utility levers include self-generation, which can be on-site, or via an off-site power purchase agreement (PPA); community choice aggregation; and renegotiation of franchise agreements. The  latter option may include a community choosing to "municipalize," that is, to purchase electric distribution assets from an investor-owned utility and operate a municipal utility (and conversely, the sale of existing municipal-utility assets to a local investor-owned utility is also an option). A third option for communities served by either investor-owned utilities or by cooperatives with long-term supply agreements from generation and transmission utilities is an "enhanced franchise agreement" that includes targets for achieving specific community goals. Examining these options can help identify the specific levers that meet community needs. See the solution boxes throughout this subsection for more information on each of these options. [Source – RMI, Community Energy Resource Guide]

Community choice aggregation (CCA) is a legislatively-enabled policy that allows local jurisdictions to aggregate electricity demand to procure renewable energy supplies while maintaining the existing electricity-provider relationship for transmission and distribution services. States that have passed CCA laws include Illinois (2009), New Jersey (2003), California (2002), Ohio (1999), Massachusetts (1997), and Rhode Island (1997). Reasons that a community may choose to develop a CCA include the option to purchase more renewable power, reduce electricity cost, and/or provide power from more local sources. Most CCAs are "opt-out," meaning that customers have the option of continuing to take service from the incumbent utility if they choose. Notably, opt-out design results in much higher participation rates compared to traditional utility green-power programs. Participation rates for opt-out programs that offer additional renewable energy are approximately 75%, compared to less than 20% for utility green-pricing programs.

The major consideration when developing a CCA option is whether or not the CCA can offer additional renewables (above the incumbent utility's generation mix) at an equivalent or lower price. The Center for Climate Protection is one organization that works with communities in California to set up successful CCA programs. For additional information on CCAs, including example communities, see the Resources box at the end of this subsection. [Source – RMI, Community Energy Resource Guide]

Large utility customers with a desire to source renewable energy for their facilities are finding that new renewable energy options, often provided by third parties, can be competitive with retail rates. Utilities, including vertically integrated utilities in regulated electricity markets, are exploring how to respond to rising demand from companies such as Google and Walmart for cost-effective renewable-energy supply. One example is the Green Source Rider recently approved by the N.C. Utilities Commission. Under the Green Source Rider, Duke Energy will match qualifying large customers with renewable energy from Duke itself or third-party suppliers, and that energy will be in addition to the power generated to satisfy North Carolina's renewable portfolio standard. At this time, only large commercial and industrial customers adding new load of more than one megawatt (e.g., manufacturers, big-box retailers, or college campuses) are eligible, and the program is reported to have no cost impact on other customers. For more information on green tariffs, the World Resources Institute has recently completed a guideline, Green Tariff Design for Traditional Utilities. [Source – RMI, Community Energy Resource Guide]

No longer will our energy dollars be poured only into massive power stations and miles of wire. The new grid is at our homes and businesses, where users control energy use and improve energy efficiency; install smart appliances; generate electricity from solar and distributed energy sources; plug in our cars; connect to community wind, solar, and cogeneration; and earn incentives for using power when the grid is most available. We can begin to think of and manage our homes and businesses as our own "micro-utilities," handling many of the services currently managed by large power companies, and doing so with new, efficient and clean technologies. [Source – ENE, Energy Vision Framework]

Under a network utility approach, the utility would provide highly differentiated price signals to direct investments by other service providers. In this case, the utility's role would increasingly be focused on maintaining and operating the grid and on creating markets, managing transactions, replacing aging distribution equipment, and/or making smart grid investments and interconnecting buyers and sellers with the network. This network utility would shepherd and coordinate the network of increasingly complex transactions among growing number of actors. The utility in this scenario would evolve toward a role more like that of grid owner/operators at the wholesale level, enabling markets for energy, capacity, reserves, and ancillary services that differentiate value for these services according to time and location.

The network utility model is the right approach because it allows the competitive markets to direct the provision of innovative technologies and services to customers, while providing incentives that reflect the costs and benefits to the grid from distributed resources. The utility isn't the most efficient or cost effective provider to install distributed resources on the customer's side of the meter, or even to manage such investments through contracting to third parties in today's rapidly changing environment. The utility of the future will look increasingly like today's independent system operators: providing time-varying price signals via the grid that encourage other companies to make customer-level investments to create value by providing energy supply, managing load shapes, or providing ancillary services to help manage the grid. [RMI – Adapting Utility Business Models for the 21st Century]

*4) To the extent certain activities now being performed by the utility may be performed by other market actors, what type of oversight should be in place to protect customer interests?*

**Reply**: Third parties, including energy service companies, will play a crucial role in optimizing customer participation, and improved access to data may be needed for these market participants. The regulatory framework must balance that usefulness with appropriate protections related to individual privacy, critical infrastructure, trade secret and other confidentiality concerns. Marketers will need to identify incentives and technologies to increase customers' knowledge and ability to manage their energy bills. For example, energy product interfaces (e.g., web portals, mobile applications, etc.) should be easy to use, simple to understand, and educate customers through the use of these technologies. Also, many customers will stay with a default option over an option that requires an affirmative decision. Default options for usage data access should be carefully weighed both for their effectiveness in shaping consumer decisions and their fairness to all customers. In many other cases, customer behavior is simply a matter of resource allocation.  [Source NYREV]

Market participants must design, and the Commission should carefully monitor, promotional frameworks that address the cultural and behavioral challenges presented by this fundamental and transformative change in how we generate, deliver, use, manage, and regulate electric energy. A vital part of a healthy market is information. Toward this end, customer outreach and education best practices will need to be identified. The interplay between traditional methods (i.e., bill inserts, direct mailings, print and digital media, etc.) and more contemporary methods (i.e., social media and community-based marketing approaches) will need to be examined. Customer diversity should be considered to accommodate different customer segments in demand-side programs. A vital part of a healthy market is information. Toward this end, customer outreach and education best practices will need to be identified. The interplay between traditional methods (i.e., bill inserts, direct mailings, print and digital media, etc.) and more contemporary methods (i.e., social media and community-based marketing approaches) will need to be examined. Customer diversity should be considered to accommodate different customer segments in demand-side programs.  [Source NYREV]

Local control and equitable access are the keys to unlocking an economic transformation that parallels the technological one, by allowing communities to maximize capture of their local energy dollar. It means an energy system that empowers electricity customers to manage their electricity use, produce power individually or collectively, and transact with their neighbors, local businesses, and their city. Consumers become, in Alvin Toffler's elegant description "prosumers." They can make the decision as to whether to consume, or produce, or store electricity at any given moment. Individuals and communities, formerly simply passive observers of utility-driven power generation, can become the agents of their own energy futures. . . The flattening of electricity demand and rise in distributed renewable energy are causing tension in the utility business. Utilities continue to make investments in the grid as though these changes are not already happening, largely because their financial incentives remain tied to a Utility 1.0 business mode. As former utility executive Karl Rabago says, "utilities simply do not think things they do not own or control can be resources."  [Farrell – "Beyond Utility 2.0 to Energy Democracy"]

**Demand Response (DR) after the court reversal of FERC order 745**

The D.C. circuit court of appeals handed regulators in "market" states a new duty: regulate demand response, arguably the most under-utilized demand-side resource. The court ruled that DR is a retail service, and not subject to FERC jurisdiction.  A large fraction of DR is unaffected by the ruling since the order applies only to states with wholesale markets.  FERC order 745 boosted demand response in wholesale markets. Now regulators in these states will step in for the market, setting compensation for demand response and ensuring that utilities make appropriate use of this valuable resource. ISOs have been using DR to meet peak demand and help integrate renewable energy; utilities in market states (like those in regulated states) can now use DR to avoid high peak energy costs, saving consumers money. Further, DR can help solve local reliability challenges in the distribution grid. As the dust settles on the court decision, "risk-aware" regulators in market states will rediscover DR as a tool to diversify and strengthen utilities' energy resources. [Source – Ceres, "Practicing Risk Aware Utility Regulation"]

*5) Many of the functions described here require the utility to manage complex technology systems. What kind of regulatory approach could address the risk of technology obsolescence?*

**Reply:** Developing a smart grid will require highly accurate monitoring of energy supply and demand, sophisticated analysis and modeling of supply and demand patterns under numerous conditions, real-time fault detection, and reliable nearly instantaneous control of varied and dispersed energy resources. To meet these goals, the DSPP must adopt communications networks capable of supporting a smart grid. Issues presented will relate to the reliability, reach, cost, latency and security of such systems. [Source NY REV]

The pace and scale of DER deployment in both NY and CA will rest, in part, on the breadth and depth of system and customer data and the availability of that data to customers (to manage their use), as well as to DER service providers (to develop new services and target those to locations most in need). For example, combined with a price signal, system data (such as metering at substation or other system nodes) exposes areas on the system where DERs can provide the most value, for example by alleviating congestion in load pockets. Customer usage data reveals the largest users of power, and therefore those most likely to be interested in DER solutions that can reduce their bills. [Source – Crosby & Call, "NY & CA Are Building Grid of Future"]

California has the head start in metering data collection due to roll-out in advanced metering infrastructure (AMI), as well as pioneering data-sharing tools such as Green Button, Green Button Connect, as well as other data-sharing mechanisms to make DER valuation more transparent that are considered in the DRP process. [Source – Crosby & Call, "NY & CA Are Building Grid of Future"]

However, NY has the potential to leapfrog CA on data in novel ways. The NYDPS straw proposal envisions a two-way data exchange, where DER providers are required to provide DER size and load reduction data to the DSP (like a generator would to a bulk system operator), and utilities would share system and customer data to the DER providers. Also, while AMI is an important enabler of measurement, verification, and communication, alternative metering and communication solutions such as revenue-grade metering and communication chips embedded in smart devices may offer more advanced features than existing AMI functionalities, particularly where metering is a challenge in environments such as New York City. [Source – Crosby & Call, "NY & CA Are Building Grid of Future"]

Additionally, in NY, the REV proceeding seeks to create a distributed system platform that allows customers, third-party service providers, and energy service aggregators to interact, not unlike other platform markets such as computer operating systems and smartphones. For example, the Apple iOS and iPhone serve as the platform on which other services are available, linking data and algorithms to devices that perform countless tasks, such as car sharing. [Source – Crosby & Call, "NY & CA Are Building Grid of Future"]

In both states, the customer is central to the adoption and integration of DERs, as well as the future business model of the utility. While utilities have established trust with many of their customers and provide safe and reliable service, there is an opportunity to let other companies offer more innovative customer solutions integrated with our online, digital lives. JD Power recently found that while overall customer satisfaction with utilities has improved, utilities are not keeping pace with other tech companies such as Google, Facebook, and Amazon that are positioned to disrupt the residential electric utility business models. [Source – Crosby & Call, "NY & CA Are Building Grid of Future"]

To achieve the goals of least cost, least risk and maximum customer benefit, regulators must require utilities to synchronize their implementation of advanced grid technologies with the growing DER market. Utilities perform this planning function today, but not usually in the public arena and not closely coordinated with other actors providing services on an upgraded distribution grid. This planning exercise is now loaded with new responsibilities for the grid operator. Further, if the utility also has a stake as a competitor with DER services, it is essential that an independent authority such as the state regulator oversees the planning. Consider the telecom sector following the passage of federal legislation in 1996. Incumbent carriers were required to unbundle their grid (the public switched network) and provide access to new players with new products, often competing with the grid owners. Regulators ensured that new competitors got access to the network on the same terms as the incumbents. Regulation of all players moved significantly away from the traditional cost-of–service model. [Source – Ceres, "Practicing Risk Aware Utility Regulation"]

*Questions for stakeholders on compensation*

*1) How should decisions made by a utility in performing particular functions affect the way it is compensated?*

**Reply**: Outdated regulations produce utility financial incentives that are locking in our energy future at a time when local energy resources like energy efficiency, rooftop solar, heat pumps, and smart energy management are reducing the need for large infrastructure. The existing rules and financial incentives are driving utilities to pick higher cost infrastructure investments while the best choices for consumers and the environment are disadvantaged. Acadia Center recommends the following reforms:

- Federal and regional electric grid regulators must allow utilities to recover costs and earn comparable returns on local energy solutions.
- Regulators must ensure that spending on the energy system is aligned with a state's goals for climate change mitigation and consumer protection.
- Regulators should develop a holistic approach towards utilities to address the conflicting incentives facing business units owned by the same parent company. To increase competition, regulators can consider prohibiting joint ownership of electric and natural gas utilities as well as transmission and distribution companies. [Source -Acadia]

Make sure Decoupling is designed and operating properly. For guidance on this see RAP, "Decoupling Design: Customizing Revenue Regulation to Your State's Priorities." While revenue decoupling can reduce the pressure to increase sales, incentives to build new power plants and power lines are often stronger. Most decoupling policies only apply to energy sales, not to the utility's return on equity – averaging 10% in 2013 – from building new power plants. As noted by Commission staff in New York: "[Rate of return] regulation may...encourage the utility to overinvest in capital spending, because earnings are directly tied to rate base." Ultimately, utilities that win approval for their capital investments are rewarded by the market, with a better credit rating and lower cost of capital. In the case of interstate transmission, utilities may be rewarded by the Federal Energy Regulatory Commission with a bonus to their return on equity. [Farrell – "Beyond Utility 2.0 to Energy Democracy"]

Avoid common pitfalls of utility net metering and interconnection policies and procedures, including:

**Restricting eligibility to certain classes of electric customers** Technical concerns have nothing to do with a customer's sector (e.g., residential, commercial, municipal, agricultural, etc.). Thousands of commercial customers have successfully connected renewable energy systems to the grid; many of these systems are in the multi-megawatt range.

**Limiting program eligibility based on the size of individual renewable energy systems** The size of a system should be determined only by a customer's load and by the nature of the grid. Given the success of policies that promote interconnected and net-metered systems in many U.S. states, policymakers considering establishing new standards should not feel obligated to limit the capacity of an individual system to an arbitrarily low limit.

**Preventing customers from receiving credit for excess electricity** Excessive limitations on surplus generation and rollover credits could render a customer's system a charitable donation machine—essentially providing free energy to the grid; energy that the utility will sell to neighboring customers. This situation will significantly lengthen the system's payback period, assuming the customer goes ahead with the project.

**Capping the total combined capacity of all customer-sited generators** Any comprehensive set of interconnection procedures must be governed by objective engineering criteria to ensure that participants do not strain the grid. Arbitrary limits on overall program participation should be avoided. Strict, artificially low limits are incompatible with aggressive renewable portfolio standards (RPS) embraced by many states. For example, a state with a goal of 2% solar electricity, such as New Jersey or Delaware, would have a hard time reaching that goal if the aggregate capacity of net-metered systems is capped at 0.1% of each utility's peak demand or annual retail sales.

**Charging discriminatory or unclear fees and standby charges** Fees for interconnection should be reasonable and proportional to a system's size and complexity. In the case of net metering, it is unreasonable to allow utilities to charge customers for reducing their electrical demand and/or consumption from the grid.

**Requiring—or allowing utilities to require—unreasonable, opaque or redundant safety measures, such as an external disconnect switch** These requirements usually arise from a utility's or a public utility commission's lack of familiarity with Underwriters Laboratories (UL)-listed inverters. In fact, a 2008 report by the National Renewable Energy Laboratory concluded that a redundant external disconnect switch only adds an economic burden on the customer and an administrative burden on the utility, without providing any necessary additional security. UL-listed inverters for small interconnected generators already provide the desired safety functions.

**Creating an excessively prolonged or arbitrary process for system approval**

National experts have already developed technical standards and procedures, such as the IEEE 1547 and the National Electrical Code, for grid-tied systems. There is no reason utilities should be allowed to spend more than a few weeks reviewing an interconnection application.

**Requiring—or allowing utilities to require—different technical provisions that vary by state to serve a distribution grid that is homogeneous nationwide** States should draw from one another's best practices for net metering and interconnection policies. No state needs to start from scratch, as several states, including New Jersey, Maryland, Illinois, and Colorado have already adopted best practices, which can be used as models for other states. Using these states as a starting point helps conserve stakeholders' resources. An additional benefit of uniform standards across states is lower costs for installers working in multiple states.

**Requiring—or allowing utilities to require—unnecessary additional liability insurance** Customers with grid-tied DG who already carry insurance policies that cover potential problems should not be required to increase their costs with unnecessary additional coverage.

[Source – Network for New Energy Choices, "Freeing the Grid"]

*2) What are ratepayers paying the utility for? How should it collect its revenue? Should its compensation differ according to each function?*

**Reply:** Rate plans should have pre-established means to determine whether a utility is spending adequate levels on necessary investments and maintenance of its system, so that later catch-up spending is not needed. There should also be upside protections on Capex spending to prevent unnecessary inflation of the rate base. Performance metrics need pre-established trigger points for re-evaluation, especially when the incentive includes both upward and downward reconciliations. Plans should have provisions to review and assess the long-term effect of the incentives and to modify them, as necessary. [Source NYREV]

Integrated Distribution Planning encourages the incorporation of DERs into every aspect of grid planning. The framework expedites DER interconnections, integrates DERs into grid planning, sources DER portfolios to meet grid needs, and ensures data transparency for key planning and grid information. Ultimately, the approach reduces overall system costs, increases grid reliability and resiliency, and fosters customer engagement. If grid planning decisions are made before consideration of customers' decisions to adopt DERs, – which is frequently the case today – grid investments will underutilize the potential of DERs to provide grid services, ultimately resulting in lower overall system utilization and higher societal costs of the collective grid assets. In contrast, prudent planners who proactively plan for customer adoption of DERs may avoid making unnecessary and redundant grid investments, while also enabling the use of customer DERs to meet additional grid needs. Ultimately, planning processes must ensure that DERs are effectively counted on by grid planners and leveraged by grid operators. The first step in grid planning is to identify the underlying grid needs. The use of alternative solutions such as DERs should be included in the portfolio of solutions that are considered to meet these grid needs. While utilities could ostensibly assess these alternative solutions within their existing process, opening up the planning process by sharing the underlying grid data would drive increased competition and innovation in both assessing and meeting grid needs. Any concerns from sharing such data – such as customer privacy, security, data quality, and qualified access – can be mitigated through data sharing practices already common in other industries. In fact, stakeholder engagement and access to planning data is already a central tenet in electric transmission planning across the country. The challenges of ushering a new industry norm of data transparency are far outweighed by the potential that broader data access can drive in increased stakeholder engagement and industry competition. Data transparency efforts should first focus on communicating the exhaustive list of grid needs that utilities already identify in their planning process. While utilities may claim that such needs are already communicated within general rate cases, the information contained in those filings are incomplete. A standard set of comprehensive data should be shared about each grid need and planned investment so that stakeholders can proactively propose and develop innovative solutions to those needs. This proactive data access broadens the set of innovative solutions made available to utilities and guards against an insular approach to deploying grid investments. While data on specific utility-identified grid needs is critical to assessing innovative solutions in place of traditional investments, underlying grid data should also be made available to foster broader engagement in grid design and operations. Access to underlying grid data allows third parties to improve grid design and operation by proactively identifying and developing solutions to meet grid needs, even before they are identified by utilities. Data that is made available on grid needs and planned investments is rarely provided in an accessible format. Often, information is provided in the form of photocopied images of spreadsheet tables within utility GRC filings, hardly a format the enables streamlined analysis. This data communication approach requires stakeholders to manually recreate entire data sets into electronic version in order to carry out any meaningful analysis, a time-intensive and needless exercise. Other potential stakeholders never attempt to engage due to the barrier of data access. The use of standard, machine-readable data formats is prevalent in many industries and within the utility industry itself; organizations like the Energy Information Agency (EIA) foster such broad access to electronic, standardized data sets. Distribution grid needs and planned investments should follow suit. [Source – Solar City, "A Pathway to the Distributed Grid"]

*3) Do any of the future utility functions described here merit a particular type of revenue recovery mechanism?*

**Reply**: Realigning the incentives of the grid planner to solely focus on delivering a safe, reliable and affordable grid, regardless of the ownership and service models that materialize in the market, is a necessary first step to realize the potential of DERs. There are two fundamental paths forward to address this conflict of interest.

The first path towards realizing this objective would be to separate the role of distribution planning, sourcing, and operations from the role of distribution asset owner, similar to the evolution of Independent System Operators (ISOs) and Regional Transmission Operators (RTO) at the bulk system level. FERC's decree to create independent operators in Order 2000 was driven by the observation that the lack of independent operation of the bulk power system enabled transmission owners to continue discriminatory operation of their systems to favor their own affiliates and further their own interests.

Solar City proposes the creation of a new utility incentive model, Infrastructure-as-a-Service, which would neutralize the utility incentive to deploy utility-owned infrastructure in lieu of more cost-effective third-party options. This model would enable utility shareholders to derive income from third-party grid services, mitigating the financial impact that may bias utility decision-making. Such a model would help ensure that utilities take full advantage of DER readily being adopted by customers.

Infrastructure-as-a-Service is a regulatory mechanism that would modify the incentives faced by utilities when sourcing solutions to meet grid needs. This new mechanism would allow utilities to earn income, or a rate of return, from the successful provision of grid services from non-utility owned DERs. Infrastructure-as-a-Service facilitates the least cost/best fit development of distribution grids by creating competitive pathways for DERs to defer or replace conventional grid investments, while maintaining equal or superior levels of safety, reliability, resiliency, power quality, and customer satisfaction. As the figure below shows, the three primary steps of a utility distribution planning process (forecast, identify needs and evaluate solutions) remain identical to the current process, followed by the infrastructure-as-a-Service mechanism's enhancements to sourcing in steps four (select and deploy) and five (operate and collect).

Under the proposed approach, after evaluating all feasible technical solutions for a particular grid need, including alternative grid solutions derived from DER portfolios, Infrastructure-as-a-Service would empower distribution planners to select and deploy third-party assets that address the specified need if more cost-effective for ratepayers than conventional solutions. Importantly, Infrastructure-as-a-Service would create an opportunity for utilities to operate and collect streams of service income, or a rate of return, based on the successful deployment of competitively sourced third-party solutions. This service income provides fair compensation for effective administration of third-party contracts that enable alternative resources to deliver grid services, and helps mitigate the structural bias towards utility-owned infrastructure that currently exists under distribution "cost plus" regulation. Note that other mechanisms attempting to achieve a similar utility indifference to DER solutions have been proposed, such as the modified clawback mechanism being discussed in New York. While the clawback mechanism offers the potential to reduce the financial disincentive that utilities face in utilizing DERs, the potential utility upside may be small as compared to the lost opportunity and insufficient to neutralize the utility disincentive. This downside to the clawback mechanism may be overcome via the infrastructure-as-a-service mechanism.

Neutralizing the utility disincentive to utilizing DERs is critical but not sufficient to drive transformation in distribution planning. New incentives may be ignored in practice without corresponding changes to long-established and familiar utility processes that have sourced only self-supplied solutions to date. The adoption of a Distribution Loading Order50 would borrow an existing concept from bulk system procurement policy in California, which prioritizes procurement of preferred resources, including energy efficiency, demand response, and renewable energy, ahead of fossil fuel-based sources. In the distribution context, a Distribution Loading Order prioritizes the utilization of flexible DER portfolios over traditional utility infrastructure, when such portfolios are cost-effective and able to meet grid needs.

In concert with a mechanism like Infrastructure-as-a-Service, a Distribution Loading Order provides the procedural framework for evaluating distribution solutions in order to ensure grid planning is consistent with longer term policy objectives that support environmental, reliability, and customer choice goals. Importantly, a Distribution Loading Order would ensure that DER solutions are properly incorporated into grid planning. However, utilities would always maintain the authority to select and deploy a suitable portfolio of solutions, including conventional solutions when more appropriate, to ensure reliability. For these conventional investments, utilities would continue to earn an authorized rate of return.

[Source – Solar City, "A Pathway to the Distributed Grid"]

*Questions for Stakeholders on Multi-Year Rate Plans*

*1) Should the utility be required to file multi-year business plans which forecast its business objectives and costs as a part of its distribution rate case? If so, what should be the period between rate cases?*

**Reply**: Extending the length of the rate plan (to as long as eight years, see later discussion of RIIO) may provide benefits such as better planning, more certainty, and fewer rate cases. This may give utilities the time and opportunity to implement an innovative sea change. An extended rate plan will create very powerful efficiency incentives (for both capital and operating expenditures) since utilities may reap more of the benefits of efficiencies until rates are reset. The term may enable utility management to focus less on rate matters and more on performance and customer goals. Deterioration of plant has always been a risk under multi-year plans and can be mitigated by clear metrics and oversight. The impacts of some extraordinary unforecasted changed circumstances (e.g., taxes, interest and inflation rates) can be resolved via reopeners; the need for flexibility and the benefit of certainty are balanced both through uniform policies and in individually negotiated cases. Perhaps the most effective tool to mitigate unintended results from extended rate plans is the presence of an earnings sharing mechanism with associated monitoring of the results. [Source NY REV]

Utilities should employ open and transparent planning processes that consider the risks, probabilities, benefits, impacts and applications of multiple energy resources under various scenarios. Planning processes should include a full commitment by utilities to implement cost-effective energy efficiency and renewable energy. Resource planning should involve greater stakeholder involvement on a wider regional level and consider the full spectrum of energy efficiency and distributed energy resources. Clear policy frameworks allow all parties to better understand the goals and regulatory objectives that will influence or constrain the planning process. Finally, utilities should update planning processes to reflect current and future values of $CO_2$, energy efficiency, distributed energy resources, equipment and permitting. [Ceres – 21st Century Utility Business Model]

Integrated resource planning is a tool to ensure that the utilities, regulators and other stakeholders have a common understanding of a full spectrum of possible utility resources; that the options are examined in a structured, disciplined way in administrative proceedings; that demand-side resources get equal consideration alongside supply-side resources; and that the final resource plan is understood (if not necessarily accepted) by all. In a transparent public process, the regulator examines competing portfolios, considering the utility's analysis as well as input from other interested parties. The regulator approves a plan and the utility is awarded a "presumption of prudence" for actions that are consistent with the approved IRP. The utility acquires (i.e., builds or buys) the resources approved in the IRP, possibly through a competitive bidding regime. The IRP must be meaningful and enforceable; there must be something valuable at stake for the utility and for other parties. Regulators must ensure that, to the greatest extent possible, all parties participating in the IRP process have timely access to utility data. Utility resource planning is one of the best examples of the need for a regulator to operate in legislative mode. When examining utilities' plans for acquiring new resources, regulators must seek to become as educated as possible. Up to a point, the more choices the better. The regulator should insist that the utility present and analyze multiple alternatives. These alternatives should be characterized fully, fairly, and without bias. [Source – RAP]

New Rules Project – Democratizing the Electricity System (Docket Page - http://www.ripuc.org/eventsactions/docket/4600-democratizing-electricity-system.pdf)

- Federal: stop favoring lavish transmission projects over local DG; simplify tax credit incentive (cash alternative)
- State: transparency about distribution system so developers can identify opportunities to interconnect; interconnection reform to ease integration (Southern CA Edison model at p 18) (model interconnection rules at p 36)
- Local: community choice aggregation for self reliance; solar access (to sun); local siting!
- No DG integration issues for grid experienced yet
- Future planner will grapple w ? of how to integrate centralized generation into grid primarily of DG & storage (p 25)
- Current stacking intermediate & peaking plants on top of baseload leads to curtailment of DG if no local load & excess capacity on grid (p 26) – change planning rather than cramming DER into baseload paradigm (need differentiation of seasonal and daily variability) – nonsensical to pursue 2 paradigms at once (both require major investment) so commit to new paradigm now (p 27)
- Tension between centralized & distributed generation of renewables manifest in transmission investment decisions – States want to generate rather than paying to be at end of pipe

Hawaii regulators began a stakeholder process in early 2013 that proposed the islands' largest utility, Hawaiian Electric Company, adopt a proactive approach to planning. The new process meant to integrate the utility's interconnection and distribution planning functions, requiring the utility to forecast distributed solar growth and to plan infrastructure upgrades to the distribution grid accordingly. Despite the proposed changes, permits for new rooftop solar installations fell by 44 percent from 2013 to 2014. In May 2014, the state's Public Utilities Commission took further steps. Issuing a white paper on the future of the state's electricity system, Commission orders also required Hawaiian Electric Company to re-do its resource plan to improve its planning for distributed generation, to "expeditiously" retire older power plants, and to increase grid flexibility with demand response and storage. The Commission also specifically ordered the Maui-based utility to stop curtailing renewable energy generation in favor of power purchases from its own fossil fuel power plants. [Farrell – "Beyond Utility 2.0 to Energy Democracy"]

*Questions for Stakeholders on Performance Incentive Mechanisms*

*1) There exist a range of policy goals to orient a performance based regulatory framework, including reliability, cost reduction, system efficiency, and greenhouse gas emissions reductions. Are there additional goals that should orient performance based financial incentives?*

**Reply**: Begin by identifying areas of interest to the state that are inadequately incentivized (e.g. SRP, environmental goals) and articulate goals. Then determine ways to incentivize these areas of interest under existing structures or through new structures. Identify candidate metrics against which performance incentives could be offered, or which would simply be reported. Based on the results of the effort, determine opportunities for performance incentives to reward utility activities that yield system, customer, equity, and environmental savings. Establish a utility performance incentive for individual processes that have already been identified by stakeholders as priority areas for performance regulation. Develop a financial incentive for reaching SRP targets, or for successfully deferring or avoiding a wires capital investment and address any impediments in statute. [Source SIRI]

New product revenue streams to achieve profitability would include investments that improve network operations and facilitate market. Key challenges in this paradigm are determining how a network utility should be compensated as the enabler of the network and in setting benchmarks for performance. [RMI – Adapting Utility Business Models for the 21st Century]

Please see RIIO, Iowa and "Grand Bargain" options discussed by America's Power Plan at Utility and Regulatory Models for the Modern Era(pp 26-30) - http://americaspowerplan.com/wp-content/uploads/2013/10/APP-UTILITIES.pdf

*2) What portion of the utility's revenue should be subject to performance incentive mechanisms? Should that portion change over time?*

Results Based Regulation – Malkin & Centolella (on the RAAB site - http://www.raabassociates.org/Articles/Public%20Utility%20Fortnightly-Results-Based%20Regulation.pdf)

- Outdated cost of service model of regulation – outdated paradigm of functions and activities (slows innovation and defers investment in avoided cost)
- Results based regulation: reward plans that deliver lasting value thru operational efficiency and shared cost savings
- UK's RIIO initiative: revenues set based on the regulator's review of a forward-looking utility business plan; a multi-year revenue cap that provides an incentive for cost reductions; an earnings-sharing mechanism that enables customers to benefit from utility cost savings; clearly defined performance metrics and incentives for delivering value to customers; and funding set aside for innovative projects.
- New tech = smarter grid & much more capacity; reduced outages, AMI, voltVAR. . .capacity to reduce peak demand by 20%

- Grid in disrepair with increased expenditures but falling demand/sales
- Some experimentation w performance based regulation but focused on reduced operating expenses and not capital investment (still based on cost of service model); While minimizing the effects of market power is important, discovering more efficient ways to operate and deliver value to customers can create much larger economic benefits.
- Utilities asked to cost justify plans/proposals based on existing paradigm but we expect new functionality: Ensuring the grid is resilient to severe weather and disruptive events; Integrating distributed and variable renewable generation; Securing the grid from cyber and physical attacks
- Rate regulation is intended to mirror the "pressures of competitive markets, to prevent regulated companies from becoming high cost-plus companies." cost-of-service regulation often fails to provide comparable incentives for investment, efficiency, and innovation.
- Reward innovation for longer term benefit – some methods have included: *Annual rate cases with a forecast test year (minimize regulatory lag); Capital expenditure trackers (a*ccelerated recovery of specific capital expenditures outside of a cost-of-service rate case); *Formula rates (*support investment in instances where there's a constructive relationship between the utility and its regulator); *Service-level options (*reflect the ability to deliver higher levels of reliability in portions of the grid and that would allocate the costs to customers who value and are willing to pay for more reliable or resilient service); *Valuing distributed energy resources; Price-responsive demand (*Influencing the timing of electricity improves asset utilization & account for the system and public benefits associated with a distribution grid that can effectively integrate renewable and distributed generation)
- To promote greater integration of renewable and distributed generation, utilities and their regulators will need to agree on a mechanism that supports needed investments and provides distribution utilities a reasonable opportunity to recover their largely fixed costs. That could involve a greater portion of costs being recovered through fixed customer or demand charges in combination with rate adjustments that decouple fixed-cost recovery from sales.
- A model that meets these objectives would provide utilities the opportunity to earn reasonable returns on investments that deliver value to customers. It would remain affordable by encouraging improved efficiency and innovation, and it would incorporate incentives for both cost savings and performance on multiple customer and public policy metrics. Results and innovation would translate into earnings.
- a results-based model would be forward-looking and take into consideration the forecasted costs for meeting new objectives. It would place a greater emphasis on providing the right incentives for cost savings, efficiency, and performance, recognizing that regulators will seldom have enough information to effectively review whether a utility's management has made the best possible decisions
- Effective results based model: Revenues set to support a forward-looking utility business plan; A multi-year revenue cap; A mechanism for sharing any cost

savings with customers; Output-based performance incentives; Support for innovation

- Overall, results-based regulation shifts the focus from the reasonableness of historically incurred costs to the pursuit of long-term customer value. It enables utilities to meet today's challenges.

*3) Are there any costs associated with new or old services which should be isolated from the utility's revenue requirement and made separately subject to performance incentives that place cost recovery at risk while creating the potential for the utility to earn more than the cost?*

**Reply**: Under US accounting standards regulated utilities are permitted to defer costs on their books, which would otherwise be charged to expense, if it is probable that the regulator will allow recovery of such cost in future rates. Generally, to make this finding, there must be a linkage between a utility's costs and its rates. This accounting policy provides financial and rate stability. If the rate setting process changes and it becomes no longer clear if and how a regulator will allow recovery of deferred assets in future rates, the utility may have to write off the deferred costs to remain in compliance with Generally Accepted Accounting Principles (GAAP). Any future ratemaking approaches should consider how such changes could affect the utility's ability to maintain consistency with accounting standards.

In addition, the likely response of the financial community (credit rating agencies, bankers, investors, equity analysts) should be considered before adopting significant ratemaking changes, because of the capital intensity of the business and future need for utilities to be able to continue raising capital at reasonable costs. At the same time, the financial outlook of utilities under a business-as-usual approach needs to be taken into consideration. Given the stresses identified above, the utility industry may be moving into an era of increased risk under traditional regulatory approaches. [Source NY REV]

*4) What is the appropriate balance between potential rewards and penalties? Should rewards begin as symmetrical with potential penalties? Should the relative size of penalties and rewards change over time as the utility gains experience operating in a new regulatory framework? Do existing performance based incentives provide a sufficient learning experience for customers, vendors and the utility?*

**Reply**: Performance incentives include performance based earnings, shared savings, and incentive rates-of-return. These mechanisms could be used to reward utilities for performance in achieving distributed resource deployment targets, and in doing so in a way that minimizes costs for the system as a whole. Utilities are in the best position to understand how and where to deploy distributed resources for greatest system benefits and should be allowed greater freedom to direct these investments to the areas on their system where they provide the greatest value. Moreover, performance incentives should ensure that utilities earn more by finding the least-cost ways to address system needs. [RMI – Adapting Utility Business Models for the 21st Century]

Revenue adjustments should be sized so that companies will perform to standards rather than finding it economic simply to pay penalties. In addition, Staff must have access to all underlying performance data for auditing purposes. Innovative performance plans should be developed through participation by all market providers. Utilities should have the ability to make incremental investments that represent modest calculated risks without fear of penalty, allowing the trial and error process that enables larger investments to be made with more confidence. [Source NYREV]

While negative-only incentive approaches have generally produced acceptable results, in order to achieve more enhanced performance it may be necessary to consider symmetrical incentive approaches that would reward the utility with additional earnings if it achieves superior results in areas such as innovation and customer service. Utilities may have concerns regarding potential negative adjustments for metrics that depend on customer decisions, e.g., DER participation. One possible approach to address this would be through positive-only incentives, at least related to elements where direct customer participation is needed for the utility to achieve its goal. To address the "windfall" concern, in this scenario, initial rates could be set at a level in the low range of rate of return, with positive- only incentives for achieving higher levels of performance. [Source NY REV]

Historically, most of our incentives have been one-way negative-only revenue adjustments. This approach was based upon the premise that the utility has an obligation to serve and is given the opportunity to fully recover its costs and earn a fair return on investment. Under this approach a positive incentive is arguably an unnecessary windfall, and negative revenue adjustments are necessary to enforce the obligation to serve. A result of this approach, however, is that the only way for a utility to enhance its earnings is to cut spending, and no explicit rewards are provided for providing superior service or otherwise meeting policy objectives. Ratemaking should optimize the level of inputs needed to achieve policy outcomes; near-term reduction of expenses will not always achieve this goal. [Source NY REV]

*5) How should a potential enterprise-wide performance-based regulatory framework interact with existing performance incentives, such as statutory performance incentives for energy efficiency and renewable energy?*

**Reply**: See America's Power Plan, "New Regulatory Models" at http://westernenergyboard.org/wp-content/uploads/2014/03/SPSC-CREPC_NewRegulatoryModels.pdf

Synapse – "Performance Incentives for Utilities" - http://www.synapse-energy.com/project/performance-incentives-utilities

Clear Result – "Lower Spending Higher Return" -

https://www.clearesult.com/insights/whitepapers/lower-spending-higher-returns/\

. . .and more resources here - http://americaspowerplan.com/power-transformation-solutions/ratemaking-and-utility-business-models/

Five steps that can transform regulation from a backward-looking accounting exercise that incents capital investment into a forward-looking system that creates more societal value:

1) Consider which societal values are most important for the regulated electric sector in your region. Seek input from many stakeholders and drive toward quantitative metrics for performance in each category. Common examples of societal values include:

• Resilience: how often do customers lose power? How many people are affected? Are critical services (hospitals, fire stations, etc.) able to stay up and running in emergencies? How quickly does the system recover from extreme events?

• Affordability: can customers obtain electricity service at a reasonable cost?

• Environmental performance: how much pollution is the electric system emitting?

• Safety: does the electric system deliver high quality service while keeping its workers and citizens safe?

2) Improve estimates of the utility's cost of equity so that they reflect the necessary markup on money they receive from shareholders. This should set the lower bound for the return on equity allowed to utilities.

3) Research the benefits in each of the value categories – estimating total benefits can set an upper bound for the incentives offered to utilities that deliver these values.

4) Consider the difference between the cost of equity and the current return on equity – this is the money that motivates shareholders and utility management. It may be appropriate for part of that difference between earnings and cost of equity to be tied to capital investment, but regulators may also choose to use part of it to tie earnings to performance in the value categories identified in step one.

5) Consider alternative ways to deliver the performance portion of utility revenues, aside from adjustments to rate of return. Adjustments to return on equity maintain the underlying incentive to expend capital, but direct shareholder incentives (or, better yet, "shared savings" programs where some of the incentive goes to the shareholder and some flows back to the customer) may provide a more direct connection to performance in the value category intended for the policy to achieve.

Utility shareholders and their agents—utility executives—need to see that the financial value engine can work to support adequate returns on investments as the electricity system, the regulatory model, and utility incentives evolve. If regulators follow these steps, they can give utilities that assurance, and put the power system on track to begin delivering more value to customers and society. [Source – America's Power Plan, "Moving Toward Value in Utility Compensation"]

Consider examples where clean energy alternatives to conventional grid upgrades are superior from both the perspective of cost and desired societal outcomes. In practice, there will be many, perhaps a majority of, instances where conventional grid upgrade strategies are preferable on both counts. Complicating matters more, there will be cases where a conventional strategy is preferable from a simple cost perspective, but society will still prefer alternative approaches given their ability to deliver desired outcomes against goals like environmental performance or resilience. At present, some tools used to drive preferred alternatives (e.g. net energy metering) destroy shareholder value, creating a tension between utilities' financial health and desired policy outcomes. A realigned utility revenue model holds the promise of rewarding, rather than harming, shareholder value when utilities are able to further policy and other societal goals.

Regulatory models combining a revenue cap and PIMs deserve greater consideration as jurisdictions determine how to align utility incentives with the outcomes society seeks. Under a revenue cap, a utility is rewarded when it is able to identify less costly approaches to meet grid needs. In past applications of revenue caps, cost savings took the form of more efficient implementation of conventional solutions. In contrast, a revenue cap model today would incentivize utilities to parse through the wide variety of new grid solutions that have been proposed, and implement those that benefit customers. For jurisdictions seeking to develop a more competitive market for energy services, a revenue cap also motivates utilities to procure third-party resources where they create more value under the cap. However, not all outcomes society seeks are likely to be priced using the cost comparisons a utility would undertake when faced with a revenue cap. For these outcomes, targeted PIMs can be a means to motivate performance where market-based value is absent. [Source - America's Power Plan, "Moving Toward Value in Utility Compensation P. 2" - http://americaspowerplan.com/wp-content/uploads/2016/08/2016_Aas-OBoyle_Reg-Alternatives.pdf]

Three Key Takeaways

1. Cost of Service Regulation (COSR) creates utility incentives that are misaligned with societal value in circumstances where non-infrastructure or non-utility owned alternatives are superior from a societal perspective.
2. Performance Incentive Mechanisms (PIMs) hold the potential to monetize presently uncaptured benefits and costs in utility regulation, and to motivate utilities to perform against outcomes that society prioritizes
3. Revenue caps can be a powerful tool to align utility shareholder value creation with non-infrastructure-based strategies to meet grid needs. These tools deserve greater consideration, alongside and in combination with PIMs, in utility regulatory model discussions.

The implementation of a revenue cap plus PIMs model is not without significant challenges, and is likely to require substantial upfront regulatory effort. To start, a revenue cap creates the prospect of both windfall profits if set too high, or threats to utilities' financial viability if set too low. The challenges of setting a well-justified cap are exacerbated during a period of technological change and shifting policy priorities, where past performance of the firm or its peers will not offer a reliable prediction of future costs. These challenges suggest that forward- looking strategies to establish utility performance benchmarks may be required in order to determine an appropriate level of allowed revenues.

[Source - America's Power Plan, "Moving Toward Value in Utility Compensation p 2"]

*6) If a performance based plan is implemented through basis point rewards and penalties on the return on rate base, what range around the utility's allowed ROE should be used?*

**Reply**:

*7) What utility behaviors should Rhode Island be trying to change with performance based incentives? What do we want the utility doing tomorrow that they are not doing today under traditional rate regulation?*

**Reply**: In the long term, utilities still have an incentive to maximize their capital expenditures, and little incentive to optimize system efficiency to reduce capital needs. With respect to operating expenses, utilities can earn money for shareholders by "beating" the operating expense allowances provided for in a rate case; this contributes to contentious ratemaking processes and, more importantly, gives utilities no financial incentive to manage operating resources positively toward the achievement of policy objectives. Revenue decoupling mechanisms also provide no positive incentive; at best they make utilities indifferent to efficiency and distributed generation. Because RDMs spread the lost revenues across all remaining sales, they leave utilities and remaining customers vulnerable to the long-term implications of widespread revenue loss. [Source NYREV]

Limited access to information, high customer acquisition costs and other transactional hurdles appear to be barriers common to many customer classes. Confusion and a lack of information regarding the factors that impact a customer's overall energy options are commonly reported as barriers for increased demand side management. Many customers do not understand the various elements of their bill, which leads to confusion and frustration regarding how and to what extent they can control their costs by managing consumption. Customers, even many large users, often do not fully appreciate the various elements including delivery, commodity and demand charges. The current regulatory framework does not provide proper and sufficient price signals to motivate and empower customers. [Source NYREV]

Energy services providers and other resources that may educate, simplify and otherwise increase the value of demand side management measures are currently in the market for large commercial customers and, more recently, within the multi-family sector and mixed use buildings. However, the market for energy management and demand side management services related to smaller commercial and residential customers has been very slow to develop. Access to energy consumption data is important to all sectors. Customers should have ready access to the information that is collected about their own usage. Understanding how and when a customer uses energy is critical to being able to manage that usage. For large commercial, industrial and multi-family consumers, detailed usage information permits optimization of building management systems and benchmarking. Customers must have access to the information in a usable format, an understanding of the value of the information and access to goods or services that empower them to extract value from the data. Many larger buildings, particularly newer ones, have existing energy management devices or systems that can benefit significantly from increased granularity of and access to usage data. [Source NYREV]

A results-based model shifts the focus of regulation from the reasonableness of historically incurred costs to the pursuit of long-term customer value. Regulatory incentive plans make it possible to place more focus on outputs, not inputs. This is consistent with economic theory regarding the workings of competitive markets. Firms in competitive markets have the leeway to choose those combinations of inputs that will allow the output characteristics (i.e., price and quantity) demanded in the marketplace. [Source NYREV]

Outputs against which performance can be measured should be broad based, quantifiable, and specific enough to produce intended outcomes. Outcome-based regulation can lead to profit and financial variability, which increases risk. It is critical to avoid overly general objectives that can only be measured by subjective judgments. Post-hoc subjective judgment of whether general objectives have been met is problematic from a process standpoint, and creates uncertainty that may impair financing. A performance-based incentive plan should contain financial provisions to ensure that the utility company retains its long-term financial stability. [Source NYREV]

The most effective outcome paradigm may be one that creates a network of incentives with an enterprise-wide effect. That is, any given employee or mission within the enterprise should be linked in some way to an outcome that, if achieved, will result in improved earnings. [Source NYREV]

Because a utility has an obligation to serve, a purely outcome-based approach is not feasible; at some level, the inputs needed to meet the obligation to serve must be provided for. Developing specific metrics will undoubtedly be a challenge. Setting specific metrics for new performance areas where there is no track record (e.g., DER-related outcomes) will require careful deliberation. It will also be important to avoid the creation of incentive gaps. Utilities may focus intensely on areas where specific metrics and incentives are detailed and may neglect other areas where there is not an incentive. [Source NYREV]

Regulators attempt to simulate competitive interests by allowing utilities to earn a reasonable return on capital investment, and to earn on operating expenses by reducing spending below the levels budgeted in the rate-setting process. One of the values of DER, however, is to reduce utilities' need for capital expenditures. Another objective – reducing peak demand on the bulk system – may have the incidental effect of reducing utility investment. Under conventional ratemaking, a utility will have no incentive to pursue these measures that would reduce its rate base. If utility rates approach levels where they can no longer be increased without exacerbating customer migration, then utilities would lose the incentive to invest in rate base; but that scenario carries even greater concerns and should be avoided. The Commission should consider ratemaking approaches that encourage the most efficient allocation between capital and operating expenses to advance Commission objectives. [Source NY REV]

What's really needed today is competitive markets on the distribution edge. It makes no sense to have utilities hostile to distributed energy and local energy management. We need entrepreneurs thinking about how to package energy services in new ways for customers, and we need utilities not just to stop impeding them or to get out of their way, but to actively empower them. [Roberts, "Utilities for Dummies Part 2" in Gristmill]

A final incentive that hampers transition to a 21st century electricity system is that utilities have every incentive to operate existing and new capital assets for as long as possible. When the payments for construction are fully depreciated, the low operating costs of existing infrastructure makes utilities reluctant to shut down power plants or power lines when they can still earn revenue in operation, even when they are no longer in the public interest. [Farrell – "Beyond Utility 2.0 to Energy Democracy"]

One of the central governing rules of interstate transmission – FERC Order 1000 – was supposed to create a meaningful evaluation of non- transmission alternatives to new power lines. But the rule only requires that a utility consider alternatives proposed in the process, it does not obligate them to offer alternatives. In other words, to have a meaningful debate of alternatives requires a dedicated third party – a state agency, commercial or industrial customer, or nonprofit – to show up to contend with a utility's transmission line proposal on its own dime. [Farrell – "Beyond Utility 2.0 to Energy Democracy"]

Participation by third parties is remarkably onerous. For an outside entity to offer a transmission alternative, they have to request access to data about grid operations that many utilities shield as "trade secrets," be able to competently model the grid impact of a non- transmission alternative without access to the same proprietary software package or trained engineering staff used by the incumbent utility, and then cast the alternative in the technical and legal language expected at a regulatory proceeding. [Farrell – "Beyond Utility 2.0 to Energy Democracy"]

Alternatives to transmission projects face another hurdle: compensation. While FERC has established rules for sharing the cost of transmission lines along the route they extend, non- transmission projects have no such cost allocation process. The following graphic illustrates how state regulators in Illinois, for example, would elect a more expensive regional transmission project rather than a less expensive localized non-transmission alternative, because the impact to their particular state is less (even if the economic benefit is greater). [Farrell – "Beyond Utility 2.0 to Energy Democracy"]

Not only is it difficult for non-transmission options to share costs, but utilities frequently receive federal incentives for high voltage transmission lines that cross state boundaries. The overseer of these bonus payments – the Federal Energy Regulatory Commission – has doled them out to 4 of every 5 requesting utilities, resulting in an average return on equity of 13%.

Finally, the federal overseers of transmission projects don't consider any non-grid benefits that would weight a decision toward a transmission alternative for serving grid needs. For example, while Vermont state regulators consider a wide range of benefits in their cost-benefit calculation of energy efficiency improvements (shown in the following chart), only a small slice of the benefits (in blue) would be considered by federal transmission planners, even though energy efficiency can meet the same needs for reliability and grid capacity. [Farrell – "Beyond Utility 2.0 to Energy Democracy"]

**Additional comments:**

1) We believe in allowing competition for any service where there is a competitive market and that market is ready to compete on providing the service. Energy efficiency is an example of a highly competitive market that is ready for competition on services now provided through National Grid (which currently are administered through RISE to the disadvantage of any highly qualified small contractors that would be in a position to compete if they were allowed to). If there's a competitive market that's not ready to compete, PBIs can be used to better prepare the market for competition.

2) We submit that it is counterproductive to think that we can't achieve better value through distributed energy programs just because existing statutes determine a method of valuation (net metering, renewable energy growth). It may be possible to administratively amend the programs to provide for more accurate valuation (the REG program encourages consideration of many factors beyond cost of development but the Board has been reticent to include such considerations). If the existing statutes do not adequately value DER in a way to best realize their true/full value then we should look to revise those statutes to better achieve that value. While existing programs have their history and their rationale, none were developed based on complete/best information. The REG program, for example, was based on a logical cost plus rate of return approach to ensure projects got sufficient price commitments to be financed while maximizing "cost effectiveness" – but, its engineers clearly did not fully consider the possibility that

such private investments could actually return higher value for customers, the power system and society.  While gradualism is important for statutory programs (to ensure stability in expectations), there has been no better stakeholder group in RI than was engaged in 4600 & if the results of that process dictate that we may need to rethink how we value and compensate DER, then we should do what we must to ensure those recommendations are acted on and programs are changed to ensure they are structured to achieve the best value for RI.