STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 07-M-0548 – Proceeding on Motion of the Commission Regarding
An Energy Efficiency Portfolio Standard

INITIAL COMMENTS OF CONSOLIDATED EDISON COMPANY OF NEW YORK, INC., AND ORANGE AND ROCKLAND UTILITIES

INTRODUCTION

Consolidated Edison Company of New York, Inc. ("Con Edison") and Orange and Rockland Utilities, Inc. ("O&R") (collectively "Companies") submit their initial comments in accordance with the Commission's May 30, 2008 Notice[1] on "[w]hether, and to what extent, financial incentives based on the extent to which performance exceeds or falls short of targets should be established prior to the submittal of proposals by utilities."

The Commission stated (at 1) as follows with respect to purpose of the Notice,

> Although the question of utility incentives has been discussed in this proceeding, the parties have not submitted comprehensive briefs on this topic. The Commission seeks comment from the parties in this proceeding regarding a number of concerns related to utility incentives. In order to provide timely guidance to utilities in the preparation of proposals, the Commission intends to adopt policies related to performance incentives substantially in advance of due dates for utility proposals.

The Commission also asked for comments on three models that are discussed in the Notice: (1) the DPS Staff model; (2) the Advisory Staff model; and (3) the California model. The Commission then asked the parties (at 3) to provide comments on:

---

[1] Case 07-M-0548, Notice Soliciting Comments (May 30, 2008) ("Notice").

a) whether incentives are necessary; b) the reasonableness of the Guidelines, and any recommended modifications; c) any other specific issues not encompassed within the Guidelines; (d) the strengths and weaknesses of the three incentive models identified above, and any recommended modifications; and (e) the range of incentive levels that will accomplish the objectives identified in the guidelines.

In order to aid the Commission in adopting incentives principles, the Company has attached the affidavit of Eugene Meehan, a Senior Vice President with NERA Economic Consulting, who has over thirty years of experience consulting with electric and gas utilities.

In sum, the Companies request that the Commission endorse a policy that incentives are necessary. As the Companies have explained in their briefs filed in this proceeding, utilities can play a significant role in achieving energy efficiency reductions. In the recent Con Edison Electric Rate Order,[2] the Commission stated (at 158) that with respect to "the EEPS proceeding, our assessment is that it is likely the proceeding will result in substantial utility involvement in delivering efficiency programs." Yet, in order for utilities to design and implement effective programs, they must earn benefits -- otherwise there is little logic to a utility purposefully crafting ways to reduce its revenue stream, its rate base, and otherwise reduce its overall flexibility by reducing the size of the company. As described by Mr. Meehan, numerous other states are providing meaningful incentives to utilities. Meehan Aff., Exh. B.

The Companies also request that the Commission adopt an incentive policy that focuses on the benefits achieved through energy efficiency programs. Specifically, the Companies request that the Commission adopts a modified version of the California

[2] Case 07-E-0523, Order Establishing Rates For Electric Service (March 25, 2008) ("Electric Rate Order").

model for New York State. Under the modified version, proposed by Mr. Meehan, net resource benefits would be defined as the present value of the estimated avoided costs, including energy and capacity costs, over the service lives of measures installed each year pursuant to programs, less program costs (*i.e.*, customer incentives, marketing, customer outreach, labor, mailing, measurement & verification, etc.) associated with the installation of these measures.

Mr. Meehan explains that his proposed definition is better than the California definition, which looks at the total cost of the energy efficiency measure, and not the program costs. An incentive based on program costs will induce utilities to design and implement the most cost effective programs. In addition, the " primary feature of a well-developed incentive program is that a utility that achieves a high percentage of energy efficiency or peak reduction targets should be able to retain a non-trivial portion (on the order of ten percent – given current economics) of the net resource benefits." Aff., ¶ 13(f).

The Companies request, however, that the Commission not adopt a specific incentive mechanism with specific numbers in its decision on the Notice. The Commission should refrain from adopting a uniform incentive mechanism directly applicable to each utility in advance of authorizing programs for each utility. This Commission has long recognized that there are significant differences between the utilities and their service territories,[3] especially between the upstate and downstate regions. Therefore, the Companies recommend that the Commission adopts, pursuant to

[3] *See, e.g.*, Case 00-M-0504, Statement Of Policy On Further Steps Toward Competition In Retail Energy Markets, at 14 (August 25, 2004) (our "deliberate approach still requires that we carefully examine market conditions by customer service class and by utility territory before deciding on how best and how aggressively to assist the development of the market.")

the Notice, principles only, and that it then tailor those principles according to the individual circumstances and characteristics of each utility, which will affect the programs that the Commission authorizes for each utility.

The Companies urge the Commission to promptly issue a decision adopting these principles. The Companies reaffirm that they are ready to submit energy efficiency programs for approval. The Companies firmly believe that they should be provided with meaningful incentives to administer energy efficiency programs to ensure that customer and shareholder interests are aligned to optimally achieve cost-effective energy efficiency measures. The decisions on incentives and authorization of programs, however, can proceed in parallel to ensure that there is no delay in moving ahead.

It is now more than a year since the Commission issued its Order initiating this proceeding,[4] finding (at 2) that "realizing the State's energy efficiency potential and reducing New York's electricity usage 15% from expected levels by 2015 are in the public interest." It has been generally recognized that utilities will have to play a significant role in seeking achievement of the 15 x 15 goal, yet there has been little movement forward in authorizing utilities to proceed with programs and providing them with the appropriate incentive.

The Companies note in particular that in 2007, the year in which the State's 15 x 15 policy was announced, there was a significant increase in electricity usage in their respective service territories as compared to 2006. In Con Edison's service territory, electricity consumption grew 2.6% on a weather-adjusted basis, while in O&R's service territory, it grew by 1.6%. Both Companies are ready to submit programs that will

[4] Case 07-M-0548, Order Instituting Proceeding (May 16, 2007).

provide significant contributions toward the State's goal and slow the growth in consumption in the Companies' service territories, but they must be provided with appropriate incentives to achieve that goal. Commission adoption of the incentive principles proposed by the Companies will send the right signals that they should continue to pursue energy efficiency.

DISCUSSION

I. Staff Proposed Principles on Energy Efficiency Incentives

Based upon the expert opinion of Mr. Meehan, Aff., ¶ 13, the Companies request that the Commission adopt the following principles:

a. Financial incentives for utilities are essential to assure successful demand response and energy efficiency programs. If utilities are to play the important role that they are uniquely qualified to play in encouraging the deployment of efficiency resources, it is essential that they have an opportunity to earn a return for their efforts to promote the efficient development and use of such resources. Utilities naturally face obstacles to demand response and energy efficiency that must be countered through means including but not limited to direct incentive programs.[5] Incentive programs are well accepted and utilized in many jurisdictions.

b. Financial penalties for failure to meet demand response and energy efficiency performance targets may be appropriate, but need to be developed considering the uncertain nature of the targets. Further, it needs to be recognized that

[5] For example, incentives do not replace the need to provide for lost revenue recovery, but should be incremental to such mechanisms which remove disincentives.

utility management does not have complete control over the success of these programs.

c. The demand response and energy efficiency programs under consideration by the Companies and the other New York IOUs are large-scale programs that may have negative financial implications for utility investors. The unprecedented scale of these programs merits special consideration when financial incentives are considered. For these reasons, the incentives must be meaningful in order to induce maximum utility performance.

d. Incentives should be determined based on a sharing of net resource benefits. Net resource benefits are appropriately defined as the present value of the estimated avoided costs, including energy and capacity costs, over the service lives of DSM measures installed each year pursuant to DSM programs, less DSM program costs (i.e., customer incentives, marketing, customer outreach, labor, mailing, measurement & verification, etc.) associated with the installation of these measures. This incentive, which shares net resource benefits, will induce the Companies to design and implement the most cost-effective programs.

e. While a cap on incentives should not be necessary, if a cap is adopted it should not be set at a level so low that the negative financial impacts from the large scale energy efficiency program are left unmitigated. Further, the cap should not be set either directly or indirectly based on program costs. The percentage that incentives comprise relative to program costs should not weigh on the Commission's decision on the incentive level or a cap. The most successful efficiency programs may well be those where participation levels and resource savings are high while program costs are low and the incentive would be a high percentage of program costs. Further, the cap should not be set in a way where there is a good chance it will be reached, as this will effectively eliminate the incentive for maximum performance as incentives earned in excess of the cap will not accrue to the shareholder.

f. The primary feature of a well-developed incentive program is that a utility that achieves a high percentage of energy efficiency or peak reduction targets should be able to retain a non-trivial portion (on the order of ten percent – given current economics) of the net resource benefits.

The basis for these principles is provided by Mr. Meehan in his affidavit.

The Companies believe that Mr. Meehan's principles should be preferred to Staff's proposed principles, but also provide herein their specific comments on the Staff principles.

1. **The overall objectives of performance incentives in the context of energy efficiency are: (1) Encourage superior performance and deter weak performance; and (2) align utilities' financial interests with energy efficiency as a resource option.**

Response

The Companies support these principles except to the extent that the Staff proposes that an incentive mechanism should "deter weak performance." First, given this State's ambitious goals, it is crucial that the Commission "align utilities' financial interests with energy efficiency as a resource option." As Mr. Meehan explains, this is a well accepted principle in the design of utility energy efficiency programs that has been implemented by numerous states that are seeking to achieve more ambitious energy efficiency goals.

The Commission has successfully used incentives to further other public policy goals, *e.g.*, promotion of retail access, without the use of penalties, and the same principle should apply here. First, promoting energy efficiency to customers, like promoting retail access service to customers, is not one of the Company's statutory responsibilities under the Public Service Law. While the Commission offered incentives to utilities to promote retail access service to their customers, the Commission did not attempt to impose penalties on utilities for failing to switch some threshold number of customers to retail access service. The Commission should recognize that, just as it is the customer's decision whether to switch to a competitive service provider, it is also the customer's decision whether to implement energy efficiency measures. The Company can educate and provide an incentive to the customer, but the customer must ultimately decide to make the change. The Commission should not penalize a utility for results that depend ultimately on customer decisions.

Moreover, the Commission should not penalize utilities if they have prudently and cost-effectively incurred expenses on behalf of customers. If a utility fails to spend money cost-effectively to achieve energy efficiency, then the Commission already has remedies at its disposal, *e.g.*, disallowance of recovery of costs. If, a utility has cost-effectively spent customers' money (*i.e.*, the utility has produced benefits for customers), but it has achieved less energy efficiency than its target, there is no basis for applying penalties.

Finally, the Commission has a fully effective remedy if it believes that a utility is not achieving enough through its energy efficiency program. The Commission can, within the bounds of due process, reduce the utility's role or put it out of the energy efficiency business. This is a real possibility in New York as evidenced by the extensive debate over program administration and the NYSERDA position that utilities should be limited to the role of marketing NYSERDA's programs and reducing losses on utility T&D systems.[6]

2. The maximum amount of money available to utility stockholders from an energy efficiency incentive should account for the size of the utility program portfolio target relative to the jurisdictional goal for the utility's service territory, and should encourage improved utility performance without placing an excessive burden on ratepayers.

Response

The Companies generally agree except that they reject the notion that an incentive based on a percentage of net resource benefits would place an excessive burden on customers. Net resource benefits measure not only the benefits to an individual customer that saves on energy costs, but also the benefits to society as a whole from less air emissions from power plants, which will mitigate climate change, and potential reductions in wholesale electric generation market energy and capacity prices. As discussed by Mr. Meehan, Aff., p. 18 n. 9, a cap is generally not appropriate because it will only encourage utilities to seek to achieve energy efficiency up to the cap and no

[6] Case 07-M-0548, Initial Brief of The New York State Energy Research and Development Authority at 8 (April 10, 2008) ("utility efforts should be steered towards finding efficiencies in the transmission and distribution system, through the promotion and development of advanced metering and SmartGrid technologies, so that electricity can be delivered more efficiently").

further. A cap is therefore conceptually contrary to a sound economic policy that would encourage maximization of energy efficiency.

Nonetheless, the Companies understand the importance of being able to determine the maximum amount of the incentives so as to be able to estimate the maximum potential impact on customer bills. But, at a minimum, if the Commission determines that a cap is appropriate, it should make clear that it will grant petitions for waivers from the cap upon a showing that an incremental incentive is justified based upon the benefits provided and other relevant factors.

If the Commission decides to adopt a cap, the Companies recommend that it adopt a cap in the form described by Mr. Meehan. He provides an example of how such a cap would be calculated, using supply-side equivalency, for Con Edison's proposed 500 MW program. Meehan Aff., ¶ 45(3). The exact cap for a Con Edison or O&R proposed program would depend upon the program that the Commission authorizes. As Staff discussed, any such cap should also take into account the size of the utility's program portfolio target relative to the jurisdictional goal for the utility's service territory.

3. The formula by which a maximum monetary incentive and intermediate monetary incentives and disincentives are calculated should not induce utilities to increase program costs artificially or to manipulate the program design and implementation inappropriately.

Response

The Companies agree with this principle, *i.e.*, that incentives should not be based on a percentage of program costs. Indeed, as Mr. Meehan explains, Aff. ¶ 13(e), the "most successful efficiency programs may well be those where participation levels and resource savings are high while program costs are low and the incentive would be an high percentage of program costs."[7]

4. The incentive formula should provide for both positive and negative revenue adjustments.

Response

See response to Principle 1.

5. The effectiveness of a utility's energy efficiency program portfolio, based on measurement and verification results, should be the basis for determining revenue adjustments.

Response

The Companies agree and reaffirm their position that the measurement and verification protocols applied to utility programs should be the same for all program administrators, including NYSERDA, NYPA and other governmental entities as well as private sector administrators.[8] It is critical that the State, especially the NYISO bulk system planners and the local utilities' system planners, have confidence in the reported achievements and sustainability of energy efficiency programs so that they can be incorporated into system load forecasts to the extent appropriate, in addition to having accurate amounts for the calculation of incentives.

[7] The Companies note that with respect to a program that involves installing a physical asset such as distributed generation, it may be appropriate to put the program costs in rate base.

[8] The Companies understand that the Commission can only encourage the authorities to use the same protocols given that the Commission does not have jurisdiction over them.

6. The utility must achieve a high percentage of its target before realizing a positive revenue adjustment tied to performance.

Response

There is no basis in economics for this principle. Given that every MWh achieved by a utility will produce net resource benefits, economic theory would dictate that a utility should be able to earn an incentive for each MWh achieved. The Staff proposal also does not take into account that if a utility is able to achieve a small amount of energy efficiency, then it would earn a small incentive. The continuous positive reinforcement of no threshold provides the utility with the correct signal to seek to achieve as much energy efficiency as possible. Minimum thresholds could also discourage innovation.

Moreover, while the Companies have some infrastructure in place, the Companies are just beginning to ramp up after many years of no involvement due to the Commission decision to transfer virtually all energy efficiency funds to NYSERDA.[9] At this early stage, if the Commission should consider any threshold for earning incentives, they should seek to set them low (e.g., less than 50%) given the need to ramp up and the uncertainty of any target due to the lack of experience and fully measured and evaluated data from which better forecasts of energy efficiency could be developed.

7. The primary gauge for determining the effectiveness of a utility's energy efficiency program portfolio should focus on verified MWH savings. For programs that are approved with a specific peak reduction target, the primary gauge should be MW savings.

Response

The Companies agree, bearing in mind that peak demand should not necessarily mean summer daytime coincident bulk power peak, but can also mean the relevant

[9] Opinion No. 98-3 (January 30, 1998).

network peak. For example, Con Edison obtains some of the T&D deferrals and ratepayer benefits from reductions in primarily residential networks that peak in the evening.

8. Incentives should be calculated over aggregated portfolio performance rather than by specific programs; however, a mechanism must be in place to assure that individual program targets are not sacrificed to maximize incentives.

Response

The Companies believe that the incentive should be based on performance of the entire portfolio and the utilities should have the flexibility to reallocate money between and among programs. Otherwise, the incentive mechanism would discourage innovative programs, because utilities would then have an economic incentive to pursue "safe" programs only. Accordingly, this principle should not assume that "sacrificing individual program targets" is always bad, especially if they are sacrificed in order to promote overall cost-effectiveness or efficacy. Instead, the principle should state that a "process must be in place to assure that certain individual program targets are not sacrificed to maximize incentives when appropriate and necessary."

In the Companies' view, this concern is more appropriately reviewed at the program approval and reporting phase. For example, the Companies expect that they will submit programs for approval and that the Commission will approve such programs. While the Companies expect that they will be allowed to shift a certain percentage of funds from one program to another, the Commission could restrict that ability with respect to certain programs that have other important public policy goals, *e.g.*, aid to low-income people.

In addition, the Companies have proposed that they would submit ongoing reports to the Commission and DPS Staff that will also be provided to stakeholders. These reports will provide an opportunity for ongoing dialogue over the status of programs and the need to adjust funds and/or programs. As part of this process, utilities, in consultation with Staff and other stakeholders, can determine if funding should be maintained for a program that has other public policy purposes even if the program may not have been successful up that point for any number of reasons.

9. Incentives would not be available for programs in which a utility transfers funds from ratepayers to NYSERDA (this principle would not preclude a utility from obtaining incentives for a program that it undertakes that was previously conducted by NYSERDA with ratepayer funds transferred by the utility).

Response

Utilities should also receive incentives for supporting NYSERDA so that they have an incentive to provide it with crucial outreach and marketing support. The Companies would agree, however, that a utility would be entitled to a lesser incentive if it is providing marketing support to NYSERDA instead of actually administering programs. In this case, the incentive should be based on the contracts entered into by NYSERDA and not a percentage of the net resource benefits. Under the 2005 Con Edison electric rate plan, it was entitled to an incentive of $22,500 for each MW enrolled in the NYSERDA program.[10] The Commission found that Con Edison's marketing efforts contributed to the promotion of the NYSERDA programs.[11] Sales

[10] Case 04-E-0572, Order Adopting Three-Year Rate Plan, Joint Proposal, Appendix A, at 71-72 (March 24, 2005).
[11] Case 04-E-0572, Order On Petitions For Modification And Modifying Electric Rate Order, at 14 (Dec. 22, 2006).

commissions are commonly used to motivate a sales department – if utilities are to be in a "sales" role for NYSERDA, then they should be appropriately compensated.

10. Consistent statewide incentive principles based upon overall program performance are necessary for ease of administration and to prevent confusion among potential market participants.

Response

The Companies agree that statewide incentive *principles* are appropriate. But the actual application of these principles, particularly to the design and implementation of energy efficiency programs, should take place on a utility by utility basis. This would be similar to how the Commission implemented its retail access policies, which generally worked well.[12] The differences in utility service territories can have a significant impact on the amount of energy efficiency potential. For example, consider that the average Con Edison residential customer, especially those located in New York City, has a much lower electric bill than elsewhere in the State, due to the smaller size of the typical dwelling unit. The ability to increase efficiency could be affected by this smaller consumption. Energy efficiency opportunities are also highly fragmented across customer classes and the size of the customer class can vary significantly by service territory (Con Edison and O&R both have relatively small industrial loads as compared to the upstate utilities).[13]

The Companies note that it is unclear what is meant by the statement that a uniform policy is necessary to prevent "confusion among potential market participants." Utilities will not be confused by their level of incentives after they are adopted even if

[12] *See, e.g.*, Case 00-M-0504, Statement of Policy on Further Steps toward Competition in Retail Energy Markets, at 14 (August 25, 2004).
[13] *See* The Vattenfall US Mid-Range Abatement Curve – 2030 published by McKinsey & Company in its report titled "Reducing U.S. Greenhouse Gas Emissions: How Much at What Cost" (December 2007)

they are different from other utilities and there is no basis for believing that any other stakeholder or market participant would be "confused." The Companies recommend that this part of the statement be eliminated.

11. Incentives (assuming performance at 100% of the utility's proposed program target) must be included in the cost estimates of program proposals.

Response

Incentives have traditionally not been part of the total resource cost ("TRC") test and the Companies continue to believe that this cost should not be included as part of the test. As explained by the Commission,

> The total resource cost test is a screening tool that compares the cost of an energy measure, including the incremental participant costs, net of incentives provided by a utility, government agency or other entity, to the total resource benefits obtained over the life of the measure. The test quantifies and values the costs and savings of physical items such as fuel, hours of labor, and equipment installation and operation (e.g., energy efficient lighting). Each item included in the test must reflect real resources that are saved or incurred by society. For an energy program to be cost-effective on a total resource cost basis, its resource benefits to society should outweigh the resource costs of the program to society.[14]

Because this test is focused on the costs and benefits of "physical" resources, it appropriately does not include such items as utility shareholder incentives.

If utility shareholder incentives are included, and the programs are to be evaluated on that basis, then the Commission should ensure that all the costs of NYSERDA programs are included when making the comparison. These costs would include: (1) all NYSERDA administrative fees (including the fees it pays to the State); (2) the time value of funds to ratepayers given that NYSERDA requires that funds be provided up

---

[14] Case 04-E-0572, Order on Demand Management Action Plan, at 30 (March 16, 2006).

front before it enters into contracts while utilities collect costs only as they are incurred, *e.g.*, as they make payments under contracts to vendors; and (3) costs associated with utility outreach and marketing for NYSERDA programs.

Finally, in comparing NYSERDA administration to utility administration, the Commission should take into account that certain service territories, especially Con Edison and O&R, have consistently received less than they contributed to NYSERDA. As demonstrated by Con Edison and O&R in their initial briefs (and not disputed by NYSERDA or Staff) while Con Edison has provided 50% of SBC funds to NYSERDA, it has received approximately 40% of such funds in return, and, for O&R, the Company has provided 3.3% of SBC funds to NYSERDA, while its customers have received approximately 2% of such funds in return.[15] Accordingly, for the Con Edison and O&R service territories the full cost of the NYSERDA program is the full amount of funds that they provide to NYSERDA and the cost should be calculated for each service territory on that basis.

Concededly, making these kinds of cost comparisons will be difficult. This is why the determination as to which entity should be the principal administrator in a particular service territory should not be made on cost alone. For example, in the recent Con Edison gas efficiency collaborative, which consisted of a diverse group of stakeholders, the consensus was that "while cost is an important element to consider in the selection of an administrator, the program administrator should not necessarily be determined solely on the basis of which is the lowest cost alternative, so long as the Total Resource

[15] Case 07-M-0548, Initial Brief of Consolidated Edison Company of New York, Inc., and Orange and Rockland Utilities, at 18 (April 10, 2008).

Cost Test is satisfied."[16] Accordingly, while the Commission should consider cost in evaluating energy efficiency programs, it should bear in mind that an entity's forecast of implementation costs should not be dispositive. The Commission should also take into such factors as the likelihood that the administrator will achieve its goals. As the Companies have previously pointed out, they are well-suited to provide cost-effective programs to their customers and should be the preferred administrators for their service territories because NYSERDA has been unable to penetrate their markets.

II. Review of Different Models and Range of Incentives

The Notice generally describes three models and provides that parties should comment on which model they favor. The Companies generally favor the California model because, as stated by Mr. Meehan, it reflects the principle that utilities should receive a return on the benefits produced by energy efficiency investment that is equivalent to their supply side return (the one difference, as explained by Mr. Meehan, is that he would calculate net resource benefits using program costs only, and not the measure cost, in order to encourage cost effective programs). This principle is consistent with the Energy Policy Act of 1992, which requires state utility regulatory commissions to consider the following standard:

> The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures are at least as profitable, giving appropriate consideration to income lost from reduced sales due to investments in and expenditures for conservation and efficiency, as its

[16] Case 06-G-1332 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service, 2008 Gas Collaborative Report at 9, filed with the Commission on April 15, 2008

> investments in and expenditures for construction of new generation, transmission, and distribution equipment.

16 U.S.C. § 2621(d) (8); *see also* 15 U.S.C. § 3203(b) (4). This principle is also supported by the Lawrence Berkeley National Laboratory report on energy efficiency incentives: "The primary analytic issue is determining earnings comparable to those that would have been earned through the acquisition of resources in lieu of DSM."[17]

In developing its model, the California Public Utilities Commission ("CPUC") adopted this principle. The CPUC stated that energy efficiency incentives should be substantial so that: "all levels of management and personnel throughout the company, and not just within the energy efficiency division, need to be motivated to view energy efficiency as a core business activity in order to achieve the aggressive energy efficiency and environmental goals of the state." It should be noted that the current California overall goals are much less aggressive than New York State's goals. California's goal is that "55 percent to 59 percent of the utilities' incremental electric energy needs between 2004 and 2013 will be met through energy efficiency," CPUC Decision 07-09-043, p. 26, while New York is seeking more than 100% of incremental electric energy needs.

As discussed above, the Companies do not believe that the Commission needs to adopt the specifics of the particular model at this time. It only needs to adopt the principle that energy efficiency incentives are important, that supply side equivalency should be the guiding principle, and that the incentive should be based on a percentage of net resource benefits. As discussed by Mr. Meehan's affidavit, a reasonable percentage level is on the order of 10%. First, at the 10 % level, customers still retain the lion's share of

---

[17] S. Stoft, J. Eto and S. Kit, DSM Shareholder Incentives: Current Designs and Economic Theory, p. 22 (Energy & Environment Division, Lawrence Berkeley Laboratory, University of California, Berkeley, January 1995).

benefits (90%). Second, 10% provides a meaningful incentive to maximize the difference between net resource benefits and program costs. He also notes that the 10% sharing level is a level that the Commission has used in the past related to incentives with respect to fuel and purchased costs and imputed sale for resale revenues. The Commission would set targets for these items and have a 90/10 sharing for deviations within a range of achieved outcomes.

CONCLUSION

Based upon the foregoing, the Companies request that the Commission adopt the energy efficiency incentive principles proposed herein.

Dated: New York, New York
June 19, 2008

Respectfully submitted,

Consolidated Edison Company
of New York, Inc., and
Orange and Rockland Utilities, Inc.

By ~~their~~ Attorney

Richard B. Miller, Esq.
4 Irving Place, Room 1815-S
New York, New York 10003
(212) 460-3389

BEFORE THE
STATE OF NEW YORK PUBLIC SERVICE COMMISSION

Case 07-M-0548 - Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard

AFFIDAVIT OF
EUGENE MEEHAN

Mr. Eugene Meehan declares:

1. I have personal knowledge of the facts and opinions herein and if called to testify could and would testify competently hereto.

I. Qualifications

2. I am a Senior Vice President with NERA Economic Consulting and have over thirty years of experience consulting with electric and gas utilities and have testified as an expert witness before numerous state and federal regulatory agencies, and in federal court and arbitration proceedings.
3. My consulting practice at NERA focuses on the areas of electricity tariff design, electricity procurement, wholesale power market design, electricity costing and pricing, regulatory economics, market power analysis and mitigation, power contract analysis, and power cost risk management.
4. I have worked extensively on the development of the power sector in New York State. I have provided consulting services for members of the New York Power Pool, and its successor the NY-ISO, on a continuous basis since 1980. This has involved advising the Pool and its members on production cost modeling, transmission

expansion, competitive bidding and reliability and marginal generating capacity cost quantification. In 1987, I prepared and sponsored the New York Power Pool's position paper on competitive bidding for IPP supplies.

5. I have provided testimony on behalf of the New York State investor-owned electric utilities concerning the proper methodology to use when analyzing the cost-effectiveness of conservation programs.
6. In 2006, I was retained by EEI to examine impediments to cost-effective and successful use of energy efficiency and demand response in electric systems and to examine potential methods for removing those impediments and providing incentives to utilities to promote demand response. As part of that effort I prepared a report on incentives.
7. I have recently completed work with the NY-ISO on the reset of the demand curve and I am currently working with the NY-ISO on forward capacity market issues.
8. I have testified before this Commission on numerous occasions, including as mentioned above an appearance regarding conservation cost-effectiveness methodology in PSC Case No. 28223.
9. My Curriculum Vitae is attached as Exhibit A hereto.

II. Purpose of this Affidavit

10. This affidavit provides my research and analysis on the need for and structure of financial incentives for utilities implementing demand response and energy efficiency programs. My opinion responds to certain issues raised by the New York Public

Service Commission ("the Commission") in its May 30, 2008 "Notice Soliciting Comments" issued in the above-captioned docket.[1]

11. I have been asked by the Consolidated Edison Company and Orange & Rockland Utilities (jointly referred to as "the Companies"") to address the following questions:

a. What incentive mechanisms have been implemented by other states?

b. Are financial incentives for utilities appropriate when demand response and energy efficiency programs are pursued?

c. Are there differences in the nature of and need for incentives for demand response and energy efficiency as compared to other initiatives where the utility may be provided an incentive (e.g., service quality)?

d. Are financial penalties appropriate in the context of demand response and energy efficiency initiatives?

e. Are there potential negative financial impacts to utilities associated with a large scale demand response and energy efficiency program?

f. Are the three models under consideration by the Commission (i.e., the Trial Staff Model, the California Model, and the Advisory Staff Incentive Guidelines) likely to be successful in providing an appropriate set of incentives for utility involvement in energy efficiency programs?

g. After considering the answers to the above questions, what recommendations would I make to the Commission with respect to incentive program design elements and incentive parameters, including any recommendation as to a cap on incentives, in order to meet the goals of the program?

12. The remainder of my affidavit is structured as follows. In Section III, I present a summary of my findings and conclusions. In Section IV, I address in detail questions a though f outlined above. In Section V, I present recommendations for incentive program design.

III. Findings and Conclusions

13. My research and analysis of the issues has led me to the following conclusions:

[1] Note that the scope of the docket is "Energy Efficiency," but the incentive principles and design elements addressed in my affidavit also apply to demand response programs.

a. Financial incentives for utilities are essential to assure successful demand response and energy efficiency programs. If utilities are to play the important role that they are uniquely qualified to play in encouraging the deployment of efficiency resources, it is essential that they have an opportunity to earn a return for their efforts to promote the efficient development and use of such resources. Utilities naturally face obstacles to demand response and energy efficiency that must be countered through means including but not limited to direct incentive programs.[2] Incentive programs are well accepted and utilized in many jurisdictions.

b. Financial penalties for failure to meet demand response and energy efficiency performance targets may be appropriate, but need to be developed considering the uncertain nature of the targets. Further, it needs to be recognized that utility management does not have complete control over the success of these programs.

c. The demand response and energy efficiency programs under consideration by the Companies and the other New York IOUs are large-scale programs that may have negative financial implications for utility investors. The unprecedented scale of these programs merits special consideration when financial incentives are considered. For these reasons, the incentives must be meaningful in order to induce maximum utility performance.

d. Incentives should be determined based on a sharing of net resource benefits. Net resource benefits are appropriately defined as the present value of the

[2] For example, incentives do not replace the need to provide for lost revenue recovery, but should be incremental to such mechanisms which remove disincentives.

estimated avoided costs, including energy and capacity costs, over the service lives of DSM measures installed each year pursuant to DSM programs, less DSM program costs (i.e., customer incentives, marketing, customer outreach, labor, mailing, measurement & verification, etc.) associated with the installation of these measures. This incentive, which shares net resource benefits, will induce the Companies to design and implement the most cost-effective programs.

e. While a cap on incentives should not be necessary, if a cap is adopted it should not be set at a level so low that the negative financial impacts from the large scale energy efficiency program are left unmitigated. Further, the cap should not be set either directly or indirectly based on program costs. The percentage that incentives comprise relative to program costs should not weigh on the Commission's decision on the incentive level or a cap. The most successful efficiency programs may well be those where participation levels and resource savings are high while program costs are low and the incentive would be a high percentage of program costs. Further, the cap should not be set in a way where there is a good chance it will be reached, as this will effectively eliminate the incentive for maximum performance as incentives earned in excess of the cap will not accrue to the shareholder.

f. The primary feature of a well-developed incentive program is that a utility that achieves a high percentage of energy efficiency or peak reduction targets should be able to retain a non-trivial portion (on the order of ten percent – given current economics) of the net resource benefits.

14. My conclusions and recommendation with respect to incentives conflict with Staff on only two major issues, but these issues are very important. I highlight these issues here for Commission consideration.

   a. First, Staff is focused on an incorrect metric, which is the incentive as a percent of program costs. That metric, which Staff recommends be set at a maximum of 12% of program costs, is irrelevant and even worse provides the wrong incentives. The more expensive the program, the higher the available incentive and this is true even when the metric is used only as an incentive cap that is set *ex ante* on a basis-point basis using expected program costs. The utility is provided an incentive to maximize program costs. If instead the incentive is developed as a percentage of net resource benefits, utilities will have two clear incentives. The first is to focus on the most cost beneficial use of customer-provided energy efficiency funding in order to achieve the greatest savings per dollar spent.[3] The second is to design programs so that participants, who are the chief direct beneficiaries, fund as much of the implementation cost as is possible, from their bill savings, within the constraint of achieving the target volume. This will increase sustainability as it will result in lower non participant rate impacts, which is desirable so long as targets can be reached. The abandonment of many conservation programs in the early 1990s is evidence that this issue is not academic. It would be

[3] While this is generally true, I am not taking issue with Staff's position that it may also be desirable to prioritize less cost effective programs such as residential weatherization because of other factors such as job creation, benefits to lower income households and market transformation measures. To the extent that is the case, incentives tied to achieving those objectives should be developed and should be incremental to the primary incentive to achieve the most cost effective energy efficiency. The same principle would apply to market transformation programs, although it is my understanding that most of such programs would be administered by NYSERDA.

foolish to ignore the lessons of such recent history. There will be times in the future as there were in the past where the pendulum of concern swings from environmental and resource concerns to price level concerns and a well-designed energy efficiency program should be able to survive those swings. Sustainability is critical not only economically, but from a reliability perspective. If generation investors perceive that there is a commitment to achieve the 15% energy usage reduction by 2015 ("15 by 15") and if this assumption is incorporated into the NY-ISO's reliability needs assessment, the market will adjust its building plans and only build to the lower expected demand level. At the same time, the NY-ISO's reliability need assessment will show adequate resources at the level because it will assume the success of the 15 by 15 program. If the energy efficiency programs turn out not to be sustainable and the goal cannot be achieved or sustained, there will be reliability issues related to inadequate installed capacity levels.

b. The second major issue where I disagree with Staff concerns incentive levels. It is unrealistic to believe that a large scale energy efficiency objective on the order of 15 by 15 can be achieved with incentives limited to low double digit basis point adders or to single-digit to low-double digit percentages of program costs. Utilities face the potential of significant negative consequences from the programs, including the slowing of rate base investment opportunities and business risks from increased price levels. Properly designed energy efficiency incentives should materially mitigate these impacts and make demand side expenditures as profitable as supply-side investments. This is a not a trivial endeavor. The Energy Policy Act of 1992 recognizes the need for material incentives that allow utilities returns comparable to what they would earn on supply-side investments:

> The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency, and other demand side management measures are at least as profitable, giving appropriate consideration to income lost from reduced sales due to investments in and expenditures for conservation and efficiency, as its investments in and expenditures for construction of new generation, transmission and distribution equipment.[4]

The California Public Utilities Commission ("CPUC") quotes this principle in its order addressing incentives and has indeed set the cap for incentives considering the foregone equity return on the investments that are deferred by energy efficiency programs.

In my opinion, Staff is missing the bigger picture with respect to incentive levels and caps and seems to be more focused on minimizing incentive payments than on creating a win - win situation, achieving objectives and setting the base for a sustainable energy efficiency future. This does not mean that it is necessarily inappropriate to cap earned incentives, and I address the issue of a cap later in this affidavit.

IV. Review of Questions that Provide Background as to the Appropriate Incentive Level

a. What incentive mechanisms have been implemented by other states?

[4] See 16 U.S.C. Sec. 2621(d) (8).

15. Other jurisdictions have, through regulatory and legislative initiatives for new demand response and energy efficiency programs, provided utilities with financial incentives at various levels based on various different methodologies.

16. There are three major types of performance mechanisms or incentives used to align utility financial interests and energy efficiency policy goals:

    a. Shared savings incentives: Utilities are permitted to earn and recover a performance incentive based on a share of the net economic benefits (benefits minus costs). In most cases these incentives are tied to performance relative to predetermined targets. For example, the CPUC allows for a tiered approach where a utility achieving 85% to 100% of the PUC-established energy target would receive 9% of the verified net benefits. If a utility achieves 100% or more it would receive 12% of the verified net benefits up to a pre-determined cap.
    b. Rate of return incentives: Utilities are able to earn a basis point premium on investments associated with energy efficiency programs. In other words, energy efficiency investment receives rate base/rate of return treatment plus a bonus rate of return. For example, the Kansas Corporation Commission can authorize an energy company to earn up to a 200 basis-point ROE premium on investments associated with energy efficiency programs.[5] In some cases, the rate-of-return incentive has applied to the full rate base.
    c. Incentives based on a share of program budgets: Utilities are allowed to earn an incentive up to a cap at a fixed percentage of the DSM program costs. This is being done in Massachusetts, Arizona, and New Hampshire.

17. Exhibit B provides a summary table of states reported by Regulatory Research Associates to have energy efficiency programs and also provides details on the financial incentives chosen by these states. As can be seen, the use of a utility incentive mechanism is a consistent with prevailing regulatory practice in many jurisdictions.

18. Of particular relevance to this proceeding is the experience in California with respect to the definition of utility financial incentives for demand response and energy

[5] Note, however, that according to the Kansas Corporation Commission there have not yet been energy efficiency programs implemented or investments made that allow an energy company to earn this ROE premium.

efficiency. The California Public Utilities Commission opened Docket 06-04-010 in order to examine the appropriate level of incentives. After a series of workshops, filings and hearings in which the CPUC gathered stakeholder opinion, the CPUC reached the following findings in Order 07-09-043 in support of its utility incentive mechanisms:

a. Positive financial incentives produce a "win-win" alignment of ratepayer and shareholder interests in achieving least-cost, integrated resource planning objectives. (pp. 60-61)
b. There are disincentives to DSM created by both regulation and the private profit-making nature of the firm that limit utility shareholders and management's interest in pursuing all practicable, cost-effective and reliable DSM. (p.61)
c. Under current regulatory practices, utilities only earn on supply-side investments absent energy efficiency incentives. (p.186)
d. Cost-effective energy efficiency investments will increase rates in the short-term, even though it will minimize revenue requirements and customer bills over time. (p. 200)
e. Without an energy efficiency incentive, given the focus of investors and utility management on increasing shareholder value, utilities will on balance be more inclined to devote scarce resources to procurements on which they will earn a return, and not on meeting or exceeding the Commission's energy efficiency goals, or maximizing ratepayer net benefits in the process. (p. 67)
f. Regulatory mandates and rate of return penalties do not create potential "win-win" situations for shareholders and ratepayers. Rather they create a "ratepayers win or else shareholders lose" approach to DSM regulation. (p. 61)

19. The CPUC approved a financial incentive whose level was set taking into consideration supply-side ROE equivalence as one of the benchmark parameters to evaluate the sufficiency and reasonableness of the incentive mechanisms for California's energy efficiency programs.

20. The CPUC determined it appropriate to "continue to endorse the yardstick we set in D.03-10-057 that the earnings levels we establish under a shared-savings mechanism should be compared to 'how much ratepayers would have had to pay if the program savings had not been realized.'" (p. 43)

b. Are financial incentives for utilities appropriate when demand response and energy efficiency programs are pursued?

21. Yes. Financial incentives are essential to assure the success of demand response and energy efficiency initiatives. The experience in other states cited above demonstrates that there is broad recognition of the need to offer incentives to utilities and many incentive programs have been put in place.

22. In 2006, NERA was retained by EEI to examine impediments to the cost-effective and successful use of distributed resources in electric systems. Distributed resources include demand response and energy efficiency, as well as distributed generation. In connection with this assignment, I prepared a report addressing the rationale for incentives for both customers and the utility to take advantage of demand response and energy efficiency opportunities. The report explains that the current regulatory and ratemaking framework in which most utilities operate provides an impediment to efficient implementation of demand response and energy efficiency programs. Further, promoting demand response requires incentives in order to induce management to devote time to such programs and to overcome business risks. Financial incentives help to solve this problem by aligning the interests of the utility with the objective of achieving energy efficiency gains.

c. Are there differences in the nature of and need for incentives for demand-side management and energy efficiency as compared to other initiatives where the utility may be provided an incentive (e.g., service quality)?

23. Yes, the nature of and need for incentives is different for demand-side management and energy efficiency as compared to other areas of utility regulation.

24. Incentives are used in many other aspects of utility regulation.[6] For example, distribution utilities may be eligible for incentives with respect to service quality. Distribution utilities exercise direct control over service quality and consequently setting incentives for performance and penalties for non-performance can be effective. Similarly, a utility with rate-based generation may be subject to incentives with respect to plant availability – a factor over which the utility would exercise direct control. Another example is performance-based ratemaking ("PBR"). There are numerous examples in the U.S. and worldwide of PBR that rely on incentives for utilities to reduce costs over which they have control.

25. Achieving high levels of performance under demand response and energy efficiency programs is different from improving service quality, increasing plant availability, or reducing costs that are subject to PBR. Performance under demand response and energy efficiency programs depends in large part on customer behavior and is not solely under the control of the utility. Further, as I explain below, the target carries great uncertainty as to whether it is achievable and incentives need to account for this uncertainty.

d. Are financial penalties appropriate in the context of demand response and energy efficiency initiatives?

26. Generally speaking, incentives can be balanced by penalties when the objective is to reach a target or desired level of performance. It is equitable if an incentive is provided for achieving a target that a penalty applies for not achieving the target, if it is reasonably clear that the target should be achievable by diligent management with the resources that will be permitted to be reflected in rates and if achieving the target

---

[6] See http://tisiphone.mit.edu/RePEc/mee/wpaper/2005-014.pdf. "Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks", Paul L. Joskow, September 15, 2005.

is part of the regulated entity's core responsibility. Hence, the use of penalties has appeal in principle and a service quality target with a penalty and incentive could be appropriate. In practice, however, penalties related to the performance of a demand response or energy efficiency program must be very carefully considered. Two important factors could frustrate the use of this type of penalty:

a. Uncertainty surrounding the reasonableness of the target; and

b. Limits on the ability of the utility to control customer behavior.

27. A target performance level for a demand response or energy efficiency program is by nature uncertain, and is in some cases arbitrary. The degree of uncertainty needs to be considered when determining whether a penalty is appropriate. While a penalty may be appropriate, it should only trigger at a level that that does not presume accuracy of the target. This principle is symmetric. The enhanced level of financial incentives for utilities, i.e., an extra incentive above the normal incentive for superior performance, should also be set at levels that recognize the uncertainty of the target. In other words, the enhanced incentive would only be triggered as a result of utility performance far above the target. In this way both the penalty and enhanced incentive will not be triggered by the inherent inaccuracy of the target.

28. A utility does not have complete control over the effectiveness of the demand response or energy efficiency programs it operates. The success or failure of the program may depend on decisions made by customers, or may even depend on economic conditions that the utility cannot control. Hence, the incentive regime should be designed with this in mind and should not penalize the utility for elements that are beyond its control. Penalties work most effectively when the utility has

control of the outcome. Whatever level the penalty is set at, the utility should be provided with the opportunity to explain why a penalty is not appropriate due to certain conditions. Even when a utility is proposing its own target level, there will be uncertainty over whether that level can be achieved.

29. Further as discussed above, a penalty is an appropriate companion to an incentive when the activity is a core part of the utility's business. A utility is clearly expected to provide adequate service and hence establishing a service quality target and implementing penalties and incentives, especially as part of longer term rate plans, is appropriate. Energy efficiency is not a core of a distribution utility's activity and in fact has negative business implications. Part of the role of incentives is to induce the utility to actively promote energy efficiency despite these negative business implications. Hence, there is a good case that a penalty is neither needed nor appropriate and that should a penalty apply, it should become effective only well below the target level.

e. Are there potential negative financial impacts to utilities associated with a large scale demand response and energy efficiency program?

30. While utilities are evidencing enthusiasm for energy efficiency and demand response, the reality is that energy efficiency and demand response can also undermine their financial performance.

31. In its Order Instituting this Proceeding on Energy Efficiency Portfolio Standards ("EEPS"), the Commission found "that realizing the State's energy efficiency potential and reducing New York's electricity usage 15% from expected levels by 2015 are in the public interest."[7] The Commission further explained:

[7] Case 07-M-0548 (issued May 16, 2007), p. 2.

> The benefits of energy efficiency include forestalling the building of new generation, reducing use of finite fossil fuels, reducing customers' energy bills, developing independent energy sources for New York State to reduce energy imports, and mitigating the environmental impacts of burning fossil fuel for energy, including greenhouse gas emissions.

New York has set ambitious and aggressive goals for its energy efficiency initiative with its 2015 15% energy reduction target.

32. Opportunities for growth and investment in new infrastructure are a key consideration of equity investors in New York State's utilities. Demand response and energy efficiency programs of the scale anticipated could eliminate the short-term prospects for growth and lead to diminished investment opportunities in the long-term. The consequences of having little or no growth opportunities could be significant and introduce new risks to attracting capital to the business.

33. Large scale energy efficiency projects will also increase prices in the short run although there may be a long-run reduction in customer bills. Higher prices increase business risk and investors will be less willing to invest in utilities with very high price levels.

34. The impacts on utility investors of large-scale demand response and energy efficiency can only be mitigated through meaningful incentives that provide an alternative route to earnings growth. Meaningful incentives are the foundation for a sustainable program that will attract the interest and energy of utility management. Meaningful incentives, nevertheless, need to be funded through rates.

35. The EPAct of 1992 sets up the use of supply-side equivalence with respect to utility returns. ConEdison currently states that it has deferred over $1 billion in transmission and distribution ("T&D") infrastructure investment as a result of its

proposed 500 MW program that will achieve only a portion of the EEPS goal. I have performed a series of simple calculations to determine what the order of magnitude impact of the deferral of these investments would be on ConEdison's shareholders. These calculations are shown in Exhibit C. In developing Exhibit C, I have employed the methodology used by California to establish the incentive cap.

36. The first calculation I performed examined what the net-present-value impact would be on ConEdison's total earnings from deferring the investment for five years. I calculate that the net present value of earnings lost as a result of deferring these T&D investments is in the range of $108 million. However, this assumes that after five years all investments that were deferred are required. In practice, so long as the demand reduction persists there would be ongoing deferrals, with the first set of deferred projects required as a result of load growth, but other projects deferred in their place.

37. The second calculation I performed was with respect to an ongoing deferral of $1 billion. This would reduce the present value of utility earnings by $239 million over 20 years or approximately $250 million in perpetuity. This latter scenario is more realistic as it would make little sense to implement energy efficiency programs that did not persist.

38. As previously discussed, it is widely accepted that utility earnings should not be disadvantaged from promoting energy efficiency. This precept is in line with revenue decoupling which is to effect neutrality in terms of revenues so the utility is not disadvantaged. These calculations provide a range of indicators for what the supply-side equivalent return would be. Hence, these measures can be used to

provide guidance in defining the parameters of the incentive program, including the level of any cap on incentives. The objective of the examination of incentives, in my opinion, is for the Commission to be in a position to go beyond eliminating the first order business disadvantages of energy efficiency such as lost revenue and to provide a framework for affirmative encouragement for the pursuit of energy efficiency.

f. Are the three models under consideration by the Commission (i.e., the Trial Staff Model, the California Model, and the Advisory Staff Incentive Guidelines) likely to be successful in providing an appropriate set of incentives or utility involvement in energy efficiency programs?

39. I will address each model in turn. First, let me address the Trial Staff Model. This model cannot be expected to be successful in providing an appropriate set of incentives or utility involvement in energy efficiency programs for two reasons.

a. The Trial Staff Model relies on an incentive based on a percent-of-program-costs metric. As I have noted previously, that metric provides the wrong incentives by encouraging expensive programs without regard for cost-effectiveness. As I have explained, an incentive that is defined with respect to net resource benefits will provide superior incentives to the utility to pursue cost-effective and sustainable energy efficiency programs.

b. Trial Staff have also considered a level of incentive that is capped at 12 percent of program costs. An incentive of this order-of-magnitude is not sufficient to meet the criteria of being meaningful and therefore will not stimulate the utility to achieve a conservation culture or develop and sustain the energy efficiency programs over the long term. This is the case because 12 % of program costs are well below the negative financial impact and would not meet a materiality threshold[8] and as such are not sufficient to mitigate the negative financial impact on the utility and are not consistent with the direction provided by the National Energy Policy Act.

40. Let me now turn to the California model, which works as follows:

a. The CPUC measures the performance of its energy efficiency programs in terms of the net dollar benefit to ratepayers, where the net dollar benefit is defined to be resource benefits minus costs. Resource benefits are quantified using a traditional avoided cost approach. As noted previously the utilities are allowed to retain between nine and twelve percent of net resource savings, depending on performance.

b. The CPUC defines a minimum performance standard, which if met, triggers the payments of financial incentives to the utilities. If the minimum performance standard is not met, the utilities do not receive financial incentives. The Commission should carefully consider and perhaps defer adopting this aspect of the policy in New York given that the utilities will be resuming administration of energy efficiency programs after a hiatus due to the Commission's 1998 decision that they should not be involved.[9]

c. Further, the utilities have committed to a "cost-effectiveness guarantee." Penalties apply when the resource savings fall short of covering the program costs, thereby making the return to ratepayers negative. If the program is not

---

[8] The Commission has considered materiality with respect to earnings to be triggered at a level of five percent of earnings. For example, if a utility files for deferral because of an extraordinary, unexpected expense, one of the pre-requisites is that the expense has to be "material," or 5% of net income. Incentives at 12% of program costs would be substantially lower than 5% of net income.

[9] Given that every MWh achieved by a utility will produce net resource benefits, economic theory would indicate that a utility should be able to earn an incentive for each MWh achieved. A minimum performance target ignores that if a utility is only able to achieve a small amount of energy efficiency, then it would achieve a small incentive.

cost effective, the utility compensates ratepayers at a level equivalent to the negative return, thereby protecting ratepayers from losses associated with utility energy efficiency programs.

d. There is a "deadband" where the utility neither receives incentives nor pays penalties. The deadband range is from zero net benefits to the minimum net benefit program performance standard, as established by the CPUC.

e. Further, the CPUC caps the amount of financial incentives that the utilities may receive and also caps the penalties that they may face. The cap for the three-year Phase 1 cycle is $450 million for the four investor-owned utilities, which applies both to incentive payments and penalties. This $450 million was deemed by the CPUC to be a conservative estimate of the supply side return that would have been earned by the utilities if they had invested in the infrastructure that would have been needed but for the state's demand response and energy efficiency programs.

41. Because the CPUC has defined incentives using a better metric – i.e., percentage of net resource savings (although I modified the metric to calculate net resource savings using program costs only) – and the CPUC has included meaningful incentives (considering supply-side equivalency in setting the cap), I believe that the California model is likely to be successful in achieving active utility participation in demand response and energy efficiency programs and a set of sustainable long-term programs that work.

42. To put the policy choices of the CPUC in context for New York State, I have estimated what the permitted level of incentive and cap on that incentive would be using Con Edison data for a 500 MW program to develop the example:

   a. I calculate that a level of incentive based on nine to twelve percent of expected net resource savings would yield dollar incentives for Con Edison of $149 million to $198 million. I base this calculation on the estimated $4,056.65 per kW of net resource savings cited by ConEdison in its last rate case and estimated program costs of $ 750 per KW based on data provided by Con Edison in that rate case.

   b. If a cap were calculated for Con Edison using the California methodology of supply-side equivalence, that cap would be $250 million assuming a program size of 500 MW and the rolling deferral of $1 billion in T&D investment. If avoided generation investments were considered as they are in California, the cap would be substantially higher.

43. Next, I provide my comments on the Advisory Staff Incentive Guidelines set forth in the Commission Notice for Soliciting Comments issued on May 30, 2008 in Case 07-M-0548 . Advisory Staff identified the following as the program incentive goals:

   a. The overall objectives of performance incentives in the context of energy efficiency are: (1) Encourage superior performance and deter weak performance; and (2) align utilities' financial interests with energy efficiency as a resource option.
   b. The maximum amount of money available to utility stockholders from an energy efficiency incentive should account for the size of the utility program portfolio target relative to the jurisdictional goal for the utility's service territory, and should encourage improved utility performance without placing an excessive burden on ratepayers.
   c. The formula by which a maximum monetary incentive and intermediate monetary incentives and disincentives are calculated should not induce

utilities to increase program costs artificially or to manipulate the program design and implementation inappropriately.

d. The incentive formula should provide for both positive and negative revenue adjustments.
e. The effectiveness of a utility's energy efficiency program portfolio, based on measurement and verification results, should be the basis for determining revenue adjustments.
f. The utility must achieve a high percentage of its target before realizing a positive revenue adjustment tied to performance.
g. The primary gauge for determining the effectiveness of a utility's energy efficiency program portfolio should focus on verified MWH savings. For programs that are approved with a specific peak reduction target, the primary gauge should be MW savings.
h. Incentives should be calculated over aggregated portfolio performance rather than by specific programs; however, a mechanism must be in place to assure that individual program targets are not sacrificed to maximize incentives.
i. Incentives would not be available for programs in which a utility transfers funds from ratepayers to NYSERDA (this principle would not preclude a utility from obtaining incentives for a program that it undertakes that was previously conducted by NYSERDA with ratepayer funds transferred by the utility).
j. Consistent statewide incentive principles based upon overall program performance are necessary for ease of administration and to prevent confusion among potential market participants.
k. Incentives (assuming performance at 100% of the utility's proposed program target) must be included in the cost estimates of program proposals.

44. These core Advisory Staff guidelines are generally reasonable principles (I note that the Companies are filing additional comments on the specifics of each principle, some of which I have not considered and do not specifically address), although as previously stated the Commission should move cautiously if at all to include penalties. In addition, Advisory Staff provides an illustration of their model, which is similar to the California Model in one aspect insofar as the level of incentive or penalty depends on the percentage of the proposed performance target achieved by the utility. However, this Advisory Staff model calls for the incentive level to be

based on a percentage of program costs,[10] which as I stated earlier is not an appropriate metric for setting the level of utility incentive. The failure to tie the incentive level to net resource benefits is a major shortcoming of the Advisory Staff model. I therefore believe that, while Advisory Staff's core guidelines are reasonable as they relate to incentives, Advisory Staff errs in tying the level of incentives to a percentage of the program costs rather than to a percentage of the net resource benefits.

V. Recommendation for Financial Incentives

45. I briefly summarize here my four key policy recommendations with respect to financial incentives for demand response and energy efficiency:

(1) I recommend that the Commission reject Staff's proposal to set the financial incentive levels and the incentive cap as a function of the program costs. This will lead to the wrong incentives and will not encourage efficient demand response and energy efficiency.

(2) I recommend that the Commission adopt an incentive mechanism that is calculated as a percentage of net resource benefits. This metric will minimize market distortion and encourage efficient demand response and energy efficiency. I believe that a reasonable percentage level is on the order of ten percent (a higher percentage would be appropriate if a utility exceeded its target). I select ten percent for several reasons.

[10] The discussion of the Advisory Staff model in the Commission Notice for Soliciting Comments states: "A percentage of the statewide program costs would be derived and then expressed in terms of return on equity basis points. The incentive level for all New York State utilities would then be set in advance at that basis point level and would therefore be independent of the program cost projections submitted by utilities." This linking to program costs, and not net resource savings, is inappropriate.

First, at the ten-percent level, customers still retain the lion's share of benefits (ninety percent). Second, ten percent provides a meaningful incentive to maximize the difference between net resource benefits and program costs. For example, an incentive of ten percent over a 500 MW program would provide Con Edison with potential incentive of $165 million over the five years it would take to implement the program, which is equal to $ 33 million per year. Assuming a $10 billion rate base that is 45% equity with a 10 percent return, earnings would be $450 million per year. The five percent materiality threshold would result in an incentive of $ 22.5 million per year. Hence this incentive level meets the materiality threshold. Further, Con Edison's rate base balances are expected to grow to over $15 billion at which a 500 MW program with a ten-percent incentive level would just meet the materiality threshold. Third, the ten percent sharing level is a level that the Commission has used in the past related to incentives with respect to fuel and purchased costs and imputed sale for resale revenues. The Commission would set targets for these items and have a 90/10 sharing for deviations within a range of achieved outcomes.

(3) There is concern expressed by Staff that a cap is needed on the level of earned incentives. So long as the incentives are tied to net resource benefits and to achieving target levels that are based on widespread participation, I do not see the need for a cap. However, were a cap to be set, I believe that the Commission could look to California. California

has set the cap so that the cap does not exceed the total equity earnings that customers would contribute if the energy efficiency and capital deferral had not occurred. For the Con Edison 500 megawatt program, this would equate to a cap of $250 million considering only transmission and distribution investment and more if avoided generation investment was considered. Were the Company to target and achieve more than 500 MW in demand reduction, the cap would be correspondingly higher.

(4) Financial incentives should be considered to be a supplement to a decoupling mechanism, which makes utilities whole for the loss in revenues but does not provide them with an incentive to pursue energy efficiency.

This concludes my affidavit.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 07-M-0548 – Proceeding on Motion of the Commission Regarding An Energy Efficiency Portfolio Standard

Executed on June 19, 2008

Eugene Thomas Meehan

Eugene T. Meehan

SS. District of Columbia

The foregoing instrument was subscribed and sworn before me this 19th day of June, 2008 by Eugene T. Meehan.

Rosalind Brown, Notary Public
My Commission Expires: November 14, 2009

Rosalind Brown
Notary Public, District of Columbia
My Commission Expires 11-14-09

NERA
Economic Consulting

Eugene T. Meehan
Senior Vice President

National Economic Research Associates, Inc.
1255 23rd Street NW
Washington, DC 20037
+1 202 466 3510 Fax +1 202 466 3605
Direct dial: +1 202 466 9287
gene.meehan@nera.com
www.nera.com

EXHIBIT A:
EUGENE T. MEEHAN
SENIOR VICE PRESIDENT

Mr. Meehan is a Senior Vice President at NERA. He has over thirty years of experience consulting with electric and gas utilities and has testified as an expert witness before numerous state and federal regulatory agencies, as well as appeared in federal court and arbitration proceedings.

At NERA, Mr. Meehan's practice concentrates on serving energy industry clients, with a focus on helping clients manage the transition from regulatory to more competitive environments. He has performed consulting assignments for over fifty large electric, gas, and combination utilities in the areas of retail access, regulatory strategy, strategic planning, financial and economic analysis, merger and acquisition advisory services, power contract analysis, market power and market definition, stranded cost analysis, power pooling, power markets and risk management, ISO and PX development, and costing and pricing. In addition, he has advised numerous utilities on power procurement issues and administered power procurements on behalf of utilities and regulators.

Mr. Meehan has experience leading NERA's advisory work on several major restructuring and unbundling assignments. These assignments were multi-year projects that involved integration of regulatory and business strategy, as well as development of regulatory filings associated with the recovery of stranded cost and rate unbundling.

Education

Boston College, BA, Economics, *cum laude*
New York University (NYU), Graduate School of Business, completed core courses for the doctoral program.

Professional Experience

	NERA Economic Consulting
1999-	Senior Vice President
1996-1999	Vice President
1973-1980	Senior Economic Analyst; Research Assistant
	Deloitte & Touche Consulting Group
1994-1996	Principal
	Energy Management Associates, Inc.
1980-1994	Vice President

Areas of Expertise

Restructuring/Stranded Cost Recovery

Mr. Meehan has directed several multi-year projects associated with restructuring and stranded cost recovery. These projects involved facilitating the development of an integrated regulatory and business strategy and formulating regulatory filings to accomplish strategy. As part of these assignments, Mr. Meehan facilitated sessions with senior management to set and track filing strategy. Clients include Public Service Gas & Electric and Baltimore Gas and Electric.

Unbundling/Generation Pricing

Mr. Meehan has formulated unbundling strategies, with a specialization in generation pricing. He has advised several utilities in standard offer pricing and has testified on shopping credits on behalf of First Energy and Baltimore Gas and Electric.

Power Procurement

Mr. Meehan has been involved in power procurement activities for a variety of utilities and regulatory agencies. He has advised utilities in developing and implementing evaluation processes for new generation, with the objective of achieving the best portfolio evaluation. He has helped regulators in Ireland and Canada design and implement portfolio evaluation processes. He has testified before FERC and state regulatory agencies on competitive power procurement. In addition, Mr. Meehan helped to design and implement the New Jersey BGS auction process.

Power Contracts

Mr. Meehan has extensive experience with power contracts and power contract issues. He has reviewed and testified on the three principal types of power contracts: integrated utility to integrated utility contracts, IPP to utility contract, and integrated or wholesale utility to distribution utility contracts. He has testified in power contracts disputes on behalf of Carolina Power and Light, Duke Power Company, Southern Company, Orange and Rockland Utilities, and Tucson Electric Power. He has also advised Oglethorpe Power Corporation in the reform of its wholesale contracts with its distributor cooperative members.

Retail and Wholesale Settlements

In addition to his expertise on power pooling issues, Mr. Meehan has significant experience with assignments related to the settlement process. He has focused on the issues of credit management as new entrants appear in retail and wholesale markets and has designed efficient specifications for retail settlement systems, including the use of load profiling, and examined the risk and cost allocation issues of alternative settlement systems.

Risk Management

Mr. Meehan has advised several large utilities on price risk management. These assignments have included evaluation of price management service offers solicited from power marketers in association with management of assets and entitlements, as well as provision of price managed service for various terms.

Marginal Costs

Mr. Meehan has provided comprehensive marginal cost analyses for over 25 North American Utilities. These assignments required detailed knowledge of utility operations and planning.

Power Supply and Transmission Planning

Mr. Meehan has advised electric utilities on economic evaluations of generation and transmission expansion. He has testified on the economics of particular investments, the prudence of planning processes, and the prudence of particular investment decisions.

Generation Strategy

Mr. Meehan has led NERA efforts on a client task force charged with developing an integrated generation asset/power marketing strategy.

Power Pooling

Mr. Meehan has in-depth working knowledge of the operating, accounting, and settlement processes of all United States power pools and representative international power pools. He has provided consulting services for New York Power Pool members on a continuous basis since

1980, advising the Pool and its members on production cost modeling, transmission expansion, competitive bidding and reliability, and marginal generating capacity cost quantification. In NEPOOL, he has quantified the benefits of continued utility membership in the Pool and the impact of the Pool settlement process on marginal cost. He has worked with a major PJM utility to explore the impact of PJM restructuring proposals upon generating asset valuation and examine the implications of alternative restructuring proposals. He has consulted for Central and Southwest Corporation, Entergy, and Southern Company on issues that involved the internal pooling arrangements of the utility operating companies of those holding companies, as well as for various utilities on the impact of pooling arrangements on strategic alternatives.

Representative Assignments

Worked with Public Service Electric & Gas Company (PSE&G) to direct a three year NERA advisory effort on restructuring. Facilitated a two-day senior management meeting to set regulatory strategy in 1997. Throughout 1997 and 1998, worked over half time at PSE&G to help implement that strategy and advised on testimony preparation, cross-examination, and briefing. Also advised PSE&G on business issues related to securitization, energy settlement and credit requirements for third party suppliers. During 1999, advised PSE&G during settlement negotiations and litigation of the settlement. PSE&G achieved a restructuring outcome that involved continued ownership of generation by an affiliate and the securitization of $2.5 billion in stranded costs.

Worked on separate assignments for a large utility in the Northeast and a large utility in the Southeast, advising on the evaluation of risk management offers from power marketers. The assignments included reviewing proposals, attending interviews with marketers and providing advice on these, and the developing analytical software to evaluate offers.

Worked with government of Ontario beginning in 2004 to help design the RFP and economic evaluation process for the solicitation of 2500 Mw of new generating capacity. Supervising NERA's portfolio-based economic evaluation on behalf of the Ontario Ministry of Energy.

Testified on behalf of Pacific Gas & Electric Company before the FERC in a case benchmarking the PSA between the distribution utility and a soon-to-be-created generating company. This effort involved developing detailed expertise in applying the Edgar standard and a detailed review of DWR procurement during the western power crisis. In addition, this effort involved the review of more than 100 power contracts in the WECC.

Directed NERA's efforts, on behalf of the electricity regulator in Ireland, to design an RFP and implementation process for the purchase of 500 Mw of new generating capacity in 2003. NERA advised on the RFP, the portfolio evaluation method, and the power contract and also conducted the economic evaluation.

Reviewed the economic evaluation conducted by Southern Company Service for affiliated operating companies in connection with an RFP for over 2000 Mw of new generating capacity. Submitted testimony before FERC on behalf of Southern Company Service.

Worked with Baltimore Gas and Electric (BG&E) to conduct a one and one-half year consulting assignment that involved providing restructuring advice. The project began in March/April 1998 with senior management discussions and workshops on plan development and filing strategy. Advised BG&E in the development of testimony, rebuttal testimony, and public information dissemination. Worked to review and coordinate testimony from all witnesses and offered testimony on shopping credits and in defense of the case settlement. BG&E achieved a restructuring outcome enabling it to retain generation ownership. As part of this assignment, advised BG&E on generation valuation and unregulated generation business strategy.

Directed the efforts of a large Southeastern utility to develop a short-term power contract portfolio and to evaluate the relative value of power options, forwards, and unit contracts to determine the optimal mix of instruments to manage price risk.

Testified for XCEL Energy on the use of competitive bids for new generation needs. Examined whether XCEL was prudent not to explore a self-build plan and the reasonableness of relying on ten-year or shorter contracts as opposed to life-of-facility contracts, in order to meet needs and facilitate a possible future transition to competition. This project addressed the comparability of fixed bids to rate base plant additions.

Advised and testified on behalf of First Energy in the Ohio restructuring proceeding on the issues of generation unbundling and stranded cost. Defended the First Energy shopping credit proposal.

Advised Consolidated Edison and Northeast Utilities on merger issues and testified in Connecticut and New Hampshire merger proceedings. Testimony focused on retail competition in gas and electric commodity markets.

Directed NERA's effort to train selected representatives of a major European power company in American power marketing and risk management practices. The project involved numerous meetings and interviews with power marketing firms.

Led NERA's effort to advise the New England ISO on the development of an RTO filing. Examined performance-based ratemaking for transmission and market operator functions.

Examined ERCOT power market conditions during the period of time from 1997 to 1999 and testified on behalf of Texas New Mexico Power Company for the prudence of its power purchase activity.

Advised a Midwestern utility on restructuring of a wholesale contract with an affiliate. Involved forecasting of the unbundled wholesale cost-of-service and market prices, as well as development of a regulatory strategy for gaining approval of contract restructuring and the transfer of generation from regulated to EWG states.

Performed market price forecasts for numerous utility clients. These forecasts have employed both traditional modeling and newly developed statistical approaches.

Examined the credit issues associated with the entry of new entities into retail and wholesale settlement market. These assignments involved a review of current Pool credit procedures, examination of commodity and security trading credit requirements, coordination with financial institutions, and recommendations concerning credit exposure monitoring, credit evaluation processes, and credit requirements.

Oversight of EMA's consulting and software team in designing and implementing the LOLP capacity payment, a portion of the UK wholesale settlement system.

Advised Oglethorpe Power Corporation in the reform of its contracts with its distribution cooperative members and the evolution of full requirement power wholesale power contracts into contracts that preserve Oglethorpe's financial integrity and are suitable for a competitive environment.

Developed long run marginal and avoided costs of natural gas service, as well as avoided cost methods and procedures. These costs have been used primarily for the analysis of gas DSM opportunities. Clients include Consolidated Edison Company, Southern California Edison Company, Niagara Mohawk Power Corporation, and Elizabethtown Gas Company.

Review of power contracts and testimony in numerous power contract disputes.

Development of long run avoided costs of electricity service and avoided cost methods and procedures. These costs have been used to assess DSM and cogeneration, as well as to develop integrated resource plans. Clients include Public Service Company of Oklahoma, Central Maine Power Company, Duquesne Light Company, and the New York investor-owned utilities.

Advised Central Maine Power Company (CMP) on the development of a competitive bidding framework. This framework was implemented in 1984 and was the first of its kind in the nation. CMP adopted the framework outlined in EMA's report and won prompt regulatory approval.

Advised a utility in the development of an incentive ratemaking plan for a new nuclear facility. This assignment involved strategic analysis of alternate proposals and quantification of the financial impact of various ratemaking alternatives. Presented strategic and financial results in order to convince senior management to initiate negotiations for the incentive plan.

Advised and testified on behalf of the New York Power Pool utilities on the methodology for measuring pool marginal capacity costs. This work included development of the methodology and implementation of the system for quantifying LOLP-based marginal capacity costs.

Provided testimony on behalf of the investor-owned electric utilities in New York State, concerning the proper methodology to use when analyzing the cost-effectiveness of conservation programs. This methodology was adopted by the Commission and used as the basis for DSM evaluation in New York from 1982 through 1988.

Developed the functional design of a retail access settlement system and business processes for a major PJM combination utility. This design is being used to construct a software system and develop business procedures that will be used for retail settlements beginning January 1999.

Reviewed the power pool operating and interchange accounting procedure of the New York Power Pool, the Pennsylvania, New Jersey, Maryland Interconnection, Allegheny Power System, Southern Company, and the New England Power Pool as part of various consulting assignments and in connection with the development of production simulation software.

Summarized and analyzed the operational NEPOOL to examine the feasibility of incorporating NEPOOL interchange impacts with Central Maine and accounting procedure of the New England Power Pool Power Company's buy-back tariffs.

Developed and presented a two-day seminar delivered to electric industry participants in the UK (prior to privatization), outlining the structure and operation of power pools and bulk power market transactions in North America.

Benchmark analysis and FERC testimony of PGE's proposed twelve-year contract between PG&E and Electric Gen LLC (contract value in excess of $15 billion).

Responsible for NERA's overall efforts in advising New Jersey's Electric Distribution Companies on the structuring and conduct of the Basic Generation Service auctions (the 2002 auction involved $3.5 billion, and the 2003 and 2004 auctions involved over $4.0 billion).

Testimony

Forums

Arkansas Public Service Commission

Federal Energy Regulatory Commission

Florida Public Service Commission

Maine Public Utilities Commission

Minnesota Public Service Commission

Nevada Public Service Commission

New York Public Service Commission

Nuclear Regulatory Commission – Atomic Safety and Licensing Board

Oklahoma Public Service Commission

Public Service Commission of Indiana

Public Utilities Commission of Ohio

Public Utilities Commission of Nevada

Public Utilities Commission of Texas

Public Utilities Commission of New Hampshire

United States District Court

United States Senate Committee on Energy and Natural Resources

Various arbitration proceedings

Clients

Arkansas Power & Light Company

Baltimore Gas & Electric

Carolina Power & Light Company

Central Maine Power

Consolidated Edison Company of New York, Inc.

Dayton Power and Light Company

Florida Coordinating Group

Houston Lighting & Power Company

Minnesota Power and Light Company

Nevada Power Company

Niagara Mohawk Power Corporation

Northern Indiana Public Service Company

Oglethorpe Power Corporation

Pacific Gas and Electric Company

Power Authority of the State of New York

Public Service and Electric Company

Public Service Company of Oklahoma

Sierra Pacific Power Company

Southern Company Services, Inc.

Tucson Electric Power Company

Texas-New Mexico Power Company

Recent Expert Testimony and Expert Reports

Supplemental Testimony on behalf of Texas-New Mexico Power Company, Docket No. 15660, September 5, 1996.

Direct Testimony on behalf of Long Island Lighting Company before the Federal Energy Regulatory Commission, September 29, 1997.

Rebuttal Testimony on behalf of Texas-New Mexico Power Company, SOAH Docket No. 473-97-1561, PUC Docket No. 17751, March 2, 1998.

Prepared Testimony and deposition testimony on behalf of Central Maine Power Company, United Stated District Court Southern District of New York, 98-civ-8162 (JSM), March 5, 1999.

Prepared Direct Testimony Before the Public Service Commission of Maryland on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, June 1999.

Rebuttal Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, March 22, 1999.

NORCON Power Partners LP v. Niagara Mohawk Energy Marketing, before the United States District Court, Southern District of New York, June 1999.

Prepared Supplemental Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, July 23, 1999.

Prepared Supplemental Reply Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, August 3, 1999.

Direct Testimony on behalf of Niagara Mohawk, Before the New York State Public Service Commission, PSC Case No. 99-E-0681, September 3, 1999.

Rebuttal Testimony on behalf of Niagara Mohawk, PSC Case No. 99-E-0681 Before the New York State Public Service Commission, November 10, 1999.

Arbitration deposition on behalf of Oglethorpe Power Corporation, last quarter of 1999.

Direct Testimony Before the Public Utilities Commission of Ohio on behalf of FirstEnergy Corporation, Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company, Case No. 99-1212-EL-ETP re: Shopping Credits.

Direct Testimony on behalf of Niagara Mohawk, Before the New York State Public Service Commission, PSC Case No. 99-E-0990, February 25, 2000.

Testimony on behalf of Consolidated Edison Company of New York, Inc., State of Connecticut, Department of Public Utility Control, Docket No.: 00-01-11, April 28, 2000 and June 30, 2000.

Testimony on behalf of Texas-New Mexico Power Company, Fuel Reconciliation Proceeding before the Texas PUC, June 30, 2000.

Testimony on behalf of Consolidated Edison Company of New York, Inc., Before the New Hampshire Public Service Commission, Docket No.: DE 00-009, June 30, 2000.

Rebuttal Testimony Before the Public Utilities Commission of the State of Colorado, Docket No. 99A-549E, November 22, 2000.

Testimony Before the Public Utilities Commission of the State of Colorado, Docket No. 99A-549E, January 19, 2001.

DETM Management, Inc. Duke Energy Services Canada Ltd., And DTMSI Management Ltd., Claimants vs. Mobil Natural Gas Inc., And Mobil Canada Products, Ltd., Respondents. American Arbitration Association Cause No. 50 T 198 00485 00, August 27, 2001.

State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv) Docket No.: EX01050303, October 4, 2001.

Direct Testimony Before the Federal Energy Regulatory Commission on behalf of Pacific Gas and Electric Company, Docket No.: ER02-456-000, November 30, 2001.

Fourth Branch Associates/Mechanicville vs. Niagara Mohawk Power Corporation, January 2002 (Expert Report).

Arbitration Deposition on behalf of Oglethorpe Power Corporation, March 2002.

Direct Testimony and Deposition Testimony Before the Federal Energy Regulatory Commission on behalf of Electric Generation LLC in Response to June 12 Commission Order, Docket No.: ER02-456-000, July 16, 2002.

Rebuttal Testimony Before the Federal Energy Regulatory Commission on behalf of Electric Generation LLC in Response to June 12 Commission Order, Docket No.: ER02-456-000, August 13, 2002.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company, in the matter of the Application of Nevada Power Company to Reduce Fuel and Purchased Power Rates, PUCN Docket No. 02-11021, November 8, 2002 and subsequent Deposition Testimony.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, Docket No. 03-1014, January 10, 2003.

Direct Testimony Before the Public Utility Commission Of Texas on behalf of Texas-New Mexico Power Company, Application Of Texas-New Mexico Power Company For Reconciliation Of Fuel Costs, April 1, 2003.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company, PUCN Docket No. 02-11021, April 1, 2003.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company, Docket No. 03-1014, May 5, 2003.

Testimony on behalf of Consolidated Edison Company of New York, Inc., Before the Public Service Commission of New York, Case No.: 00-E-0612, September 19, 2003.

State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv), September 2003.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Deferred Energy Case, November 12, 2003.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, January 12, 2004.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, May 28, 2004.

Direct Testimony on behalf of Texas-New Mexico Power Company, First Choice Power Inc. and Texas Generating Company LP to Finalize Stranded Cost under PURA § 39.262, January 22, 2004.

Rebuttal Testimony on behalf of Texas-New Mexico Power Company, First Choice Power Inc. and Texas Generating Company LP to Finalize Stranded Cost under PURA § 39.262, April, 2004.

State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv), September 2004.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Deferred Energy Case, November 9, 2004.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, January 7, 2005.

Expert Report on behalf of Oglethorpe Power Corporation, March 23, 2005.

Arbitration deposition on behalf of Oglethorpe Power Corporation, April 1, 2005.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's December 2005 Deferred Energy Case.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2006 Deferred Energy Case, January 13, 2006.

Remand Rebuttal for Public Service Company of Oklahoma before the Corporation Commission of the State of Oklahoma, Cause No. PUD 200200038, **Confidential**, March 17, 2006

Answer Testimony on behalf of the Colorado Independent energy Association, AES Corporation and LS Power Associates, LP, Docket No. 05A-543E, April 18, 2006.

Cross-Answer Testimony on behalf of the Colorado Independent energy Association, AES Corporation and LS Power Associates, LP, Docket No. 05A-543E, May 22, 2006.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2006 Deferred Energy Case, Docket No. 06-01016, June 2006.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, December 2006.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Application for Recovery of Costs of Achieving Final Resolution of Claims Associated with Contracts Executed During the Western Energy Crisis, December 2006.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Application for Recovery of Costs of Achieving Final Resolution of Claims Associated with Contracts Executed During the Western Energy Crisis, December 2006.

Direct Testimony Before the Public Utilities Commission of the State of Hawaii, on behalf of Hawaiian Electric Company, Inc., Docket No. 2006-0386, December 22, 2006.

Direct Testimony Before the Public Utilities Commission of the State of Hawaii, on behalf of Hawaiian Electric Company, Inc., Docket No. 05-0315, December 29, 2006.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2007 Deferred Energy Case, January 2007.

Declaration Before the State of New York Public Service Commission, on behalf of Consolidated Edison Company of New York, Inc.'s Long Island City Electric Network, Case 06-E-0894 – Proceeding on Motion of the Commission to Investigate the Electric Power Outage and Case 06-E-1158 – In the Matter of Staff's Investigation of Consolidated Edison Company of New York, Inc.'s Performance During and Following the July and September Electric Utility Outages. July 24, 2007

Answer Testimony Before the Public Utilities Commission of the State of Colorado on behalf of Trans-Elect Development Company, LLC, and The Wyoming Infrastructure Authority, Docket No. 07A-447E, April 28, 2008

May 2008

Exhibit B: Energy Efficiency/DSM Programs in the U.S.

State	Type of Program	Description
Arizona	Incentive	APS will be permitted to earn and recover a performance incentive based on a share of the net economic benefits (benefits minus costs) from approved energy Efficiency DSM programs. Such performance incentive will be capped at 10% of the total amount of DSM spending.
Arkansas	Recovery through Rates	Required utilities to file for PSC approval of a portfolio of initial energy efficiency programs (EEPs) in mid-2007, that are to remain in place from Oct. 1, 2007-Dec. 31, 2009. The rules also required the utilities to demonstrate the cost savings expected to be achieved through these programs; these programs may include incentives to encourage energy efficiency investments by customers; all programs are to be "fuel neutral"; the utilities are permitted to request recovery of costs associated with EEPs through a separate surcharge; subsequent EEPs are to remain in place for terms of up to three years; and, the utilities are required to annually submit to the Commission a report that addresses the performance of their EEPs.
California	Incentive	On Sept. 20, 2007, the PUC adopted an incentive framework for the electric and gas energy efficiency programs of the state's utilities. Under the adopted framework, if a utility achieves between 85% and 100% of the PUC-established energy savings goals for the years 2006-2008, utility shareholders would receive 9% of the verified net benefits (resource cost savings minus total costs), and ratepayers would receive 91%. If the utility achieves 100% or greater of the 2006-2008 goals, 12% of the verified net benefits would accrue to shareholders and 88% to ratepayers. If a utility meets 65% or less of the goals, the greater of two penalties would apply: a penalty of 5¢ per KWH, $25 per KW, and 45¢ per therm; or, a "cost effectiveness guarantee," which would require the utility to fully reimburse ratepayers for any negative net benefits. No shareholder rewards or penalties accrue if the utility achiéves between 65% and 85% of the goals.
Colorado	Recovery through Rates	PSCO is permitted to recover DSM costs through a separate adjustment clause, known as the demand-side management cost adjustment (DSMCA). DSM costs, including the company's low-income energy assistance and weatherization programs, are recovered over five years through the DSMCA, while non-labor incremental costs and carrying costs associated with deferred DSM costs are recovered annually.
Florida	Incentive	The PSC is authorized to provide incentives to utilities that perform well relative to their goals and to penalize those that perform poorly. In addition, the legislation would permit the PSC to authorize a utility a return-on-equity premium of up to 50 basis points if its annual load growth is offset by more than 20% through energy efficiency and conservation measures.
Georgia	Inactive	Several years ago, the PSC ordered GP to discontinue its demand-side management (DSM) programs. The PSC stated that any future DSM programs must not lead to rate increases, and new DSM programs must be evaluated using a rate impact measure test. No new DSM programs have been filed.

Hawaii	General Plan	In February 2007, the PUC issued an order addressing DSM program costs and incentives for Hawaiian Electric Company (HECO). The PUC continues to permit the recovery of reasonably-incurred DSM implementation costs under the company's IRP framework. Specifically, labor costs are to be recovered through base rates, while non labor costs will be recovered through a surcharge. DSM incentives will be derived from a graduated performance-based schedule of net system benefits. In order to qualify for an incentive, HECO must meet MW and MWH reduction goals for its DSM programs in both the commercial/industrial and residential sectors. The amount of the annual incentive is capped at $4 million for HECO, and may not exceed either 5% of the net system benefits, or utility earnings opportunities foregone by implementing DSM programs in lieu of supply-side resources. Negative incentives will not be imposed for underperformance.
Indiana	General Plan	On Jan. 31, 2008, IMP filed a rate case in which it proposes to implement a DSM/energy efficiency (EE) program tracker to facilitate recovery of costs associated with new DSM and EE programs, and to mitigate the impact of reduced customer electricity usage on company revenues;
Kansas	Incentive	By law, the KCC can authorize an energy company to earn up to a 200 basis-point ROE premium on investments associated with: the generation of energy from renewable resources; conservation; or, energy efficiency. However, no such premiums have been approved to date.
Kentucky	Lost Revenue Recovery	On Oct. 19, 2007, in the context of a DNG rate proceeding, the PSC adopted a settlement that permits the company to initiate a proceeding in the near future in which the merits of a decoupling mechanism, referred to as the Customer Conservation and Efficiency Program (CEP) program, and associated cost recovery mechanisms (including the CEP "Revenue from Lost Sales" and CEP "Incentive" mechanisms) that had been proposed by the company in the instant proceeding, can be addressed.
Maryland	Incentive	On Jan. 3, 2008, the PSC directed Pepco and Delmarva to file Demand Response Programs designed to achieve peak load reductions by 2011. On April 18, 2008, the PSC approved the Demand Response Programs including provisions that will allow Pepco and Delmarva to retain a portion of the benefit associated with achieving demand reductions that exceed certain benchmark levels. On April 15, 2008, the PSC had rejected a plan proposed by Potomac Edison finding that it would not be cost-effective.
Massachusetts	Incentive	Distribution companies that achieve targeted performance levels for energy efficiency programs may earn an incentive.
Minnesota	Incentive	Incentive demand-side-management (DSM) mechanisms are in place for regulated electric and gas utilities including NSP and MP. While program costs are recoverable, lost margins are not. Instead, the PUC approves utility KWH energy savings goals, and incentives begin when the utilities surpass 90% of these goals. The incentives are capped at the lower of 30% of actual expenditures or 30% of DOC approved expenditure levels.
Montana	Legislation	State statutes allow the PSC to approve up to a 200-basis-point ROE premium for demand-side management (DSM) program investment. To date, no companies have requested such a premium. From 1996-1998, NorthWestern Corporation (then MP) operated under an electric alternative regulation plan (ARP), that provided for earnings in excess of an 11.4% ROE to be shared equally with ratepayers. MDU Resources' currently authorized ROE includes an implicit premium for management performance.
North Carolina	Incentive	NCUC rules require the utilities to develop integrated resource plans (IRPs) that cover a 10-year time horizon. The IRPs are to consider conservation, load management, and other energy efficiency measures as supply sources, along with new generating plants. Status reports must be submitted annually. Duke Carolinas is permitted to retain DSM savings of up to 0.5% of annual jurisdictional revenues.
New Hampshire	General plan	New Hampshire utilities are required to file least-cost integrated resource plans every two years. On May 14, 2007, the PUC opened a proceeding (Docket No. DE 07-064) to investigate rate mechanisms, such as revenue decoupling, that may be instituted to remove obstacles for encouraging investments in electric and gas energy efficiency. The proceeding remains open.

Nevada	Renewable Credit	Up to 25% of the renewable energy requirement in each calendar year may be met with energy efficiency programs. Electric providers may receive one portfolio energy credit for each kWh that the provider generates, acquires, or saves from a portfolio energy system or efficiency measure.
South Carolina	Recovery through Rates	Electric utilities are required to annually submit 15-year integrated resource planning (IRP) proposals encompassing supply-side and demand side management (DSM) alternatives. Both Duke Energy Carolinas and South Carolina Electric & Gas have been authorized to recover in rates DSM costs, including incentives.

Sources:
Regulatory Research Associates (www.rra-focus.com) and the Regulatory Assistance Policy (www.raponline.org)

Exhibit C
DSM Impacts (5-year Deferral) Based on California Method

Deferred investment	$1,000,000,000
NPV of shareholder earnings impact	**$107,666,288**
Fed. and State Income Tax	40%
After-tax ROE	10%
Debt to Total Capital	50%

Year End	CapX Deferred Due to DSM/EE	Book Value Deferred Due to DSM/EE	Book depreciation Deferred Due to DSM/EE	Tax Depreciation Deferred Due to DSM/EE	Deferred taxes Deferred Due to DSM/EE	Rate Base Deferred Due to DSM/EE	Equity In Rate Base Deferred Due to DSM/EE	Shareholder Earnings Deferred Due to DSM/EE
2008	0	0	0	0				
2009	$200,000,000	$194,000,000	$5,000,000	$7,500,000	$1,000,000	$97,000,000	$48,500,000	$4,850,000
2010	$200,000,000	$379,225,000	$10,000,000	$21,937,500	$4,775,000	$286,612,500	$143,306,250	$14,330,625
2011	$200,000,000	$556,108,125	$15,000,000	$35,292,188	$8,116,875	$467,666,563	$233,833,281	$23,383,328
2012	$200,000,000	$725,050,016	$20,000,000	$47,645,273	$11,058,109	$640,579,070	$320,289,535	$32,028,954
2013	$200,000,000	$886,421,264	$25,000,000	$59,071,878	$13,628,751	$805,735,640	$402,867,820	$40,286,782
2014		$846,564,670	$25,000,000	$62,141,487	$14,856,595	$866,492,967	$433,246,484	$41,707,982
2015		$808,572,319	$25,000,000	$57,480,876	$12,992,350	$827,568,495	$413,784,247	$27,047,800
2016		$772,304,395	$25,000,000	$53,169,810	$11,267,924	$790,438,357	$395,219,179	$16,138,590
2017		$737,408,490	$25,000,000	$49,739,764	$9,895,906	$754,856,443	$377,428,221	$5,713,869
2018		$703,514,010	$25,000,000	$47,236,200	$8,894,480	$720,461,250	$360,230,625	($4,263,720)
2019		$670,278,157	$25,000,000	$45,589,631	$8,235,852	$686,896,084	$343,448,042	($8,979,844)
2020		$637,383,844	$25,000,000	$44,735,783	$7,894,313	$653,831,001	$326,915,500	($8,686,875)
2021		$604,537,764	$25,000,000	$44,615,201	$7,846,080	$620,960,804	$310,480,402	($8,473,878)
2022		$571,691,684	$25,000,000	$44,615,201	$7,846,080	$588,114,724	$294,057,362	($8,337,086)
2023		$538,845,603	$25,000,000	$44,615,201	$7,846,080	$555,268,643	$277,634,322	($8,259,630)
2024		$505,999,523	$25,000,000	$44,615,201	$7,846,080	$522,422,563	$261,211,281	($8,223,676)
2025		$473,153,442	$25,000,000	$44,615,201	$7,846,080	$489,576,483	$244,788,241	($8,212,726)
2026		$440,307,362	$25,000,000	$44,615,201	$7,846,080	$456,730,402	$228,365,201	($8,211,520)
2027		$407,461,281	$25,000,000	$44,615,201	$7,846,080	$423,884,322	$211,942,161	($8,211,520)

Year End	Actual CapX	Actual Book Value	Actual Book depreciation	Actual Tax Depreciation	Actual Deferred taxes	Actual Rate Base	Actual Equity In Rate Base	Actual Shareholder Earnings
2008								
2009	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	$200,000,000	$194,000,000	$5,000,000	$7,500,000	$1,000,000	$32,333,333	$16,166,667	$1,616,667
2015	$200,000,000	$379,225,000	$10,000,000	$21,937,500	$4,775,000	$286,612,500	$143,306,250	$14,330,625
2016	$200,000,000	$556,108,125	$15,000,000	$35,292,188	$8,116,875	$467,666,563	$233,833,281	$23,383,328
2017	$200,000,000	$725,050,016	$20,000,000	$47,645,273	$11,058,109	$640,579,070	$320,289,535	$32,028,954
2018	$200,000,000	$886,421,264	$25,000,000	$59,071,878	$13,628,751	$805,735,640	$402,867,820	$40,286,782
2019	0	$846,564,670	$25,000,000	$62,141,487	$14,856,595	$866,492,967	$433,246,484	$43,324,648
2020	0	$808,572,319	$25,000,000	$57,480,876	$12,992,350	$827,568,495	$413,784,247	$41,378,425
2021	0	$772,304,395	$25,000,000	$53,169,810	$11,267,924	$790,438,357	$395,219,179	$39,521,918
2022	0	$737,408,490	$25,000,000	$49,739,764	$9,895,906	$754,856,443	$377,428,221	$37,742,822
2023	0	$703,514,010	$25,000,000	$47,236,200	$8,894,480	$720,461,250	$360,230,625	$36,023,062
2024	0	$670,278,157	$25,000,000	$45,589,631	$8,235,852	$686,896,084	$343,448,042	$34,344,804
2025	0	$637,383,844	$25,000,000	$44,735,783	$7,894,313	$653,831,001	$326,915,500	$32,691,550
2026	0	$604,537,764	$25,000,000	$44,615,201	$7,846,080	$620,960,804	$310,480,402	$31,048,040
2027	0	$571,691,684	$25,000,000	$44,615,201	$7,846,080	$588,114,724	$294,057,362	$29,405,736

Exhibit C
DSM Impacts (Rolling Deferral) Based on California Method

Deferred investment	$1,000,000,000
NPV of shareholder earnings impact	**$238,671,599**
Fed. and State Income Tax	40%
After-tax ROE	10%
Debt to Total Capital	50%

Year End	CapX Deferred Due to DSM/EE	Book Value Deferred Due to DSM/EE	Book depreciation Deferred Due to DSM/EE	Tax Depreciation Deferred Due to DSM/EE	Deferred taxes Deferred Due to DSM/EE	Rate Base Deferred Due to DSM/EE	Equity In Rate Base Deferred Due to DSM/EE	Shareholder Earnings Deferred Due to DSM/EE
2008	0	0	0	0				
2009	$200,000,000	$194,000,000	$5,000,000	$7,500,000	$1,000,000	$97,000,000	$48,500,000	$4,850,000
2010	$200,000,000	$379,225,000	$10,000,000	$21,937,500	$4,775,000	$286,612,500	$143,306,250	$14,330,625
2011	$200,000,000	$556,108,125	$15,000,000	$35,292,188	$8,116,875	$467,666,563	$233,833,281	$23,383,328
2012	$200,000,000	$725,050,016	$20,000,000	$47,645,273	$11,058,109	$640,579,070	$320,289,535	$32,028,954
2013	$200,000,000	$886,421,264	$25,000,000	$59,071,878	$13,628,751	$805,735,640	$402,867,820	$40,286,782
2014		$846,564,670	$25,000,000	$62,141,487	$14,856,595	$866,492,967	$433,246,484	$43,324,648
2015		$808,572,319	$25,000,000	$57,480,876	$12,992,350	$827,568,495	$413,784,247	$41,378,425
2016		$772,304,395	$25,000,000	$53,169,810	$11,267,924	$790,438,357	$395,219,179	$39,521,918
2017		$737,408,490	$25,000,000	$49,739,764	$9,895,906	$754,856,443	$377,428,221	$37,742,822
2018		$703,514,010	$25,000,000	$47,236,200	$8,894,480	$720,461,250	$360,230,625	$36,023,062
2019		$670,278,157	$25,000,000	$45,589,631	$8,235,852	$686,896,084	$343,448,042	$34,344,804
2020		$637,383,844	$25,000,000	$44,735,783	$7,894,313	$653,831,001	$326,915,500	$32,691,550
2021		$604,537,764	$25,000,000	$44,615,201	$7,846,080	$620,960,804	$310,480,402	$31,048,040
2022		$571,691,684	$25,000,000	$44,615,201	$7,846,080	$588,114,724	$294,057,362	$29,405,736
2023		$538,845,603	$25,000,000	$44,615,201	$7,846,080	$555,268,643	$277,634,322	$27,763,432
2024		$505,999,523	$25,000,000	$44,615,201	$7,846,080	$522,422,563	$261,211,281	$26,121,128
2025		$473,153,442	$25,000,000	$44,615,201	$7,846,080	$489,576,483	$244,788,241	$24,478,824
2026		$440,307,362	$25,000,000	$44,615,201	$7,846,080	$456,730,402	$228,365,201	$22,836,520
2027		$407,461,281	$25,000,000	$44,615,201	$7,846,080	$423,884,322	$211,942,161	$21,194,216