STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

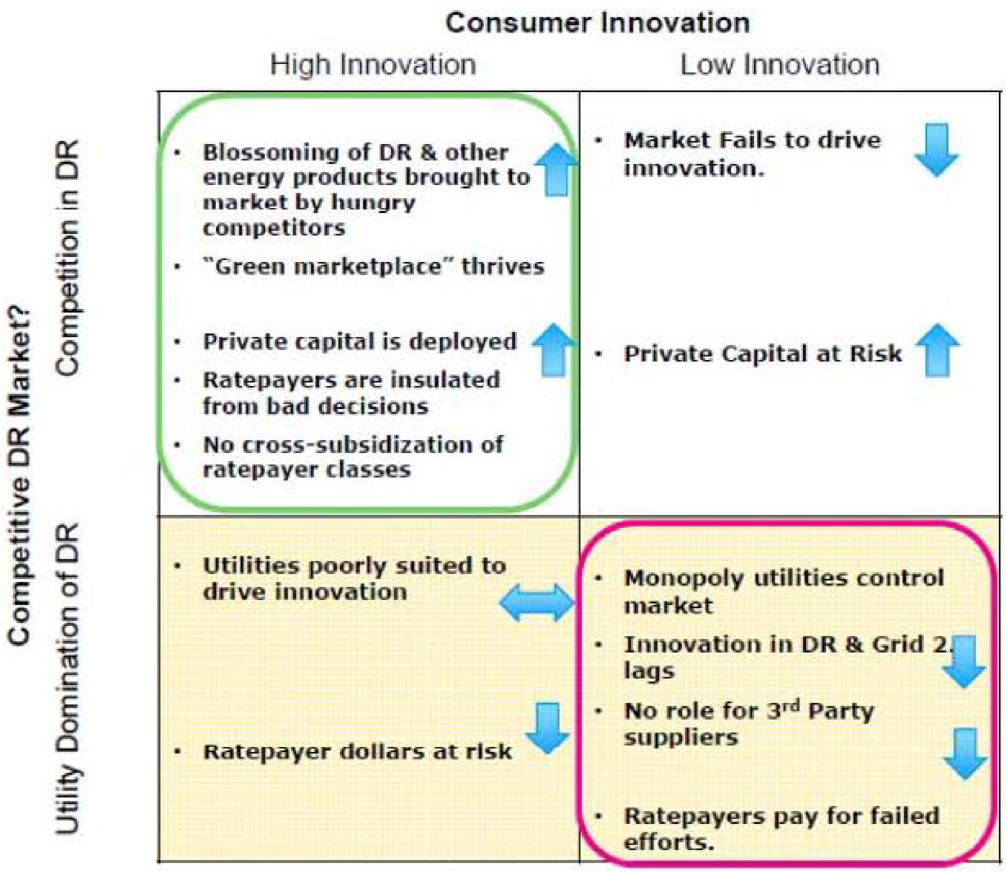
CASE 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.

COMMENTS OF NRG ENERGY, INC. ON TRACK 2 QUESTIONS

I. Introduction

The NRG Companies ("NRG") submit that a core principle of Rethinking the Energy Vision ("REV") proceeding is that a utility, as the operator of the distribution network, should be a disinterested party as it pertains to ownership and operation of individual resources. Instead, the utility should enable the interconnection and hosting of DERs on the distribution system. A Commission-mandated separation of interest is necessary to ensure that resources owned by a utility or its affiliates are not favored or subsidized by the utility, to the detriment of independent, competitively-owned and operated DERs.

Seeking the next great advance in energy market innovation from monopoly utilities is inconsistent with over 100 years of experience, which shows that innovation is largely driven by private parties investing shareholder dollars. As the chart below shows, the Commission should aim for the upper left box, where private innovation is maximized and ratepayer risk is minimized. Should the Commission incentivize utilities to directly compete with private investment in DERs, New York risks ending up in the lower left corner, where significant ratepayer dollars are put at risk, cross subsidization risks are high, and innovation is at a minimum.



How do we end up in the 1st rather than the 4th quadrant?

For the REV to be a success, the Commission should align utility incentives with the objective of moving away from ratepayer capital toward private capital investment in DER resources. To accomplish this alignment, the Commission should strongly incent utilities to maximize competitive investment and minimize ratepayer expense. Specific proposals include:

- Providing tangible rate penalties for utilities that fail to process 90 percent or more of distribution-level interconnection requests within a week;
- Elimination of standby charges for DER investments made in clearly identified areas of the transmission system that are most in need of reinforcement;
- Decreasing rates of return unless utilities make consumer meter information available on a real-time (or near real-time) basis to end-use customers or their designated agents; and

- Provide defined targets for penetration of competitive DER resources that, if not met, would result in an additional rate of return decrease.

While the universe of potential rate reforms is large, all these ideas have in common the goal of aligning utility incentives with the Commission's stated goal of removing barriers to bring end-user and third-party DER resources onto the system. These rate structures can make New York a leader in promoting adoption of innovative clean, low-carbon, and competitively sourced DERs.

II. Response to Select Questions[1]

1. Outcomes-Based Ratemaking: Incentives and Disincentives in Current Ratemaking

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

NRG submits that the existing rate incentive mechanisms around traditional reliability and safety functions incent positive utility behavior and should be retained. NRG asserts that in addition to the "Big Four" incentives (outage duration, number of outages, customer service, and safety), the Commission should strongly consider adding additional rate incentives, including adoption of competitively-sourced DERs, information transparency, and improved resiliency. We discuss these new proposals below.

In terms of existing rate mechanisms, New York's Revenue Decoupling Mechanism ("RDM") deserves special discussion. On one hand, the RDM ensures that utilities are not penalized for promoting policies that reduce energy consumption. On the other hand, however, the RDM does nothing to incent competition at the distribution

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[1] NRG addresses many of the Commission's below, but omits questions on which it has no direct view.

level. For example, the Commission recognizes that the "RDM provides no positive incentive for utility bill management[.]"[2]

Competition in distributed energy services will bring additional energy savings and enhanced energy value to consumers, beyond that which can be created by utility programs. RDM may reduce the utility's exposure to revenue loss due to these beneficial competitive activities, but does nothing to affirmatively incent the utility to support or facilitate them. Thus, the Commission should explore requiring utilities seeking access to RDM revenues to meet certain competitive benchmarks, such as those relating to interconnection time tables, access to information, etc.

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

There is broad recognition that encouraging end-users to adopt behind-the-meter generation, storage and other technologies that can operate in "islanded" mode in the event of catastrophic loss of the distribution system, such as occurred during Super Storm Sandy, will enhance overall reliability. Positioning these resources at strategic points across the state can ensure continuity of emergency first-responder services and ensure that key community resources remain online. Micro-grids or nano-grids that can operate even during a widespread outage thus contribute to reliability as they can reduce the demands on the system when operating in a grid-connected mode and be deployed during outages to avoid customer interruptions.

Utilities should be strongly incented to create a competitive framework that attracts private micro-grid capital in a manner that leads to bringing these micro-grids to fruition. By expressly including a benchmark for successful competitively-sourced

[2] Source: Page 53-54 of the Staff report.

micro-grids in the determination of earnings, the Commission can send a strong message that utilities will be rewarded for meeting and exceeding expectations for increased resiliency of their systems – even though the resiliency increase occurs through non-utility spending.[3]

NRG thus submits that including an “enhancing resiliency” metric in the bucket of reliability-related revenue adjustments is sensible. By establishing minimum benchmarks for incenting competitively-sourced resiliency-enhancing DER investments, the Commission can ensure that utility earnings are decreased if the benchmarks are not met. A utility can avoid any decrease in its rate of return by establishing competitive programs that attract DERs capable of operating in “islanded” mode.

Likewise, the Commission should consider whether to decrement rates of return for utilities that frustrate adoption of micro-grid and DER investment by denying timely access to information or pose barriers to the building of such systems.

c. How would superior performance be defined and measured?

The Commission’s goal should be to link earnings to the outcomes beyond “bread and butter” results such as customer satisfaction and environmental impact.[4] Superior performance for attracting “resiliency” DER resources needs to be measured based on benchmarks identified in advance (*i.e.*, by meeting a specified percentage of load served by enhanced resiliency solutions). Utilities meeting the benchmarks for their resiliency targets would qualify for full earnings.

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[3] Source: Refer Page 58 (2nd Para) of the Staff report.
[4] Source: Refer Page 88 of the Report to Ontario Energy Board by Pacific Economics Group.

2. New Outcomes/Metrics

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

The Commission should tie earnings to new metrics, including DER-related outcomes. In addition to the enhanced resiliency metric discussed above, utilities should be rewarded or penalized based on:

- **Interconnection Processing Times:** The Commission should tie earnings to a requirement that the utility markedly improve interconnection processing times for small- to medium-sized DERs. The Commission could establish a minimum benchmark of improving process times by 20%, with an extra bump if the utility reduces interconnection processing times by greater than 50%, or, alternatively, for completing 90% of distribution level interconnection requests within one week.

- **Information Access:** The Commission should create a new category of rate incentives and rate demerits for a utility's information transparency. In order to avoid a decrease in earnings, the Commission should insist that utilities: (1) make real-time meter information available to third-parties with less than a 24 hour lag, and (2) allow customers and their agents improved access to historic meter data.

- **Competitive DER Market:** The Commission should tie earnings to enhanced adoption of competitive DERs. Top performing utilities (*i.e.*, those that attract the largest number of DERs on a load-ratio share) should receive full earnings, while bottom performing utilities should receive a demerit.

- **Transparent Reservation Price for DER Capacity:** The Commission should also consider tying rates of return to the establishment of a clear locational price signal to signal the value of additional DER on constrained portions of its system.

- **Net Metering:** The Commission should incent the utilities to adopt tariffs and business practices that enable competitive companies such as energy supply companies ("ESCOs") to provide customers with net-generation credits. Current net metering tariffs by the NY distribution utilities discourage ESCOs from offering DER products due to the way utilities report a negative net-generation value on the ESCO's NYISO settlement statement. Amending this practice would effectively enable ESCOs to structure combined distributed generation/commodity supply products for customers in keeping with the objectives of REV.

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

NRG takes no specific position on basis points adders, but submits that they should be sufficient to drive utility behavior.

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

The Commission should consider adopting a *pro forma* DER rate structure for all utilities across the state. Common standards will make it easier for third-party competitive entities to interface with various utilities across the state. To the extent that additional customization is needed, the Commission should consider allowing utilities to request case-specific modifications to the *pro forma* standards. In order to enhance uniformity, the Commission should consider setting a high standard on proposed changes.[5]

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

One important measure of efficiency is line losses. As in the United Kingdom, the allowed electrical losses on the distribution system should be monitored and measured annually. This means that the performance of distribution companies is evaluated based on their performance in managing and reducing losses. Deployment of properly located DERs is an extremely effective method for reducing system losses which could be encouraged.[6]

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[5] For example, FERC established a "consistent with or superior to" standard when it implemented its *pro forma* open access transmission tariff in Order No. 888. That system was used to great effect to drive standardization across the industry, while also being respectful of regional differences across states and utilities.

[6] Source: Refer Page 10 of the Staff report.

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

No. The most efficient way to change customer behavior is to allow customers and competitive energy services to access meter and usage information and use that information to optimize energy use and save customers money. The Commission's ratemaking policies should encourage access to information and other goals identified above. These more generic reforms will allow the Commission to leverage scarce resources in a manner that will provide the biggest payoff.

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

Absolutely. The Commission should structure its rate incentives in a manner that encourages utilities to invite third-parties to participate in the distribution system. The goal must be to align utility incentives with the needs of a competitive marketplace. Nothing speaks as loudly as results, so the Commission should insist that utility earnings be tied to actual accomplishment of the items discussed above.

g. *What utility incentives are necessary to promote comprehensive integrated resource planning at the distribution level that would consider all DER alternatives to satisfy system expansion, system replacement, and / or to meet clean energy goals? Are there examples for multi-year performance metrics which would be superior in providing value to customers compared with an annual metric?*

If the Commission is going to allow utilities to control DER investment (which is clearly a second-best outcome to establishing a competitive market), earnings should be directly tied to whether the utilities have conducted competitive solicitations for DER alternatives to distribution upgrades and that those alternatives are measured and selected based on clear, predefined, objective criteria presented to the Commission in advance for its review.

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

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

No, the only bridge investment that utilities should be incented to make would be distribution infrastructure enhancements or communications systems that would increase the DER hosting capability of the current system.

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

First, utilities should be incented to identify <u>where</u> new investments are needed, as well as the <u>value</u> of that investment to the utility. The DLRP, for example, meets both of these requirements. The DLRP provides geographic transparency into where investments are needed by publishing easy-to-read maps describing where on the system DERs provide the most value to the utility. The program likewise provides price transparency by establishing a stated "reservation" payment for making the resource available for a given forward period (*i.e.*, a capacity payment), as well as a stated-rate for energy/ancillary services actually deployed by the resource. The program thus is extremely helpful in driving new investment.

Second, utilities should be incented to process DER applications in a timely manner. Again, establishing interconnection milestones and speeding up the interconnection process is the key metric on which utility earnings should be based.

Third, the Commission should reward success. Utilities should be told in advance what targets for third-party DER investment they will be required to meet.

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

In order to drive the REV process, the Commission should allow utilities to recoup their investment in creating the platform for bringing DERs to the market, while prohibiting utilities from bypassing competition in the ownership and operation of DERs. To accomplish this, the Commission must prohibit direct utility investment in DERs themselves and establish firm functional separation rules.

This philosophy has direct implications for how the Commission addresses Construction Work in Progress ("CWIP") recovery for DER investments. We recommend that the Commission allow CWIP recovery for any investments made to establish a competitive framework for private DER investment, while prohibiting any utility investment in DER resources.

This distinction is absolutely critical. If utilities are not only allowed, but incented, to begin direct investment in DERs, the Commission risks wiping out private investment in DER systems in New York. The micro-grid market, in particular, is an important but relatively finite market. Allowing the utilities to ratebase investment in the "lowest hanging fruit" would be extremely destructive to private investment in micro-grids.

6. Benchmarking

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

While cost benchmarking has historically been used, particularly with reference to the utilities, the Commission should primarily consider performance benchmarking in connection with the REV proceeding goals. Putting all parties on notice that the Commission will use performance benchmarking to measure market framework improvements, process improvements, and eventual outcomes the Commission is looking for will help align utility incentives with the incentives for third-parties bringing innovation to the DER market.

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

Benchmarking is clearly advisable. However, there is no question that it will be difficult to rely on traditional benchmarking for REV outcomes. While traditional benchmarking requires sophisticated model – whether be it statistical, mathematical or engineering models[7] – the Commission can avoid many of these complexities by adopting straightforward targets for utilities to meet.

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

Yes. As discussed above in Question 3, Input, the Commission should adopt clear forward prices for specific unbundled energy attributes.

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[7] Source: Performance Benchmarking in utility regulation: Principles and UK experience; Parker, D and Page 60-61 of the Staff Report.

7. Utility as DSPP and as DER-owner: neutralizing incentives

a. Can ratemaking or structural mechanisms be established to remove the utility bias in favor of DER investments owned by the utility or its affiliates?

There is an inherent and irreconcilable tension between having the utility as the DSPP and as a competitor in the market. The Commission's goal should be to attract private, not ratepayer, dollars into the DER sector. While the Commission can reinforce existing functional separations, those efforts will only be partly successful in attracting private capital to the market. There is still a broad-based and well-founded concern on the part of competitive market participants that affiliate conduct standards mandating functional separation, no matter how well constructed, simply provide less protections against abuse than actual functional separation.

The best case scenario is that the Commission will either establish an independent entity to perform the DSPP function or prohibit the utility's unregulated affiliates from providing the non-essential value-added energy services that are the hallmark of the REV proceeding. This will provide private parties the certainty necessary to invest in New York, secure in the knowledge that their investments in long-lived assets will not be undercut by ratepayer-backed investment by the utility or cross-subsidization by utility ratepayers.

The second best scenario is to ensure adequate separation of the DSPP function from the utility's business interest in the growth of distributed ratebase. This could be done, for example, through the kind of firewall required in FERC's Orders 888 and 889 between transmission scheduling and the rest of a utility's businesses. Further protection against self-dealing and foreclosing competitive DER is needed, as well as positive incentives to embrace and support a competitive DER platform. These can be provided by:

- Establishing standards of excellence for the utilities' interconnection, data provision and service for competitive DER providers;
- incentives for exceeding those standards of excellence and earnings disincentives for failing to meet them;
- additional earnings incentives for reducing the size and increasing the efficiency of a regulated ratebase, which should take the form of a "shared savings" approach so that both customers and utility shareholders benefit from substituting private capital for ratepayer capital; and
- in the event the Commission decides to allow unregulated utility affiliates to participate in the DER market, strong and robust affiliate interest rules to assure a level playing field for competitors, and protection against affiliate abuse for ratepayers.

As part of this effort, the Commission should exclude investments made by the utility's unregulated arm for qualifying for the rate incentives discussed above. Instead, those extra returns should only kick in if the utility is creating a competitive framework, in its role as DSPP, which is bringing private, unaffiliated, investment into the market.

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

Given the Hobson's Choice outlined in the question, NRG would prefer to compete against a utility's non-regulated arm. While non-regulated affiliates are clearly preferentially situated vis-à-vis third-party non-affiliated investors, the other choice is simply even more unpalatable. Third-parties cannot compete – and will not bring substantial private dollars – into a market where they are competing against ratepayer-backed investment. It is a fool's errand for a competitive supplier to make an investment in a new technology, and then see its investment wiped out as the utility moves into the same field using riskless ratepayer-backed investments.

However, there are clearly better options. The REV proceeding should strive to create a vibrant distribution market administered by an independent party with no financial interest in grid outcomes. If the Commission can create a framework that makes information easily sharable, creates transparent price signals, and allows competition, then private investment will enter the market.

Of course, this does not have to be a binary choice. As an alternative to direct utility ratebasing of DER investment, the Commission could consider the California experience as a glide-path to a fully competitive DER market. California's proliferation of renewable resources was largely driven by the establishment of a series of Requests for Offers ("RFO"), whereby the California Public Utilities Commission directed its utilities to conduct a competitive solicitation for stated quantities of the specific product. Through use of designated targets combined with competitive solicitations open to third parties, California is leveraging its prior success in bringing renewables to market additional alternative technologies through its "preferred resources" all-source RFO and other solicitations. At the end of the process, California utilities will enter into long-term contracts with several gigawatts of storage and renewable, battery, micro-grid and fuel cell technologies. While ultimately problematic from a competitive standpoint, the RFO model more closely tracks competitive outcomes than allowing utilities to invest directly in DERs.

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

The Commission should ensure that any rate-based investment in the DSPP function is limited to creating a competitive framework that will enable the interconnection and participation of DERs in a competitive distribution marketplace. In so doing, the Commission can leverage a relatively limited investment of ratepayer dollars in distribution market infrastructure to leverage a relatively large corresponding investment in private dollars. As discussed above, the appropriate role for the DSPP includes upgrades to information sharing infrastructure to enable real-time (or near real-time) sharing of meter information; developing maps to identify where distribution system reinforcements are needed; whether those distribution reinforcements would be alleviated through investment of private dollars; establishing transparent price signals; and speeding the interconnection process.

II. Long Term Rate Plans

1. Pros and cons of long term rate plans

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

The focus of the Commission's actions in the REV proceeding should be to establish an enduring market framework at the distribution level that will enable greater third-party investment in DERs. We expect that this will be a multi-year process, and it makes sense to give the utilities a routine checkup as we move forward.[8] Linking utilities' investment in plant and equipment (and therefore long-term company earnings)

[8] Refer Page 55 of the Staff Report & Page 77 of the Report to Ontario Energy Board by Pacific Economics Group.

to measures of the long-term value created by their actions should be a strong motivator and encourage longer term planning and initiatives.

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

Given the uncertain nature of the REV proceeding outcomes, we recommend establishing regular "rate check-ins" that will allow the Commission to adjust the utility's ratemaking incentives and outcome goals as more information becomes available. In order to reduce utility risk, these "check-ins" should be designed to review outcomes and provide guidance, but not change the overall rate structure or basic incentives.

3. Baseline cost-of-service recovery; ROE

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

In order to deal with the "windfall" concerns as a result of the positive incentives under outcome-based rate making, the initial rate can be set in the low range of return for achieving higher levels of performance.[9]

4. Interim investment provisions (avoiding deterioration)

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

The capital expenditure reconciliation mechanisms need to be modified because while the reconciliation mechanism removes the financial benefit to utilities from slippage (under-spending) in their capital expenditure budgets in long-term rate plans, they do not distinguish between achieved cost savings and slippage – meaning that the utility is not rewarded for efficiently managing capital budgets. Also, the mechanism

[9] Source: Refer Page 53 of the Staff Report

potentially discourages beneficial projects with higher up-front capital budgets, since overspending is absorbed by the utility until rates are reset.[10]

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

Competitive market participants are concerned that the regulated utilities will over-spend on infrastructure in the new DER field, if given the opportunity to do so. Given the obvious potential incentives for over-investment in this new field, the Commission needs to adopt strong protections against utility overspending. Not only does this overspending threaten to substantially increase retail rates, but it also has the effect of strongly discouraging private investment in DER infrastructure – at the very moment that technology is poised to bring massive innovations into this sector.

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

This is a key element of making Track 2 successful. One of NRG's key theses is that the utility will identify needed infrastructure on the distribution system and allow private investment in DERs to delay, or obviate, the need for that distribution investment. Clearly, an effective rate design is critical to rewarding the utility appropriately when this socially desirable outcome occurs. A sharing of the benefits is thus an absolutely critical component of any REV-friendly rate reforms. (Indeed, a truly successful program will share the savings both with the utility and the end-use customers making the investments that obviate the need for distribution upgrades.)

6. Exogenous factors and reconciliations

b. Typically, utilities are provided with protections against certain risks during long term rate plans (e.g., commodity pass through, uncontrollable costs

[10] Source: Refer Page 48 of the Staff Report.

provisions, etc.). In return, the utility must absorb any deficient returns. Should this type of approach be retained or modified? What costs should be included?

The goals of REV demand a different approach. If we are going to ask the utilities to create a first-of-its-kind DSPP system, there are likely to be investments that, in retrospect, were not prudent. The Commission should allow CWIP and other protections that allow utilities to recover all costs associated with developing the DSPP market infrastructure. However, utilities should be prohibited from investing directly in DER technologies. This properly aligns the utility in the role of furthering competition without putting ratepayer funds at risk backing projects that would otherwise be funded by shareholders.

III. Rate Design

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

Standby charges represent a major disincentive to customer participation in DERs. Other barriers include restrictions on multi-site micro-grids and lack of sufficient incentives for utilities to improve access to information.

2. **Tariffs for DSPP products**

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

The DSPP should identify a price for various products. This would allow the Commission to control the procurement prices passed through to ratepayers and decide whether to include a price for carbon and other environmental goals.

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

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

No. As discussed above, the Commission should require utilities to set a stated rate for as many energy products as possible, including reservation charges that vary by location. While the traditional electric rate design has been based on the embedded cost to serve each customer class with the assumption that the peak demands of the class drive the cost, new rate design approaches will be necessary to recognize the two-way transactive[11] grid and the future roles of the utility that are envisioned under REV. As a second best option, the Commission could adopt the RFO model discussed above, which would establish quasi-market prices for specified products.

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

Yes, in general, pricing should be determined through a market mechanism and should reflect locational based pricing.[12] However, in order to minimize the complexity of the DSPP systems, utilities should utilize a clear and concise "price to beat" methodology for setting reservation charges, with a separate unbundled price for energy and ancillary services (or demand reduction) produced from the DER.

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

No. Ideally, the Commission will mandate a fully competitive framework to determine prices. However, if the Commission does adopt an RFO structure, many of the terms of individual contracts should remain confidential for a period of years, in order to

[11] Source: Refer Page 58 of the Staff Report.
[12] Source: Refer Page 60 of the Staff Report

avoid affecting the outcome of future RFOs.[13] Thus, specific contracts should be approved by the Commission as confidential filings, with the agreement's term released at the time of approval, and other information remaining confidential for at least 3 years.

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

Reservation/capacity pricing is a critical component of incenting DER investment. But yes, on the energy and ancillary services side, the level of granularity that is needed would primarily be peak/off-peak, with potential adders for resources that perform at super peak periods.

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

Yes, the pricing should be by time and geographic location.[14]

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

Yes, pricing should be differentiated for products related to reliability, economics, or public policy. Algorithms that include solving for reliability, economics and overall system efficiency would be necessary, depending upon the product being transacted. Time-sensitive rates will require investment in advanced metering, which is more likely to be cost-effective for larger customers.[15]

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[13] California requires the following in terms of confidentiality: "The Commission, in implementing Pub. Util. Code § 454.5(g) . . . . has determined . . . that certain material submitted to the Commission as confidential should be kept confidential to ensure that market sensitive data does not influence the behavior of bidders in future RPS solicitations. D.06-06-066 adopted a time limit on the confidentiality of specific terms in RPS contracts. Such information, such as price, is confidential for three years from the date the contract states that energy deliveries begin, except contracts between IOUs and their affiliates, which are public."

[14] Source: Refer Page 60 of the Staff Report

[15] Source: Refer Page 60 of the Staff Report

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

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

Yes, unbundling is absolutely critical. Competitive DERs rely on a wide-array of revenue streams, including reliability, ancillary services, energy and capacity components.

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

No, it should be established pursuant to the competitive framework discussed above.

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

Yes, the energy and ancillary services component of any energy produced or consumption reduced should be done on a locational basis. Depending on the level of complexity, the Commission may want to shy away from real-time variable price signals at the retail level for smaller customers. Again the DLRP model provides a stated-rate for both a reservation charge and the energy component. This simplified approach to "Locational Marginal Pricing" may be preferable for attracting smaller customers into the market.

5. **New rate designs**

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

Preferably, prices would be fixed for smaller customers and vary as the size and sophistication of the customer increases. For example, customers on a time-of-use wholesale service rate are going to be more adept at meeting real-time dispatches than smaller customers.

g. What payment structure would facilitate distribution utility ownership of DER behind customers' meters? For example, should a customer be provided with a direct payment for allowing the utility to locate the DER on its property or should the customer be allocated a portion of the ongoing DER benefit?

Utilities should not be allowed to own DERs.

7. Standby rates

a. How can the current standby rate design be revised to reflect the diversity of DER and the unlikelihood that all DER resources would fail at once and all during the system peak hour?

Standby rates are a major impediment to DER investment and the Commission should revisit the justification for charging standby rates equivalent to a customer's peak load. Experience has shown that customers relying on behind-the-meter investments to control their load – either generation or demand response – are extremely reliable players in the distributed energy markets. There is no justification for allowing the utility to plan its distribution system as if each of these resources were unavailable during system peak periods.

For example, for customers enrolled in a penalty-free demand response program, NRG's data demonstrate that a distributed set of customers in New York reduced a <u>minimum</u> of 50 percent of their eligible load when called upon, over a number of different events. Thus, the Commission can allow utilities to reasonably rely on DER installations to address peak periods without in any way jeopardizing reliability. Reducing the need for distribution infrastructure contributions from specific customers will do a tremendous amount to improve the economics of DERs.

c. *How would the current standby rate design need to change to be applicable to multi-customer microgrids?*

Standby rates should be eliminated for customers enrolled in multi-customer micro-grids. As discussed above, it reasonable for the utility to assume that a given microgrid will be a highly-reliable resource that can be counted on in all distribution planning scenarios.

8. Gas and steam rate implications

a. *How do the current gas and steam rate designs encourage or discourage the installation of DER, specifically gas fired DG and CHP?*

b. *Which aspects should be eliminated, expanded, or redesigned, and how?*

The Commission should consider adding a firm gas supply tariff for distribution-connected DER CHP facilities. Currently, the only gas tariff service accessible for small scale CHP is interruptible. DER CHP should be eligible for firm gas supply since it is providing point-of-use enhanced efficiency through combined electricity and thermal benefits that reduce both net demand on the electric grid and gas usage by large central power stations.