EDF ENVIRONMENTAL DEFENSE FUND™
Finding the ways that work

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VIA ELECTRONIC MAIL

Hon. Kathleen H. Burgess
New York Public Service Commission
Three Empire State Plaza
Albany, New York 12223-1350

Re:
Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision

Dear Secretary Burgess:

Environmental Defense Fund (EDF) hereby submits for filing its comments in response to the May 1, 2014 Ruling Issuing Track 2 Questions and Establishing a Response Schedule.

Respectfully submitted,

Elizabeth B. Stein

Cc: Administrative Law Judge Eleanor Stein
Administrative Law Judge Julia Smead Bielawski
Active Parties

STATE OF NEW YORK

PUBLIC SERVICE COMMISSION

Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision

RESPONSES BY ENVIRONMENTAL DEFENSE FUND TO TRACK 2 REGULATORY CHANGES AND RATEMAKING QUESTIONS ISSUED MAY 1, 2014

New York opened this proceeding to re-shape the utility business model. The Environmental Defense Fund (EDF) commends the Commission for considering these important issues and thanks the Commission for the opportunity to provide comments.

New York played a leading role in developing today's utility business model. Thomas Edison developed the first power plant on Pearl Street in Manhattan in 1882, serving 85 lighting customers. The business model of Edison and his protégé, Samuel Insull, was simple – keep adding more customers and keep building larger power plants. This was a win/win model for utility customers and for the utility companies. Customers won because the ever-larger power plants were more efficient, so utilities could sell electricity at a lower per-unit cost every time they built a new plant. As the price per kilowatt of electricity kept declining, customers used more electricity. To encourage growth in this new electricity infrastructure, New York, like all of the other states, protected the utilities' investment by granting them an exclusive right to serve customers. In exchange for being permitted to operate as a monopoly, New York set the price the utility could charge for electricity. These prices were structured to reward the utility for successfully building a bigger and bigger system.

This business model was incredibly successful. We now have access to electricity 24/7, at the flip of a switch. The U.S. electric power industry powers the world's largest economy. We rely on our heating and air conditioning, appliances, televisions, computers, phones – all powered by electricity – to provide our daily needs. The electrification of America was the greatest engineering feat of the 20th Century, surpassing the internet and putting a man on the moon.[1]

This model worked well for the past 130 years because it used the right incentives for what society needed then. But today the old business model is out of sync with what we need now. Customers are no longer delighted simply by lights burning without whale oil. They need and expect power quality and reliability to support a digital economy. We need a system that is less polluting. We have come to recognize that our reliance on fossil fuels burned in large centralized plants is creating a legacy of environmental burden for our children. We need a system that encourages innovative technologies to provide economic and environmental benefits. We now know that when customers learn that the cost to produce electricity varies by time of

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[1] National Academy of Engineering, Greatest Engineering Achievements of the 20th Century (available at: http://greatachievements.org/) (last viewed July 12, 2014).

day and year, they actively -- or enabled through their smart appliances, are willing to change when they use electricity in exchange for price savings for themselves while also yielding system-wide savings for all of us. Many customers want to take advantage of advances in technology and falling prices for distributed generation, like rooftop solar, to enjoy on-site generation options. More efficient buildings, industry, homes and appliances now allow customers to accomplish much more with far less energy. Advances in telecommunications and information systems create new opportunities for energy services we could not have imagined just a few years ago. Increasingly, we see the electrification of our transportation sector. In this world, large central plants are not always the most cost-effective way to meet our energy needs and the monopoly utilities we established to build them may not be the most effective business models to deliver these new services.

To meet the needs of today and tomorrow's world, it is time break the link between monopoly utility revenue and utility spending and to re-think which of the services we want or need are really best delivered by a monopoly. Our outdated model must be replaced with a new business model that rewards utilities for successfully furnishing a platform for delivering all the services that can meet our energy needs sustainably. Utilities should be rewarded for providing customers access to smart energy services, not just more power plants and equipment. The utilities will be our portal to energy services but they do not necessarily need to be the provider of all energy services.

To accomplish this, the Commission, in consultation with stakeholders, must identify the outcomes they want utilities to achieve – and tie the utilities' revenues to their performance in meeting these outcomes. New York has a good start with performance-based ratemaking. It is time to build on that foundation to reward results, not utility spending.

This will be no easy task. The electric power industry has grown into a $300 billion/year industry using the old model.[2] Over the last 130 years, regulators, utilities, investors and customers have become entrenched in our ways. Erasing the distinction between rewards for prudent capital investment and effective operations will require a shift in deeply -rooted practices. Changing to a performance-based model will take great care to establish optimal outcomes and performance metrics. The outcomes must still be tied to traditional objectives of adequacy and reliability of service, as well as new outcomes tied to clean energy, customer engagement, system efficiency, and transparency that open the door to energy service innovations available from others. This requires fundamental changes in the reward system. This is much more than decoupling. New reward systems are needed to align the incentives for traditional utility companies, the clean tech industry, and consumers. As always, regulators must be vigilant in monitoring the utilities' performance but it will mean developing new skills. Rather than judging prudency in retrospect, the Commission will be challenged to be more of a partner in visioning the possibilities of the new utility.

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[2] Edison Electric Institute, Key Facts about the Electric Power Industry (available at: http://www.cewd.org/toolkits/teacher/eeipub_keyfacts_electric_industry.pdf) (last viewed July 12, 2014).

New York boldly proposes to take on this challenge. New York gave birth to the electric power industry 130 years ago and New York will now build a new utility business model with the right incentives to achieve the outcomes we need for the 21st Century.

EDF's mission is to preserve the natural systems on which all life depends. Guided by science, we design and transform markets to bring lasting solutions to the most serious environmental problems. EDF will bring to this proceeding its perspective and experience in solving environmental problems through innovative market-based solutions. The Commission has stated that one objective of a new business model is to reduce carbon emissions. Some strategies by which the Commission can achieve this objective in part include: (1) transitioning from traditional rate of return regulation to performance based regulation; (2) fully valuing all costs and benefits associated with distributed energy resources (DER); (3) removing barriers to non-utility entities participating in energy service markets; and (4) requiring the utility to optimize the load it serves; (3. This will be the overriding themes for EDF's comments in this proceeding.

In a ruling issued on May 1, 2014, Administrative Law Judge Stein issued a list of Regulatory Changes and Ratemaking Questions compiled by the Department of Public Service Staff relating to Track 2 of this proceeding. This proceeding will investigate the building blocks for the new business model. Environmental Defense Fund (EDF) thanks the Commission for considering these important issues and for the opportunity to provide comments. EDF would also like to thank Mr. Scott Hempling for providing valuable assistance in helping us to think through several of the questions. Mr. Hempling is an attorney specializing in energy policy. More information on Mr. Hempling is available at: http://www.scotthemplinglaw.com/. EDF's responses to these questions are set forth below.

I. <u>Outcomes-Based Ratemaking</u>

1) Incentives and disincentives in current ratemaking

a. How should existing incentive mechanisms (reliability, service, safety or other targeted performance incentives) be modified? Should any be eliminated?

<u>Response</u>:

If this proceeding is successful, the result will be a new neutral energy service platform which will enable system-wide greenhouse gas emissions reductions, load optimization, greater resiliency and reliability, technological innovation, and uncomplicated customer access to a vibrant marketplace of energy services. The transition to such a service platform can only succeed if all relevant parties – the incumbent wires company, customers, and service providers – receive economic signals which align with this outcome. This means a fundamental transformation in the existing reward mechanisms. The Commission must abandon traditional rate of return regulation in which the utility's opportunity to earn comes from increasing its ratebase or selling more electricity. In its place the utility/DSPP opportunity to earn will be based solely upon successfully delivering the desired performance. This paradigm goes significantly passed standard performance based regulation because the utility will earn 100% of its revenue for successful performance. For purposes of our comments, we will call this regulatory structure PBR+.

The Commission will likely find that its existing metrics relating to quality of service and safety will provide a sound foundation for measuring some aspects of desired utility performance. These referenced incentives are tied to the outcome of reliable service. This will continue to be an important performance standard under the new PBR+ plans, so these types of incentives should remain useful in developing more comprehensive metrics. Prior to deciding whether to eliminate any existing metrics, the Commission should decide what outcomes it seeks for the new PBR+ plans. The Commission can decide on the appropriate metrics after the new outcomes are established.

b. Should rewards (revenue adjustments) be provided for superior reliability, service, or safety performance?

Response:

As for "superior" performance: whether to award more profit for superior performance depends first on whether customers receive value and benefits, including environmental benefits, from that performance, and second whether customers desire the value and benefits offered. The Commission should make this determination when the PBR+ plan is established and also decide how superior performance is to be measured and the incentive for such superior performance.

c. How would superior performance be defined and measured?

Response:

Superior performance must be defined and measured according to the outcome under consideration. There can be no uniform rule for this. In all cases, the Commission should consider the costs and benefits associated with achieving the higher level of performance. The Commission must ask whether customers truly benefit from the higher level of performance and, if so, how benefits would be measured. The costs may be easier to measure than the benefits. The benefits may include economic losses incurred by customers from the normal level of outages as compared to a lower level of outages. Societal benefits may be an appropriate measure for certain types of outcomes related to resource diversity and environmental outcomes. Qualitative or subjective measures may be needed for some areas of performance, such as customer education or customer engagement.

2) New outcomes/metrics

a. What new targeted performance incentive approaches should be considered?

Response:

"Targeted performance incentive" connotes an incentive structure layered on top of traditional rate of return regulation ("traditional PBR"). As discussed above, EDF urges the Commission to abandon this regulatory structure. In its place, the Commission would develop comprehensive performance metrics to measure the utility's success in delivering the new neutral energy service platform. The Commission's work in developing these performance metrics will be informed by a rich history of traditional PBR. PBR plans have been used in the United States, including New York, for several years. Typically these PBR plans use incentives linked to the outcome of service reliability. As the REV Staff Report noted at pages 54-56, the United Kingdom Ofgem's "Revenue set to deliver strong Incentives, Innovation and Outputs" (RIIO) model is a well-designed PBR model which introduces new types of incentives that could be used to achieve the innovative outcomes which the Commission is seeking here. In Appendix A to the Track 1 questions, the Commission has identified several outcomes for this proceeding which go beyond the traditional outcome of service quality. EDF recommends that the Commission use these more comprehensive performance metrics to develop a PBR+ plan.

To transition a utility's profit opportunity from a strategy of investing in additional infrastructure or selling more electricity to a strategy of superior performance or PBR+, regulators may find the following process helpful. First, establish standards for performance, focusing not only on keeping electric current flowing at reasonable rates, but also on dimensions such as those listed above to provide a neutral energy service platform. This step involves detailed consideration of what utility "performance" means in the context of each of these objectives. Second, Design PBR+ plans that condition compensation on a utility's performance. This step involves: establishing the level of revenues necessary for a well-managed utility to produce the necessary performance; and designing the compensation scheme so that the utility's profit depends on its performance. Finally, develop a method to evaluate the utility's performance and assign consequences.

In designing the PBR+ plan, it may be helpful for the Commission to consider design challenges experienced in traditional PBR efforts including some of the following: :

(1) Compensation misaligned with performance: A PBR+ proposal may not align the utility's compensation with performance because it fails to define performance effectively. Performance should be defined to include the objectives described above.

(2) Balancing cost-cutting and long-term investment: PBR plans often reward cost-cutting, because the rate stays constant when costs decline. But cost-cutting is not a proxy for performance. PBR design should ensure that the utility will balance short-term cost cuts and investments in long-term performance.

(3) Mis-matched time horizons: A PBR plan usually is related to certain timelines; *i.e.,* the Commission and/or consumer advocate refrain from initiating a new rate case long enough for the utility to earn the higher returns called for by the plan. The time period between these rate cases does not necessary bear a logical connection to the time period required for a particular type of performance. The period of time over which benefits emerge for new meters, renewables purchases, or new technology experiments will not necessarily match up with the time periods between PBR cases.

(4) Asymmetric information: Because the utility knows more about how it reports its performance than does the Commission, there is potential for selecting metrics which result in performance scores to reward results which would have occurred without the incentives, or making performance appear better than it actually is.

(5) Worker-reward gap: What enhances performance is people; specifically, people who work daily have the opportunity to drive innovation in the delivery of services. While shareholder investment is a pre-requisite of performance, and deserves the return

authorized by law, the actual performance which makes service worth compensating is performed by workers. A PBR plan truly focused on utility performance would align employee compensation with the utility's objectives and reward the employees who enable the utility to achieve these objectives. Those employee rewards would, of course, drive better company performance, which would enable the utility to meet or exceed its incentives.

b. **What specific outcomes of REV should be incentivized? What percentage of utilities potential earnings or how many basis points of earnings should be tied to these incentives at standard and superior performance levels?**

Response:

As discussed above, EDF urges the Commission to adopt PBR+ regulation. The percentage of a utility's earnings that should be tied to its performance to achieve the state's goals is, therefore, 100%. Conversely: No portion of the utility's earnings should be an entitlement granted without regard to performance.The Commission has identified appropriate outcomes in the matrix provided with the 'Questions on Track 1 Policy Issues. EDF's comments on the Track 1 questions include EDF's recommendations for modifications to these outcomes. The Commission should develop incentives for all of these outcomes. This is the best way to motivate utilities to achieve the outcomes sought by the Commission.

As for "superior" performance: whether to award more profit for superior performance depends first on whether customers receive value and benefits, including environmental benefits, from that performance, and second whether customers desire the value and benefits offered.

However, there is a role for experimentation and innovation. As the REV Staff Report states (at p. 2): "Current ratemaking provides few incentives for utilities to innovate or to support third-party innovation, to address the current challenges in ways that promote a more efficient system and benefit consumers." As beneficiaries of innovation, consumers should be prepared to reward performance delivering successful transformation at levels greater than performance necessary to maintain traditional electricity distribution services. But to avoid excess risk-taking, and innovation unrelated to value, regulators must first define the desired outcomes and the associated value to ratepayers. We have identified above fundamentally important state policy outcomes, such as system-wide greenhouse gas emissions reductions, load optimization, greater resiliency and reliability, technological innovation, and uncomplicated customer access to a vibrant marketplace of energy services. Since this whole approach requires innovation and risk, utility incentives for superior performance, such as implementing the kinds of non-traditional solutions which Con Edison is implementing through the North Central Brooklyn collaborative, would be appropriate.

c. **Should metrics tied to new outcomes be generic across all utilities or utility specific?**

Response:

Metrics which are generic across all utilities would establish consistency with regards to progress made in achieving the desired outcomes. The performance reward associated with each metric, however, could vary. Differences in performance across different utilities should be analyzed and explained given the inputs and outputs of the actions taken to achieve these outcomes. This would allow each utility to identify how its own efforts could be re-aligned to better deliver on the desired outcomes.

d. How should a distribution system efficiency incentive be designed? What performance measures and targets need to be developed for a distribution system efficiency incentive?

Response:

Distribution system efficiency incentives should be designed so as to encourage optimal use of delivery assets. The utility/DSPP should be incentivized to improve system load factor, an indicator of delivery asset utilization. The regulated entity or entities should be incentivized to invest in DER solutions that avoid or defer the need for distribution system capacity investment.

Con Edison's recent efforts to defer investments in a substation capacity expansion in the North Central Brooklyn area is an example of an opportunity for a utility to stimulate changes in customer behavior, including engagement in DER programs, and as a result change distribution system efficiency. Use of economic incentives, including rates and rebates with the goal of reducing peak demand, and effective customer education and empowerment, may be able to stimulate changes in customer behavior. It may turn out that the traditional utility is not necessarily the most qualified entity to change customer behavior and that another party has more experience and expertise in devising incentives that will stimulate changes in customer behavior. The Commission should seek-out and invite ideas from various parties to identify the role of rate design, customer education, etc. in meeting the desired outcomes. This can be done through stakeholder meetings, workshops and issuing requests for proposals (RFP).

e. Can utility incentives stimulate changes in customer behavior? Should incentives be used in this way?

Response:

We are uncertain as to whether this question is intended to address incentives faced by utilities, or incentives provided to customers by utilities. Our response elucidates the connection between those two market signals and customer behavioral outcomes that may result if they are properly aligned.

If regulated entities were compensated for, among other things, successful customer engagement, they would have an incentive to furnish compelling value propositions to customers. Those compelling value propositions would be likely to include customer-facing incentives, including price signals, which in turn change customers' consumption patterns.

The North Central Brooklyn project is an example of a circumstance where the utility may be in a position to stimulate customers to obtain DERs or engage in demand side management behaviors. It is well established, for example, that time-differentiated price signals to mass market customers can create significant load changes; see for example Herter et al. (2005), Alcott (2011), and Faruqui and Palmer (2010). In a future landscape where a DSPP is compensated for its success in stimulating these changes in load, we expect to see these types of customer-facing incentives (such as time-differentiated price signals that could yield desired load changes when coupled with tools that would enable those changes) being implemented and adopted by customers on a far greater scale than is currently the case. Thus, well-designed utility incentives could indirectly stimulate changes in customer behavior. We would strongly recommend that the future performance-based regulation provide incentives to utilities that give rise to such outcomes.

f. Can utility performance targets and incentives be helpful in ensuring reasonable working relationships between distribution utilities and market participants such as ESCOs or DER providers, for example facilitating interconnections or encouraging microgrids?

Response:

Removing the utility's underlying bias toward capital investment through adoption of PBR+ regulation could be the more effective method of ensuring not only a "reasonable" working relationship but a highly collaborative relationship between the utility and market participants. Because when a utility is regulated under PBR+, it will not have any incentive to over-invest in DER, there is no reason to anticipate that its actions will inherently undermine competition. The utility's success at delivering a neutral energy services platform would be rewarded. Indicia of successfully delivering this platform would likely include a vibrant market in energy services. Thus, both the utility and the market participants would have an aligned interest in delivering the services customers need most. In fact under the recommended PBR+ approach, it would be in the utility's financial interest to incent the siting of customer or third-party owned DER that also performs the function of grid optimization as opposed to paying for the entirety of the investment.

Some additional performance targets and incentives can be very helpful in improving working relationships between utilities and market participants. For example, tracking the average time required to process certain requests may prove a useful indicator of the appropriateness of resources in place to meet these requests. Some metrics may not adequately measure the performance of any one entity (utility, DSPP, third-party service provider, *etc.*) because performance may not be under that entity's full control. However these same metrics may serve as useful indicators of market trends and progress towards outcomes.

By adopting PBR+ style regulation, the Commission will have the tools to lead the utility to become an enthusiastic promoter of the specific types of working relationships the Commission wants to see. The Commission may do this by establishing the utility's obligations to customers for distribution service, as FERC has in establishing transmission owners' obligations for transmission service including impartial interconnection service. FERC has complaint procedures, provided by statute and supplemented by rules, along with penalties should the transmission fail to follow required procedures. (There can also be penalties imposed on the interconnection customer.)

g. What utility incentives are necessary to promote comprehensive integrated resources planning at the distribution level that would consider all DER alternatives

to satisfy system expansion, system replacement, and/or to meet clean energy goals? Are there examples for multi-year performance metrics which would be superior in providing value to customers compared with an annual metric?

<u>Response</u>:

Utilities should be indifferent as to which integrated resource planning solutions are selected as long as the distribution planning needs and state policy objectives are met. Utility compensation should not depend on the solution selected, but rather on the advancement of the Commission's desired outcomes in a cost-effective manner.

Under the PBR+ model recommended by EDF, utility revenues should initially be set so as to allow the utilities to recover prudent costs associated with accomplishing desired service outcomes which may increase the prevalence of DER, including system expansion and system replacement. Once the Commission has determined the desired outcomes, metrics representative of progress towards meeting said outcomes should be developed. These metrics need not only be tied to utility performance, but should also capture various aspects of the markets which the Commission seeks to animate.

Multi-year performance metrics would be particularly superior in measuring progress across initiatives whose envisioned functionality may not be fully realized within one year of when deployment efforts begin (such as the full functionality of the DSPP market operations platform). Multi-year performance metrics may also be appropriate in the early years of deployment of DSPP services, as these begin to ramp-up, customer outreach regarding new services increases, *etc.*

Migration to a full-fledged performance-based regulation system, where utilities are no longer compensated primarily for building capital equipment to meet all system needs, should reduce the utilities' bias toward such solutions and (implicitly) against DER alternatives. However, to ensure consideration of "all" DER alternatives may require that the Commission go further. The direction that has been given to Con Edison, in the context of its load growth needs in North Central Brooklyn, is an example of the kind of analysis that the Commission should expect of all utilities prior to undertaking any major infrastructure expansion. This can be accomplished by setting a clear expectation that such a rigorous inquiry should in fact be performed, and making the performance (or failure of performance) a driver of utility compensation. This additional step has the benefit of giving the Commission a sense, which it does not have, of what is possible – which would enable the Commission to be better prepared to set revenue requirements in a performance-based future.

3 Inputs

a. Are there instances where utility inputs are a proper metric to assess performance? For example, employees per MW served, cost per distribution MWh, cost per customer, or some other metric (please specify).

<u>Response</u>:

Metrics based on inputs are useful for informational and diagnostic purposes. By examining inputs, divergences in outcomes among different utility entities that are taking different actions can be better understood and learned from. In addition, input measurements may signal temporary or locational stresses on the system and may inform evaluators of deeper rooted issues within the utility's performance.

However, input-based metrics are problematic as a basis for compensation; outputs bear a far closer relationship to performance. Even worse, input measurements can cast positive improvements in a negative light. For example, a metric focused on productivity (e.g., employees per MW delivered) would appear to suffer as a result of efficiency improvements, since a reduction in MW without a proportional reduction in staff would yield a larger ratio. All of the "input" metrics described above are operating expenses. A comprehensive list of the different types of utility operating expenses which could be considered as input metrics for information purposes can be found in the utility's FERC Form 1.

4. Accommodating bridge investments. Bridge investments are long term projects that may require several years or levels to achieve.

a. Should the Commission incent utilities to build/acquire bridge investments?

<u>Response</u>:

Yes. As discussed above, it is appropriate for the utility to be rewarded at earnings levels above those which may otherwise be appropriate for delivering traditional distribution services for successfully transforming itself to a neutral energy service platform provider. The Commission should consider performance metrics which guide utilities to acquire bridge investments because some of the capital investments which the utility must make to perform the new types of functions to be performed by the DSPP will be multi-year investments which will take several years to implement and which will provide benefits for many years in the future.

b. If so, what incentives will engage utilities in "bridge investments" necessary to meet the Commission's goals for the new system? (For example, one incentive approach is to establish incentive to achieve milestones along the path to conclusion rather than establish an incentive at the conclusion of the project.)

<u>Response</u>:

If the DSPP function is to be initially assigned to the incumbent wires company, that assignment should be clearly framed with performance expectations and a timeline for potential transition to a third party. The Commission could use milestones or some other type of short-term objectives in developing the incentives for a long-term investment. The guiding principle, in all cases, should be to tie the incentives to the outcome which the Commission seeks for a particular time period, regardless of whether the outcome is a short-term objective or a long-term objective. The assignment should be framed as an opportunity, not a gift. As a first mover, the incumbent wires company will be in a position to gain experience, establish interim goals and set expectations that will support long term goals to maintain the role of the DSPP. This implies an implicit incentive against bad performance: if the utility does not perform adequately and meet its interim goals, then the role of the DSPP may be awarded to a third party.

c. What ratemaking should apply to bridge investments that do not produce complete results during the term of the incentive period?

Response:

This question assumes a PBR+ incentive period that is not aligned with the necessary investment period. The purpose of a PBR+ rate incentive period is to align expenditures and benefits within that period. In utility regulation, non-alignment is unavoidable, because there will always be needs whose expenditure schedule do not align with the benefit schedule, or with the period between PBR rate cases. An example is consumer education. Expenditures might occur in Years 1-3, while the resulting efficiencies, we hope, will be permanent as educated consumers pass their habits on to the next generation.

The ideal approach is for the PBR plan to allow the regulated entity to be compensated by customers over the same period during which benefits accrue. Expenditures are, of course, incurred prior to the benefits, but that timing difference is covered by financing (whose costs can be lowered if the regulator makes a clear commitment to the PBR plan outcomes and metrics). That approach can work for distribution system upgrades that take three years to build and produce benefits for 30 years or when the financial value of the benefit is not well established but is clearly defined as part of State policy (such as reduction of GHG emissions which can have long term benefits but short term costs). It does not work as well for the consumer education example, where the benefits can be longer than 30 years. The Commission should be flexible in its approach to establishing incentive periods. The Commission should also establish an open, transparent process for deciding the appropriate incentive periods and modifying them when necessary.

One approach is to take the outliers, (*i.e.,* large expenditures whose benefit period does not coincide with the PBR incentive period), and recover them over a longer time period designed to achieve the temporal alignment. This approach requires two steps. First determine that a proposed "bridge" expenditure is prudent (*i.e.,* essential to achieving the obligatory outcome), and therefore appropriate for inclusion in the PBR plan for recovery from customers. Then put that specific expenditure on its own distinct path along with earnings tied to the desired outcomes from that investment.

5. **Symmetry options**
   a. **What are the advantages and disadvantages of symmetrical, penalty only and asymmetrical incentives relative to the Commission's goals in this proceeding?**

Response:

Symmetrical:

Symmetrical incentive structures seem inherently logical as they reward favored outcomes and punish unfulfilled goals. They give regulated entities a reason to excel rather than merely perform adequately, while giving commensurate attention to subpar performance. Under a symmetrical approach to deployment of carbon-neutral resources, for example, the DSPP could receive additional compensation for surpassing its target and face a corresponding penalty for failing to meet it. Such a system might make sense where underperformance and over-performance are equally valuable to customers or to regulators. The intuitive appeal of symmetry may seem like a matter of fundamental fairness to the regulated entities themselves, particularly if underperformance and over-performance seem equally probable.

However, symmetry could be disadvantageous in a context where underperformance and over-performance are not balanced. For example, where performance above the target is not valued by customers or does not further advance the purposes for which the target is set, symmetry may not make sense because it would cause ratepayers to be required to pay for something without value simply to counterbalance a necessary penalty. Even where underperformance and over-performance both matter, there is no particular reason for incentives and disincentives to be balanced unless the value associated with underperformance and over-performance is similarly balanced.

Penalty Only:

Under penalty-only structures, a utility is penalized for failure to meet obligations, and not rewarded for surpassing targets. Such a structure may make sense where, due to the nature of the target, exceeding the target is of no value to customer or regulators, as it would avoid charging customers extra for superfluous service. This may seem especially appropriate in a realm where there is effectively zero tolerance, such as safety. In addition, where the purpose of the target is simply to discourage bad behavior on the part of the utility or DSPP; in such a case, there is no need to have a corresponding additional reward for simply not misbehaving. For instance, DSPPs should not engage in system gaming to shape the outcomes of bidding processes, especially if that DSPP is an incumbent utility or owns DER, and should not be entitled to compensation for just being fair.

However, such a construct fails to compensate utilities for excellence. In areas where surpassing a target is indeed valuable, penalty-only compensation would be inappropriate.

Asymmetrical:

Asymmetrical incentives have the advantage of giving a means for recognizing the values of both over-performance and underperformance in circumstances where those values are unequal. One reason these values could be unequal is simply market reality: consumers caring more about over-performance, or the reverse. From the regulators' standpoint, however, these values could be unequal because they are trying to change the way a regulated company approaches familiar problems. A new approach to addressing an old problem may pose some risk of failure – which from the regulated entity's standpoint means a heightened risk of underperformance and associated penalties – while offering a possibility of far higher performance. To the regulated entity, the probability of upside may seem unknowable, so, being risk-averse, the company may tend to avoid such innovative approaches. However, where the regulators actually want the utility to behave in a less risk-averse manner in a particular context (such as, for example, investments in new and potentially untested clean technology), placing a higher value on over-performance than on underperformance may be a useful tool.

The disadvantages of asymmetrical incentive structures include the risk of catastrophic underperformance on targets if they are mis-calibrated and cause the utility to take many risks (or large risks) that turn out poorly. For example, if a regulated company would face little to no cost for failure, but high rewards for success, it would be encouraged to try even ill-advised solutions in the hopes of a payoff.

b. In order to achieve the Commission's objectives, how should the Commission determine which metrics and associated value to tie to such incentives?

Response:

The REV Staff Report (at p. 2) states: "Current ratemaking provides few incentives for utilities to innovate or to support third-party innovation, to address the current challenges in ways that promote a more efficient system and benefit consumers." We agree that traditional ratemaking has focused more on cost recovery than on performance. The problem is not merely "current ratemaking"; it is current ratemaking in a context where the regulator may not have adequately defined utility obligations, and may not have determined the consequences for the utility of failing to meet those obligations. The Commission can improve on this situation by stating objectives, including new metrics relating to efficiency and environmental outcomes, with more clarity and precision than the typical standard of "safe and adequate service at just and reasonable rates." Here are three principles to consider:

(1) Real "incentives" are both positive and negative. The regulator should set clear obligations, then provide reasonable compensation for the cost of fulfilling those obligations, coupled with consequences for failing to do so. Performance-based rates must be sufficient, and no more than sufficient, where traditional infrastructure investments and utility operations are concerned, to attract the necessary capital and to hire the necessary employees. However, the present transition to a new business model in this proceeding will require the Commission to establish higher earnings which reward innovative solutions, with the North Central Brooklyn project as a current example, if the utility in question were to develop "non-traditional" solutions to substation capacity expansion, including a comprehensive DER program, and then help implement and perhaps fund that program.

(2) Resistance to reducing cost is not a legal basis for allowing prices above cost. Some argue that incentives are necessary to overcome utility "resistance." This has the ironic, and counter-productive result of increasing rewards in proportion to the resistance; with the cooperative, non-resistant entities receiving the least. If the utility wants to use a $5 million tool while the least expensive, equally effective tool is $3 million, there is no public policy reason to give the utility $4 million to overcome its "resistance," or to produce "win-win." We allow $3 million and let the chips fall where they may. On the other hand, if we are to encourage utilities to investigate non-traditional solutions to addressing peak demand challenges and to pursue the implementation of innovative solutions which may cost significantly less than the traditional investment but require utility engagement with its customers going well beyond traditional experience, then incentives to adopt a strategy that would reduce costs may very well be appropriate.

(3) Cost-effective compensation favors the most cost-effective providers. The talk of "incentives" always seems to focus only on the incumbent utility. But "incentives" must exist for all players, not only incumbents, but also for customers and providers of DER services in which new players may play a role.

6. Benchmarking

a. **Should the Commission consider cost and performance benchmarking to determine utility performance on pre-established metrics?**

Response:

If "cost and performance benchmarking" means setting standards using actual experience from high performers, the answer is yes. Benchmarking brings objectivity. It sets the standard by asking "What does best in class performance look like?" rather than "What costs did our utility incur?"

b. **If so, what measurements/metrics should the Commission benchmark and how should the benchmarks be developed (e.g., across the entire state, outside the state, level of benchmarking complexity)? Should non-utility companies or utility companies from outside the state be included? Does benchmarking require a sophisticated statistical model?**

Response:

The Commission should consider benchmarking metrics related to all of the outcomes which the Commission wants the utility/DSPP to achieve from any relevant source. Such benchmarking, however, is most useful when it can also take into consideration distinctions between utilities such as the age and functionality of the utility's existing equipment.

c. **The U.K. Ofgem's RIIO approach employs some benchmarking techniques in determining utility rates. What are the advantages and disadvantages of adopting a similar benchmarking approach to meet the Commission's goals? If adopted, what, if any, modifications should the Commission consider?**

Response:

As stated in response to 6(b) above, benchmarking may be one appropriate method for measuring the utilities' performance under a PBR+. Such benchmarking would be most useful if it were to to account for differences regarding the utilities' service territories, customer base, age and condition of equipment. One possible approach would be to place increasing importance on benchmarking as a performance metric which is linked to earnings as utilities reach similar positions regarding grid modernization and use it as an informational diagnostic tool in the interim.

d. **Societal values – are there appropriate metrics over which the utility has less than full control that can be useful in promoting public policy goals (e.g. fuel diversity, CO2 reduction, new market development) while also being manageable for the PSC?**

Response:

In light of the increasingly perverse dynamics that result in suboptimal environmental outcomes while simultaneously driving up costs, the imposition of order by an entity filling a new function – a system integrator of sorts – has great promise. The Commission should establish metrics over which the utility/DSPP has less than full control if they are aligned to optimize environmental outcomes. This implies that, for example, the DSPP should be held accountable to a certain point for the amount of CO_2 emitted by its portfolio; even though the DSPP is not completely able to control all of the emissions from the portfolio, it can incentivize cleaner resources by correctly pricing carbon or implementing other customer incentives. Thus, an environmental metric that in some way quantifies CO_2 emissions could be used to identify whether the DSPP is improving its portfolio's footprint, or at minimum, reaching the State's goals. This will support ongoing State efforts to achieve GHG reduction goals and help align future products and services envisioned by third party providers utilizing the DSPP platform towards those same goals. In these cases, the Commission could consider using asymmetrical upside incentives, where the utility/DSPP can only benefit and cannot be penalized for achieving outcomes which rely, in part, on factors such as customer behavior, which lie outside the utility/DSPP's control.

7. **Utility as DSPP and as DER-owner: neutralizing incentives**
   a. **Can ratemaking or structural mechanisms be established to remove the utility bias in favor of DER investments owned by the utility or its affiliates?**

Response:

Removing the utility's underlying bias toward capital investment through adoption of PBR+ regulation could be the more effective method of ensuring no anti-competitive bias for itself or its affiliate. Because when a utility is regulated under PBR+, it will not have an incentive to over-invest in DER, there is no reason to anticipate that its actions will inherently undermine competition. The utility will be rewarded for successfully delivering a neutral energy services platform in the most cost-effective manner, not for spending money to install it. Indicia of successfully delivering this platform would likely include a vibrant market in energy services. Thus, both the utility and the market participants would have an aligned interest in delivering the services customers need in a collaborative fashion. In fact under the recommended PBR+ approach, it would be in the utility's financial interest to incent the siting of customer or third-party owned DER that also performs the function of grid optimization as an alternative to paying for the entirety of the investment. For further protection, the Commission could consider preventing the utility from offering tariffed DER services to customers. As such, the utility would only have an economic interest in investing in DER when it would represent the most cost-effective mechanism to serve its role as a neutral energy services platform and for which its compensation would be limited to performance based revenues. Additionally, the DSPP can be required to make available to market participants vast amounts of information about the utility system and operations, to make it possible for third parties to develop solutions that would work well with the system. The DSPP can also be required to open up opportunities for bidding, and can be required to select among options, including their affiliate's proposals, based on predetermined and clearly communicated benefit-cost analyses and other criteria. The DSPP can be penalized from diverging from these fair practices. Finally, if the Commission determines that utility ownership of DER is appropriate it should limit utility ownership of DER in accord with the following principles:

1. It is reasonable to presume, subject to rebuttal, that a utility serving as a DSPP may own DER, without interfering with competition, where the predominate function of that DER is to meet DSPP needs in lieu of building substations or other distribution equipment; and

2. Utility (DSPP) ownership of DER must not be permitted to interfere with the emergence and functioning of robust third party markets for generation and other DER services.

There are many cases where DERs will be more cost-effective than distribution system upgrades, as shown in the North Central Brooklyn project discussed earlier. A similar project is the Maine Public Utilities Commission's innovative smart grid coordinator initiative, involving the Boothbay Sub-Region Smart Grid Reliability Pilot Project developed in Docket No. 2011-138. In the Boothbay project, the Commission selected GridSolar as the "smart grid coordinator" to implement non-transmission alternatives to avoid re-building a 34.5 transmission line. GridSolar issued RFPs to procure non-transmission alternatives consisting of energy efficiency, photovoltaic (PV) solar panels, demand response, back-up generation and energy storage. This solution saved customers $17.6 million over ten years and provided a cleaner alternative than re-building the transmission line.

If the utility performs the DSPP integrated system planning function, the Commission could consider requiring the utility to put out an RFP to implement a reliability or DSM program where the utility would procure DER. A utility affiliate could bid to provide the DER. Introducing this element of competition would help ensure that costs are kept at a reasonable level. Under this scenario, the selection of winning bids must be undertaken in a manner to ensure that the utility does not favor its affiliate.

Another example of an effective incentive program which eliminates utility bias in favor of owning DER is Con Edison's pilot program to incentivize DER by implementing the same type of rate designs used in the ISO markets. Under this program, Con Edison works with NYSERDA and developers to inform developers of the locations where the substation load relief would benefit the utility by deferring or avoiding investment in the delivery system. NYSERDA provides extra incentives known as "adders" to attract customers in substation-specific areas targeted for load relief in the next ten years. For large PV projects, for example, if the customer is in such an area, NYSERDA will add 25% to the up-front incentive for power purchase agreements (PPAs). For combined heat and power (CHP), NYSERDA adds an incentive of 10% for PPAs. Detroit Edison has a similar program in Michigan.

b. If the utility owns DER investments, is it better if they are ratebased and rate regulated or owned by unregulated affiliates? Is there another option? Does this provide utility incentives to misallocate costs between regulated and unregulated products?

Response:

EDF urges the Commission to make a clean break from traditional ratemaking and the practice of ratebasing investments and adopt PBR+. The current distinction between capital investment and operational expensing distracts and detracts from achieving the performance society now needs from the utility. Capital investment should not be ratebased. If the utility procures DER to support the neutral energy services platform, the utility's only opportunity to recover the costs for the investment under its PBR+ plan would be if the investment aided the utility to meet its performance objectives. The utility would be motivated to invest in DER because this would allow the utility to achieve the Commission's desired outcomes cost-effectively. Utility affiliates may be permitted to own DER when a customer wishes to purchase their services within the vibrant competitive market, provided they follow a code of conduct where the utility does not favor its unregulated affiliate's business. As stated earlier, the guiding principle for utility or utility affiliate ownership of DER is that it should not undermine a vibrant competitive market.

c. What, if any, incentives are required for the utility to make the necessary up front investments in the DSPP?

Response:

At the outset of this new regulatory model, the utilities will probably all need to invest in grid modernization and in the equipment necessary to serve as the DSPP. If the utility revenues necessary for these investments are not budgeted in the PBR+ plan, this could impair the utility's financial condition. This would lead to a higher cost of capital and ultimately to higher rates for customers. The proper incentive to encourage the utility to make appropriate investments is to establish a budget for the capital and O&M for these investments, and to annualize it. The budgeted revenue requirement for these investments would be tied to metrics designed to achieve the Commission's desired outcomes and would be included in the PBR+ plan. The utility/DSPP would earn revenues based on actual performance.

8. Removing bias toward increasing capital expenditures

a. What ratemaking mechanisms or incentives would encourage the most efficient mix of capital expenditures and operational expenses?

Response:

A utility's obligation is to minimize total cost. That obligation is independent of whether the utility profits more or less from a particular mix of capital and operating expenditure. For a particular service, therefore, the regulator must determine the appropriate total cost based on what it finds is the optimal mix of capital and operating expenditure, then include a budget for this amount in the PBR+ plan. How the entity then chooses the actual mix of capital and operating expenditure is its choice. The incentive is simple: Do it cost-effectively and earn the projected authorized return (or more) on equity under the PBR plan; do it imprudently and earn less.

b. Should the Commission employ any mechanisms to eliminate the bias in favor of managing operating expenses (O&M vs. capital issue)? Should the Commission develop mechanisms to treat capital savings the same as O&M savings?

Response:

Yes. As discussed above, EDF urges the Commission to consider PBR+ regulation. Traditional ratemaking provides an incentive to over-invest in capital investments because the utility earns a return on capital investments. Traditional ratemaking also provides an incentive to spend below-normal levels of O&M between rate periods because this allows the utility to maximize earnings. PBR+ plans eliminate these biases. In a PBR+ plan, the utility is incentivized to obtain the most cost-effective solution for the outcomes of the PBR+ plan. The utility would not have any incentive to prefer capital investment over O&M or to under-spend on O&M between rate periods.

c. The current ratemaking paradigm provides utilities with earnings based on the size of the rate base (amount of infrastructure investment). Are there other ways to provide utilities with earnings that would not be dependent upon/linked to the size of a utility's rate base?

Response:

As discussed above, PBR+ regulation will sever the relationship between earnings and the size of rate base. EDF urges the Commission to transition to PBR+ regulation. There are several ways to determine the appropriate revenue requirement for the PBR+ plan. One is investigation -gathering information on alternative approaches and their cost. A related approach is benchmarking: identifying and analyzing similar or analogous projects undertaken by others and determining their costs. The third approach is using competition: each competitor, not knowing the other competitors' costs, has an incentive to offer a proposal at minimum cost. Assuming sufficient competition, this third way is the most accurate way. The incentive is unambiguous and objective: It is the profit from winning, and the foregone profit from losing.

In the case of the third approach, the Commission would create the competitive conditions that will produce cost-minimizing incentives, rather than trying to guess about the compensation structure that will induce the best mix. Each competitor assesses its own costs, its own tolerance for risk, its competitive interest in offering a low-cost deal to gain a competitive foothold, taking into account its ignorance of what competitors might be offering. All these factors drive the prices down, favoring the consumer.

II. **Long Term Rate Plans**

1) Pros and cost of long term rate plans

a. What are the pros/cons of an extended rate plan term (i.e., greater than three years)?

Response:

Since the purpose of compensation is to compensate for performance, it makes sense to align the period of compensation with the period of performance. In competitive markets, a supplier usually is paid when performance is complete (although for long term projects there can be interim payments to cover the costs, although these interim payments are usually conditioned on achieving specific milestones). Since the Commission aims for outcomes that will take longer to achieve (and whose benefits will last longer) than the typical space between rate cases, a longer-term PBR plan makes sense.

b. How can long term planning and priorities be better encouraged under the current rate making approach?

Response:

EDF urges the Commission to abandon current rate making approach and adopt PBR+ regulation. The Commission can encourage long-term planning and priorities by developing a

PBR+ plan tied to long-term objectives. The Commission should use care when developing long-term PBR+ plans because the Commission will want to avoid surprises where a utility has been collecting revenue for a long period, but unexpectedly fails to meet the Commission's objectives at the end of the long-term PBR plan. The Commission can avoid this result by developing milestones or interim metrics which the utility will need to meet as it progresses toward the long-term objectives.

c. Are longer term rate plans a preferable way to enable utilities to achieve identified strategic outcomes?

Response:

Longer-term PBR plans are appropriate for long-term investments and for outcomes which take several years to achieve. It will be necessary to use different approaches for different situations, a challenge not new to ratemaking. Traditional embedded cost ratemaking already has within it multiple rate plans. We call it a single rate but it is a composite of multiple rate plans, each reflecting a different asset or cost center. A $300 million upgrade of the distribution system will generate benefits over a period of at least 30 years, and so has a depreciation schedule for rate purposes reflecting that length of time. The 30-year PBR plan for that expenditure is mixed in with other items, such as current recovery under the PBR plan of labor costs and three-year recovery of storm repair costs.

2) Optimal number of years

a. What is the optimal length for a long term rate plan? Are there any impediments to achieving the recommended term, or negative aspects to such terms, and how can they be mitigated?

Response:

There is no reason to have the same length of time for all utilities, any more than there should be a single revenue requirement for all utilities. Each utility will have a different mix of priorities, resulting in a different cost flow. If the utility were contracting out its various activities to separate entities (which, by the way, is a possibility for the utility or the DSPP), each activity would have its own metrics for success, its own cost calendar and its own revenue flow. The different treatment of each activity would reflect the different types and schedules of costs for each activity, as well as the timing of benefits from the activities.

Further, within each utility there need not be a single "rate period" to cover all its benefit-producing efforts. To think of PBR+ as requiring a single revenue requirement would apply an old world revenue concept to a new world. In the old world, the utility was providing a single service: electric current necessary to power homes and businesses. A single service, provided by a monopoly, needed a single revenue requirement. But in the new world, there will be multiple products and services--not just from the new competitors but from the DSPP itself. Even today, large percentages of a utility's revenue requirement (in some states, as much as 60 percent, we are told) is recovered not through a single base revenue requirement but through multiple, separate surcharges, pass-through clauses or riders. Each of these is designed with specific attention to a regulatory goal and the appropriate cost necessary to attain that goal. We do not advocate single issue rate-making but separate revenue requirements for discrete neutral energy service platform functions is reasonable.

What drives performance are incentives, mandates, deadlines, compensation and consequences. If the Commission wants every customer to know how much energy they use and when they use it within five years, it imposes that mandate and that deadline. It commits to revenue requirement sufficient to cover the utility's costs, and it induces compliance by committing to pay an incentive based upon successful performance. In short, there is no reason to have a single PBR+ rate period for the multiple activities we expect from the utility/DSPP. What matters is for the utility/DSPP to present to the Commission a clear picture of the costs and benefits associated with each activity, at different levels of quality; and then for the Commission to decide, based on that information, what activities deserve ratepayer support, and on what risk terms.

This approach has the added advantage of transparency. A single revenue requirement for multiple outcomes risks confusion and over-simplification, where the utility inserts all its information it has into a black box to produce a number, say a three percent increase in rates for ten years. This approach runs the risk of luring the intervenors and regulator into agreement because it "feels right," rather than because there has been the detailed cost scrutiny that traditional regulation would provide, and the type of accountability that a competitive market would provide. The more specific a commission's expectations, the more it can tie specific PBR treatments to those expectations.

This answer has focused on long-term plans for long-term goals. But there can be short-term goals also. Take a specific distribution sub-territory, with load growth anticipated to cause constraints in three years. The Commission may want to spur the development of DER in that particular location before the constraints hit. The Commission can establish incentives, a mandate, a deadline, cost recovery and consequences for that particular element. The North Central Brooklyn initiative required under the Con Edison distribution base rate case settlement may be seen as an example of this approach, although to ensure the development of a wide range of DERs, expectations may need to be set more expressly. A long-term PBR+ plan, by itself, would not produce that result.

Implicit in the debate over PBR+ plan length is a question of regulatory prescriptiveness. The premise underlying a long-term rate plan is that the Commission establishes general goals and customer value associated with those goals, then delegates to the DSPP the decisions on how to achieve them. But the regulator can also specify particular deadlines for particular outcomes, creating specific revenue paths for those outcomes. There is room, therefore, for flexibility. Besides specifying a set of short-term, medium-term and long-term goals, there can be a "bonus" category for improvements the Commission has not specified because it cannot anticipate every possibility, and wants to leave it to the DSPP's ingenuity, and quest for reward. Other than the "bonus" category, the performance metrics should be clearly established in advance and should not be changed retrospectively because this would be unfair and would add uncertainty to the process, which would increase the utilities' risk and hence their cost of capital.

Finally, to facilitate the possibility that the Commission may wish to allocate the functions of the distribution utility and the three DSPP functions – market operations, grid operations and integrated system planning to separate providers, the Commission could consider establishing separate revenue requirements for each function. The will better enable the Commission to decide whether an independent entity should perform one or more of these functions.

3) Baseline cost-of-service recovery; ROE

a. For current multi-year rate agreements, the Commission sets rates (including the ROE) for the initial rate year. What are the challenges you expect in setting initial rates under outcome-based ratemaking?

Response:

The main challenge will be to establish budgets for major investments which the Commission determines are appropriate to enable the utility to provide new DSPP functions necessary to achieve the outcomes envisioned in this proceeding. For example, if the utility is selected as the market operator, then it might need to invest in new equipment to provide platforms to enable new types of communication and transactions with DER providers and other third parties. The initial level of revenues established under the PBR plan will be an annualized amount, based on the past few years of service. In the example cited, the Commission would need to layer on an additional revenue requirement reflecting the budget for the new market operations investments and services. This incremental revenue requirement will be based on budget projections and this could be more challenging than the traditional approach of approving cost recovery only after the new equipment is placed in service. The Commission could consider managing this challenge by issuing an RFP for this type of new service and the competition among bidders would help ensure that costs are kept at a reasonable level. In many traditional ratemaking states, Commissions have implemented pre-approval process for major investments, which is similar to the budgeting process which this Commission would perform for a PBR+ plan.

b. What are the advantages and disadvantages of setting initial rates under outcome-based ratemaking?

Response:

We understand the reference to "initial rates" to refer to the rates associated with the initial creation of the DSPP functions.

The advantage of setting initial rates under outcome-based ratemaking is that outcome-based ratemaking incentivizes the outcomes rather than the inputs, and that such an approach can better approximate what a competitive market would do, if it were possible for a competitive market to exist. Transitioning from input-based ratemaking to outcome-based ratemaking is a tremendous challenge that now faces the regulators and the incumbent regulated entities. Setting initial rates in accordance with the new paradigm from the start, particularly for all new investments going forward, would avoid needing to effect such a transition almost immediately for the new functions.

The disadvantage is that with respect to these new functions, we have little sense of what these outcomes are actually worth (in a marketplace) nor do we know how much they will cost to achieve. Whereas for functions with a track record, past years can provide some information about revenue requirements, that information will be unavailable for the new functions.

c. How should the Commission set initial rates under outcomes-based ratemaking?

__Response__:

If there had been no history of service, *i.e.,* if the utility/DSPP and the customers were new to the service territory, and there was no investment already made, no iron in the ground, the initial revenues recovered under the PBR plan would be based on facts specific to the future: the regulator's predictions for what the array of services should cost.

But the reality is different. Prospective service will make use of past expenditures (including investments whose costs have not been fully recovered) and future expenditures. If the incumbent is the chosen DSPP, the utility must have the opportunity to recover costs under a PBR+ plan. The same concern applies if a new entrant is chosen to take over the incumbent utility's past activities, in addition to performing the new activities; the incumbent's past costs still must be paid off. The initial PBR plan therefore must provide an opportunity to recover both past and future costs.

The relative certainty associated with performance relating to existing services may justify a lower authorized return on equity to be reflected in the PBR+ plan than should be applied to the costs expected to be incurred for new services.

These facts suggest separating the revenue requirement associated with sunk costs and traditional service, from the revenues appropriate for the new DSPP activities. In addition, since the initial assignment of the DSPP functions to the incumbent utilities should not be seen as a permanent enlargement of their existing monopoly, it is important that the Commission, from the start, separate the revenue requirements for these activities into separate "buckets" at the outset of the proceeding – a separate bucket for the distribution function and each of the three DSPP functions: market operations, grid operations and integrated system planning. As previously stated, this will be helpful if the Commission chooses to allow the incumbent utility to perform all of the utility and DSPP activities at the outset. If the Commission establishes separate revenue requirements, this would make it easier for the Commission to evaluate whether to replace the utility with another entity as the DSPP provider for one or more of these functions at some later date.

Once the revenue requirement has been established for each function, then traditional principles for rate design apply: allocate costs to homogenized subsets of customers and design rates to reflect an opportunity for the utility to recover the costs that group of customers imposes on the system.

d. Earnings sharing mechanisms are a key feature in the current ratemaking system. They provide for the sharing of efficiency gains during the term of the rate plan,

and potentially militate against unintended consequences. Should these be retained, modified or eliminated?

Response:

Earning sharing mechanisms are used to insert reward for performance into traditional rate of return regulation. EDF urges the Commission to abandon traditional rate of return regulation and replace it with PBR+ regulation. As such, the utility has the opportunity to keep all of its savings so long as it meets or exceeds its performance standards. The sharing mechanism is an artifact of traditional rate of return regulation and is not consistent with PBR+. The Commission, however, may wish to be mindful that it does not set performance earning opportunities such as it overpays for monopoly utility services. "[A] public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties." *Bluefield Water Works & Improvement Company v. Public Service Comm'n*, 262 U.S. 679, 692 (1923).

It should be cautious not impose on ratepayers a quality level and cost level above what is obligatory and sufficient, merely to create an "upside" to match the downside risk of performing sub-optimally. That is the logical error. If it is sensible to impose a standard of "no more than ten hours of outages per customer per year," then the Commission must set rates consistent with the costs (and reasonable profit) necessary to limit outage to that level. If the Company has a greater number of outages, it will suffer a financial penalty. It is not necessary then to give the utility an opportunity to earn PBR+ revenues above the reasonable revenue level in the PBR+ plan for getting through year at only eight hours of outages, if the customers did not need or value that higher standard.

Put another way: Where "sharing" means "allowing a return on equity in the PBR+ plan above the normal amount," then: if that higher ROE compensates for a higher level of performance that customers don't need or value, it is unnecessarily expensive; if the higher ROE can be earned even without the supra-normal performance, it is unnecessary.

e. **What are the advantages and disadvantages of maintaining the Commission's current methodology for setting the ROE in multi-year rate plans under outcome-based ratemaking? What, if any, modifications should the Commission make to its return on equity methodology in the new incentive environment?**

Response:

It may be appropriate to update the ROE during the course of a long-term PBR+. There are a few different methods which can be used for deciding the appropriate ROE. The Commission should be consistent in the ROE methodology it uses, and simply update the ROE formula with current inputs. At the outset of the PBR+ plan, the Commission should identify what events or the time intervals for which it will allow the ROE to be updated. Finally, the ROE would be used to adjust the utilities' potential revenues under the PBR plan and whether the utility earns those revenues must be based on the utilities' actual performance.

4) **Interim investment provisions (avoiding deterioration)**

a. **Capital expenditure reconciliations are an important feature in the Commission's current ratemaking system. They provide for the capture of under spending during the term of the rate plan as a secondary measure which potentially militates against unintended future service or reliability consequences. Should these be retained, modified, or eliminated?**

b. **Should there be additional upside protections against capital spending in excess of forecasts?**

c. **Should downward only capital expenditures mechanisms be modified to allow utilities to keep the benefits of efficiencies implemented in capital budgeting (projects completed at lower cost than expected)? How?**

Response:

This response addresses 4(a)-(c). EDF chooses not to submit a response to this question at this time.

5) **Reopening conditions**

a. **What sort of mid-term reopeners are needed to evaluate long term plans?**

Response:

Mid-term reopeners should be developed to ensure that long term targets established by the Commission can be economically achieved. Re-openers could be based on several factors, including: (1) the length of time since the last ROE or incentive adjustment: (2) material change in the assumption in the PBR+ plan; (3) changes in law that impact Commission targets; (4) the Commission wishes to add new outcomes mid-way through an existing PBR+ or metrics at some point before the closing of the existing PBR+ plan.

Most significantly, reopeners should be developed to address performance with respect to environmental and societal metrics. As further described in our Track 1 responses, certain aspects of the REV proceeding and related proceedings present a material risk of backsliding on key environmental outcomes and to adjust the revenues the utility could earn under the PBR plan, resulting in harmful quality of life impacts for communities. As the market evolves to take advantage of the new opportunities created by the DSPP, performance should be monitored to ensure that adverse impacts to these metrics can be identified and adjustments made accordingly.

b. **Should a long term rate plan be terminated if certain performance targets are not met mid-way through the rate-plan period?**

Response:

Under traditional ratemaking, the utility, the regulator or intervenors may seek rate increases or decreases when changes in costs or sales produce actual returns that vary from authorized returns. Many jurisdictions have modified the traditional approach by allowing riders, surcharges, pass-through clauses and various forms of "single issue ratemaking" to allow for more predictable (and sometimes automatic) adjustment in rates to reflect specific costs.

While these measures have dis-advantages (such as the risk of plugging costs into a rate-increasing spreadsheet without evaluating prudence), an advantage is they allow for experimenting with new products and services whose cost and benefit paths are unclear. As discussed above, a PBR+ plan should include the conditions which would allow the utility/DSPP to seek to re-open the plan. These conditions could be based on the passage of a certain amount of time, or the occurrence of some material change not anticipated when the plan was approved.

6) Exogenous factors and reconciliations

a. What uncertainty mechanisms would be needed for long term plans to deal with unexpected costs or new governmental requirements?

b. Typically, utilities are provided with projections against certain risks during long term rate plans (e.g., commodity pass through, uncontrollable costs provisions, etc.). In return, the utility must absorb any deficient returns. Should this type of approach be retained or modified? What costs should be included?

c. Should we consider changing the existing pass through recovery of electric commodity costs by electric utilities? Explain.

Response:

This response addresses 6(a)-(c). EDF chooses not to submit a response to this question at this time.

7) Reporting requirements

a. What level of financial monitoring is necessary during a long term plan? What reporting requirements are necessary under a long term plan?

Response:

This response addresses 7(a). EDF chooses not to submit a response to this question at this time.

b. What level of service quality and other performance reporting and monitoring is necessary?

Response:

All rate plans are imperfect experiments, in which the utility has more access to more data, about cost and performance, than does the regulator. Under these circumstances, the regulator's job under a PBR+ plan is not to trust, but to verify. It must have continuous access to all data necessary to determine whether the plan's premises were accurate, whether the utility is carrying out the "incentivized" activities effectively and at least cost, and whether non-incentivized features of the utility's service obligation are receiving insufficient attention. There should be no expectation that plan is working just because it has been approved.

There is no legitimate basis for utility objections to the regulator's access to all data. Assertions of "competitive sensitivity" simply reveal that the utility has a conflict between its public service obligations (whose oversight requires full and continuous data access for the Commission) and its other business aims. For the Commission to compromise its own access in favor of the utility's other business aims conflicts with the Commission's own obligations.

The utilities' PBR reports should also be subject to periodic audits by an independent auditor.

c. **How should the Commission monitor cost allocations to other subsidiaries including unregulated subsidiaries?**

Response:

This is less of a concern under PBR+ than under traditional ratemaking. Nevertheless, the regulators monitoring a PBR+ plan will still need to be concerned with cost allocations in order to monitor the utility's financial condition. Cost allocations are also an important consideration where: (1) there is a transition period to full PBR+ regulation; or (2) under PBR+ regulation, when a utility/DSPP submits a budget for some proposed new material investment not covered by the current PBR+ plan. In all cases, the utility should follow standard cost allocation principles consistent with FERC's Uniform System of Accounts.

8) **Application of RIIO concepts (to the extent not addressed above)**

a. **Should the Commission focus more on outputs and less on inputs? If so, by which means could the Commission accomplish this? Which outputs and inputs would be appropriate?**

Response:

As discussed in our earlier responses, EDF submits that outputs are a better metric than inputs because the outputs seem less subject to extraneous factors and also seem easier to normalize. Inputs can be used for informational purposes.

b. **If the NY Commission were to focus on outputs as is done in RIIO, which outputs should we focus on? Which ones should we ignore or add?**

Response:

The outcomes listed in Appendix A to the Track 1 questions provides a suitable list of outcomes on which the Commission could focus. EDF recommended changes to some of these outcomes in our response to the Track 1 questions.

c. **What are your thoughts (pros/cons) on the 8 year rate plan length?**

Response:

There is nothing magical about an eight-year plan length. In deciding the appropriate plan length, the Commission should consider all factors, including: (1) whether the plan contemplates any new long-term investments necessary to perform new services; (2) the depreciation schedule for such equipment; and (3) the circumstances under which the utility is allowed to re-open the plan or seek any adjustments.

d. **Is it a reasonable expectation that an extended rate plan can be redesigned within the statutory 11 month suspension period or will it take more time (how long)?**

Response:

Much of the generic work on designing plans can be done outside of the PBR case, then applied to a specific utility in a PBR case. The more we lean in this direction, the less constraining is the 11-month suspension period.

9) **Financial implications of ratemaking changes**

a. **How can we insure that any new incentives do not adversely affect the utility's credit rating?**

Response:

Assuming the Commission has properly established quality standards and compensation levels and then performs predictably to implement them, but the utility is either (a) spending within budget but failing in quality, thereby incurring Commission penalties; or (b) maintaining quality but spending over budget, the capital markets will punish the company. The capital markets will respond by reducing their confidence in the company. Shareholders will demand higher returns, rating agencies will lower credit ratings, so bondholders will insist on higher interest rates. If the Commission protects the company from these outcomes, it is undermining its own reform vision. If the Commission wants to improve performance it must hold regulated companies accountable for performance. If the utility cannot perform at the quality level required by the Commission while earning the compensation deemed appropriate by the Commission, the Commission must replace the utility, not give it more money.

The Commission therefore cannot ensure that its efforts "do not adversely affect the utility's credit rating." It can best support utilities in protecting their credit by establishing clear regulatory decision-making criteria and then implementing it transparently. The purpose of regulation is performance. We will not get performance if we protect the credit ratings of those do not perform. This is why it is essential for the Commission to incentivize the utility/DSPP to achieve the desired performance outcomes.

Importantly, the desired outcomes and performance metrics will evolve over time. Yet they must be applied prospectively, not retrospectively. The Commission should not make after-the-fact changes to the outcomes and metrics because this would be unfair and would increase the utilities' risk and their cost of capital.

In response to earlier questions and in its Track 1 comments, EDF has suggested that the Commission should investigate whether to select an independent party to undertake some or all of the DSPP role. If the Commission appoints an independent entity to this role, then the Commission must clearly define which outcomes are the utility's responsibility and which are the independent party's responsibility.

b. **Under US GAAP Accounting Standards Codification (ASC) 980-Regulated Operations utilities are permitted to record regulatory deferrals. Would a revised regulatory regime focused on performance-based ratemaking impact utility qualification under ASC 980? To what extent is that a concern?**

c. Would there be any concerns about asset impairment under a revised regulatory regime focused on performance based ratemaking? How much of a concern is that and how can any concern be mitigated?

Response:

This response addresses 10(b) and (c). EDF chooses not to submit a response to this question at this time.

III. Rate Design

1) How do the customer incentives and disincentives under current rate design affect DER participation?

Response:

This response addresses III. 1. EDF chooses not to submit a response to this question at this time.

2) Tariffs for DSPP products

a. How should non-monetized benefits and costs (e.g., carbon) be accounted for in rates, if at all?

Response:

For the DSPP in the role of grid operator, the DSPP would want to acquire DERs for reliability and optimizing load purposes. During the planning for reliability and demand-side management programs, the utility should consider all costs and benefits, including non-monetized benefits, associated with each resource option. The utility should use the social cost of carbon for such integrated system planning purposes. After the utility selects the appropriate type of resource in this manner, the utility can acquire the resource through a competitive bidding process because this would help the utility manage its costs.

For the DSPP in the role of market operator, the DSPP would provide a platform where DER customers could interact with the DSPP, third-parties and NYISO. To the extent that the DSPP/market operator function acquires any DER from customers, this should be for the purpose of grid support. In other words, the DSPP market operations function would provide the platform for acquiring the DER which the DSPP grid operator would use for reliability and demand-side management purposes.

b. Which non-monetized benefits should be accounted for, if any?

Response:

The utility/DSPP grid operator should account for non-monetized benefits when it does its system planning. Environmental costs and benefits of clean energy should be accounted for, including greenhouse gas emissions (carbon dioxide and methane), criteria air pollutants (SO2, NOx, PM), water consumption (different amounts used by different sources of energy generation), and land usage (e.g., DER can help eliminate the need to clear land in order to build a power plant).

Second, reliability and resilience is another area of non-monetized benefits that should be accounted for. Some DER, for example, demand response, helps to reduce the impacts of blackouts due to excessive demand, and other forms of DER, such as storage and microgrids, could help reduce the impacts of larger-scale outages and can also provide back-up power during these outages. Reducing these outages not only provides monetary benefits but also provides non-monetary benefits such as decreased security risks.

The DSPP/grid operator and DSPP/integrated system planer would calculate the costs and benefits of different resource options (including grid upgrades) using this approach. After the appropriate types of resources are identified, the DSPP/market operator would acquire these resources.

3) **For each of the products and services to be procured by the DSPP, how should the pricing be determined? (If the answers differ by product, please specify to the extent possible.)**

a. **Should pricing be based on embedded cost of service?**

Response:

No. As discussed previously, the Commission must break away from the old model of cost of service ratemaking and adopt PBR+.

b. **Should pricing be determined through a market mechanism which might reflect locational based marginal pricing?**

This response addresses III.3.b EDF chooses not to submit a response to this question at this time.

c. **Should pricing be determined via request for proposals and individually negotiated contracts? Should individually negotiated contracts be made available for public inspection?**

Response:

Service costs are minimized though competitive bidding. We anticipate that this cost minimization will be worth the extra administrative burdens placed on utilities and regulators to host solicitations for services. Ultimately, the choice of bilateral contract or RFP will depend on what products or services are being procured and the circumstances (*i.e.,* market conditions) at the time of the transaction, including the extent to which fair competition exists, and the number of market actors prepared to compete.

Competitive pricing is more likely to result in bids close to a producer's cost and thus be the best deal for customers. For competition to deliver this benefit, there must be a fair playing field and the boundaries of that field ought to be broad enough to encompass the full range of solutions (so as to allow for selection of the least cost alternatives). So, for example, distributed energy resources ought to be able to compete for the right to provide energy, capacity, and other reliability and ancillary services that are necessary to deliver the DSPP neutral energy services platform.

In considering the expansion of the regulatory compact, and the clear need to embrace and unleash a clean energy marketplace, EDF suggests a starting point "line in the sand": whereas the portions of the grid that society concludes should rightfully remain natural monopolies – notably provision of wires and poles, and potentially the DSPP function (even if the latter function is not played provided by a different entity than the wires company) – should remain, those monopolies cannot be allowed to squelch or bias competition that would otherwise be fair and economically efficient.

However, while unfettered price-based competition should advantage the least cost producer, it is not true that in every instance the least cost producer is preferable. For example, some producers may internalize more external costs than others (*e.g.*, an electricity producer in California has a cost of greenhouse gas pollution, whereas a producer in Denver does not (yet)). For these reasons it is critical that externalities be internalized to the maximum extent possible when procuring bids or RFPs. If bilateral contracts are permitted to be kept confidential, that confidentiality must not impair the Commission's ability to evaluate matters of legitimate public interest, such as the carbon and other emissions impacts of selected resources and how those impacts are considered and monetized.

d. Should pricing be administratively determined to provide an incentive to achieve a predetermined outcome? If so, what level of granularity is needed (e.g., peak/off-peak vs. hourly)

Response:

Pricing should be structured in such a way as to incentivize DER where and when it is needed the most to deliver the DSPP neutral energy services platform. The value of DER varies both by location and time, as areas/times with lots of congestion in the distribution system would benefit more from DER than areas/times with little congestion. Thus, if the price for DER reflects how its different benefits and costs are distributed over space and time, then the pricing will help incentivize DER in the areas that most need it. For example, paying more for demand response in an area with lots of distribution congestion can help to incentivize these conservation actions in that congested circuit.

The DSPP should try to allow the marketplace to reveal as many of the benefits and avoided costs of DER as possible. However, some of the avoided costs, such as the avoided cost of carbon, may not be fully revealed in the marketplace; hence it is important for these costs (such as the social cost of carbon or reliability) to be reflected administratively.

To the extent that the DSPP has the ability to identify the true costs of distribution over the course of the day (at sub-day time intervals), then time-variant pricing for DER can help to ensure that the resources are deployed at the time that is most valuable to the DSPP neutral energy services platform. For example, if demand response is paid at a rate higher in the late afternoon due to system needs, investors will have the incentive to install building energy management systems that can be programmed to respond during the time that it is most valuable. Pricing should also be variable throughout the year, as DER deployment may be much more beneficial during the summertime, when distribution costs are quite high. Therefore, the DSPP should develop tariffs (whether for DER or customer energy demand) that closely follow cost causation with fine spatial and temporal precision. With such rates, customers will seek to avoid demand at high cost times and locations by investing in DERs, thereby aligning their actions with system needs.

e. Should the pricing vary by time and / or geographic location?

Pricing should be structured in such a way as to incentivize DER where and when it is needed the most. The value of DER varies both by location and time, as areas/times with lots of congestion would benefit more from DER than areas/times with little congestion. Thus, if the price for DER reflects how its different benefits and costs are distributed over space and time, then the pricing will help incentivize DER in the areas that most need it. For example, paying more for demand response in an area with lots of congestion can help to incentivize these conservation actions in that congested region.

To the extent that the DSPP has the ability to identify the true costs of distribution over the course of the day (at sub-day time intervals), then time-variant pricing for DER can help to ensure that the resources are deployed at the time that is most valuable to the system. For example, if rooftop solar generation is paid at a rate higher in the late afternoon due to system needs, investors will have the incentive to tilt their panels west rather than south in order to generate more electricity during the time that it is most valuable. Pricing should also be variable throughout the year, as DER deployment may be much more beneficial during the summertime, when distribution costs are quite high. Therefore, the DSPP should develop tariffs (whether for DER or customer energy demand) that closely follow cost causation with fine spatial and temporal precision. With such rates, customers will seek to avoid demand at high cost times and locations by investing in DERs, thereby aligning their actions with system needs.

Varying price by time and geographic location is therefore essential to ensuring that the investments are being made in the place they are most valuable and resources deployed at the time they are most valuable. The challenge is to avoid or delay more costly (and dirtier) investments in resources with DERs that, when aggregated, provide equal or better service and reliability at lower total social cost.

There is another dimension that also needs to be taken into account: the extent to which resources are currently available within each geographic location. Take for example two areas- one with little or no DERs are deployed, and one where substantial investments have been made. The first of these areas would benefit greatly from having DER, and the benefits would increase as more and more customers become involved; however, investments required to aggregate the DERs may be necessary. The second of these areas, which is already flush with resources, will not have as many benefits from each new unit coming online, but also may require lumpy investments necessary to sustain such DG. Therefore, the value of DER will depend in part on the extent of local DER penetration as well as whether lumpy investments need to be made in order to support such expansion.

f. **Should the pricing be differentiated for products related to reliability, economics, or public policy?**

__Response__:

These may be appropriate considerations for differentiating pricing.

4) **For each of the products and services to be offered by the DSPP, how should the pricing be determined?**

a. **Should delivery services be unbundled into reliability, power quality, ancillary services components and other value added services? What value added services need to be unbundled?**

__Response__:

EDF notes that the central functions of government – in this case the Commission - in any marketplace are to establish, validate and enforce property rights, define and enforce market rules, and, particularly with respect to environmental goals, develop policies to address conflicts associated with common property and open access resources. In the context of NY REV, the Commission must provide the property rights clarification and market rules that will set the stage for fair competition to buy, sell and trade the right products. Markets for capacity already provide a means to ensure reliability in NYISO. These markets ought to be opened, increasingly until fully, to DERs that meet product standards.

The delivery of unbundled services will, to most customers, be as simple as the lights staying on and the coffee maker working. For these customers, full exposure to variable wholesale energy prices or anything other than bundled rates may be inappropriate. For sophisticated customers who seek to become prosumers, the monetization of goods and services ought to be driven by market opportunities to harvest value. Put differently, for traditional providers, new third-party providers and sophisticated customers who will, at times, behave like third-party providers, the categorization of products into reliability, power quality, ancillary service and others components, may be a useful way of organizing market design. Ultimately, the market will determine what products and services – in combination or isolation – are "worth" in actual transactions.

b. **Should pricing be based on embedded cost of service?**

__Response__:

Our subsequent answer is based on the assumption that one of the products the DSPP will be offering is delivery.

No. As discussed previously, the Commission must break away from the old model of cost of service ratemaking and adopt PBR+.

c. **Should pricing be determined through a market mechanism which might reflect locational based marginal pricing? If so, how should any remaining revenue requirement be collected?**

Response:

This response addresses III.4.c EDF chooses not to submit a response to this question at this time.

d. Should pricing be determined via request for proposals and individually negotiated contracts?

Response:

Optimally, the marketplace would determine prices, however this may not always be viable, for example if there is no established market for the good in question. In this case, RFPs can help the DSPP to glean information on underlying costs with which to help choose best prices. Competitive bids for considering alternatives to capital investments can also help to demonstrate the cost of these DER investments, and then a price can be chosen given the lowest bidder's cost.

e. Should pricing be administratively determined to provide an incentive to achieve a predetermined outcome?

Response:

As a general rule, pricing should be structured in such a way as to incentivize DER where and when it is needed the most. The value of DER varies both by location and time, as areas/times with lots of congestion would benefit more from DER than areas/times with little congestion. The only difference is for distribution services which are provided by a natural monopoly. In this case, rates should be determined administratively. Over time, however, we encourage evolving away from rate of return regulation to PBR plans and to pricing determined by the competitive pressures of the marketplace.

The DSPP should try to allow the marketplace to reveal as many of the benefits and avoided costs of DER as possible. However, some of the avoided costs, such as the avoided cost of carbon, may not be revealed in the marketplace; hence it is important for these costs (such as the social cost of carbon or reliability) to be reflected administratively.

f. Should the pricing vary by time and/or geographic location?

Response:

Our subsequent answer is based on the assumption that one of the products the DSPP will be offering is delivery services.

Yes. Varying price by time and geographic location is essential to ensuring that the investments are being made in the place they are most valuable and resources deployed at the time they are most valuable. The challenge is to avoid or delay more costly (and dirtier) investments in resources with DERs that, when aggregated, provide equal or better service and reliability at lower total social cost.

5) **New rate designs**

a. **Should rate designs reflect different levels of service, e.g. essential monopoly service versus non-essential value-added competitive service? Can fees from non-monopoly services constitute a portion of the incentives otherwise provided through ratemaking?**

Response:

Yes. As stated in our answers to Track 1 (Section 6: Enhanced Services), customers vary in their need for non-essential services and reliability. Those who have very large negative impacts from experiencing very short outages would benefit more (and likely be willing to pay more) for a service that guarantees no outages. However, all customers deserve a basic level of service that is reliable and secure, and it is unfair to expect customers to pay extra for the basic service. It is therefore important to provide a menu of options that customer can choose from in terms of non-essential or value-added services to reflect the different needs and capabilities of customers.

b. **Should the products and services procured and offered by the DSPP be offered on a service class basis or uniform pricing for all customers? If the answer differs by product, please specify.**

Response:

Uniform pricing (as defined by one price for all) will likely not lead to the desired outcomes at least cost. Different regions (even within the same service territory) have different needs, especially in terms of peak demand, and therefore they should face different prices. For example, consider a region which has several buildings that are very inefficient and the utility needs to expand capacity given the large energy demand of that region. The utility can either invest in a new substation for a very high cost, or the buildings could be weatherized at considerably lower cost. An "any source" solicitation would allow energy service companies to compete for the right to provide DERs rather than a new substation. The DSPP could use such bids to set a price for EE in that area thereby providing precision in pricing that can be the spark to action by the building energy manager. Without correct price signals that vary by location, there will be little to no incentive for these managers to make the investments that provide large system benefits.

Regarding prices varying by customer class: what is most important is to allow customers to choose from a menu of different pricing options, regardless of their customer class, and instead to help them choose from prices that can best both serve the customer as an individual and the system in the aggregate. For example, with time varying pricing, having only one tariff with a single peak time will lead to very low levels of adoption – even if those who face the prices reduce their peak demand coincidentally with the system peak, not enough customers will have adopted the prices in order to provide a system benefit. Alternatively, providing several peak time options will allow customers to choose which of these will provide the best incentive to conserve- even if each individual customer's load does not end up conforming to the system load, in the aggregate, the system peak can decrease.

c. **Should rates for products or services procured to achieve certain incentives, like more efficient utilization of the distribution system through peak load reductions, be set by the Commission or allowed to be set by the utility companies as necessary?**

<u>Response</u>:

The prices should be set by the utility. The utility companies likely have more information about the costs incurred and the benefits of DER in their service territories.

d. **Should the current volumetric rate designs used to recover embedded costs be revised to move toward fixed pricing? What are the tradeoffs or unintended consequences of moving towards fixed pricing that should be considered?**
e. **To what extent should the existing revenue decoupling mechanisms (RDM) continue to be applied and what modifications would be necessary?**
f. **Should lost revenues due to customer bypass be fully, partially, or not included and recovered in the RDM, or some other, reconciliation process?**
g. **What payment structure would facilitate distribution utility ownership of DER behind customers' meters? For example, should a customer be provided with a direct payment for allowing the utility to locate the DER on its property or should the customer be allocated a portion of the ongoing DER benefit?**
h. **How can rates best be structured to equitably share system benefits among participating and non-participating customers (i.e. customers without DER onsite)?**
i. **How can rates best be structured to equitably share system benefits among participating and non-participating customers (i.e. customers without DER onsite)?**

<u>Response</u>:

This response addresses 5(d) - (i). EDF chooses not to submit a response to this question at this time.

<u>Response</u>:

6) **Enhanced service and basic service**
a. **How should default service be defined?**
b. **Should the DSPP offer default service and if so what products and services should be included and what rate design should be employed?**
c. **Should there be different level of default service, for example, basic and enhanced and what features would each have?**

<u>Response</u>:

This response addresses 6(a) - (c). EDF chooses not to submit a response to this question at this time.

7) **Standby rates**

a. **How can the current standby rate design be revised to reflect the diversity of DER and the unlikelihood that all DER resources would fail at once and all during the system peak hour?**
b. **How can the current standby rate design be revised to reflect environmental or system values of certain types of DER?**
c. **How would the current standby rate design need to change to be applicable to multi-customer microgrids?**
d. **How should the prices for products and service reflect the additional system and environmental values represented by technologies that are currently eligible for net metering?**

__Response__:

This response addresses 7(a) - (d). EDF chooses not to submit a response to this question at this time.

8) **Gas and steam rate implications**

a. **How do the current gas and steam rate designs encourage or discourage the installation of DER, specifically gas fired DG and CHP?**
b. **Which aspects should be eliminated, expanded, or redesigned, and how?**

__Response__:

This response addresses 8(a) and (b). EDF chooses not to submit a response to this question at this time.

Respectfully Submitted,

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