**STATE OF NEW YORK**

**PUBLIC SERVICE COMMISSION**

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

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**Acadia Center, Association for Energy Affordability, Citizens for Local Power, Clean Coalition, Environmental Advocates of New York, Environmental Entrepreneurs, Natural Resources Defense Council, Nature Conservancy, New York League of Conservation Voters, New York Public Interest Research Group, Pace Energy and Climate Center, and Sierra Club**

**Dated: October 26, 2015**

**Acadia Center, Association for Energy Affordability, Citizens for Local Power,**

**Clean Coalition, Environmental Advocates of New York, Environmental Entrepreneurs,**

**Natural Resources Defense Council, Nature Conservancy, New York League of**

**Conservation Voters, New York Public Interest Research Group,**

**Pace Energy and Climate Center, and Sierra Club**

Comments to New York State Department of Public Service

Track 2 White Paper

Case 14-M-0101

October 26, 2015

**PREAMBLE**

Under New York Governor Cuomo's leadership—most recently demonstrated by his signature of the "Under 2 MOU"— the state is solidifying its status as a national climate and clean energy leader. The state has adopted one of the most aggressive solar programs in the nation, led the charge to strengthen the Regional Greenhouse Gas Initiative ("RGGI") and make it a national model on how to reduce carbon from the power plant sector while growing the economy, and adopted a State Energy Plan with 2030 clean energy targets as strong as any state in the country. Specifically, meeting the 40% greenhouse gas reduction goal from 1990 levels, 50% renewables, and 23% energy efficiency goals the Plan envisions would ensure the state is on track to meet the longer term emissions cuts necessary to avoid the worst impacts of climate change. We agree that achieving these goals requires new thinking and moving beyond "business as usual" efforts.

Integral to this vision is the weaving together of the ambitious New York State Public Service Commission ("Commission") proceedings currently underway, namely the Large Scale Renewables ("LSR") docket, Clean Energy Fund ("CEF)", and the Reforming the Energy Vision ("REV")[1] docket that is the focus of these comments.

The members of the Clean Energy Organizations Collaborative ("CEOC") [2] continue to support the Governor and the Commission in their efforts under the REV to reshape the grid into one that is more nimble, cleaner, and empowers consumers of all socioeconomic classes and across all sectors to better manage their energy consumption. In addition, we support the effort in REV's Tack II to fundamentally reform the utility business model and regulatory framework in New York. The changes should ensure utilities remain financially viable while receiving the necessary signals to pursue investments that will facilitate the REV transition by maximizing energy efficiency and other clean distributed energy resources and expanding market

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[1] Case 14-M-0101. Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.

[2] The Pace Energy and Climate Center and the Alliance for Clean Energy New York co convene an independent group called the Clean Energy Organizations Collaborative on REV-related matters. This collaborative is made up of national and state-based environmental organizations, clean energy companies and organizations, renewable energy industry trade associations, consumer groups, energy efficiency providers, and academic centers. The CEOC seeks to ensure environmental outcomes that are consistent with New York's overall pollution reduction goals; break down existing barriers to clean energy services; and inform its members on market and rate design issues.

opportunities for third parties to deliver clean DER. To date, the stakeholder process in the REV has been robust, and we urge the Commission to continue that inclusive and transparent approach.

But achieving the REV objectives will depend on getting the details right; these comments outline our specific position on many of those important details. We support the Commission's willingness to tackle these complex challenges, and we will continue to work with the Commission to make REV a model for the nation.

## I. INTRODUCTION AND SUMMARY

On July 28, 2015 the New York State Department of Public Services Staff ("Staff") filed a White Paper ("White Paper")[3] in response to the Commission's April 2014 Order Instituting Proceeding regarding Case 14-M-0101. The Staff invited parties to submit comments on several recommendations pertaining to Track 2 of the REV proceeding by October 26, 2015.

Acadia Center,[4] Association for Energy Affordability, Citizens for Local Power, Clean Coalition, Environmental Advocates of New York, Environmental Entrepreneurs, Natural Resources Defense Council, Nature Conservancy, New York League of Conservation Voters, New York Public Interest Research Group, Pace Energy and Climate Center, and Sierra Club, filing jointly as the Clean Energy Organizations Collaborative, appreciate the opportunity to provide these comments on the White Paper. This document builds upon many points raised in previous filings from CEOC members.[5]

The CEOC agrees with Staff's assessment of the limitations of current cost of service ratemaking, and the need for new ratemaking and utility business models to support REV practices and goals. We are also pleased to see that Staff recognizes the need for significant shifts in the financial incentives provided to electric utilities to encourage the development of

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[3] Case 14-M-0101. Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Developing the REV Market in New York: Staff White Paper on Ratemaking and Utility business Models (July 28, 2015).

[4] Acadia Center will file additional comments individually in this proceeding regarding distributed energy resource valuation and rate design.

[5] Case 14-M-0101. Core Principles for Reforming the Energy Vision and Creating a Clean Energy Fund from Columbia's Sabin Center for Climate Change Law, Environmental Defense Fund, Natural Resources Defense Council and Pace Energy and Climate Center (May 27, 2014).

distributed energy resources ("DER"), and plans to accomplish these shifts through a gradual, informed, and thoughtful transition from today's practices. The CEOC is optimistic that REV will contribute to a new paradigm for clean and efficient, environmentally friendly energy in New York.

The CEOC parties generally agree with Staff proposals to revise utility revenue models, establish earning incentive mechanisms ("EIMs") and scorecard metrics, and offer pre-approval for certain DER-related investments. These measures will better align utility financial incentives to support improved long-term planning and much more aggressive promotion of DER. We also generally agree with Staff proposals to provide customers with better information and a more accurate valuation of DER. This, along with better rate design signals, will empower customers to become more engaged and to make investment decisions that more closely account for the true value of DER to themselves and to the utility system as a whole.

These comments also identify a few areas of concern and provide several alternative recommendations for the Commission to consider. REV seeks to accomplish a fundamental restructuring of the way that New York utilities make long-term investments in the electricity system; it has the potential for significant risks as well as benefits for electricity customers. Both the benefits and the risks must be carefully addressed as we transition to new utility ratemaking practices.

The CEOC remains concerned about the extent to which markets will develop to implement some of the key elements and achieve some of the key goals outlined in the Staff's proposals. Third-party DER developers might not emerge to the extent envisioned by Staff. These developers may see insufficient profits available in some of the DER markets to justify entry, and market incentives might cause developers to fail to provide the level of customer aggregation necessary to support some of Staff's proposals. DER providers also might not attempt to serve large portions of customers who are more expensive to market, aggregate, and serve. Similarly, customers might not respond to the new price signals established by the utilities, regardless of how well prices are structured or how well prices reflect the full value of DER. Furthermore, the Staff proposals provide few specific recommendations regarding how the value of environmental benefits, particularly carbon dioxide emission reductions, will be accounted for in either the newly developed markets or in the improved price signals provided to customers.

Our recommendations here build upon the Staff's proposals by addressing these important concerns. We support the Staff's proposals to investigate the opportunities for utilities to identify and pursue market-based earnings ("MBEs") from utility services, but recommend that the Commission not depend upon MBEs to provide a significant stream of revenues to help offset customer bills until there is sufficient experience and evidence that they will be able to do so. We support the Staff's proposals to establish EIMs and scorecard metrics. However, more specificity is needed regarding the process for how they will be established and implemented over time. We provide several recommendations regarding how this should be done. We also provide specific recommendations for how EIMs and scorecard metrics should be structured and used. We support the Staff's proposals to establish better information on the value of DER and to provide customers with better price signals to adopt DER, and offer recommendations to ensure that cost-effective DER will be promoted and developed if customers do not respond to better prices as anticipated. Finally, throughout our recommendations we offer suggestions for how the new ratemaking approaches can be used to achieve the REV environmental goals.

## A. Guiding Principles

The CEOC offers the following principles as guidance to the Commission and Staff in developing specific policies and recommendations.

### 1. Emissions reduction must be central to the Commission's new ratemaking policies.

The Commission has been clear that reducing environmental damage from the electricity industry, particularly in terms of reducing carbon dioxide emissions, is one of the key goals of the REV initiative.[6] In order to achieve this important goal, the new utility business models and ratemaking practices addressed in the White Paper must incorporate means of promoting clean

[6] Case 14-M-0101, Order Instituting Proceeding, at 2 (April 25, 2014).

energy resources through the incentives provided to utilities, through the price signals sent to customers, and through the third-party market-based mechanisms.

**2. The Commission must strongly support and expand energy efficiency.**

Energy efficiency is the lowest cost and most universally-available way to reduce customer bills, reduce carbon dioxide emissions, improve the efficiency of the electricity system, and achieve other REV goals. Yet decades of experience have demonstrated that today's customers will not adopt a large portion of energy efficiency on their own, and that market-based approaches have limited ability to provide all cost-effective energy efficiency to all customers. New utility business models and ratemaking practices must recognize these market barriers and continue to require utility support and minimum performance levels for energy efficiency programs until the alternative approaches have been demonstrated to be at least as effective.

**3. The Commission must ensure that all customers are allowed to and encouraged to benefit from REV innovations.**

Another important goal of the REV initiative is to reduce electricity system costs and empower customers to reduce their bills. One of the best ways for customers to experience lower bills is for customers to implement distributed energy resources in their homes or businesses, whether in the form of energy efficiency, demand response, distributed generation, or other means of controlling their bills. Therefore, new utility business models and ratemaking practices must emphasize and promote widespread customer participation to ensure that all customers are allowed to benefit from them.

**4. Distributed Energy Resources must be fully valued.**

Regardless of whether DER are implemented by utilities, by customers, or by third parties, it is imperative that they be fully valued. This requires a comprehensive assessment of the value of avoided distribution, as well as transmission and generation costs. It also requires a meaningful assessment and application of the benefits of avoiding environmental impacts, particularly reducing carbon dioxide emissions.

**5. Utility financial incentives should be aligned with REV objectives.**

For both the short term and long term, utilities will play a critical role in the analysis, support, and implementation of DER. In order for them to play this role as effectively as possible, it is essential that they be provided with clear financial incentives that overcome existing disincentives to DER and are aligned with the key REV objectives.

**6. Market mechanisms must be demonstrated to be effective before they are relied upon.**

While we applaud Staff's efforts to utilize third parties and market-based approaches to implement DER, it is important to recognize the limits of these approaches, particularly with regard to serving those customers who are harder and more expensive to identify, market to, and serve. Low-income customers are not the only group that is at risk under market-based approaches—many other residential customers, and many small commercial and industrial customers are also at risk. Before relying too heavily on market-based approaches to implement DER, the Commission must determine that they will be sufficient in serving these important customer segments. It is likely that hybrid structures will be required during the transition to market-based mechanisms, and that regulated approaches will be required for some segments for quite some time. The Commission must maintain its ability to design and implement these approaches until markets really can carry the load.

## B. Summary of Recommendations

**Regulatory Process**

Many of the reforms proposed in the White Paper are ambitious and will require considerable work from the utilities, oversight by the Commission and Staff, and input from interested stakeholders. Therefore, we recommend that the Commission provide much more detail in terms of the regulatory process required to implement the proposals in the White Paper. It is important to articulate the timing, order, and inter-related aspects of the various elements proposed by Staff.

The CEOC recommends that the Commission provide more clarity regarding the regulatory process. We offer several suggestions for how to do so:

- By the close of this docket, the Commission should resolve key revenue model and rate design decisions that must be reflected in distribution system implementation plan (DSIP) filings. At a minimum, these include: any revisions to the clawback mechanism; findings on the rate plan period; findings on pre-approval of investments; and the key definitions and formulas used to set the EIMs.

- The first DSIP should commence as soon as is practical after the close of this docket. The DSIP process should be fully adjudicated, and provide all parties with the due process provided in rate cases.

- DSIPs should be used to make key decisions regarding at least: capital expenditures for the next rate plan; operating and maintenance costs for the next rate plan; the value of avoided distribution costs; initiatives and investments necessary to support the development of DER and the goals of REV; the types and amount of DER that are cost-effective; and the target levels of DER implementation that will be used for setting EIMs.[7]

- At the completion of a utility's DSIP, the utility should open a rate case that would use the decisions and the information from the DSIP to inform the determination of allowed revenue requirements, cost allocation, and rate design decisions.

- At the completion of a utility's first DSIP, the utility should begin collecting the necessary information to support its EIMs and scorecard metrics. This information should be reported on each utility's web-based dashboard, and updated at least monthly.

- At the completion of each calendar year, each utility should submit a report to the Commission detailing the results of the EIMs and scorecard metrics for that calendar year. These reports should be subject to a brief review and comment process. Once that process is complete, the approved adjustments from the EIMs to a utility's revenues will be made in a reconciling account.

**Market-based Earnings**

The CEOC parties support the Staff's proposal to encourage utilities, in their role as DSPs, to seek market-based revenues for providing relevant services. However, we do not expect these revenues to constitute a large portion of utilities' overall revenues in the near- to mid-term

[7] NRDC provides additional recommendations regarding the DSIP process in its August 21, 2015 comments to the Department of Public Service in Case 14-M-0101 regarding the Benefit Cost Analysis White Paper.

future. Thus, the Commission should not rely on these MBEs to replace ratepayer funds until experience demonstrates that MBEs can be relied upon as a stable funding source.

**Utility Revenue Model**

The CEOC recommends that rate plan periods be limited to three years, at least for the first few cycles of rate plans. In the initial cycles, there will be too many fundamental changes to ratemaking and revenue recovery to allow for four or five years before the next rate case. The Staff's recommendations to consider utility performance results before allowing an extended rate plan, or to allow for rate plan openers if there are indications of problems, are not sufficient to offset the risks to customers associated with longer rate plans at this stage.

We also recommend that the net plant reconciliation mechanism be modified to allow a utility to retain 20 percent of the difference between the carrying costs of planned capital projects and the costs of DER investments that are used to avoid those projects. We believe that this balanced sharing provides utilities with a reasonable incentive to incur DER-related expenses, which should help offset the existing financial incentive that utilities have in favor of capital projects.

The CEOC parties recommend that certain utility investments, including those related to DER and infrastructure needed to support DER, be eligible for pre-approval in a rate case. We agree with Staff that pre-approval "would not supplant the requirement that the utilities' execution of the projects must be prudent, but it will address the risk entailed in the decision to undertake those investments."[8] We further recommend that the Commission pre-approve the adoption of advanced metering *functionality* in rate cases, but that the Commission should only consider specific decisions on the implementation of advanced metering infrastructure based on the recommendations of AMI stakeholder collaboratives. The Commission can provide utilities with regulatory guidance regarding whether to make these types of investments based on the analyses in the DSIP dockets.

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[8] White Paper, page 69.

The CEOC supports the Commission's efforts to establish EIMs, which are likely to have a direct, transparent, and significant impact on the development of DER. We believe that the EIMs and scorecards are most in-line with the overall goals and spirit of REV, because they bring utilities into the realm of the competitive market by rewarding exemplary performance and improved efficiencies. However, to ensure that EIMs are implemented in the most effective manner possible, we provide several recommendations for how the Commission should clarify which EIMs and scorecard metrics to apply, how they should be defined, how much utility revenue should be at stake, and how they should be implemented. Furthermore, we recommend that recovery of the expense of utility executive bonuses from ratepayers should be contingent on the utility meeting minimum performance standards for certain scorecard metrics.

**Accurately Valuing DER**

The CEOC supports the Staff's proposal for utilities to develop much more comprehensive and detailed estimates of the value of avoiding distribution investments. We also agree that the location-based marginal price of energy ("LMP") plus the value of DER ("LMP+D") should be construed as a broad measure "capturing the full range of values provided by distribution level resources."[9] In order to capture this full range of values, it will be necessary to include the value of avoided environmental impacts, particularly avoided carbon dioxide emissions. Therefore, we recommend that the value of DER should be based on LMP+D+E, where the "E" refers to environmental benefits and externalities, especially the benefits of reducing carbon dioxide emissions. As discussed in both the Natural Resources Defense Council ("NRDC") and Pace Energy and Climate Center ("Pace") comments on the Staff's White Paper on Benefit Cost Analysis, the value of avoided carbon dioxide emissions should be based upon EPA's social value of carbon.[10] We recommend that staff articulate a mechanism for regularly updating LMP+D+E so that the value reflects the most current and accurate understanding of how to calculate LMP, D, and E.

[9] White Paper, page 75, footnote 72.

[10] Natural Resources Defense Council. Comments to New York State Department of Public Service, Case 14-M-0101. August 21, 2015, p. 18.; Pace Energy and Climate Center, Comments to New York State Department of Public Service Case 14-M-0101, August 21, 2015, at 13.

The CEOC parties agree with Staff that the net energy metering ("NEM") practices in place today should continue to be used to encourage customers to implement distributed generation resources for their homes and businesses. In particular, the bill crediting mechanism should continue to be employed to credit customers for the generation they provide to the utility system.[11] However, in order to provide NEM customers with price signals and credit for the full value of DER, the amount of credit to NEM customers should be based on the value of LMP+D+E, which should account for environmental benefits. This credit to NEM customers should be based upon the value of the distributed generation during the hours when it is expected to operate, which can be significantly different than the flat retail rate that is currently used to credit NEM customers.

**Rate Design Reforms**

The CEOC supports the Staff's proposal to investigate several aspects of time-of-use ("TOU") rates, including opt-in smart home rates and potential improvements to commercial and industrial rate designs.

The Staff notes that the fixed customer charge should "reflect only the costs of distribution that do not vary with customer demand or energy consumption."[12] We offer three important clarifications to this description of the fixed customer charge. First, the fixed customer charge should reflect the costs to serve a customer that are independent or almost entirely independent of that customer's past and future usage, such as metering and billing costs. This should not include the cost of local distribution facilities necessary to serve that customer. Second, when considering the magnitude of fixed customer charges, it is important to recognize the fundamental principles that (a) price signals should reflect long-term marginal costs, and (b) "long-term" should be defined to include generation, transmission, and distribution capacity lifetimes. Third, for the purpose of sending proper price signals, long-term marginal costs should include the costs associated with environmental impacts, particularly the impacts of climate

[11] White Paper, page 94.
[12] White Paper, page 98.

change. These three clarifications dictate that the existing fixed customer charges not be increased as a part of the ratemaking reforms considered in this REV initiative.

The CEOC supports the Staff's recommendation for utilities to investigate options for establishing demand charges. However, we have significant concerns about the impact that demand charges might have on customer equity and on the development of distributed generation resources. Bill impact analyses will not be sufficient to fully analyze the potential risks of establishing demand charges. Prior to implementing any demand charges, the utilities must first establish that the conditions required to effectively implement demand charges are in place. The utilities should investigate and report, during the Track Two proceeding if possible, whether customers will have the information and the resources needed to effectively respond to demand charges, how demand charges should be designed to reflect long-run marginal costs including environmental benefits, how demand charges will affect customers' incentives to implement distributed generation and other distributed energy resources, and whether and to what extent demand charges may cause group and system peaks to coincide and exacerbate system issues. It is vital that the Commission and staff recognize that the principle of ratemaking is that rates must *reflect* costs; there is no sound ratemaking or market principle that price *structure* must mimic cost *structure*.

## II. MARKET-BASED EARNINGS IN A FULLY DEVELOPED MARKET

### A. Platform Service Revenues, Customer Enhancements, and Synergy Opportunities

**<u>Staff Recommendation 1:</u> Utilities should develop MBEs opportunities, and should further analyze potential revenue streams from platform services.**

As the market for DER and related services grows, so too will demand for DSP services. It is reasonable to expect that the utilities, as DSPs, will earn some market-based revenues for providing such services, but it is unlikely that these revenues will constitute a meaningful portion of utilities' overall revenues in the near- to mid-term future. Thus, the Commission should not rely on these earnings to replace ratepayer funds until market-based earnings begin to materialize.

In order to facilitate market-based earnings and support nascent DER markets, several foundational issues related to MBEs must be addressed. First, any legal questions pertaining to Commission jurisdiction over fees for DSP services should be addressed.

Second, because the DSPs will have monopolies on many of the services they provide (e.g., access to customer-level data), it will be essential to ensure that DSPs do not charge rent-seeking monopoly prices, and that service charges are open and transparent to all market participants. Prevention of unduly high or discriminatory prices is fundamental to ensuring that market participants do not face unnecessary barriers to entry. In support of transparency and market entry, there should be a state or industry wide data standard, and utilities should not be allowed to use their own proprietary data formats. Moreover, services must be continuously reassessed for the potential to unbundle service components that become amenable to competitive provision.

We recommend that any services provided by the DSP in an area where robust competition does not exist should be provided at cost-based rates. Where adequate competition does exist, it is appropriate to allow the DSPs to charge market-based rates. However, market monitoring will be required to ensure that a market or sub-market is sufficiently competitive, and to exercise oversight over affiliate transactions. The Commission should establish appropriate metrics for determining whether market power exists and clarify what entity will be responsible for monitoring the markets, and what that entity's responsibilities will be. As technologies and markets mature, we anticipate that more services will emerge as competitive.

Third, Staff should provide additional clarification regarding the steps that a DSP will need to take in order to earn market-based earnings, and how fees will be established. Further, in establishing specific fees, Staff should clarify the time period that such fees will be in place. Staff should also explain how the review and approval process of fees will be kept "rapid and nimble."

Finally, Staff should consider and address the interaction of MBEs with other aspects of the utility's revenues and planning processes. Specifically, it should address how MBEs will affect the Commission's determination of the utility's allowed return on equity, how market-based earnings will impact revenue stability (particularly as the share of MBEs grows), and how MBEs will be included in the BAC framework and utility planning practices.

## B. Benefits of the MBE Model (REC#2)

**<u>Staff Recommendation 2:</u> PSRs and other MBEs in a full-scale market should supplant some or all EIMs.**

As noted above, MBEs may not constitute a material portion of utility revenues in the near- to mid-term future, and thus it is unlikely that MBEs will be large enough to supplant Earnings Impact Mechanisms (EIMs) in the foreseeable future. The purpose of many EIMs is to encourage utilities to take actions that they otherwise would have insufficient financial incentive to undertake, or to offset certain existing incentives. Thus until MBEs constitute a substantial portion of a utility's earnings, it is unlikely that sufficient revenues will exist to obviate the need for EIMs.

In addition, EIMs will be necessary to the extent that the market does not fully internalize all externalities or that certain market failures remain. For example, there are numerous market failures that affect adoption of energy efficiency, such as split incentives, transaction costs, and imperfect information. EIMs may be necessary to ensure that an economically efficient level of energy efficiency investments is undertaken, and to ensure that the DER funding is sufficient to address needs that are not served by the market, including the need to serve hard-to-reach customers.

## C. Pricing and Revenue Sharing (REC#3)

**<u>Staff Recommendation 3:</u> The Commission should develop formulas for sharing platform revenues between utility shareholders and customers, and should pay special attention to shareholder risk, use of regulated resources, and market alternatives.**

The CEOC parties cautiously support the use of earnings sharing mechanisms for platform revenues that will provide utilities with sufficient incentives, while protecting ratepayers. Earnings sharing mechanisms have allowed customers to benefit from utility operational activities such as off-system sales in other jurisdictions. For example, Public Service Company of Colorado (a subsidiary of Xcel Energy) was permitted to sell hybrid renewable energy certificate ("REC") products to other states for a profit, under a sharing mechanisms of 57 percent to customers, 33 percent to Public Service, and 10 percent to a carbon offset program.[13] The sharing ratio should depend in part on the degree to which ratepayer funds are at stake. So as to protect consumers, we recommend that the Commission establish a sharing ratio of 90/10 (customers/utility) for DSP activities that are largely funded from utility revenues collected from ratepayers. As the utilities and the Commission develop more experience with platform revenues over time, the Commission can consider alternative ways to share and utilize these platform revenues.

## III. MODIFICATIONS TO THE UTILITY/DSP REVENUE MODEL

### A. Capital Expenditures and Operating Expenses (REC#4)

**Staff Recommendation 4:** **Clawback mechanisms should be modified to encourage cost-effective use of operating resources or third-party investment.**

Under the current regulatory framework, the clawback mechanism (or "net plant reconciliation mechanism") serves to ensure that utility underspending for capital expenditures is captured for the benefit of ratepayers. While this mechanism permits utilities to retain only the revenues that match actual costs, it provides little incentive for utilities to reduce costs through investments in operational or DER alternatives, since any cost reductions will be passed on to ratepayers and reduce rate base.

The CEOC supports a modified clawback mechanism that would enable utilities to retain a portion of any savings achieved through investments in DER or through operational expenditures ("opex") rather than through traditional capital expenditures ("capex"). Staff correctly notes that, "[a]t a minimum, utilities should not have a disincentive to use operating resources or third party assets in lieu of utility capital investment, where the former are more efficient and cost-effective."[14] Allowing utilities to retain a portion of any savings achieved

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[13] Sonia Aggarwal and Eddie Burgess, "New Regulatory Models" (Prepared for the State-Provincial Steering Committee and the Committee on Regional Electric Power Cooperation, March 2014), http://westernenergyboard.org/wp-content/uploads/2014/03/SPSC-CREPC_NewRegulatoryModels.pdf.
[14] White Paper, page 40.

through displacing a capital project with a lower-cost alternative investment (i.e., through DER or opex) will help to create incentives that remove the bias toward capital investments.

Staff proposes a modified clawback mechanism that would allow the utility to retain any savings until the next rate case. Staff illustrates this with an example, under which a $3 million capital project is displaced by a $200,000 (annual) DER expense. Assuming that the annual carrying costs for the capex investment would be $500,000, this would yield $300,000 of annual savings. Under Staff's proposal, the utility would retain these savings until the next rate case.

It is worth noting that under any clawback mechanism, there is a risk that capital expenditure budgets will be inflated in order to achieve artificial "savings." In the UK, utilities are allowed to keep savings relative to expenditure forecasts, but substantial effort is expended up front in order to ensure that the capital expenditure forecasts reflect efficient levels of expenditure. The efficient level of expenditure is determined using peer comparison groups and extensive modeling, and the process spans several years.[15] It is unclear whether this level of effort can or should be sustained in New York in order to ensure that capital budget forecasts are not inflated.

On the other hand, the current clawback mechanism also encourages inflated investment forecasts, since the utility must absorb any overages. In addition, the current clawback mechanism provides the utility with little incentive to reduce costs relative to this forecast, since reductions in cost would reduce rate base.

The CEOC parties propose a modification to the Staff's proposal, where a utility would be able to retain only a portion of the savings until the next rate case. We recommend that the utility be able to keep 20 percent of the savings, thereby allowing customers to keep 80 percent. In this way, the utility would be provided with some incentive to identify and implement DER projects, but not so much incentive that they are encouraged to inflate capital cost forecasts or that customers are at risk of being harmed by modifications to the clawback mechanism. It is also important to note that utilities will be required to identify opportunities for DER through

[15] Ofgem, "RIIO-ED1: Final Determinations for the Slow-Track Electricity Distribution Companies," Final Decision (Office of Gas and Electricity Markets, November 28, 2014).

their specific Distributed System Implementation Plans ("DSIP"). Protecting consumers from utilities recovering inflated traditional capital expenditures in the clawback modification will only be as effective as the DSIP review, approval, and implementation process.

In addition to a modified clawback mechanism, the White Paper raises the concept of using a complementary approach that would provide an earnings opportunity on operating expenses equivalent to that for capital projects, such as under the Brooklyn-Queens Demand Management ("BQDM") project.[16] NRDC and Pace do not generally support allowing utilities to earn an incentive rate of return while amortizing all capital and operating costs associated with procuring DER, as incentive rates of return may encourage higher project costs.

## B. Public Policy Achievement (REC#5)

**Staff Recommendation 5:** **Utility-sponsored energy efficiency should transition from general resource acquisition to targeted and market-based approaches, with goals informed by the ETIP, DSIP, and State Energy Plan processes.**

New York State has a long record of leadership in promoting energy efficiency to capture both economic and environmental benefits, and the Commission should continue to build on this impressive record. The CEOC parties have concerns with Staff's proposal to transition to more market-based approaches. In theory, there is value to this, but it will take time to make this transition, and we must ensure that the current efficiency initiatives and goals are not jeopardized as we move toward a more market-based approach. Staff states that "When third parties and market transformation are relied on to meet efficiency goals, metrics that include efficiency gains will be more outcome-based and will not be tracked to specific MWh obtained by individual utility resource acquisition programs." However, it is unclear how outcomes will be appropriately and accurately measured without measuring MWh savings.

As the CEOC and Energy Efficiency for All ("EE for All") noted in our September 28 comments on the Energy Efficiency Transition Implementation Plans ("ETIPs") and Budgets and

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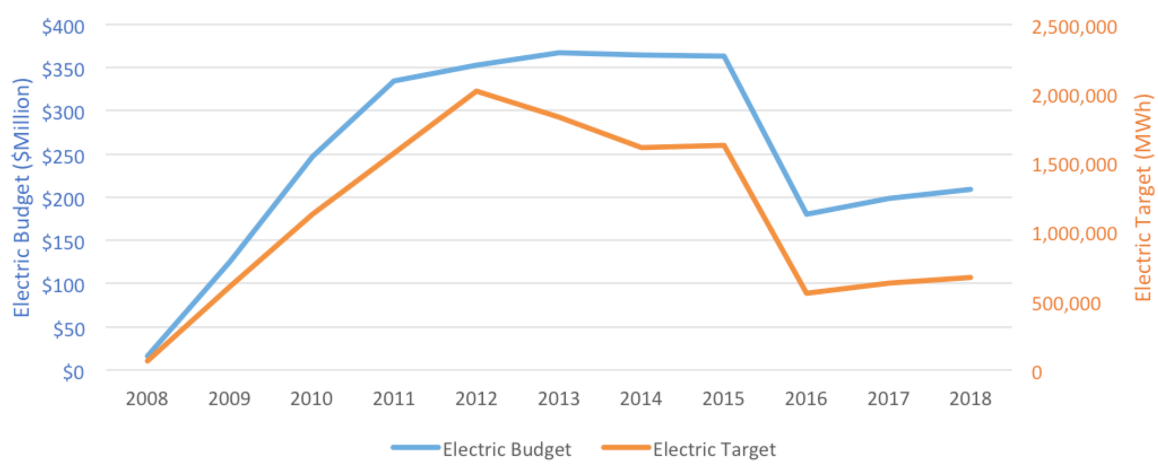
[16] White paper, page 42.

Metrics Plans ("BMPs"),[17] the Commission should ensure sustained ratepayer investment in NYSERDA and utility-run energy efficiency programs until new market-based approaches have a proven track record of performance. Under the Energy Efficiency Portfolio Standard ("EEPS"), investor owned utilities were responsible for acquiring approximately 32 percent of the overall electricity EEPS goal, with NYSERDA responsible for the rest. As we enter a transition period away from this model, it is important to guard against backsliding on energy efficiency targets. Unfortunately, it very difficult to judge the adequacy of the utility BMPs and ETIPs, as NYSERDA's CEF proposal did not include specific dollar budgets or MWh targets for the upcoming transition period.

Figure 1 shows the contribution of all program administrators toward EEPS goals and the BMP goals included in the utility plans; the significant drop in MWh targets is driven by the lack information on NYSERDA's plans.

**Figure 1. Combined NYSERDA and Utility Electric EEPS and BMP Annual Budgets and Targets**




Based on a review of all utility BMPs, the utility goals are modest in their scope. Together, the currently proposed utility plans will not put New York on the path toward reaching the State Energy Plan goals. As stated in the our ETIP comments, we recommend that the Commission authorize continued ratepayer collections to fund NYSERDA efforts beyond 2015 and also require NYSERDA to provide a clear three-year plan for its energy efficiency

[17] CEOC and EE for All ETIP comments, Case 15-M-0252, September 28, 2015

investments, as has been required of the utilities. The transition to a more market-based approach will need significant attention and guidance, and should begin with incorporating a bidding process into utility efficiency programs, as mentioned in the White Paper.[18] However, it should not begin with a step back from previous efficiency achievements and goals.

Furthermore, the Commission should require increased budgets and more aggressive investments in energy efficiency by the utilities, and should hold them to the Track One Order energy efficiency targets in order to achieve New York's stated public policy objectives. In their BMP filings, some utilities have proposed more aggressive programs than others, and the overall increase in energy savings is driven largely by the targets of ConEd and NiMo. The Commission should reject any proposals by the utilities to reduce their transition year (2016-2018) targets below the 2015 levels approved in the Track One Order. Any incentives related to energy efficiency should be designed to drive over-compliance (i.e., more than 100%) with targets.

The CEOC parties support a gradual transition to a more market-based and outcome-oriented approach. In the future, energy efficiency targets should be established through the DSIP process, to the extent that the DSIP process identifies all cost-effective energy efficiency and sets ambitious targets related to achieving this. In the interim, however, utilities should be encouraged to at least maintain the prior trajectory of energy efficiency investments; backsliding should not be permitted. This approach will create incentives for utilities to seek effective ways to support development of efficiency markets while not shifting the baseline for evaluation to a lower level.

### C. Earnings Impact Mechanisms, Scorecards, and Outcomes (RECs #6-10)

EIMs and scorecards can provide a valuable tool for enabling regulators to provide specific guidance on important state and regulatory policy goals, and to determine whether REV outcomes and goals are being achieved. EIMs in particular will play a critical role in the

[18] White paper, page 50.

redesigned market for (a) implementing DER, and (b) providing utilities with sufficient revenues in a high-DER future.

Staff's White Paper presents a variety of metrics and incentive mechanisms by which to measure utility performance, as summarized in the table below.

**Table 1. Current and Proposed Performance Metrics**

| Current Metrics | Proposed EIMs | Proposed Scorecard Metrics |
|---|---|---|
| Safety | Peak Reduction | System Utilization and Efficiency |
| Reliability | Energy Efficiency | DG, Energy Efficiency, and Dynamic Load Management |
| Customer Service | Customer Engagement and Information Access | Opt-In TOU Rate Efficacy |
| Utility-specific | Affordability (Low-income) | Market Development |
| | Interconnection | Market Based Earnings (MBEs) Use |
| | | Carbon Reduction |
| | | Customer Satisfaction |
| | | Customer Enhancement |
| | | Conversion of Fossil-Fueled End Uses |

The CEOC parties believe that, among all of the incentive mechanisms and revenue sources proposed in the White Paper, EIMs and scorecard metrics are likely to be most able to directly, immediately, and successfully promote the development of DERs. For this reason, we offer some detailed recommendations on how the Commission can make the most of this important regulatory tool. We first make recommendations regarding the process of developing EIMs and scorecard metrics, design principles, and specific EIMs and scorecard metrics that the Commission should adopt. Then, the CEOC briefly responds to each of Staff's Recommendations 6 through 10.

### 1. Process for Developing EIMs and Scorecard Metrics

The White Paper has not addressed a number of important considerations for the design of EIMs and scorecard metrics, including precisely how the metrics should be defined and measured, what the targets will be, and what the magnitude of any financial rewards or penalties should be. These are critical issues that deserve considerable attention. Therefore, we recommend that a clear process that includes significant stakeholder involvement be established to accomplish full development of EIMs and scorecard metrics. Specifically, the CEOC parties recommend that:

- The definitions of the EIMs and scorecard metrics, and the availability of data required to support these metrics, should be clarified in the Track Two process, prior to the development of the first DSIPs;
- The actual targets for the EIMs and scorecard metrics, and estimates of the net benefits associated with achieving those targets, should be vetted and established in the first DSIPs; and
- The amount of the incentives for the EIMs should be established in the rate cases that immediately follow the DSIPs.

In support of public engagement, the utilities should provide information on the EIMs and scorecard metrics on their web-based dashboards, updated at least on a monthly basis. The utilities should file annual reports to the Commission (and also make them available on their web sites) that identify the actual results, the deviation from the targets, and the amount of compensation (positive and negative) that goes to the utility. Further, stakeholders should have an opportunity to question or challenge any of the results in the annual reports by petitioning the Commission. After a petition period is over, utilities should be allowed to recover or refund compensation amounts through a separate rate rider.

## 2. Considerations for Developing EIMs and Scorecard Metrics

When determining performance metrics, targets, and financial incentives, it is important to recognize potential interaction effects among incentives in order to ensure that utilities are not doubly rewarded (or penalized) for achieving (or failing to achieve) the same outcome. A robust stakeholder review and comment process for the development of specific metrics, targets, and financial incentives will help to avoid such pitfalls.

We offer the following high-level principles to consider when establishing metrics and performance targets.

Establishing Metrics:

- Metrics should be clearly linked to policy goals, and should provide meaningful information regarding whether or not policy goals are being achieved.
- Metric definitions are critical. Metrics must be defined precisely, using regional or national definitions where possible, in order to avoid contention and to facilitate comparisons over time and across jurisdictions. Utilities already report a large amount of data to the EIA, FERC, EPA, NERC, and other entities that may be leveraged. Utility and stakeholder input should be solicited where possible to ensure metric definitions are clear.
- Where possible, metrics should be largely free from arbitrary influence. Otherwise it is difficult to determine whether the results actually reflect utility actions. Econometric techniques can help to control for exogenous variables, but such techniques reduce transparency and introduce contention.
- Metrics should be easily measured and interpreted. Unnecessarily complex data analyses reduce transparency.
- Independent parties should be used to collect or verify data. This helps to discourage gaming and manipulation. Stakeholder input should be incorporated in metric design to help identify pitfalls and areas that may be vulnerable to manipulation/gaming.
- Data should be easily accessible. This enhances transparency and reduces monitoring burdens on regulators and stakeholders. Data should be collected and reported in a publicly accessible place (e.g., a website). Data should show historical trends, performance across utilities, and performance across multiple areas. Independent parties and customers should be able to download raw data as an Excel file or in comparable non-proprietary format.

Setting Performance Targets:

- Costs of achieving the target should be balanced with the benefits to ratepayers. Customer surveys can help determine value to customers (e.g., is extra reliability worth the additional cost?) Efficiency in administrative costs is a critical element of overall performance.
- Targets should be realistic. Various analytical techniques can help to set such targets: (a) Historical performance (if still relevant); (b) Peer utility performance (if inherent differences between utilities can be controlled for); (c) Frontier methods (measures

technical efficiency of various firms); (d) Utility-specific studies (IRPs, potential studies and engineering studies can be useful).

- Deadbands should be used to mitigate uncertainty. For example: a one-standard deviation deadband (neutral zone around the target) helps to reduce the risk that the target was set too low or too high, or that the utility will be rewarded or penalized due to factors outside its control.

- Targets should be adjusted only slowly and cautiously. There may be good reason to adjust targets (e.g., as technology changes, or to reflect pre-determined milestones), but care should be taken not to do so arbitrarily. Otherwise utilities will not undertake the long-term investments that may be necessary to achieve goals.

### 3. Considerations for Developing Financial Incentives for EIMs

Staff should exercise caution when designing EIMs for investments or initiatives whose cost will be passed on directly to ratepayers. Utilities will likely seek to pass through costs associated with attaining (or exceeding) EIM targets through the use of cost trackers, or through incorporating these costs into pre-approved expenditure budgets. This could be problematic for several reasons:

- If a utility is allowed to recover costs through a cost tracker, that could reduce the utility's incentive to minimize these costs, particularly if an EIM also provides positive financial reward for the same investment. For example, a cost tracker for smart grid investments (including customer information portals) would erode the utility's incentive to contain costs of carrying out these investments, particularly if it could potentially also receive a financial reward for delivering a sophisticated (but expensive) online portal through the "customer engagement and information access" EIM.

- Where costs are pre-approved or cost forecasts are used to set a revenue target for a multi-year rate plan, the utility will have an incentive to ensure that adequate budget is approved to enable it to achieve (or exceed) EIM targets in order to earn a reward. For this reason, it is important to guarantee that the costs of achieving (or exceeding) the EIM target, plus any applicable utility reward for doing so, do not outweigh the benefits.

- It is unclear how market-based earnings may impact achievement of EIMs, but any interaction effects should be identified to avoid perverse incentives or excess rewards.

In short, great care must be taken when developing incentives to ensure that the total costs of incentives and projects do not exceed the benefits to ratepayers, that perverse incentives are avoided, that administrative gold-plating is avoided, and that any opportunities for gaming and manipulation are minimized. A robust stakeholder review and comment process for the development of specific metrics, targets, and financial incentives will help to avoid such pitfalls.

Below we offer high-level principles to consider when establishing financial rewards and penalties.

- Financial rewards to utilities should not outweigh benefits to ratepayers. Earnings sharing mechanisms can help safeguard customers, but also weaken the incentives provided to utilities.
- Rewards should not be administered directly as basis point adjustments, since doing so encourages the utility to increase rate base.
- Cliff effects should be avoided. The amount of the reward or penalty should not change dramatically due to a small change in performance.
- Incentives should be large enough to capture utility management's attention, but should not overly reward or penalize utility. Incentives should be periodically revisited and increased as necessary. A cap should be used to make sure incentives remain within reasonable bounds.

**4. Recommendations for Specific EIMs and Scorecard Metrics**

The CEOC offers the following specific recommendations for certain EIMs and scorecard metrics. The tables below summarize these recommendations, and indicate which metrics should be used for scorecards only, and which should be used for EIMs.

As indicated in the tables, we believe that the Commission should establish significantly more scorecard metrics than proposed in the White Paper. This is because we see scorecard metrics as a relatively low-cost, low-risk way for the Commission and other stakeholders to monitor the transition of the electricity industry, and to provide on-going guidance and incentives to ensure that the transition follows the general path desired by the Commission.

The CEOC parties also believe that the Commission should establish significantly more EIMs than proposed in the White Paper. This is because we believe that EIMs are likely to directly, immediately, and successfully promote the development of DERs. Table 2 below summarizes our recommendations. Our recommendations focus on two types of metrics: one that measures the extent to which energy and capacity is being developed or saved through DER investments; and one that measures the extent to which customers implement DERs or participate in DER programs. Together, these metrics provide a clear indication of the extent to which DERs are affecting the electricity system and the extent to which customers are benefiting from those DERs.

**Table 2. Proposed scorecard metrics and EIMs**

| Metric | Formula | Scorecard | EIM |
|---|---|---|---|
| **Energy Efficiency** | Demand savings (MW) by program | X | X |
| | Annual and lifecycle savings (MWh) by program | X | X |
| | MWh savings as a percentage of utility's total load | X | |
| | Percent of customers served per year, by rate class | X | X |
| | Program and portfolio cost of saved energy ($/MWh saved) | X | |
| | Costs and benefits by program (ratio and net present value) | X | |
| | Reduction in CO2, particulates, NOx, and $SO_2$ by program | X | |
| | Conversions of fossil combustion appliances to high-efficiency electric appliances, per year | X | |
| **Demand Response and Dynamic Load Management** | Demand savings (MW) at the local distribution peak, by program and per year, during the top peak load hours | X | X |
| | Demand savings (MW) as a percentage of utility's peak load | X | |
| | Percent of customers served per year, by rate class | X | X |
| | Program and portfolio cost of saved energy ($/MW saved) | X | |
| | Costs and benefits by program (ratio and net present value) | X | |
| | Reduction in $CO_2$, particulates, NOx, and $SO_2$ by program | X | |
| **Distributed Generation** | Number of installations per year by resource type | X | |
| | Generation (MWh) by resource type | X | X |
| | Generation (MWh) as a percentage of utility's total load | X | |
| | Installed capacity (MW) by resource type | X | |
| | Percent of customers per year, by rate class | X | X |
| | Program cost ($/MWh generated) by resource type | X | |
| | Costs and benefits (ratio and net present value) | X | |
| | Reduction in $CO_2$, particulates, NOx, and $SO_2$ by program | X | |
| **Electric Vehicles (EVs)** | Adoption of EVs (number of additions per year) | X | |
| | Percent of customers with EVs on demand response | X | X |
| | Percent of customers with EVs on time of use rates | X | X |
| **Energy Storage** | Number of installations per year | X | |
| | Installed capacity per year by type (thermal, chemical, etc.) | X | |
| | Percent of customers with storage technologies on demand response | X | X |
| **Peak Reduction, System Utilization and Efficiency** | Percent reduction in peak load per year, relative to average load of top 10 peak load days | X | X |
| | Reduction in system peak load (MW), per year | X | |
| | Monthly system average load/monthly system peak load | X | |
| | T&D losses/MWh generation excluding station use | X | |

| Metric | Formula | Scorecard | EIM |
|---|---|---|---|
| **Customer Engagement and Information Access** | Percent of customers able to access historical energy usage data electronically and share with third-party DER providers | X | |
| | Percent of customers who have accessed historical energy usage data electronically and shared with third-party DER providers, per year | X | |
| | Third party vendor satisfaction with utility interface (based on survey of all vendors with requests to provide services through tool during one year period) | X | |
| **Time of Use Rates** | Percent of customers on time of use rates, by rate class | X | X |
| | Range and average savings for customers on TOU rates | X | |
| **Standby Rates** | Time to process standby rate applications | X | X |
| | Ability to process electric, gas, and steam applications as one | X | X |
| **Affordability** | Annual and lifecycle MWh savings, by low-income program (EE, DR, and TOU) | X | |
| | Annual and lifecycle bill reductions per low income participant, by low-income program (% of average low income monthly bill) | X | |
| | Percent of low income customers per year participating in EE, DR, and TOU programs | X | X |
| | Normalized reductions in terminations, per year, relative to 5 year average | X | X |
| | Normalized reductions in uncollectible expenses, per year, relative to 5 year average | X | X |
| **Interconnection** | Percent and number of applications of 50 kW or smaller approved on timely basis, based on Standardized Interconnection Requirements | X | X |
| | Percent and number of applications of greater than 50 kW approved on timely basis | X | X |
| | Customer satisfaction with interconnection process (based on survey of all customers with applications opened during one year period) | X | |
| | Percent of outage assignments to DG that are overturned | X | X |
| **Market-Based Revenues** | Total revenue by service or source, per year | X | |
| **Carbon Free Acquisition Rate** | [Contracted and Owned Bulk Renewables, Nuclear, Hydro (MWh) + Clean Behind-the-meter (MWh) + Energy Efficiency (MWh)+ Other Load Reduction (MWh)] / [Load (MWh) + DR (MWh) + Energy Efficiency (MWh)] | X | X |

Energy Efficiency

As noted in the ETIP comments, an EIM for energy efficiency should also guard against backsliding on energy efficiency targets. The Commission should establish energy efficiency targets in each utility's DSIP. The DSIP should be used by each utility to identify all cost-effective energy efficiency, which would then be used to inform the setting of efficiency targets. The process should also include periodic studies of, and reports on, the energy efficiency programs within each utility's territory, and should take into account the "bigger-picture" context of how each utility's performance contributes to the State Energy Plan goals.

The CEOC and EE for All stakeholders recommend that the Commission hold a technical conference or series of workshops to explore the details of future energy efficiency in New York. This conference would consider short-term and long-term energy efficiency program design, implementation, and administration in order to avoid unintended negative consequences that may result from the large shift in energy efficiency service provision contemplated in the REV.

While achieving demand and energy targets is important, utility efficiency programs should, at a minimum, ensure that the basic core efficiency markets are served: (a) low-income: new construction, multi-family, and single family; (b) multi-family (not low-income); (c) residential: new construction, home retrofits, products & services; and (d) commercial & industrial: new construction, prescriptive, custom.

The energy efficiency EIM should take into account both demand savings (MW) at the local distribution level peak and annual and lifecycle MWh savings, with targets that are at least as high as the Track One Order targets. Utilities should use consistent algorithms and methods to calculate savings, with adjustments as appropriate to account for weather and other utility-specific factors. Participation in energy efficiency programs should also be an EIM, defined as the percent of customers participating in the utility's energy efficiency programs per year, by rate class, adjusted for repeat participation as feasible.

The CEOC also suggests additional scorecard metrics for energy efficiency, including the following:

- MWh saved as a percentage of utility's total load (including permanent EE load reduction);
- costs per MWh of energy saved, at both the program and portfolio level (and disaggregated by kind of cost);
- cost effectiveness as measured by the Societal Cost test, including non-energy benefits, by program, and presented both as a ratio and net present value;
- reduction in non-$CO_2$ pollution, including but not limited to particulates, $NO_x$, and $SO_2$, by program; and,
- conversions of fossil combustion appliances to high-efficiency electric appliances, per year.

Demand Response and Dynamic Load Management

Staff proposed a scorecard metric for dynamic load management. However, demand response and dynamic load management are critical for helping customers experience system benefits, not just costs. As such, we recommend that each of these resources have an EIM reflecting participation, defined as percent of customers enrolled per year by rate class, and an EIM reflecting demand savings (MW) at the local distribution system peak.

The CEOC also recommends scorecard metrics, including MW saved as a percentage of utility's total load (including permanent EE load reduction); costs per MW of energy saved, at both the program and portfolio level; cost effectiveness as measured by the Societal Cost test, including non-energy benefits, by program, and presented both as a ratio and net present value; and reduction in non-$CO_2$ pollution, including but not limited to particulates, NOx, and $SO_2$, by program.

Distributed Generation

Staff proposed a scorecard metric for distributed generation. Like energy efficiency, distributed generation ("DG") will be critical for achieving the goals of REV. Therefore, we recommend that DG have an EIM reflecting participation, defined as percent of customers enrolled per year, by rate class. Also, there should be an EIM for MWh generation for each type of DG resource (Combined Heat and Power or CHP, rooftop photovoltaics, etc.). Scorecard metrics for DG should include the following:

- geographic, technological, and customer class diversity;
- number of DG installations by resource type;
- MWh generated as a percentage of utility's total load (including load offsets);
- installed capacity (MW) by resource type;
- program costs per MWh generated by DER, at both the program and portfolio level;
- cost effectiveness as measured by the Societal Cost test, including non-energy benefits, by program, and presented both as a ratio and net present value; and
- reduction in non-$CO_2$ pollution, including but not limited to particulates, NOx, and $SO_2$, by program.

Electric Vehicles

Staff proposed a scorecard metric for electric vehicles ("EVs") in the context of conversion of fossil-fueled end uses. Depending on when they are charged and whether they are allowed to discharge power onto the grid, EVs have the potential to drastically impact system use, for better or worse. We recommend that EVs have EIMs that address participation in demand response programs and the number of EV customers that opt into time of use rates. Also, the number of EV additions per year should be tracked as a scorecard.

Energy Storage

Staff does not propose any EIMs or scorecard metrics for energy storage. However, energy storage can facilitate higher levels of distributed and centralized clean energy resources, and the market segment is evolving rapidly. The CEOC parties recommend tracking the number of installations and installed capacity per year by type (thermal, chemical, etc.) as scorecard metrics, and including an EIM for percent of customers with storage technologies on demand response.

The Commission has also placed an emphasis on storage as a tool in other parts of the REV proceeding. The Track One Final Order granted utilities the right to own energy storage technology, citing "reliability and [the ability] to enable the optimal deployment of other distributed resources."[19] The Staff's draft DSIP Guidance reiterates this purpose, and proposes that utilities "define how to evaluate and incorporate the use of energy storage as part of the overall planning process, and as part of solutions to avoid more traditional infrastructure investments, to improve grid functions or to increase the level and/or utilization of DER."[20] In light of the Commission's specific focus on energy storage as both a means and an end to DER deployment, the CEOC recommends an EIM for energy storage.

<u>Peak Reduction, System Utilization and Efficiency</u>

We wish to emphasize that while peak load reduction is a priority and should have an EIM associated with it, efforts to reduce peak should not come at the expense of pursuing aggressive energy efficiency. Other issues related to this EIM may need to be worked out as well. For example, the peak reduction EIM appears to be redundant with some of the other EIMs and scorecard metrics proposed by Staff (e.g., with Direct Load Management). As described by Staff, peak load may change for many reasons beyond the utility's control. Thus, any peak load reduction EIM may require several adjustments for weather and economic conditions. Further, the specific target suggested in the White Paper, a 3% reduction in peak load per year relative to a baseline calculated as the average load of the top 10 peak load days per calendar year, does not appear to be grounded in research on what is achievable.

The CEOC recommends that the Commission consider these points when defining the financial rewards for meeting the peak reduction EIM. In particular, this EIM should not have a penalty applied if a utility fails to meet it, and the amount of the positive financial compensation should be small relative to the other financial compensation available for the other EIMs. These two provisions will mitigate the risk of utilities spending more than is necessary to reduce peak demand, as well as the risk of overcompensating a utility for outcomes that are partly beyond its control or addressed by other EIMs.

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[19] New York Public Service Commission, Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (Feb. 26, 2015), at 68-69.

[20] New York State Department of Public Service, Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Staff Proposal Distributed System Implementation Plan Guidance (Oct. 15, 2015), at 11.

Scorecard metrics for system utilization and efficiency should include reduction in system peak load (MW) per year, load factor (monthly system average load divided by monthly system peak load), and transmission and distribution system losses divided by total MWh generation (excluding generating station use).

Customer Engagement and Information Access

The CEOC parties recommend that the "early indicators" include user-friendly data formats, ideally with automatic generation of charts that show typical summer weekday consumption patterns, or other data that the customer can meaningfully act upon. The White Paper mentions an online portal as the basis of an EIM. However, more definition is needed in terms of what will be measured. Percent of customers who have accessed historical energy usage data electronically and shared with third-party DER providers should be assessed within 6 months of tool implementation as a scorecard metric. Also, this metric should be tracked in an ongoing way even after the portal is operational. Access to information should be further defined to include metrics regarding what data are accessible and how.

A scorecard metric should be developed for third party vendor satisfaction with the utility interface, based on survey conducted by an independent party of all vendors with requests to provide services through tool during one year period.[21]

Time of Use

TOU engagement should be a separate EIM based on the percentage of customers signed up. Savings per customer should be tracked as a scorecard. Other data that the Commission could consider tracking include the number of customers contacted, marketing media type (in order to improve marketing approaches going forward), and customer awareness and comprehension of TOU rates (based on customer survey results, similar to those used in O&R's service area regarding comprehension of retail choice).

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[21] The independent party could be a relevant government agency, such as the New York State Energy Research and Development Authority, or it could be a private company selected by a relevant government agency, such as the Commission Staff.

Standby Rates

The CEOC proposes including EIMs that focus on standby rates, until such time as these rates are phased out. Standby rate EIMs should include metrics for time to process applications, and the ability to process electric, gas and steam applications as one. We discuss these in further detail in Section V.

Affordability

The CEOC supports use of EIMs for affordability, but suggest that this set of metrics include three components: 1) low-income participation rates in EE, DR, DG (especially solar), and TOU programs, 2) reductions in terminations, and 3) reductions in uncollectible expenses. Furthermore, we suggest that participation rates be considered for all rate classes, by type of DER.

We also note that metrics based on reductions in residential terminations and bad debt write-offs may be easily measured, but they may be highly correlated with variables outside of utility control, such as the economy. To account for this, reductions in termination and bad debt could be normalized relative to a publically available economic index, such as the unemployment rate. In addition, achieving a score of better than two standard deviations from the five-year average will likely be very difficult to do; the EIM target should be considered in light of the literature on utility performance improvement in this specific area.

Affordability scorecard metrics should be created for annual and lifecycle MWh savings, and for annual and lifecycle bill reductions per low income participant, by low-income program (EE, DR, solar DG, and TOU).

Interconnection:

Interconnection EIMs should include the metrics described in the White Paper, with additional detail on how "timely approval" will be defined regarding applications for interconnection of resources greater than 50 kW. Scorecard metrics should include customer satisfaction with interconnection process, based on an independent survey of all customers with applications opened during a one-year period.

Market-based Revenues:

The CEOC parties support the scorecard metric for total revenue by service or source, per year, as proposed by Staff.

Carbon Reduction and Intensity:

The CEOC supports the carbon free acquisition rate (CFAR) metric proposed by Staff. We recommend that the CFAR be an EIM because it is such a high priority to the Commission and for achieving state energy goals. The Commission should also consider advancing a separate CFAR metric without nuclear in the numerator to provide a clearer indicator of the contribution of truly clean energy resources to the electric system.

**5. Performance Metric Dashboards**

The CEOC parties strongly recommend the use of data dashboards as a means of collecting utility performance information in a central location and presenting the data in a transparent and meaningful way for both EIMs and scorecard metrics.[22] Without context, such as a comparison of current performance to historical trends or benchmarks, utility performance data convey little meaningful information to regulators and stakeholders. Similarly, when performance statistics are not aggregated in a central location, but are provided only in filings made in various dockets on different reporting cycles, it becomes difficult and time-consuming to develop a holistic view of utility performance across multiple dimensions.

A designated website—hosted either by the utility or the commission—would provide a useful forum for displaying performance information. Such a website should include both interactive graphs and downloadable data. Dashboards allow data comparison across years and between utilities. If a performance target is set, the dashboards enable all users to quickly determine whether the utility is meeting or failing to achieve the targets.

[22] Melissa Whited, Tim Woolf, and Alice Napoleon, "Utility Performance Incentive Mechanisms: A Handbook for Regulators" (Synapse Energy Economics, March 9, 2015), http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf, p. 32.

Performance metric dashboards should be:

- Accessible: Performance data should be presented in a publicly-accessible manner, such as on a designated website, and should include a means for downloading the underlying data. Performance data should also be accessible in a non-proprietary raw data format (such as xls) to enable experts and intervenors to support the Commission through ensuing DSIPs, rate cases, and other implementation phases of REV.[23]
- Contextualized: Performance targets, historical performance data, peer performance, and explanations of any major events that impacted performance should be included in the data presentation.
- Clear and concise: Performance should be presented in graphs that are clear and easily interpreted. An explanation of how the metric is calculated should also be included. Highly technical terms should be adequately defined or avoided.
- Comprehensive: The dashboard website should provide data and graphs for all aspects of utility performance that the commission wishes to monitor.
- Up to Date: The data and graphs should be updated frequently. The characteristics of many metrics may warrant quarterly updates, while others should be updated at least on an annual basis.

**6. Responses to Staff Recommendations**

**Staff Recommendation 6:** **Existing safety, reliability, customer-service, and utility-specific performance mechanisms should be retained subject to evaluation as needed.**

The CEOC supports Staff's proposal to maintain existing performance mechanisms, but to modify associated metrics, targets, or financial incentives as necessary. Modifications to these performance mechanisms should be undertaken at the same time as final development of new performance mechanisms in order to ensure that all performance incentive mechanisms complement each other.

[23] *See e.g.* NYSERDA Energy Efficiency Portfolio Standard ("EEPS"). The EEPS website offers an option to query and export program raw data in as an excel file, enabling customers and third parties to use data in novel ways that help support public participation and program development.

**<u>Staff Recommendation 7:</u> EIMs should be developed for peak reduction, energy efficiency, customer engagement and information access, affordability, and interconnection.**

The CEOC parties are supportive of the creation of EIMs for addressing peak reduction, energy efficiency, customer engagement and information access, affordability, and interconnection. However, many of these EIMs may need further refinement before they are implemented.

As noted above, the details of these incentive mechanisms should be further developed through stakeholder processes in order to ensure that targets are set appropriately, perverse incentives are avoided, and rewards to utilities do not exceed benefits net of costs. Nonetheless, some overarching questions about these incentive mechanisms should be addressed up front. For example, it is unclear whether Staff intends for EIMs to replace or supplement the utilities' existing revenue adjustments, as shown in Appendix C to the White Paper for each utility. Staff should clarify whether the energy efficiency EIM would replace or supplement the utilities' existing positive revenue adjustments for achieving EEPS2 maximum MWh, and whether the affordability EIM would replace or supplement existing service termination/bad debt revenue adjustments.

**<u>Staff Recommendation 8:</u> Initial EIMs should represent a mix of positive and symmetrical adjustments. Longer term positive EIMs should be contingent on an overall customer bill impact metric, which should be proposed by utilities.**

The CEOC agrees that initially, it may be reasonable to provide only positive incentives for certain EIMs, particularly those related to DER investments, except in the case of egregious utility behavior in the form of obstruction, mismanagement, or imprudence.

A concept similar to a bill impact metric is that of net benefits. Rewards earned under EIMs should be contingent upon the degree to which the utility's expenditures provide net benefits relative to a business-as-usual investment plan. Overall net benefits of the utility's expenditures should be identified in DSIPs, and utilities should only be allocated a portion of those net benefits. The majority of net benefits (and bill savings) should be retained by and/or allocated to customers.

**<u>Staff Recommendation 9:</u> EIMs should be established on a multi-year basis, accompanied by interim reviews and reporting metrics, unless it is demonstrated that single-year mechanisms are preferable on a case-by-case basis.**

The CEOC agrees that many EIMs should be implemented on a multi-year basis, as this supports long-term investment strategies.

**<u>Staff Recommendation 10:</u> Scorecard measures should be developed for system utilization and efficiency, DG, energy efficiency, and dynamic load management penetration, carbon reduction, market development, MBEs use, opt-in TOU rate efficacy, customer enhancement, customer satisfaction, and conversion of fossil-fueled end uses.**

The CEOC generally supports Staff's recommended metrics for inclusion on a scorecard, with the modifications proposed above.

### D. Earnings Sharing Mechanisms (REC#11)

**<u>Staff Recommendation 11:</u> ESMs should be tied to a performance index.**

The CEOC parties generally agree with Staff's proposal to tie the earning sharing mechanisms ("ESMs") to base performance metrics. The proposal, as illustrated in the table on page 68 of the White Paper, should serve to amplify the incentives provided to a utility to improve performance.

However, it will be important for the Staff to provide some important details of how the ESM would be modified, and what base performance metrics would be used to account for utility performance in the ESM. We recommend that base performance metrics be based on an indication of reduced costs, increased system efficiencies or customer participation in DER, to ensure that customers will directly experience benefits of improved performance before utilities obtain amplified earnings for that improved performance.

In addition, the CEOC recommends that the Commission establish a performance threshold that should be used to determine whether utility management is eligible for utility compensation packages in each year. The performance threshold should use the same performance metrics that are used in the ESM. This provision would provide a very clear signal that utility management must meet certain performance goals before they personally earn any special compensation. Using the performance indicators for both the ESM and the utility compensation packages will send comparable signals to both utility management and utility shareholders regarding the performance expected of them.

## E. Capital Expenditures to Implement REV (REC#12)

**Staff Recommendation 12: Plans to invest in DSP-related capabilities should be given pre-approval, where appropriate.**

The CEOC agrees with Staff's recommendation that certain investments be given pre-approval. We also agree with the important clarification that this pre-approval "would not supplant the requirement that the utilities' execution of the projects must be prudent," but rather that the pre-approval would be designed only to "address the risk entailed in the decision to undertake these investments."[24]

We also agree with Staff's proposal to allow pre-approval only for investments needed to support DSP-related capabilities, but not for traditional utility system expenditures.[25] Pre-approval shifts much of the burden of determining the reasonableness of expenditures to the regulators, and much of the risk to ratepayers, and therefore should only be allowed cautiously. In addition, preapproval should only be allowed for costs that (a) have been investigated in a utility's DSIP, and (b) have been reviewed as part of the revenue requirements in a rate case.

We also recommend that the Commission allow for pre-approval of the costs of implementing DER. For example, the Commission should pre-approve the costs associated with implementing energy efficiency and demand response programs, where the costs and benefits of these programs have been evaluated and demonstrated in the DSIPs.

The CEOC recommends that the Commission give slightly different treatment for utility investments related to advanced metering infrastructure ("AMI"). AMI poses unique challenges for regulatory review because there are a variety of different options for utilities to pursue, the

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[24] White Paper, page 69.
[25] The distinction between these two types of investments should be identified in each utility's DSIP.

costs and benefits of each option can be challenging to pin down, the various AMI options can have significant implications for implementing DER and achieving REV goals, and AMI decisions can have significant implications for all customers. For these reasons, we recommend that utilities provide as clear a case as possible for whether and how AMI should be used as part of their DSIPs, and that rather than pre-approving AMI programs, the Commission provide some regulatory guidance as to the utility's case for AMI. The focus should be on the *functionality* needed, and not the technology *per se*. This type of regulatory guidance would be less detailed than pre-approval and would provide the utility with less certainty that costs would be recoverable. Still, it would provide the utility with some comfort regarding the general direction it pursues with regard to AMI.

### F. Long-Term Rate Plans (REC#13)

**<u>Staff Recommendation 13:</u> Three-year rate plans should be retained with an opportunity for two-year extensions to allow rate plans to be in effect for up to five years. Any extension beyond three years should be accompanied by interim reviews, scorecards, and performance metrics.**

The CEOC recommends that rate plan periods be limited to three years, at least for the first few cycles of rate plans. In the initial cycles there will be too many fundamental changes to ratemaking and revenue recovery to allow for four or five years before the next rate case. Waiting for four of five years will place too much risk on customers, especially hard-to-reach and hard-to-serve customers, that they are not being adequately served or the utility is recovering too much revenues from them.

We appreciate Staff's recommendation that extensions to rate plan periods should only be allowed if a utility is able to: (i) achieve satisfactory price and earning levels; (ii) adhere to capital plans; and (iii) achieve certain gateway measures (such as the development of platform capabilities, a successful interconnection record, DER penetration and system efficiency improvements).[26] However, these regulatory oversight options are not sufficient to offset the risks to customers associated with longer rate plans. There will be a lot of significant ratemaking

[26] White Paper, page 71.

and revenue recovery changes in the first few rate plans, and we firmly believe that the Commission should investigate utility performance, customer impacts, and market development every three years.

The CEOC parties are also concerned that allowing utilities to independently decide whether to extend the rate plan period would limit the ability of stakeholders and the Commission to assess whether such an extension is the best interests of customers, emerging markets, and oversight efficiency.

Furthermore, we recommend above that each utility should implement a DSIP prior to conducting a rate case. The CEOC parties feel strongly that utility DSIPs should be revisited every three years to ensure that they represent the latest information regarding DER technologies, costs and opportunities; customer response to the new rate designs; and third party and market developments. After each utility completes a DSIP, it should open a rate case to account for the new DSIP results in setting revenue requirements and addressing other ratemaking decisions. Consequently, allowing the utility to choose when the next rate plan should take place could offset this important connection between DSIPs and rate cases, or could prolong the period between DSIPs more than is appropriate.

## IV. ACCURATELY VALUING DER

### A. Determining the System Value of DER (REC#14)

**Staff Recommendation 14: A method of calculating the value of DER, based on a formula of LMP+D (location-based marginal prices plus distribution value) should be adopted.**

The CEOC supports the Staff's proposal for utilities to develop much more comprehensive and detailed estimates of the value of avoiding distribution investments. We also agree that the location-based marginal price of energy ("LMP") plus the value of DER ("LMP+D") should be construed as a broad measure "capturing the full range of values provided by distribution level resources."[27] In order to capture this full range of values, it will be necessary to include the value of avoided environmental impacts, particularly avoided carbon emissions. Therefore, we recommend that the value of DER should be based on LMP+D+E, where the "E" refers to environmental benefits, especially the benefits of reducing carbon emissions.

As discussed in NRDC's comments on the Staff's White Paper on Benefit Cost Analysis, the value of avoided carbon emissions should, at least initially, be based upon EPA's social value of carbon.[28] As additional environmental and distribution impacts are identified or further refined, the value of LMP+D+E should be likewise updated.

The EPA's social cost of carbon will provide a value in terms of dollars per ton of emissions. Another important input needed in valuing carbon emissions is the carbon emission rate from the electricity system, in terms of tons/MWh. For the purpose of valuing carbon emissions avoided by DER, this emission rate should be based on the marginal emissions from the electricity system, ideally on an hourly basis. There are several methods of estimating the marginal emission rates from the New York electricity system. We recommend that the Commission factor the marginal emission analysis into rate design as part of Track Two. Pace will provide a detailed description of a proposed methodology in a future filing.

A useful precedent for both the process and methodology is Maine's Value of Solar study, which brought together utilities, the consumer advocate, the solar industry, environmental advocates, and municipalities to collaboratively develop the study's methodology.[29] The executive summary for the Maine Value of Solar study is provided as an attachment to these comments.

## B. Potential Compensation Mechanism Reforms (REC#15)

**<u>Staff Recommendation 15:</u> Net energy metering (NEM) should remain in place for on-site projects of mass-market customers. Remote and community projects should continue to**

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[27] White Paper, page 75, footnote 72.
[28] Natural Resources Defense Council. Comments to New York State Department of Public Service, Case 14-M-0101. August 21, 2015, p. 18; Pace Energy and Climate Center, Comments to New York State Department of Public Service Case 14-M-0101, August 21, 2015, at 13.
[29] Maine Public Utilities Commission. Maine Distributed Solar Valuation Study. Revised April 14, 2015. http://www.maine.gov/mpuc/electricity/elect_generation/valueofsolar.shtml.

**use the bill crediting mechanism of NEM and an improved method of calculating credits for net export should be developed, based on LMP+D.**

The CEOC agrees with Staff that the net energy metering ("NEM") practices in place today should continue to be used to encourage customers to implement distributed generation resources for their homes and businesses. In particular, the bill crediting mechanism should continue to compensate customers for the generation they provide to the utility system.[30] This mechanism is simple and transparent, and does not create any taxation or regulatory problems by implying that distributed generation customers are selling power to the utility. NEM is an important policy mechanism that DER industry providers are relying on to achieve DER growth gains in New York. Benefits of NEM likely exceed the costs by a wide margin today and for the foreseeable future.[31]

However, in order to provide NEM customers with price signals that reflect grid distribution and delivery costs, and fair credit that reflects the full value of DER, the amount of credit given to NEM customers should be based on the value of LMP+D+E. This credit should reflect the value of the distributed generation during the hours when it is expected to operate, which can be significantly different than the flat retail rate that is currently used to credit NEM customers. Customer investments in DER, especially distributed solar generation, are already highly motivated by the full range of these values; market credits should, in turn, reflect the inherent value proposition.

Furthermore, we do not see the need for distinguishing between customer generation that is used to offset customer load and that which could be considered net export generation. It can be very difficult to draw the line between these two types of generation, and if the DG customer is credited at the appropriate value of LMP+D+E there is no reason or need to distinguish between the two. Eliminating this distinction for customers who primarily generate electricity to serve their own load offers the added benefit of further guarding against undesired tax or other federal regulatory consequences.

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[30] White Paper, page 94.
[31] RMI 2014. A Review of Solar PV Benefit-Cost Studies. http://www.rmi.org/elab_emPower. *See also*, Environment America. Shining Rewards: The Value of Rooftop Solar Power for Consumers and Society, June 24, 2015. http://www.environmentamerica.org/reports/amc/shining-rewards.

## V. RATE DESIGN REFORMS

### A. Rate Design Principles for REV (REC#16)

**Staff Recommendation 16: The Commission should adopt the proposed rate design principles.**

The CEOC generally supports Staff's rate design principles related to cost causation, encouraging outcomes, policy transparency, facilitating decision-making, representing a fair value, customer-oriented, stability, access, and gradualism. We offer two specific additional recommendations:

1) Staff defines the principle of cost causation as, "rates should reflect cost causation, including embedded costs as well as long-run marginal and future costs." We recommend modifying this principle to read "The Commission should establish rates that, to the extent possible, reflect long-run marginal costs but also recover embedded costs. Fixed charges should only be used to recover costs that do not vary with demand or energy usage."

   We reiterate and emphasize that resource allocation is most efficient when prices reflect long-run marginal costs, and when the use of fixed charges is minimized (at least until we realize an idealized future in which all customers have meaningful, and cost-effective means to address costs reflected in rates according to their nature as fixed or variable). This position is rooted in economic theory and was clearly acknowledged by James Bonbright, who wrote, "as setting a general basis of minimum public utility rates and of rate relationships, the more significant marginal or incremental costs are those of a relatively long-run variety – of a variety which treats even capital costs or "capacity costs" as variable costs."[32] A fixed charge provides no price signal relevant to resource allocation, since customers cannot reduce their consumption to avoid the charge unless they leave the grid entirely. In other words, rate design should avoid confusing sunk fixed costs with fixed costs in general.

[32] James Bonbright, Principles of Public Utility Rates (New York: Columbia University Press, 1961). p. 336.

2) In addition to defining the principle of customer orientation as "The customer experience should be practical, understandable, and promote customer choice," we recommend augmenting this principle with "Rate designs should empower customers with opportunities to reduce their bills by changing their usage profiles and consumption behavior."

### B. Proposed Rate Design Reforms (RECs #17-22)

**Staff Recommendation 17:** **Utilities should file tariffs for opt-in smart home or other time variable rates.**

The CEOC supports Staff's proposal regarding opt-in time variable rates for smart home customers. Opt-in participation rates in the smart home rate may provide useful information regarding customer interest in DER. A pilot program for "smart home" users was recently conducted in Austin, and may be informative for the development of this rate.[33]

**Staff Recommendation 18:** **Opt-in TOU rates should be improved with outreach and education, and default TOU rates should be examined. Utilities should develop TOU rate demonstration projects. Utility proposals for AMI/AMF should include a demonstration of the value of AMI/AMF for TOU rate improvements.**

The CEOC strongly supports the recommendation to investigate TOU rates further. We note that there exists significant experience with TOU rates across the country that can be leveraged to quickly implement opt-in TOU rates, rather than conducting several more years of pilot programs. While TOU programs are widely used, they should never be implemented in isolation. Their roll-out must be accompanied by customer education (as noted below) and tools to manage energy usage (including enrollment in energy efficiency programs, demand response programs, data access, etc.)

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[33] Jay Zarnikau et al., "How Will Tomorrow's Residential Energy Consumers Respond to Price Signals? Insights from a Texas Pricing Experiment," *The Electricity Journal* 28, no. 7 (September 2015): 57–71.

TOU rates should be designed such that the peak period prices reflect marginal capacity costs, as well as marginal energy costs and environmental benefits. This sends the appropriate price signal based on long-run marginal costs. Peak periods should be short enough to enable customers to reasonably shift their usage from on-peak hours to off-peak or shoulder-peak hours. Further, the differential between on-peak and off-peak rates should be large enough to encourage meaningful behavioral change. However, it may be appropriate to gradually increase this differential transparently over the course of several years so as to prevent sudden large changes in customer bills. Plans to increase this differential should be announced in advance in order to facilitate efficient investments. In addition, we recommend investigating TOU rate designs with a critical peak price component. Finally, we also recommend separating the rate used for consumption of energy from the rate paid for DER generation in order to avoid perverse price signals.

The decision whether to implement a TOU rate on an opt-in versus opt-out basis can significantly affect the impact that a program has on avoiding system costs by shifting load. Opt-in tariffs typically achieve much lower load shifting, as it is typically very difficult and time-consuming to encourage a large percentage of customers to voluntarily enroll in any new rate design, often simply because of customer inertia and poor understanding among customers regarding how they will be impacted by a new rate. For this reason, the CEOC supports transitioning to an opt-out tariff after several years, if this is legally feasible. If an opt-out approach is adopted, it must be implemented with protections for vulnerable customers and significant customer outreach and education. Education may include:

- "Shadow billing" to the extent implementation costs are not excessive.
- Providing customers with information and program participation options regarding they can take to shift load to achieve the lowest bill. Information would ideally be tailored to the customers' particular appliance ownership and usage patterns.
- Online bill calculators to help customers determine what rates would result in the lowest bill under their historical usage patterns, and then under slightly modified usage patterns.

In the event that an opt-out option is not feasible, we recommend implementation of an "all opt-in" provision in which all customers are required to affirmatively opt-in to a rate plan (even if there is a default.) In addition, customers could be asked to periodically reaffirm their rate plan choice, as is frequently done with two-year cell phone contracts. This would improve customer awareness of the rate chosen, and may overcome customer inertia that would otherwise prevent certain customers from enrolling in the TOU rate.

**Staff Recommendation 19: Each utility should examine its commercial and industrial rates to improve their reflection of the value of time variability.**

The CEOC supports the recommendation that rates for commercial and industrial customers be improved to better reflect time-differentiated costs.

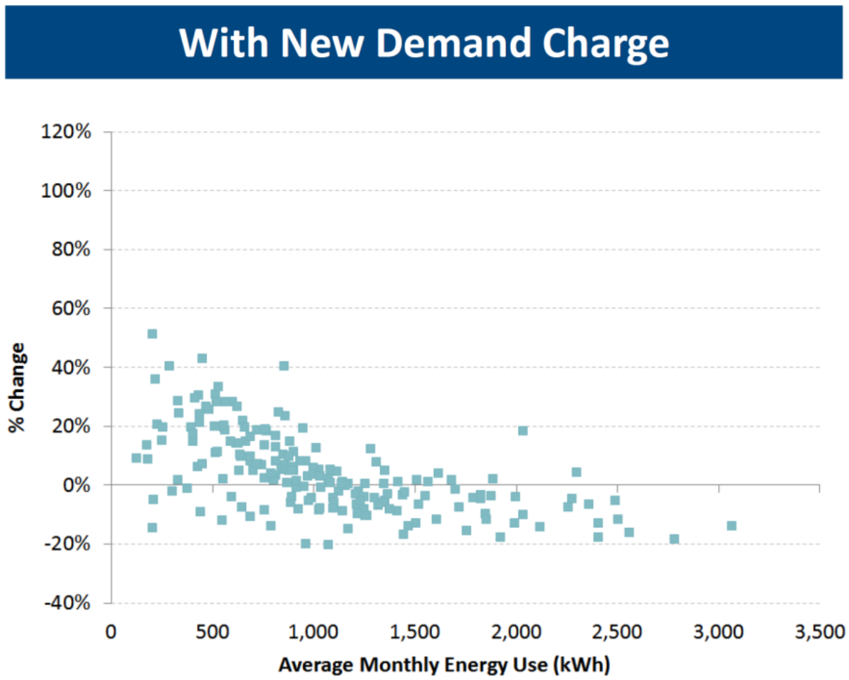
**Staff Recommendation 20: Consistent with the Staff report on energy affordability, application of the anticipated low-income discount should be supplemented by locating it within a basic usage block.**

The CEOC parties highlight the fact that only a fraction of the population that is eligible to participate in HEAP actually does (by some estimates, approximately half), as noted in the Staff Low-Income report (p. 23). The CEOC has concerns that some REV design elements (such as changes to rate structures) could result in increasing energy burdens on low income and other hard-to-reach populations. Care must be taken to verify that those customers are protected by programs like HEAP and utility bill assistance before making these shifts.

**Staff Recommendation 21: Bill impact analyses should be performed for potential demand charge scenarios; these analyses should include impacts on low-income customers.**

While the CEOC supports investigation of demand charges, we urge Staff to take great caution in considering any such charges. Many mass-market customers do not have the tools, knowledge, time, or desire to understand and manage their demand, and demand charges would likely result in low-usage customers seeing the greatest increase in their bills. The CEOC is also concerned about the potential for a demand charge to undermine energy efficiency incentives, as the demand charge will reduce the $/kWh charge.

A recent study by Hledik (2015)[34] shows the impact of a revenue-neutral demand charge on various types of customers (Figure 2, below). In general, such a demand charge increases bills for low-usage customers, but reduces them for high-usage customers. This effect could lead to both customer confusion, as well as a significant increase to the pay-back period for certain energy efficiency investments.




*Note:* The three-part rate includes a monthly fixed charge of $10, an energy charge of $0.060/kWh, and a demand charge of $9/kW. The revenue-neutral two-part rate includes a monthly fixed charge of $40 and an energy charge of $0.083/kWh.

One option is to introduce demand charges gradually, where the initial demand charge is less than the actual demand costs, and then is increased over time only as tools to manage customer demand become widely available and effective education programs are implemented to educate customers regarding demand charges Another option is to implement an opt-in demand charge, and encourage customers with relatively high energy usage to adopt the rate structure. Such customers would likely benefit the most from a demand charge (due to the reduced energy charge), and may be more likely to invest in technologies to help them reduce their demand,

[34] Ryan Hledik, "The Top 10 Questions about Demand Charges" (Presentation, EUCI Residential Demand Charges Symposium, May 14, 2015).

since it could result in significant savings. Further, demand charges should be designed to ensure that local, circuit-level peaks are not exacerbated through a demand charge designed to reduce utility system peaks, or vice versa. At the same time, contributory effects should be assessed, such as the benefits of reducing class or circuit peaks in advance of system peaks.

**Staff Recommendation 22: Standby rates should be reviewed and modified to include a reliability credit and a wider application of the campus tariff.**

The CEOC parties have repeatedly commented in rate cases and proceedings for the judicious use of standby rates, if they are used at all. While the purpose of standby rates is to match the rates paid by a specific customer with the cost of serving that customer, an imbalanced approach can seriously limit the development of a robust DG market. As such, standby rates must be carefully applied to different types and sizes of generators in different ways, leaving room for operator flexibility and fair assignment of fault. In taking on the issue of standby rate design in Track Two, we make the following six recommendations:

1. **Maintain standby rate exemptions with opt-in choices for clean DG**

In 14-E-0488, the Commission extended standby rate exemptions for certain beneficial DG and efficient CHP customers through 2019. The CEOC continues to support the application of the exemption as stated in the April 2015 order, including the caveat that exempt standby rate customers may opt-in to new REV rates following the Track Two order. The stability and flexibility of the nascent clean DG market must continue to be a priority in all aspects of REV. In support of this goal, the CEOC supports the continued exemptions for beneficial DG with an opt-in provision for whatever standby rate outcome Track Two produces.

The Commission should also consider how on-site storage will be treated under the standby rate, if on-site storage should be included in standby rate structures at all. The CEOC believes that storage should be exempt from standby rates as it supports the peak reduction by load shifting towards less carbon intense generation, and thus falls within the beneficial DG policy intent. In addition, exempting on-site storage from standby rates will help buffer potential market power issues in one of the utility-DER ownership categories provided for in Track One.

2. **Standby rates should eventually be replaced with a proper assessment of LMP+D**

The CEOC parties believe that the proper valuation of LMP+D+E should obviate the need for standby rates, while creating the rate structure the Commission alluded to in the April 2015 order extending standby rate exemptions. Compensation at LMP+D+E would recognize the reliability, capacity, and avoided T&D costs that advocates of less onerous standby rates have argued for in past proceedings and rate cases. The CEOC reiterates, however, that the LMP+D+E compensation calculation must include environmental externalities in order to guard against the proliferation of dirty and inefficient DG. The proper calculation of LMP+D+E for each type of DER would limit the potential cost-shifting effects of standby rates and standby rate exemptions, and reduce inequitable pricing of environmental externalities among different types of generation.

### 3. Develop a standby rate to bridge the LMP+D transition

The CEOC recognizes that the proposed LMP+D compensation and rate design may not be ready to completely replace standby rates in the near-term, and that a favorable standby rate could provide stability in the DG market while the LMP+D is in the development cycle. The Commission should use Track Two as an opportunity to intervene on the issue of standby rates to develop guidelines that support continued DG development, and that are in line with the larger goals of REV. Against this back drop, there are several other issues that should be considered in creating a Track Two rate design.

### 4. The standby rate transaction should use the reliability credit

For the purposes of developing REV standby rates, the CEOC agrees with the Staff proposal that a reliability credit should be created, based on the experienced difference between a customer's contract demand and as-used demand, and agree that customers should have the option of which method to use in the determination of their credit. Despite support for the reliability credit transaction, the CEOC parties are concerned that the credit has the potential to incentivize standby customers to run high-emission generators that can quickly be brought on-line, such as diesel-fueled reciprocating engines, in an effort to meet the reliability benchmark. In order to avoid such a perverse incentive, the CEOC recommends that the credit be opened to any and all forms of DER, and to standby customers who engage in any kind of load-reducing behavior that obviates the need to run an offline generator. Expanding the qualification standards for the reliability credit would also allow more customers to participate.

### 5. Responsibility for outages must be fairly assigned to protect DG customers.

Because the value of DG is assessed through a reliability credit, it is essential that standby rate design has a proper method for assigning responsibility for and during outages. Frequently, DG operators have reported outages due to utility operations or due to a third party, such as a telecommunications provider. If the DG operator is not responsible for the outage, there should be no impact on their reliability credit.

The issue in outage responsibility assignment then becomes what investigation mechanism should be used to determine who caused the outage, and what procedures should be applied to settle disputes. The CEOC proposes that DG operators should request an investigation from the utility in the event of an outage with an unknown cause. The DG operator is in the best initial position to assess whether it caused the outage, and thus is best equipped to determine the need for investigation. Utilities should be allowed to recover the costs of investigation of standby reliability, because the benefits of DG performance extend beyond standby rate customers.

Unexpected outages during peak periods where no investigation is initiated should be presumed to be the responsibility of the operator. Utility-caused outages should never affect the reliability credit of the standby customer. Third-party outages should also not affect the reliability credit of the standby customer, but the Commission should consider how it will address the nexus of electric reliability and data systems as New York moves into a modernized, distributed energy system moving forward.

On the topic of dispute resolution, the CEOC parties see little option other than to allow disputes to be appealed to Staff/Commission, but believe there may be incentive structures that could be put in place relating to their ability to self-govern in investigations. First, the CEOC agrees with the proposal to amend the EIMs to include standby rate metrics including processing of standby rate applications, accounting for the time to process, and the ability to process electric, gas and steam applications as one. Additionally, the CEOC proposes that the interconnection EIM should be further modified to include outage assignment, in which a decision that is appealed and overturned will negatively affect the interconnection EIM. From the opposing side, an appealed and upheld decision should cap (but not eliminate) a standby customer's future year reliability credit. The goal of the reliability credit dispute resolution should be to incentivize fairness and market stability, while expanding the utility's role as the DSP market operator.

**6. Track Two standby rates should have a twilight period.**

The Commission should treat its Track Two standby rate as a market stability tool for existing non-exempt DG customers to use while a more nuanced LMP+D and time-of-use rate structures are developed, with hopes of having all standby rate customers transition to LMP+D compensation in the near-future. To accomplish this, the Commission should consider giving the Track Two standby rate proposal a term equal to the current standby rate exemption proposal, stabilizing standby rates through 2019 with opt-out provisions for customers choosing LMP+D. The standby rate twilight could also align with the terms attached to the 'smart home' rate to help coordinate DSPs and customers with the stepwise development of REV policies.

Thank you.

*[Signatures to follow.]*

Respectfully submitted,

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