Reports
07-M-0548
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STATE OF NEW YORK DEPARTMENT OF PUBLIC SERVICE

THREE EMPIRE STATE PLAZA, ALBANY, NY 12223-1350

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December 11, 2007

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Hon. Jaclyn A. Brilling, Secretary
Hon. Rudy Stegemoeller, Administrative Law Judge
Hon. Eleanor Stein, Administrative Law Judge
NYS Public Service Commission
Three Empire State Plaza
Albany, NY 12223-1350

Re: Case 07-M-0548 – Energy Efficiency Portfolio Standard

Dear Secretary Brilling and Judges Stegemoeller and Stein:

On behalf of Working Group 3, enclosed please find an original and five copies of the final report of Working Group 3 dated December 5, 2007, prepared in the above-captioned proceeding. A PDF version was previously forwarded to the parties electronically via the EPS Listserve.

We would like to thank all the Working Group 3 participants who invested countless hours in support of our efforts. The professionalism and commitment of the group is deeply appreciated.

Respectfully submitted,
Working Group 3 Co-conveners:

William P. Saxonis
William Saxonis, NYSDPS

Carol White
Carol White, National Grid

Enclosure
Cc: Active Parties (via E-Mail)

Evaluation and Monitoring

WORKING GROUP III

EPS Proceeding

12/5/07

Co-Conveners:

Bill Saxonis - NYS Department of Public Service

Carol White - National Grid

I. Summary

I. Executive Summary

Working Group III was charged with making consensus recommendations (as possible): (1) defining 15x15 energy savings goals for electricity and natural gas; (2) establishing guidelines, roles, and responsibilities for monitoring and evaluation; and (3) establishing benefit cost test guidelines. The group met eleven times, including the two plenary meetings, eight telephone meetings, and one full day in-person meeting. All of these meetings were supplemented by extensive email communications.

In the text below, the term "consensus" refers to the general sense of the group. Individual members may disagree with particular findings and recommendations contained in this document, and all members reserve their rights. In particular, it should be noted that all Working Group members may not have been able to fully review the report presented here due to the tight schedule guiding this process. In addition, it should be noted that not all Working Group members attended the meetings that led to the development of this report.

The EPS "15x15" goal is to reduce electric energy consumption by 15% from 2007 forecasted levels by 2015. More precisely, we need a baseline forecast showing what loads would have been in the absence of demand-side management (DSM) measures whose impacts count toward achievement of the goal. We identified three primary options regarding which DSM should count toward the 15x15 goal. The options include:

1. All DSM dating back to 1998, including the beginning of System Benefits Charge (SBC) funded programs
2. Only DSM measures installed on or after January 1, 2007
3. All DSM beyond what is currently planned, including new SBC measures through June 2011

The consensus of the Working Group was that from a conceptual standpoint, Option 2 is the preferred approach. Several members of the Working Group cautioned that it was important to analyze the results for the three options before making a final recommendation.

The consensus of the Working Group is to consider two ways of counting the reduction in line losses, involving whether to define and measure progress toward the 15x15 goal in terms of requirements "sendout" or of retail sales, with baseline load forecast adjustments as necessary.

The Working Group agrees that the baseline forecast for 2015 should be reviewed periodically, probably every 2-3 years. We recommend the results of these reviews be formally submitted to the Commission to determine if any action is necessary.

Due to the complexity of the forecasts and the need for accuracy, a subcommittee of the Working Group (i.e., Staff, NYISO, and NYSERDA) is continuing to review the relevant data. The initial results for all three DSM reporting options and the point of sale/sendout scenarios will be made available no later than the December 14, 2007 Plenary Meeting in New York City. Initial results suggest that Staff's original estimate, a reduction of approximately 27, 400 GWh by 2015 is reasonable.

The Working Group also proposes that additional time be permitted to establish a target for natural gas efficiency, primarily because we are awaiting the results of the Optimal Gas Potential Study commissioned by Staff and expected in early 2008.

The group favored counting towards the goal "upstream" T&D and possibly generation efficiency measures justified as part of the EPS effort (perhaps not economic under the usual tests). However, the group agreed that it is beyond its scope to endorse specific programs, including those that directly impact the efficiency of the T&D system. Any T&D programs adopted as part of the EPS will need to be carefully evaluated.

The group agreed that the effects of improved State building codes and Federal and State appliance and other end use efficiency standards for new equipment, implemented after January 1, 2007, are an important component of meeting the EPS goal. Estimated impacts from these strategies should be subtracted from the EPS goals to determine the energy efficiency savings goals that will be related to customer end use and upstream efficiency measures.

The group discussed a preliminary 'bottom-up' assessment of each proposed component of the energy efficiency portfolio to determine whether sufficient cost-effective energy efficiency resources have been identified in total to reach the goal. For non-statewide efforts, the program administrator (PA) should take into account the specific customer mix in the territory being targeted with its regional expertise and market potential studies. Allocating the statewide goal to each PA based only on current usage within the relevant geographic area might lead to unrealistic goals. PA regional goals may need to be adjusted in the future for significant shifts in the State or local economy and changes in customer-base.

In addition to an energy savings goal, the Working Group recommends that program evaluation of the electric DSM programs contributing to the EPS goal should also document the impact efforts have on peak demand. There was also agreement that programs designed primarily to reduce on-peak usage should be considered as part of the EPS program portfolio. There was less agreement about the value of recommending a specific EPS demand savings goal, with concern that setting such a goal might exceed the intent of the EPS.

Evaluation of the EPS programs will be required – including monitoring & evaluation, measurement & verification, and impact and process evaluations. The Working Group has not reached consensus on the level of spending to be dedicated to this effort. However, a cap of 5% of program cost has been discussed. The Group has recommended the creation of a statewide Evaluation Task Force (ETF) which will be charged with developing evaluation protocols that will be adopted by all Program Administrators. The ETF is discussed further, below.

The Working Group reviewed benefit/cost testing practices in several jurisdictions and considered the applicability of those practices to New York with particular reference to the California Standard Practice Manual, which identifies the cost and benefit components and calculations from several major perspectives. The group considered how the attributes of each of the benefit/cost tests align with the objectives of the EPS proceeding and with a March 2006 Commission order ruling on this issue as part of a Consolidated Edison rate case proceeding (Case - 04-E-0572). The Commission endorsed the Total Resource Cost Test (TRC) with some flexibility for worthwhile, but failing programs. The group recommends assessment of program cost-effectiveness using a TRC test that is modified to possibly include other resource benefits beyond energy savings (e.g., the value of conserved water) and other quantifiable non-energy effects (e.g., the dollar value of reduced operation and maintenance expenses). Although the working group was not able to reach full agreement about including environmental benefits in the test immediately, there was some agreement that further study may be warranted. There was also some support, but not a consensus, for including the Ratepayer Impact Test as a secondary benefit/cost test.

The Working Group recommends using benefit-cost tests as a guide, but also considering factors not accounted for in the benefit-cost tests in certain instances such as program offerings for low-income or hard to reach customers programs. In addition, the Group recommends that the Evaluation Task Force (ETF) develop a list of recommended inputs for assessing a DSM program's cost-effectiveness and that the Evaluation Task Force develop a common approach to be adopted by all Program Administrators when calculating avoided transmission and distribution costs.

The Working Group members agree that the ETF role must fit within the overall EPS governance structure that will be determined based on the efforts of Working Group The role of the ETF would be modeled after the System Benefits Charge (SBC) Advisory Group and be composed of: representatives of energy and environmental industry and associations, building trade associations, State agencies including the Department of Public Service, consumer and equipment product manufacturer groups, and other organizations. All EPS program administrators would be represented on the ETF. This composition of the ETF will provide the balance and representation needed. Like the SBC Advisory Group, the ETF would serve as the EPS Independent Program Evaluator, ensuring that all program administrators are evaluating programs and reporting results consistently and regularly. The ETF would also help ensure that all program results can be aggregated and reported on a statewide basis. The Commission would offer the final determination for the organizations it regulates. There was a lack of consensus regarding the entity that would be responsible for making this determination for public-run programs not under Commission jurisdiction, such as programs run by NYPA, LIPA, DASNY, DOS and DHCR.

The Working Group had extensive discussions about the specific responsibilities of the ETF. Some felt the ETF should limit efforts to studies related to methodological issues while others felt it should also include broader research issues (e.g., appliance baselines) that might be more efficiently conducted on a statewide basis.

The Working Group also considered the timing and content of detailed reports that will be needed to assess progress being made toward achievement of the 15 x 15 goals. The Group reached a consensus that quarterly reports should be sufficient to allow for monitoring performance and optimizing resource allocations to maximize EPS results.

Two appendices are included with this report. Appendix A describes a Process for establishing a natural gas savings goal. Appendix B provides a summary of the benefit/cost tests as defined in the California Standard Practice Manual.

II. EPS Statewide Goals

A. The Baseline Load Forecast and DSM Measures that Count Toward the 15 x15 Electricity Goal

The EPS "15x15" goal is to reduce loads by 15% from 2007 forecasted levels by 2015. We identified three primary options regarding which DSM should count toward the 15x15 goal. The options include:

- All DSM dating back to 1998, including the beginning of System Benefits Charge (SBC) funded programs;
- Only DSM measures installed after January 1, 2007. NYSERDA, other state agencies and many utilities have currently proposed DSM plans. These measures should count towards fulfillment of the 15x15 goal;
- All DSM beyond what is currently planned, including new SBC measures through June 2011.

The consensus of the Working Group was that from a conceptual standpoint, Option 2 is the preferred approach. Several members of the Working Group cautioned that it would be necessary to analyze the results for the three options before they could make a final determination of the goal. Additional effort will be needed within the next 90 days to further refine data that have been developed in this and other working groups. The activities to perform are:

- finalize the baseline forecast
- identify proposed DSM activities among state agencies and utilities
- develop a preliminary 'bottom-up' assessment of each 'wedge' of the energy efficiency portfolio

- determine whether sufficient cost-effective energy efficiency resources have been identified in total.

i. The Baseline Electricity Load Forecast-- Point of Sale or "sendout"

The Order instituting the EPS Proceeding provides that the ALJ and the parties should "[c]onsider and prioritize end-user efficiency programs, market transformation approaches, research and development, and generation, distribution and transmission efficiencies." Accordingly, energy savings in the form of lower losses on the Transmission and Distribution (T&D) system should potentially be counted toward achievement of the goal.

If this Proceeding defines and measures progress toward the 15x15 goal in terms of requirements or "sendout," then measures that reduce losses will show up as progress toward the goal. If we define the 15x15 goal in terms of retail sales, the benefits of T&D efficiencies will not be reflected unless a separate adjustment reflecting savings on the T&D system is included. The consensus of the Working Group is that this Proceeding measure progress toward the goal showing the data under both scenarios.

Due to the complexity of the forecasts and the need for accuracy, a subcommittee of the Working Group (i.e., Staff, NYISO, and NYSERDA) is continuing to review the relevant data. The initial results for all three DSM reporting options and the point of sale/sendout scenarios will be made available no later than the December 14, 2007 Plenary Meeting in New York City. Initial results suggest that Staff's original estimate, a reduction of approximately 27, 400 GWh by 2015 is reasonable.

ii. Periodic review and update of the forecast

Energy forecasts are based on a number of difficult to predict independent variables including economic activity, weather, energy prices and inflation rates. While our forecasts will be based on the best available data, even the most carefully constructed forecasts can prove less than 100 percent accurate. The Working Group agrees that the 2015 forecast should be reviewed periodically, probably every 2-3 years and that the results of these reviews be formally submitted to the Commission to determine if any action is necessary with respect to the 15x15 goal.

B. Process for Establishing Natural Gas Target

Establishing a target for natural gas efficiency is an important question for consideration by the Working Group. We propose that additional time be permitted for discussion of this issue at a future time in the EPS proceeding. The primary reason is that we are awaiting the results of the Optimal Gas Potential Study commissioned by Staff. The results of this update, expected in early 2008, will need to be reviewed prior to establishing a natural gas goal. Parties should make provisions for the submission of written initial and reply comments after the release of proposed natural gas energy efficiency targets. A discussion of Staff's process for establishing a target for natural gas efficiency is included in Appendix A.

iii. Additional Electricity Goals and Establishment of Program Administrator Goals

A. Peak Demand Goal

Peak demand reduction has been an important goal of state energy policy in recent years. The need to reduce stress on the distribution system is especially critical downstate. The Working Group recommends that program evaluation of the electric

DSM programs contributing to the EPS goal should document the impact on peak demand.

There was less agreement about the value of recommending a specific EPS demand savings goal. The lack of consensus was not a negative reflection on the value of peak demand programs, but a reflection of the uncertainty about the appropriateness of establishing a goal in this proceeding. For example, would establishing a goal be consistent with goals of the EPS Proceeding? Is a goal necessary given that the EPS energy efficiency programs would naturally reduce peak demand and there already are peak demand reduction programs available to New York consumers? The Working Group concluded that determining whether a goal was necessary, and identifying the best approach for establishing this goal, would require additional analysis and discussion.

B. Codes and Standards Goal

Codes and Standards are an important component of meeting the EPS goal. Codes refer to New York State government mandated building codes for state owned facilities, and State and local building standards for new construction within New York State. Standards refer to Federal and State appliance and other end use efficiency standards for new equipment. Estimated statewide impacts for codes and standards should be based on the anticipated savings from codes and standards that have been or are anticipated to be implemented after January 1, 2007. These estimated impacts should be subtracted from the 15 percent electric energy reduction goal to determine the percentage of energy efficiency savings that potentially need to be obtained from customer end use and upstream efficiency measures.

C. Upstream Electric Efficiency Measures

Upstream electric efficiency measures refer to the efficiency measures that affect the T&D losses and efficiency in electricity production. The Working Group agrees that these measures could be significant and deserve additional analysis in Working Group IV. Typical T&D losses are in the 6 to 8 percent range. Transmission system losses typically are in the 1 to 3 percent range with the remaining losses occurring on the distribution system. The potential to reduce upstream losses varies greatly from one T&D system to another depending upon the underlying design of the system. Some in the Working Group maintain that the efficiency goal from T&D loss reductions be separately set for each T&D system, but others were not sure this is the best approach .

In setting goals for T&D efficiency programs, primary focus needs to be placed upon the cost effectiveness of the measures. Particularly, cost recovery will be a key factor in the utility's ability to deploy more efficient design standards onto the distribution system. Utilities are already responsible for providing the most cost-effective improvements to the T&D system, and it should be presumed that the correct economic decisions are being made in the context of the current economic trade-off between fuel and generating costs and T&D investment. Accelerated investment in the T&D system may not be economic relative to the expected impact on the ratepayer's bill from a more efficient T&D investment policy. In order to promote the accelerated replacement of T&D system components with more energy efficient alternatives, at least three separate analyses could be considered:

- Identification of improved T&D design and construction methods and equipment that will reduce energy losses and improve efficiency.

- Quantification of the rate impact from accelerated replacement of existing T&D equipment and alternative design standards in order to promote energy efficiency on the T&D system. Such an analysis would consider alternative financing approaches (capitalization, amortization or expensing of the incremental cost of the more efficient system components), allocation of the impacts among customer segments and classes, and customer bill impacts from the proposed allocations.
- Policy determinations about the appropriate level of rate impact on the delivery system that would be acceptable to improve energy efficiency and reduce fuel use and environmental emissions. Such policy determinations may need to go beyond the simple cost benefit tests or net present value calculations that are used in many engineering economic analyses, and establish tolerable levels of "uneconomic" choices that will create non-financial benefits to the State and the environment, but they also need to be affordable in a very real financial sense, from the ratepayers' perspective.

D. Goal Setting Process for Recommended Programs –Statewide and Program Administrator Goals.

It is important to establish a framework and a process for allocating the EPS energy savings goal among the entities that may have a role in administering programs that will contribute toward the goal. Since responsibilities for program administration have not yet been articulated, it is not possible to propose program administrator-specific goals. Once program administration responsibilities are determined, the framework and process discussed below can be followed to determine program administrator specific goals.

i. Goal Setting Should be Determined Through Bottom-Up Studies by Program Administrators

The process used to establish energy savings program goals must take into account the potential for energy savings in the specific area covered by the program administrator. For example, energy savings goals related to codes and standards are appropriately viewed as being the responsibility of the State and do not necessarily need to be refined by region within the State (except to the extent that municipalities or counties adopt more stringent codes). If a utility is designated as the program administrator responsible for addressing the needs of its service territory, the goals for that utility should take into account the specific characteristics of its service territory. In creating goals for the State's energy efficiency programs, it is critical to have well thought out targets that are designed to take advantage of the knowledge of each of the investor owned utility service territories and other potential administrators of programs (including NYSERDA, NYPA, LIPA and municipalities). As each of these entities may be program administrators (PA) in some form, each of the PAs should be responsible for proposing program delivery goals informed by knowledge of the constituents that they will serve. This structure is most likely to result in the establishment of achievable goals. The PA-specific goals setting process should be informed by an assessment of the technical, economic, and achievable market potential defined consistently by the region or market covered by the PA. Each PA should then be responsible for proposing savings goals that are informed by the unique attributes of the consumers the PA will be serving. It will be necessary to verify that over time, the sum of proposed goals for each PA (including codes and standards) meets or exceeds the statewide 15 x 15 savings goal.

Goals by PA should be adjusted over time to take into account findings from impact evaluations.

PA goals should be developed using PA forecasts(where applicable) and market potential studies for the various EPS programs (both fast track and long range) within the relevant geographic area. This will allow each PA to take into account the diverse demographics and economies within the state to assess program design and how to best achieve efficiency savings. Based on these studies, each PA will estimate the level of energy savings that it will be able to achieve over time.

The PA goal setting process will:

- Identify markets to be served;
- Estimate the technical, economic, and achievable market potential in each PA's market in 2015;
- Develop a method for apportioning goals for programs serving a single market among the various PAs providing those services;
- Set initial savings goals focusing on cumulative annual savings for 2015 informed by the information gathered for each PA;
- Set intermediate year goals for each PA that take into account a reasonable trajectory of savings that is designed to achieve the longer term goals discussed above;
- Determine if adjustments to PA goals are needed based on impact evaluation findings and new opportunities identified in the marketplace; and
- Develop a process for reconciling individual PA goals with the overall statewide goal. If PAs' cumulative annual forecasted program savings do not meet or

exceed the State's 2015 goals, the need for additional programs or program enhancements should be assessed.

Allocating the statewide goal to each PA based only on current usage witbin the relevant geographic area might lead to unrealistic goals. Instead, goals set by PAs should consider factors such as economic and achievable market potential and other unique attributes by region in the State. There was general consensus in the Working Group that this is a reasonable approach.

ii. Goal Adjustments

As with any complex effort, the goals of the program cannot be set in stone from the outset. At the State level, a timeline of efficiency savings must be estimated based on the current 2015 forecast. These savings over time are not likely to be linear, as the programs will take time to gain momentum. In addition, forecasts change due to factors including, but not limited to changing technology (e.g., plug-in electric vehicles and natural gas fired distributed generation), significant shifts in the State or local economy and changes in customer-base. The State 2015 goal and interim targets may also be evaluated and reset, which will affect individual PA goals.

IV. Monitoring and Evaluation

The goal of meeting 15% of energy requirements through efficiency improvements by 2015 creates tbe need for aggressive energy efficiency program efforts that will be undertaken by a number of organizations in New York. Efforts will be needed to assess progress being made in achieving goals based on actual accomplishments. Work will also bc required to identify how programs and their delivery can be improvcd. In addition, efforts will be required to inform new program designs and initiatives that may become an important focus as additional efficiency opportunities are identified and new technologies and practices are adopted in the future.

Monitoring and evaluation ("M&E") addresses both the quantitative and qualitative performance of program efforts. M&E encompasses measurement and verification efforts, impact evaluations, and process evaluations. Measurement and verification ("M&V") refers to the efforts employed to develop an initial estimate of savings that is based on expected energy use after completing a DSM project. These efforts include refinements that may be made as a result of quality assurance efforts but do not include findings from formal impact evaluations. M&V efforts provide information that can be used to verify that program installations are occurring and producing savings as expected. M&V provides estimates of gross savings. Gross savings also provide an initial measure of progress toward the goal prior to refining the savings estimates to reflect impact evaluation results. These results must be considered by the program administrator as well as for the State as a whole.

Impact evaluations are needed to "measure" the savings that can be attributed to program efforts. Impact evaluations lead to refined estimates of program savings that can include energy savings, demand savings, other resource effects, and non-energy effects. Impact evaluations provide estimates of net savings, which are savings estimates that are further refined to account for program attribution.

Process evaluations are needed to identify how program delivery efforts might be improved, resulting in increased participation, greater sustained savings and higher levels of program participation satisfaction.

M&V, impact evaluation, and process evaluation are discussed in greater detail below. Discussions about evaluation planning, budgeting, and evaluation protocols follow those discussions.

A. Measurement & Verification

Measurement and verification efforts will allow each program administrator to document progress being made to achieve its goals as well as its contribution to the overall 15 x 15 goal. M&V efforts include quantification of expected savings from completed program installations where the savings are based on an engineering estimate of savings, or deemed savings that may or may not be qualified by the results of completed impact evaluations (see below), and quality assurance efforts. Gross savings estimates, the outcome of M&V efforts, reflect the difference in energy use between standard efficiency equipment and practices compared to the more energy efficient equipment or practice adopted by program participants. Gross savings estimates do not account for program attribution. Common M&V techniques could include but are not limited to pre- and post-installation analyses, participant versus non-participant analyses, engineering analysis, billing analysis, other statistical analysis, and the use of interval metering and data loggers to determine actual reductions.

Quality assurance (QA), including an appropriate level of pre- and post-inspections of proposed and completed efficiency projects, will be needed to verify that proposed projects make sense in the context of program objectives and to verify that installations were completed in accordance with plans that have been approved by the program administrator. The level of QA will depend upon several factors, including experience with the implementation vendor, the complexity of the proposed project, and the intended use of the data. For example, if the program administrator has extensive experience with a particular implementation vendor who has demonstrated quality installation efforts, then a lower level of QA may be required. Conversely, if an implementation vendor has not established a consistent track record for providing quality installations, a greater level of QA may be required.

B. Impact Evaluation

Impact evaluations produce quantified savings based on the actual performance of measures installed through efficiency programs or practices adopted as a result of program efforts. In general, an impact evaluation seeks to quantify the difference between energy use that would have occurred in the absence of a program and the energy use that is occurring after participation in a program as informed by an analysis that considers post-installation use. Impact evaluations can focus on total program effects, but also may focus on specific technologies, end-uses, or practices. The findings from impact evaluations can be used to refine the menu of program measures and services offered through programs, to adjust the estimated savings that are reported through M&V efforts, and to assess goals setting for future periods.

Impact evaluations can focus on energy savings as well as non-energy effects. Non-energy effects can include but are not limited to other resource benefits, operation and maintenance expense savings or costs, effects unique to low-income focused efforts, and other economic and environmental effects that may be attributed to the program(s).

Depending on the approach taken to complete an impact evaluation, results may include estimates of gross savings, net savings, or both gross and net savings. Gross savings reflect the difference in energy use between standard efficiency equipment and practices compared to the more energy efficient equipment or practice adopted by program participants. Gross savings estimates do not account for program attribution. Net savings take into account all of the savings that can be attributed to program efforts. They could exclude savings associated with free-ridership[1] and include savings associated with spillover[2]. Net savings may also include other adjustments to take into account program effects including persistence[3] and snapback[4].

Common impact evaluation techniques could include but are not limited to pre- and post-installation analyses, participant versus non-participant analyses, engineering analysis, billing analysis, other statistical analysis, and the use of interval metering and data loggers to determine actual reductions. These techniques can be combined with information gathered through customer and trade ally surveys to arrive at net savings. The Evaluation Task Force discussed in the next chapter of this report will be charged with developing evaluation protocols in support of these efforts.

A key issue in program impact evaluations is the matter of persistence of savings. The impact evaluation techniques listed above are all based on data that reflect a recent history of energy use and/or behavior, considering periods prior to and subsequent to

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[1] "Free-ridership" refers to the percentage of savings attributed to customers who participate in an energy efficiency program but would have, at least to some degree, installed the same measure(s) on their own if the program had not been available.

[2] "Spillover" refers to the energy savings associated with energy efficient equipment installed by consumers who were influenced by an energy efficiency program, but without direct financial or technical assistance from the program. Spillover includes additional actions taken by a program participant as well as actions undertaken by non-participants who have been influenced by the program. Sometimes spillover is referred to as "free-drivership" or as "market effects." Market effects may be current or may occur after a program ends. When market effects occur after a program ends, they are referred to as "momentum" effects or as "post-program market effects."

[3] "Persistence" refers to the percentage of first year savings expected to continue over the life of the installed energy efficiency equipment. Persistence takes into account if an installed measure remains in place and continues to be used as expected.

[4] "Snapback" occurs when the use of equipment increases due to the lower operating costs associated with the installed equipment. For example, a consumer who insulates his or her home might turn the thermostat up to a higher temperature, investing some energy savings in a higher level of comfort. In this case, the energy savings would be lower than expected.

installation of the measures being evaluated. Policy makers want to know if the savings measured or inferred in 2009 will still be occurring in 2015 and thereafter. A common practice is to claim the savings persist for the expected operating life of the equipment installed as part of a measure. But what happens at the end of life? Does the purchaser buy a second efficient item, or buy a less-expensive/less-efficient replacement? What if the purchaser moves, or a business-participant goes out of business? How frequently might a lamp with a CFL installed fall and break, or the CFL prematurely fail? And when this happens, will the original purchaser replace it with a CFL or an incandescent bulb? The impact evaluation must make assumptions regarding these persistence issues, or use the results from other states (e.g., California), where long-term persistence studies have been conducted. One possible way of addressing this issues is to conduct limited-scope impact evaluation efforts in New York should be repeated every few years for each program to assess persistence (i.e., verify that savings are persisting).

C. Process Evaluation

A process evaluation is an in-depth, systematic assessment of an energy efficiency program for the purposes of: 1) documenting program operations at the time of the examination, and 2) identifying and recommending improvements that can be made to the program to increase the program's efficiency and/or effectiveness for meeting its goals while maintaining high levels of participant satisfaction[5]. Process evaluation is used for many purposes including, but not limited to: helping design or redesign programs and services, identifying staff or staffing needs and issues; assessing the effectiveness of program outreach efforts; identifying bottlenecks created by program

[5] This definition of process evaluations was prepared by Nick Hall of TecMarket Research as part of the "Evaluation Management 101" workshop given at the International Energy Program Evaluation Conference in 2007.

operational procedures and recommending alternatives to eliminate those bottlenecks, and refining program objectives. Timely process evaluation efforts can help to uncover program delivery shortcomings early in the implementation process so that efforts can be adjusted, leading to improved results.

Examples of process evaluation methods include participant surveys, non-participant surveys, trade ally surveys, inspections of program materials, review of the program tracking database and focus groups.

D. Evaluation Planning

It is most efficient to consider program evaluation needs before a program is launched. Developing an initial evaluation plan in advance of launching a program allows program evaluators to work with program planners to identify the data collection needs that may be satisfied most cost-effectively at the time of program implementation. In some cases, this includes identifying information to be collected on program intake forms. In some cases, it may include a means of getting prompt feedback from participants about their program implementation experiences through a simple mail back postcard that can be provided to all program participants.

As discussed, early program evaluation efforts should focus on process related issues. Impact evaluations cannot be completed until a sufficient number of projects in a program have been completed and post-installation operations can be observed.

In general, program evaluation efforts should be focused on programs or aspects of programs that may have a critical effect on achieving the 15 x 15 goals, including codes and standards. Some assessment of portfolio risk should be undertaken to identify the most critical areas of focus for program evaluation. This risk assessment can be undertaken by considering the following questions:

- What portion of the savings being achieved is accounted for by the program or end-use?
- How long has it been since the program or end-use was the subject of an impact evaluation?
- How stable have the results been when looking at recent impact evaluations for this program or end-use?
- Do we expect activity in this program or end-use to increase in the future?
- Does the program appear to be producing results as expected?

Considering the above questions will help to prioritize where evaluation funding should be directed to minimize the risk of under or over estimating savings associated with the portfolio of programs.

The following are guidelines for what might be included in an evaluation plan:

- Process evaluation -- evaluation of program design, delivery, and implementation; identify opportunities for improvement; track progress;
- Impact evaluation – quantification of energy and demand savings and identification of other potential impacts, as appropriate (e.g., environmental benefits);
- Gross and net savings analysis—This is usually represented as a ratio of the net savings of a program (i.e., energy savings actually attributable to the program after adjusting for factors such as measurement error, measure installation quality, user behavior, and the actions program participants would have taken absent the

program e.g. free ridership) to the gross savings resulting from the energy measures. Strategy to provide both long and short-term evaluation. It is critical, especially for new programs, to have an "early warning system" to identify program deficiencies;

- Benefit/Cost test(s) to be performed(and who is to perform them);
- Evaluation standards and specifications (e.g., required statistical precision levels for customer surveys);
- Data required to undertake the study;
- Database management protocols;
- Project timeline;
- Budget;
- Roles and responsibilities (i.e., who does what?);
- Format and timing of periodic program progress reports (These reports will focus on routine data such as dollars spent and measures installed.);
- Evaluation report format and release schedule;
- Other relevant issues (This will vary depending on the program.).

E. Evaluation Budgeting

Budgeting for evaluation can be either a top-down or a bottom-up exercise. A top-down approach suggests setting aside a specified percentage of program implementation funding in support of program evaluation efforts. In this approach, evaluation efforts can be prioritized and completed subject to the budget constraint. This does not, however, suggest that every program will include an evaluation budget that is based on a fixed percentage of cost. A bottom-up approach suggests identifying the evaluation studies to be completed over a specified time period and then budgeting the funds needed to complete those studies irrespective of the implementation budget. Caution must be taken when employing either a top-down or a bottom-up approach to ensure that program evaluation efforts do not cause an otherwise cost-effective program to no longer be cost-effective.

F. Evaluation Protocols

There should be a single set of statewide protocols that are applicable to all program administrators (including program administrators that may not be subject to the Commission's jurisdiction) and all programs.[6] A statewide evaluation task force should determine the appropriate statewide protocols for New York by examining protocols adopted by other jurisdictions that describe the objectives for program evaluation and the acceptable techniques that can be used to evaluate program performance and results. The evaluation protocols created for this purpose should not result in requirements that are unduly burdensome or that add unneeded costs to program efforts. Instead, they should focus on identifying clear, understandable definitions of requirements and acceptable approaches that will allow results to be shared and combined statewide.

G. Measurement and Verification of Upstream Electric Measures and alternative programs

Just as with the customer-based energy efficiency programs, not all of the upstream benefits can be directly observed. Some need to be estimated, based on known attributes of the replacement equipment, and others need to be studied in more depth in order to quantify (let alone verify) the benefits that can be attributed to utility actions to

[6] This statement is not intended to mean that all program administrators should be running the same programs.

reduce losses. Generation efficiency programs also need to be taken into consideration, and the resulting fuel savings counted towards the 15 x 15 Goal.

Certain upstream measures can be measured directly in terms of kWh for the purposes of determining compliance. Other upstream measures produce energy savings in terms of BTUs – which is a measure of fuel usage at the generation level. In addition to upstream measures, other efficiency related programs also pose M&V challenges (i.e., the proliferation of plug-in hybrid electric cars).

In order to count these programs towards the 15 x 15 Goal, a generally accepted methodology needs to be adopted. It is beyond the scope of Working Group III to endorse specific programs, including those that directly impact the efficiency of the T&D system. Any T&D programs adopted as part of the EPS will need, like all program components, to be carefully evaluated. The following measurement approaches for these upstream programs could be considered:

- **Renewable distributed generation located on the customer side of the meter –** Where available, the actual output from each and every customer owned renewable generator should be tallied and counted towards the goal where the installation results in electricity savings and not export. In the absence of direct metering, estimates will need to be developed based on verified installed capacity and annual load factors specific to the technology, location, equipment and installation design, and pre-determined site specific factors.
- **T&D Loss Reductions** –T&D loss reductions could be calculated using load flow calculations on a test year basis. Calculation of loss reductions might be done in the following manner:

- A model of the transmission and/or distribution system at the beginning of a year would be created
- A model of the transmission and/or distribution system at the end of the year would be created
- Both models would be simulated using the historic load for the year
- The losses in kWh for each model would be calculated
- The efficiency gain in kWh for the given year would be calculated by subtracting the value of the losses at the end of the year from the value of the losses at the beginning of the year.

Lost and Unaccounted (L&U) for Energy

L&U studies could be performed periodically on an individual utility basis. Only reductions in company use and unaccounted for energy would be counted as efficiency savings. Some Working Group members did not endorse this approach. Moreover, natural gas utilities also have losses, but efficiency programs aimed at reducing those losses were not addressed by the Working Group.

Transmission Induced Generation Efficiency Recovery ("TIGER")

Generators operate less efficiently when transmission constraints exist, and generators may operate that otherwise would not need to be running. To capture efficiency increases resulting from alleviating the transmission constraints, the reduced use of fuel could be quantified and translated into kWhs. The efficiency savings could be calculated using a production simulation model in the following manner:

The system commitment and dispatch constraints would be modeled after the transmission improvements designed to reduce dispatch constraints. The base fuel requirement in BTUs could be calculated for both the before and after case. The system average heat rate before the system improvements would be calculated. The equivalent kWh of savings from the TIGER program could be calculated by [(Base Fuel Requirement in BTUs - New Fuel Requirements in BTUs)/(System Average Heat Rate)]. The gains here could also be counted from a gas efficiency perspective.

Generator Ancillary Services Efficiency Gains

Energy can be saved by installing more efficient equipment in the generating stations. To the degree that these savings are not captured through other means, the efficiency gains from such efficiency improvements should be captured in a manner similar to other efficiency measures installed in customer facilities. Protecting the potential confidentiality of the data will need to be considered.

Increased power plant efficiency measures

When power plants are generating power, more efficient generation equipment can result in a reduction in the unit's heat rate and a reduction in total fuel consumption. Other efficiency measures can also reduce the total fuel consumption of the unit. Since improvements in power plant efficiency result in an overall reduction in the heat rate, or BTUs consumed per kWh energy produced, the following formula is used to translate generator efficiency improvements into yearly efficiency savings in terms of kWhs [(Heat Rate Improvement)/(Base Heat Rate) x Base kWh output]. The result is the equivalent amount of kWhs in fuel saved the base generator would be able to generate. This amount could be used to reduce the annual electric consumption data or could be considered as contribution toward gas efficiency goal to the degree that efficiency gain occurs at gas-fired plants. Protecting confidentiality of data will need to be considered.

Efficient Electro-technologies - If efficient electro-technologies increase, the resulting additional load will need to be netted out through a proper estimation of the technology's resulting increased demand. The following approach should be considered to net out the impacts of efficient electro-technologies:

First a study should be performed to determine which technologies should be considered an efficient electro-technology. The study should also determine a multiplier that would be used to calculate the net energy savings for a technology[7]. As mentioned above, the baseline forecast should be adjusted to account for the eligible electro-technologies from the forecast. In the absence of directly metered data, surveys and other data collection processes, an evaluation process should be considered to establish the extent to which the technology has penetrated the market.

V. Benefit/Cost Test Options

Benefit/cost testing considers the dollar value of benefits compared to costs over the expected life of benefits created by a measure, a program, or a portfolio of programs. Various tests have evolved over time in an attempt to consider cost-effectiveness from a variety of perspectives. Some differences in application have also evolved in various areas as a way to address specific issues of importance in the area[8]. The benefit/cost tests adopted in a particular area reflect the importance that regulators and other policy makers in a jurisdiction place on various factors.

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[7] For instance, if a given technology saved 45,000 BTU of fossil fuel for each kWh of electricity used and an average of 9,000 BTUs were used to produce a kWh of electricity, a multiplier of 4 based on a savings of 36,000 BTU might be applied to that technology. Depending upon transmission constraints, the multiplier might vary from one location to another.

[8] An example of this is the Total Resource Cost Test (TRC) that is used in Massachusetts. In the Massachusetts version of the TRC, quantifiable non-resource effects such as benefits unique to low-income consumers are included in addition to the dollar value of all resource benefits expected over the life of the installed measures.

i.Menu of Tests

The Working Group reviewed benefit/cost testing practices in several jurisdictions and considered the applicability of those practices to New York[9]. For example, the California Standard Practice Manual describes five tests in common use today. The manual identifies the cost and benefit components and calculations from four major perspectives: Participant; Ratepayer Impact Measure; Program Administrator; and Total Resource Cost (TRC). The Societal test is viewed as a variation on the TRC. The results of the cost-effectiveness assessment can be expressed in a variety of ways, but in all cases it is necessary to calculate the net present value of program impacts over the lifecycle of those impacts. California does not require program administrators to assess the cost-effectiveness of informational programs in recognition of the challenges associated with evaluating the savings that can be attributed to these programs. A brief description of the five-benefit/cost tests described in the California Standard Practice Manual is provided in Appendix B of this report.

The Working Group considered how the attributes of each of the benefit/cost tests described in Appendix B align with the objectives of the EPS proceeding. The Working Group also considered how a March 2006 Commission order ruled on this issue as part of a Consolidated Edison rate case proceeding (Case - 04-E-0572).[10] The Commission endorsed the Total Resource Cost Test (TRC) The Commission concluded that "each

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[9] We reviewed material on benefit-cost tests from the PSC of Utah (Docket number 05-057-T01; Questar Gas Company; 1/16/07), Summit Blue Consulting ("Demand-Side Management: Determining Appropriate Spending Levels and Cost-Effectiveness Testing" - prepared for Canadian Associated members of Public Utility Tribunals; 1/30/06), Richard Sedano ("Including System Values in Cost Test for Energy Efficiency"- prepared for Southbeast Implementation Meeting for the National Action Plan; 9/28/07), the Iowa Utility Board, and the state of California ("California Standard Practice Manual - Economic Analysis of Demand Side Management Programs and Projects"; 07/02).

[10] Case 04-E-0572 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, *Order On Demand Management Action Plan* (March 16. 2006).

item included in the test must reflect real resources that are saved or incurred by society," The Commission allowed for some flexibility for programs that have a high degree of merit, but fail the TRC test. Based on these considerations, the Working Group developed several recommendations.

The consensus of the Working Group is that the Commission should assess program cost-effectiveness using a TRC test that may be modified to include other resource benefits beyond energy savings (e.g., the value of conserved water) and other quantifiable non-energy effects (e.g., the dollar value of reduced operation and maintenance expenses). The Working Group could not reach agreement on whether environmental benefits that are not already internalized in prices through, e.g., cap and trade programs, should be part of the calculated benefit. Although the Working Group was not able to reach full agreement about including these benefits in the test, there was some agreement that further study may be warranted.

Although not supported by all participating in our Working Group, some did express support for also including the Ratepayer Impact Test as a secondary benefit/cost test and a participant cost test to aid program design. It is unclear how the participant cost test would be applied to NYSERDA.

ii.Benefit-Cost Tests in Perspective

Regulators use benefit-cost tests as a guide for decision-making, but the benefit/cost ratio on its own should not be used to decide if an efficiency measure or program should be implemented. Decisions should reflect public values not embodied in the benefit/cost ratio. For example, Utah commented that even though a few specific DSM program measures either barely pass or barely fail some of the benefit-cost tests, inclusion of these measures might contribute to a net positive for the overall DSM portfolio. Some states have a minimum benefit-cost criterion for the total DSM portfolio and a lower minimum for certain priority programs. In Iowa, low-income programs are exempt from benefit-cost tests by statute. There is also precedent in New York for adopting this type of benefit-cost testing.

iii. Additional Recommendations

The Working Group recommends that the Evaluation Task Force, described later in this report, develop a list of recommended inputs to be used when assessing a DSM program's cost-effectiveness. In addition, the Working Group recommends that the Evaluation Task Force develop a common approach to be adopted by all Program Administrators when calculating avoided transmission and distribution costs and the impact of codes and standards.

VI. Role of the Evaluation Task Force

This section presents the current view of the Working Group on the Evaluation Task Force (ETF). Working Group 3 members agree that the ETF role must fit within the overall EPS governance structure that will be determined based on the efforts of Working Group 1. The ETF description that follows could fit within some of the governance structures being considered by Working Group 1. However, minor adjustments may be necessary after the final governance structure is decided.

The proposed ETF could reside within the overarching governance committee for the EPS programs. The role of the ETF could be modeled after the SBC Advisory Group and composed of: representatives of energy and environmental industries and associations, building trade associations, State agencies including the Department of

Public Service, consumer and equipment product manufacturer groups, NYISO and other organizations. All EPS program administrators would be represented on the ETF. This composition of the ETF will provide the balance and representation needed.

Like the SBC Advisory Group, the ETF would serve as the EPS Independent Program Evaluator, ensuring that all program administrators are evaluating programs and reporting results consistently and regularly. The ETF would also help ensure that all program results can be aggregated and reported on a statewide basis.

The process for the formal creation of the ETF is still unclear. One member of the Working Group suggested that it be created by a Memorandum of Understanding (MOU) between DPS and NYSERDA. Under the MOU, DPS and NYSERDA would provide the staffing and assistance needed for the ETF to fulfill its role. Some Working Group members expressed concern because NYSERDA would also have a role of as a PA.

The DPS Revised Staff Proposal of November 26, 2007 suggests that administrators of fast track programs will be required to contribute a small percentage of their program budget (less than one percent) to an evaluation and reporting task force established to deal with fast track programs. These funds will be made available to the ETF to hire consultants to assist in assessing the technical merit of plans and evaluations. Having program administrators set aside a small percentage of their program budgets for ETF staffing and assistance would also be a practical way to provide for support and assistance to the ETF over the long term, beyond the fast track program time period. General evaluation assistance consultants may be needed to provide additional staffing and assistance, but there was a lack of consensus relative to who should select and supervise these consultants. For organizations that are not within the Commission's jurisdiction, suggestions included DPS and/or NYSERDA and the ETF themselves. For the regulated utilities, the Commission and Staff would play a major role.

In consultation with any general evaluation assistance consultants hired to work with the ETF, DPS would oversee development of specific evaluation plans and reports for programs operated by utilities or other entities under the PSC's jurisdiction. There was a lack of consensus regarding who would coordinate the corresponding plans and reports for public-run programs not under Commission jurisdiction such as NYPA, LIPA, DASNY, DOS and DHCR and local governments. NYSERDA proposed that it could act in this coordinating role, although there has not been adequate discussion among Working Group members to determine if that is the best approach.

Prior to the launch of major EPS programs, the ETF would establish common terminology, direct measurement standards, statistical standards, and measurement and verification protocols (as necessary beyond what is defined within this report). Additionally, the ETF and any general evaluation assistance consultants hired on its behalf would provide overall guidance to:

- Oversee and guide implementation of the EPS evaluation effort.
- Coordinate evaluation, especially for customers participating in multiple programs under the auspices of multiple organizations,
- Coordinate cross-cutting, statewide evaluation studies, and possibly perform overarching process, impact and market evaluation studies, and
- Review program progress against stated goals, including suggesting adjustments based on performance.

Staff is investigating the possibility of working on the development of M&V protocols and sharing of data with multiple states. The Working Group, however, has not had the opportunity to consider this possibility.

Methods need to be established for handling the possible lack of unanimity and consensus on key issues and identifying the appropriate level of detail and specificity in developing standards and protocols. The Commission would provide the final determination for the organizations it regulates, but the Working Group did not reach a consensus as to how disagreements would be resolved involving organizations not under the Commission's regulatory authority. There was also disagreement relative to what statewide evaluation studies would be appropriate for the ETF to coordinate. Some felt that it should be limited to studies related to methodological issues(e.g., best practices for measuring free ridership) but others felt it should also include broad research areas that might be more efficiently conducted on a statewide basis(e.g., appliance sales, economic impacts of energy efficiency programs).

The following roles could be a part of the general EPS governance: reviewing goals proposed by EPS program administrators (both at a program level and across all programs collectively), and ensuring that programs offered by different administrators are complementary and not competing for customers in a counterproductive manner. While these roles are not specific to evaluation, the ETF may provide input on these issues.

i. Who Performs Evaluations?

Program evaluation efforts should be fully integrated with program design and implementation so that data and information on participants, non-participants, impacts, market effects, and other relevant metrics are collected regularly and cost-effectively throughout the programs' operations wherever possible. This data collection is naturally a role for program administrators to perform themselves or with the assistance of consultants or contractors.

Each program administrator would be responsible for the day-to-day management and conduct of evaluation activities for their programs using competitively selected third-party evaluation contractors. Management and conduct of these evaluations would be in accordance with the standards and protocols agreed to by the ETF, DPS and programs administrators, and the proposed evaluation plans.

Alternatively, general evaluation assistance consultants hired by the ETF could help develop the evaluation protocols and the ETF will determine which portions of each protocol will be the responsibility of the program administrator (primarily day-to-day data collection) and which portions will be conducted by competitively-selected third-party evaluation contractors supervised by the program administrators.

ii.Evaluation Budget

The DPS Revised Staff Proposal of November 26th recommended an evaluation budget of 5 percent of the overall program budget. Budgets for specific program could be higher or lower than five percent, but the overall evaluation budget would be capped at five percent. NYSERDA's System Benefits Charge (SBC) Program represents the most recent and broad evaluation effort in New York. SBC Program evaluation is conducted on a budget that is 2 percent of the total program budget. This experience indicates that an evaluation budget of 5 percent of the overall EPS program budget is necessary.

Reasons for a higher evaluation budget include:

- Higher confidence and precision levels will likely be necessary, especially in the area of measurement and verification, to ensure that the 15x15 goal is being met and to provide an adequate basis for lost revenue recovery or incentive payments if approved for utility program administrators.
- Confidence/precision levels of 90/10 (90% confidence that the savings are within 10% of the estimated value) for sampling purposes should be considered as target for EPS program M&V activities.
- Statewide studies to establish baselines, characterize markets, quantify energy efficiency saturation, and estimate energy efficiency potential are needed to provide an adequate basis for program development and refinement and goal tracking. Where possible, this information should be acquired by relevant geographic area such as utility service territory and up-state versus down-state versus Long Island. Studies of this magnitude have not been conducted under the SBC Program due to lack of funding.
- Updated avoided costs that will be used to assess program cost-effectiveness should be developed using consistent methodologies and assumptions, and taking into account cost differences by load zone.
- Development of a common approach for developing avoided transmission and distribution costs should be explored.
- Substantial staffing and support are required for the ETF to track progress of each individual program, among all programs, and toward the overarching 15x15 goal.

There was support for the budget proposal, but no complete consensus.

VII .Program Reporting

i.Data Consistency and Program Report Formats

Program reports should be standardized so that data on customers served, measures installed, and energy saved can be effectively compiled. This will simplify EPS reporting and monitoring progress toward goals. Program reporting could utilize standardized Excel spreadsheets so that data from multiple programs can be efficiently compiled. This process offers the advantage that it could be effectively implemented quickly, but would require further manual processing to compile the results of the entire EPS effort. An on-line reporting system could be utilized to reduce manual compilation tasks, but this approach would require development that could delay the process. Reports could be submitted quarterly on key program metrics. Program report content is listed below:

- Customers served
- Installations committed/in process (carefully defined: i.e. signed customer agreement/contract)
- Installations completed
- Energy Savings in Kwh or dt, kW demand reduction, DR delivered (Deemed) Funds spent and encumbered by key categories (Administration, Marketing, Direct Installation, incentives, evaluation) and overall program budget-- shown as percentage of allocated budget.
- Customer satisfaction/complaints
- Projected energy savings/demand reduction delivery schedule over upcoming quarter

ii. Report Timing

Detailed reports should allow for monitoring performance and optimizing resource allocations to maximize EPS results. Programs that are running above or below target would be subject to further assessment, from the standpoint of factors such as overall program methodology, target market, applicable technologies, and marketing approach. Programs that are exceeding targets might be considered for additional resources to capitalize on successes. The exact mechanism for making recommendations and changes may be an issue that will need to be addressed by Working Group 2. Major programmatic and funding changes may require Commission approval.

Appendix A

Process for Establishing Natural Gas Target

The following is a write up discussing Staff's process for establishing a target for natural gas efficiency. The majority of this information is taken from Staff's Initial Proposal. However, the material at the beginning is new and includes discussion of the different baseline forecasts reviewed by Staff. Staff welcomes discussion of these baselines and also exposure to any other forecasts parties have reviewed.

<u>Baseline Natural Gas Load Forecasts</u>

In preparing its Initial Proposal in the EPS Case, Staff reviewed three baseline forecasts: Optimal/EEA[11]; the Federal Energy Information Administration (EIA); and LDC forecasts. Following is a discussion of each.

The EEA forecast was used by Optimal Energy in its October 31, 2006 study entitled "Natural Gas Energy Efficiency Resource Development Potential in New York." The EEA forecast focused on all residential, commercial and industrial usage, including interruptible customers and transportation customers who purchase gas supply from third parties but rely on local distribution companies (LDCs) for delivery. EEA developed a forecast for the study for every year through the study period.

The EIA annually updates its forecast for natural gas usage. The forecast is done on a regional basis, not on a state basis, so one must make some assumptions about New York's share of the region's usage. The EIA forecasts use of all energy sources by sector, but does not distinguish interruptible customers from firm customers. Some definitions may be different between the EIA and other sources. For example, industrial

[11] Energy and Environmental Analysis, Inc.

customers who generate their own power may have their natural gas usage classified differently by the EIA than by EEA or the LDCs. Also, the EIA includes customers, such as power generators, that take gas directly from interstate pipelines within New York but are not LDC customers.

The LDCs annually present their five year forecast of demand to Staff as part of the winter supply review, the results of which are reported by Staff to the Commission at the October session every year. The data is proprietary and cannot be shared by Staff, although Staff may aggregate the data and make some results public.[12] The LDCs' forecasting focuses on peak day, design winter, and annual requirements of firm customers. For most LDCs, the peak day is forecast as the most extreme weather expected to occur in a 24-hour period in terms of degree-days.[13] In many years, the LDCs do not experience a peak day, but they must be prepared to do so. In addition, LDCs only plan to meet the load of firm customers on a peak day. Interruptible customers and temperature-controlled customers are not served on these days, and that includes electric generation for the most part. A design winter is generally based on the worst actual winter weather a LDC has ever experienced over the November through March time period. Annual requirements are based generally on the average degree-days for the last 30 years. Another important point is that LDCs classify customers differently within their service classifications. For example, one utility may categorize a multi-

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[12] Since there is no institution for natural gas analogous to the ISO on the electric side, it may be helpful for discussion purposes for WG3 if the LDCs were to make their peak day and design winter load forecasts available to the parties.

[13] For example, 75 degree days on a peak day would mean the average temperature was ten below zero, with perhaps a high temperature of zero and a low of twenty below zero.

family dwelling with five or more units as a residential customer, while another utility may categorize it as a commercial customer.

As can be seen by the above discussion, it is difficult to comparc each of these baseload forecasts since they include different customer groups and break down regional market sectors differently. Staff used the EEA forecast in its analysis in the Initial Proposal, becausc it seemed to be the most familiar to parties to the proceeding and provided a link to the electric efficiency targets since Optimal also performed that study. The following table provides a comparison of the three baseload forecasts (with the short term being defined as the period through 2011 and long term being defined as the period through 2016):

Source	Average Annual Growth Rate, Short Term	Average Annual Growth Rate, Long Term
LDC Data	0.98%[14]	Not applicable
Optimal Study	0.47%[15]	0.79%
EIA	0.79%	0.71%

[14] Based on LDC projections made as part of the 2006 Winter Supply Review Filings to Staff of the DPS.

[15] Staff calculated this number using the data that supports Figure 2.2 in the Optimal Study on page 2-6. It represents the projected growth in the residential, commercial and industrial sectors only.

Process for Development of Natural Gas Target

A. Introduction

Staff's analysis indicates that a natural gas reduction target of 15% percent by 2015 may be feasible. It should be noted that this target applies to residential, commercial, and industrial firm load, and not total gas usage, as discussed below.

Some natural gas utilities currently have energy efficiency programs, and NYSERDA's SBC programs result in incidental natural gas efficiencies. A higher level of commitment can produce further natural gas savings. In addition, it is expected that changes to building codes and appliance standards would boost gas savings levels.

B. Natural Gas Industry in New York State

Although there are a total of 18 natural gas local distribution companies (LDCs) in the State, several are very small and therefore were not included in Staff's analysis, which focused on the major LDCs.[16] Generally, these can be divided into upstate and downstate regions, with Con Edison, O&R, KEDNY/KEDLI, and Central Hudson being considered downstate LDCs and the rest being considered upstate LDCs.

The downstate region has been experiencing steady natural gas load growth. Although use per customer has been declining due to weatherization and the replacement of outdated equipment with newer, more efficient models, new customer attachments have been continuing. These attachments result from both conversion of oil or electric

[16] Those LDCs are the following: Central Hudson Gas and Electric Corporation (Central Hudson), Consolidated Edison Company of New York, Inc. (Con Edison), Corning Natural Gas (Corning), KeySpan Energy Delivery (KEDNY/KEDLI), National Fuel Gas (NFG), National Grid, New York State Electric and Gas (NYSEG), Orange and Rockland Utilities (O&R), Rochester Gas and Electric (RG&E), and St. Lawrence.

heat/hot water customers to natural gas usage and from new construction. The downstate load growth continues to constrain existing capacity. The upstate region has relatively stagnant growth, with shrinking use per customer generally offset by new customer attachments, except in the case of NFG, which is experiencing shrinking throughput on an annual basis.

At the present time, National Grid, Con Edison, NFG and KEDNY/KEDLI have natural gas efficiency programs in place. Some natural gas savings have also been achieved as an indirect benefit of the electric efficiency programs administered by the New York State Energy Research and Development Authority (NYSERDA), funded by the System Benefits Charge (SBC) program.

C. Efficiency Potential

There are several factors that need to be considered when developing reasonable goals, timetables, and programs for natural gas usage efficiency. First, while use per customer of electricity continues to increase due to innovations in consumer products (such as computers, cell phones, etc.), use per customer of natural gas continues to decline due to the lack of new end-use applications, increased efficiency of space and water heating equipment, and building envelope improvements. Second, natural gas is an important fuel choice for the generation of electricity, including micro combined heat and power distributed generation applications. Third, some electricity applications have natural gas fueled alternatives, such as clothes drying and water heating, which are generally more efficient than their electric counterparts. Finally, natural gas competes directly in many applications with petroleum products, including residual and distillate products, but natural gas contributes much fewer greenhouse gas emissions than petroleum products when providing the same level of service.

The focus of this Staff analysis is on residential, commercial, and industrial natural gas usage efficiency. There is potential for increased natural gas usage from possible increased use of distributed generation, from the conversion of existing power plants to natural gas fuel from petroleum or coal, and the construction of new gas fired power plants. That potential is not quantified in this analysis.

The potential for reductions in natural gas usage due to cost-effective energy efficiency improvements consists of several elements. They are: the savings to be achieved via the new efficiency programs, savings from existing natural gas efficiency programs, natural gas savings resulting from existing and possibly expanded SBC programs, and savings resulting from new building codes and standards. These elements are discussed below.

Potential Savings from New Programs

On October 31, 2006, NYSERDA released its study entitled "Natural Gas Energy Efficiency Resource Development Potential in New York" prepared by Optimal Energy, Inc. (Optimal Study). The Optimal Study objectives include:[17]

- Evaluate potential cost-effective natural gas efficiency savings (economic potential) in New York over a 10 year horizon
- Evaluate natural gas efficiency program designs and recommend programs for implementation

[17] Optimal Study, p. E-1. Optimal also performed a similar study for the Con Edison sales territory.

- Estimate the potential cost-effective natural gas efficiency savings in New York over a 10 year horizon resulting from the implementation of a portfolio of recommended efficiency programs given a specified funding level (program scenario)

The Optimal study concludes that the New York State economic potential is a 28% reduction in forecasted 2016 residential, commercial, and industrial gas demand. However, the authors of the study caution readers interpreting and using the analysis. They state that "the Economic Potential estimates do not account for market barriers to adoption of efficiency technologies or the costs of market intervention strategies to overcome those barriers." Based on the professional judgment of the authors, the maximum achievable savings potential is about 65% of the Economic Potential, or 18% of the expected 2016 residential, commercial, and industrial gas load, excluding power generation load[18]. The study finds the greatest potential savings could be realized from the commercial and residential sectors with the balance, approximately 14% of savings, derived from the industrial market sector. Costs associated with the maximum achievable savings, however, are prohibitive. Optimal estimates the net present value, in 2005 dollars, cost of the Economic Potential (28% savings) to be about $14 billion in net present value in 2005 dollars. However, Optimal estimates that costs to pursue maximum achievable savings would require spending about 30% in excess of measure costs to cover program delivery costs such as marketing, tracking, and monitoring, and evaluation, so that if the maximum achievable represents 65% of the Economic Potential, it would cost almost $12 billion (65% of $14 billion plus 30%) through 2015.

[18] The achievable savings as a percent of total gas demand (which includes power generation gas use) was not established, but would be about 12%, if use of gas for power generation remained unchanged from the predicted level.

The Optimal Study offered a Program Scenario, which is a subset of the maximum achievable savings potential, at a funding level of $80 million per year for five years (or approximately 1% of statewide gas utility revenues). When developing the allocation of funds for this scenario, the study sought to meet certain goals, including: "maintaining equity across sectors by matching sector-level spending to existing sector revenues; providing low income services, set at 50% of the residential budget; and providing a balance between short-term resource acquisition efforts and long-term market-transformation benefits. In addition, the study sought to provide program services targeting all New York gas customers and to address all important end uses. Finally, the study explicitly designed the recommended programs around broad markets, rather than specific customers and technology types." Measuring the results after ten years, Optimal projects that the efficiency savings would be 1.5% of the forecast residential, commercial, and industrial gas demand,[19] with total program costs of $400 million.[20]

As part of its analysis, Staff reviewed other natural gas efficiency programs in the country, in addition to the programs currently underway at some of New York State's LDCs. Of these, the KeySpan program stood out because KeySpan has been administering a natural gas efficiency program at its New Hampshire and Massachusetts affiliates for about ten years. KeySpan recently proposed to extend that program to its New York affiliates. The proposal was approved by the Commission and commenced implementation on August 1, 2007. KeySpan estimated natural gas savings of about 1.5% in the third year of the program for a cost of about $30 million, or about 1% of

[19] It should be noted that Optimal included interruptible customers in its analysis.

[20] Total expenditures do not include needed customer investments. For instance, the LDC may give a rebate of $300 for installation of a high efficiency furnace, but the furnace may cost the customer $3,000.

2004 combined total operating revenues for the two LDCs. KeySpan also indicated that it expected to experience savings in that range for an extended period of time, as much as ten years.

Staff sought to reconcile the differences between the results of the Optimal Program Scenario and the KeySpan Efficiency Program. First, KeySpan's initial estimates of savings percentages were based on 2005 actual throughput. When the percentages were recalculated as a percent of forecasted sales for the future period, the expected savings dropped to about 1.25%, since future load is expected to be higher. Second, the Optimal Study Program Scenario features expenditures for only five years. Optimal agrees that savings would certainly be higher in 2016 if expenditures continued at $80 million per year, after year five of their Program Scenario. Finally, the Optimal Program Scenario's program elements and expenditures differ from those of KeySpan.

The result of this analysis, to date, is that there appears to be a range of expected savings for the 2015 program year of about 6-10% of load, with spending of 1% of revenues. Additional analysis being performed by Staff will narrow this range.

KeySpan proposed ramping up its program spending to a level of $30 million for its New York affiliates, KEDNY and KEDLI, by the third year of the program. This fully ramped up funding level equates to roughly 1% of the combined total revenues of the two LDCs. If KeySpan's program were expanded to cover the entire state, it would equal about $80 million.

D. Savings from Existing Natural Gas Efficiency Programs

During the gas year of 2006-2007, there were some efficiency programs in place that resulted in savings of expected natural gas consumption. These fell into two categories: LDC programs and NYSERDA programs. Although NYSERDA does not currently have any major programs that specifically target natural gas efficiency, savings of natural gas is an auxiliary benefit of many of the System Benefits Charge (SBC) programs it administers. According to NYSERDA, the cumulative annual fuel savings of natural gas resulting from their SBC programs for 2006 was 2,888,854 MMBTU, or about 2,889 Mdt[21] This equals about one-third of a percent of expected total residential, commercial and industrial natural gas load for 2007 of 847,707,192 decatherms.[22]

Two LDCs, Consolidated Edison Company of New York, Inc. (Con Edison) and National Grid, had gas efficiency programs in place during 2006-2007. Both programs are administered by NYSERDA. In the most recent quarterly report, NYSERDA estimated that the Con Edison program saved customers a total of about 34 Mdt, which on an annual basis would equate to about 136 Mdt.[23] National Grid's program, which served only low income gas heating customers, saved about 32 Mdt in the 2006-2007 gas year.[24] The total of these two programs represents less than a tenth of a percent of expected 2007 natural gas load statewide.

KEDNY/KEDLI recently implemented a natural gas efficiency program for the coming year; they estimate first year natural gas savings of about 843 Mdt for New York and 364 Mdt for Long Island. While NFG does not provide estimated savings for its program, if this program is as successful as KeySpan expects its own program to be, it

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21 New York Energy $mart Program Evaluation and Status Report, Year Ending December 31, 2006, Final Report, released March 2007.

22 From the EEA load projections contained within the Optimal Study.

23 Case 03-G-1671, 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, Gas Efficiency Program Quarterly Report for the Period Ending March 27, 2007, prepared by the New York State Energy Research and Development Authority.

24 National Grid Low-Income Gas Customer Energy Efficiency Program Quarterly Report for the Period Ended March 31, 2007.

should see first year savings in the neighborhood of 600 Mdt. Totaling all LDC programs and the NYSERDA existing program savings, current spending on natural gas efficiency should result in savings of about 4,864 Mdt for the upcoming year. This represents about 0.6% of existing firm natural gas load from programs operated in a single year. Many of these programs are just starting, so as further experience is gained some ramp-up in savings can be expected.

The existing natural gas efficiency programs statewide would deliver annual savings of just over five tenths (0.5) percent of 2015 expected natural gas load. After nine years of operation (2007-2015), savings will be roughly 5% of 2015 firm load. Since some of those savings result from NYSERDA's programs, a significant increase in SBC funding would result in increased natural gas savings. Overall, increases to gas utility programs could save an additional 1,300 Mdt per year and increases to NYSERDA program could save perhaps 3,800 Mdt per year.

E. Building Codes and Appliance Standards

Changes in building codes at the State level would make new construction in both the residential and commercial sector more energy efficient. Changes in appliance standards, such as making residential dishwashers or commercial boilers more energy efficient, could be accomplished through federal legislation or rulemakings or through New York State standards. It is expected that changes in building codes and appliance standards will result in savings of about another 2% of 2015 expected natural gas load.[25]

If existing programs, expected increases to the SBC programs, and expected changes in codes and standards are totaled, it would equal about 11% of expected 2015

[25] An American Council for and Energy-Efficient Economy study shows that total saving from codes and standards is expected to be about 19,000 billion BTU of gas in 2015.

load. If additional efficiency could be gained by implementing new natural gas efficiency programs totaling 2 to 6% of 2015 load, which is possible with spending of about 1% of total statewide annual natural gas utility revenue, savings of about 13 to 17% of 2015 load is achievable. Increasing spending on new programs to 1.5% of total revenues could raise that to the range of 16 to 20%.

Appendix_B

Benefit/Cost Tests

The following is a summary of the benefit/cost tests as defined in the California Standard Practice Manual[26]:

Participant Test - In this test, the benefits of participation in a DSM program include the reduction in the customer's utility bill, any incentive paid by the utility or third party, and any federal, state or local tax credit received. In the case of fuel substitution, benefits to the participant also include the avoided capital and operating costs of the equipment/appliance not chosen. The reductions to the utility bill are calculated using the actual retail rates charged for the energy service that would have been provided. Savings estimates are based on savings that are seen at the Participant level (at the meter).

The costs to a customer from program participation are all out-of-pocket expenses incurred as a result of participating in a program, plus any increases in the customer's utility bill. Out of pocket costs can include the cost of equipment or materials purchased, including sales tax[27] and installation, any ongoing operation and maintenance costs, any removal costs, and the value of the customer's time.

Program Administrator Cost Test – This test assesses cost-effectiveness from the perspective of the program administrator with the DSM program viewed as a resource comparable to traditional supply. The costs included in this test include the costs incurred by the program administrator. Participant costs are excluded in this assessment.

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[26] The state of California ("California Standard Practice Manual - Economic Analysis of Demand Side Management Programs and Projects"; 07/02. This the primary source of data used in this section.

[27] Some jurisdictions exclude all tax payments and tax credits. They are considered a transfer payment.

The benefits quantified in this test include the avoided supply costs of electric energy, generation, transmission, and distribution capacity, and natural gas valued at marginal costs for the period when there is a load reduction.

The costs included in this assessment arc the program costs incurred by the administrator, the incentives paid to the customers by the program administrator, and the increased supply costs for the periods where load is increased.

In this test, revenue shifts are viewed as a transfer payment.

Ratepayer Impact Measure Test - This test measures what happens to customer bills or rates due to changes in utility revenue and operating costs caused by the program. It serves a similar function to what we in New York call the "Non-Participant Test". Rates are essentially costs divided by loads. Under DSM programs, both may fall, and the RIM is used to assess the impact on rates of a simultaneous drop in both costs and loads.

The benefits calculated in the RIM test are the savings from avoided supply costs. These include reduction in costs of electric energy, generation, transmission, and distribution capacity, and natural gas for periods when load has been reduced and the increase in revenues for any periods when load has been increased. The avoided supply costs are a reduction in total costs and are included for botb fuels for a fuel substitution program.

Tbe costs for the test are the program costs incurred by the utility or any other entity incurring costs of creating or administering the program, the incentives paid to the participant by the program administrator, decreased revenues for any periods in which load has been decreased and increased supply costs for any periods when load has been increased. The utility program costs include initial and annual costs such as cost of equipment, O&M, installation, program administration, and removal of equipment.

In contrast to most supply options, DSM programs cause a direct shift in revenues. The RIM test is the only test that reflects this revenue shift along with the other costs and benefits of the program. Revenue decoupling mechanisms (RDM's) allow utilities to raise their rates enough for programs to pass the Program Administrator Cost Test, but this also means that RDM's make it harder for the programs to pass the Ratepayer Impact Test.

Total Resource Cost Test – The TRC Test is similar to the Program Administrator Test. It also considers the resource value of a demand-side management program. Unlike the Program Administrator Test, the TRC includes both the ratepayer and the program administrator costs. It represents the combined effects of a program on both the participating customers and those not participating in a program.

The benefits calculated in the TRC Test are the avoided supply costs, including the reduction in costs of electric energy, generation, transmission, and distribution capacity, and natural gas, valued at marginal cost for the periods when there is a load reduction.

The program costs are those paid by the utility and participants plus the increase in supply costs for any period when load is increased. All equipment, installation, O&M, cost of removal, and administration costs are included. In some jurisdictions, tax credits are considered a reduction to costs in this test. Other jurisdictions exclude tax consequences from the assessment of cost-effectiveness. These tax effects are considered to be a transfer payment.

Societal Test - The Societal Test is a variation of the TRC test. The Societal Test differs from the TRC Test in that it includes the effects of externalities (e.g. environmental, national security).

The Societal Test is structurally similar to the TRC Test. It goes beyond the TRC Test in that it attempts to quantify the change in the total resource costs to society as a whole rather than to only the service territory (utility and ratepayers). There are five ways the Societal Test can differ from the TRC:

The Societal Test may use higher marginal costs than the TRC Test if a utility faces marginal costs that are lower than other utilities in the state;

tax credits are treated as a transfer payment and thus are left out;

in case of capital expenditures, interest payments are considered a transfer payment;

a societal discount rate should be used;

marginal costs used in the Societal Test would also contain externality costs of power generation and combustion of natural gas not captured by the market. These values are also referred to as "adders" designed to capture or internalize such externalities. They can include

- Benefit of avoided environmental damage
- Benefit of increased system reliability
- Non-energy benefits - e.g. saved water, help for low-income customers
- Benefits of fuel diversity

In Iowa, the Societal Test is the defining test for programs and plans.

The primary strength of this test is in its scope. Also, since the test treats incentives paid to participants and revenue shifts as transfer payments, the test results are unaffected by uncertainties regarding projected rates.