



Enver Acevedo  
Associate Counsel  
Law Department  
Consolidated Edison Company of New York, Inc.  
4 Irving Place, Room 1815-S, New York NY 10003  
Tel.: 212-460-3762 Fax: 212-677-5850  
Email: acevedoe@coned.com

September 28, 2018

Honorable Kathleen Burgess  
Secretary  
State of New York Public Service Commission  
Three Empire State Plaza  
Albany, NY 12223-1350

Re: Case 17-G-0606 – Petition of Consolidated Edison Company of New York, Inc. for  
Approval of the Smart Solutions for Natural Gas Customers Program

Dear Secretary Burgess:

In its September 2017 Petition in the above-referenced proceeding, Consolidated Edison Company of New York, Inc. (“Con Edison” or “Company”) advised the Commission that it was developing a Benefit-Cost Analysis (“BCA”) Handbook to evaluate programs to benefit its natural gas customers. The Company said that it would use the BCA Handbook as a guide for preparing a BCA for responses to its Non-Pipeline Solutions RFP and, eventually, for evaluating other initiatives. Con Edison stated that it would provide stakeholders with an opportunity to review and comment on a draft of the Handbook in early 2018, and would file a copy of the completed document with the Commission.

On February 21, 2018, Con Edison filed a draft of its BCA Handbook with the Commission and posted an electronic version of the document on its Non-Pipeline Solutions webpage. The Commission invited stakeholder comments on the document, and indicated that it will permit the Company to utilize its planned methodology until further guidance is provided. Accordingly, the Company hereby submits for informational purposes a version of its BCA Handbook that reflects some of the modifications suggested by stakeholder comments (the “Interim BCA Handbook”).

The Interim BCA Handbook includes several revisions intended to clarify how greenhouse gas benefits will be determined. Specifically, revisions have been made to clarify that the greenhouse gas benefits and costs directly attributable to local supply measures will be recognized in the BCA for such measures. For example, the methane emissions avoided by processing waste into Renewable Natural Gas (“RNG”) will be recognized as will the additional fuel used to compress or liquefy natural gas associated with deliveries of CNG or LNG to Con Edison’s gas distribution system. Con Edison believes that these revisions will enable the Company to capture verifiable greenhouse gas emissions impacts associated with local supply options and do not conflict with the Commission’s preferences.

A stakeholder meeting regarding Con Edison’s concurrent NPS Portfolio Filing has been scheduled on October 12, 2018. Additional questions regarding Con Edison’s BCA framework may be raised at that event.

If there are any questions, please contact me.

Sincerely,

*/s/ Enver Acevedo*

Attachment



# **Interim Benefit Cost Analysis Handbook for Non-Pipeline Solutions**

September 28, 2018

---

### BACKGROUND

Consolidated Edison, Inc. (Con Edison) provides an expansive portfolio of energy-related products in the Northeastern states. It serves the electrical needs of approximately 3.7 million customers and provides gas service to approximately 1.2 million customers through two regulated subsidiaries: Consolidated Edison Company of New York, Inc., which provides electric, gas and steam services to New York City and Westchester County; and Orange & Rockland Utilities, Inc., which provides electric and gas services in Rockland County and Orange County of New York State, and electric service in portions of northern New Jersey.

Con Edison's natural gas market is growing rapidly principally due to customer conversions from fuel oil to natural gas heating, and growth is expected to continue in the future. To meet customer needs, Con Edison will require additions to its supply portfolio and gas distribution system. However, traditional sources of incremental peak period supply may not be readily available. Through the solicitation and development of non-pipeline solutions Con Edison seeks to find new solutions to find cost-effective alternatives to traditional interstate pipeline and distribution system expansions. Some examples of non-pipeline solutions are renewable natural gas (RNG), local gas storage, including compressed natural gas (CNG) and liquefied natural gas (LNG), environmentally advantageous fuel switching, and demand response.

This Interim BCA Handbook was developed to assist in the evaluation of demand-side reductions and/or non-traditional local supply-side additions. The BCA approach included herein is based on the Standard BCA Handbook, which was developed by Con Edison in collaboration with the New York Joint Utilities to provide consistent and transparent statewide methodologies for electric non-wires solutions and other electric demand-side measures.<sup>1</sup> Wherever suitable, this Interim BCA Handbook considers and takes into account the guidance provided by the New York State Public Service Commission in the BCA Order on Non-Wires Solutions BCA.<sup>2</sup>

The Interim BCA Handbook presents applicable BCA methodologies and describes how to calculate individual benefits and costs as well as how to apply the necessary cost-effectiveness tests for performing a complete BCA. The Interim BCA Handbook also presents general BCA considerations and notable issues regarding project and investment benefits assessments. Definitions and equations for each benefit and cost are provided along with key parameters.

---

<sup>1</sup> "Benefit Cost Analysis (BCA Handbook) Version 1.1", August 22, 2016.

<sup>2</sup> Case 14-M-0101 "Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision", Order Establishing Benefit Cost Analysis Framework, January 21, 2016.

## Table of Contents

<b>ACRONYMS AND ABBREVIATIONS</b>	iv
<b>1. INTRODUCTION</b>	<b>1</b>
<b>2. GENERAL METHODOLOGICAL CONSIDERATIONS</b>	<b>3</b>
<b>2.1 General BCA Considerations</b>	<b>3</b>
2.1.1 Establishing Appropriate Time Horizon for Evaluation	3
2.1.2 Performance Sensitivity Analysis	3
<b>2.2 Broad NPS Related BCA Considerations</b>	<b>3</b>
2.2.1 Incorporating Company Retained Gas into Analyses	3
2.2.2 Accounting for Benefits and Costs across Multiple Value Streams	4
<b>3. KEY NPS RELATED BENEFITS AND COSTS</b>	<b>5</b>
<b>3.1 Summary of NPS Related Benefits and Costs</b>	<b>5</b>
3.1.1 Main Benefit Categories	5
3.1.2 Main Cost Categories	5
3.1.3 Applicable Units	6
<b>3.2 Timing of Impacts</b>	<b>6</b>
<b>3.3 Key NPS Related Benefits</b>	<b>7</b>
3.3.1 Avoided Upstream Supply Costs	7
3.3.1.1 Definition	7
3.3.1.2 Setting Baseline for Evaluation	7
3.3.1.3 Estimating Project Specific Benefits – Fixed Costs of Avoided Upstream Supply	8
3.3.1.4 Estimating Project Specific Benefits – Variable Cost of Avoided Upstream Supply	10
3.3.2 Distribution System Benefits	11
3.3.2.1 Avoided Distribution System Capacity Infrastructure	11
3.3.2.2 Avoided Distribution O&M	13
3.3.3 Reliability/Resiliency Benefits	14
3.3.4 External Benefits	14
3.3.4.1 Avoided Greenhouse Gas Emissions	14
3.3.4.2 Other Avoided Emissions	15
3.3.4.3 Net Non-Energy Benefits	16
3.3.4.4 Other External Benefits	16
<b>3.4 Costs Analysis</b>	<b>16</b>
3.4.1 Program Administration Costs	16
3.4.2 Incremental Distribution System Investments	17
3.4.3 Lost Utility Revenue	17
3.4.4 Participant NPS Costs	17

3.4.5	Alternative Fuel Costs	18
3.4.6	External Costs	19
3.4.6.1	Alternative Fuel CO <sub>2</sub> Emissions	19
3.4.6.2	Alternative Fuel Other Emissions	20
3.4.6.3	Net Non-Energy Costs	20
3.4.6.4	Other External Costs	21
<b>4.</b>	<b>RELEVANT COST-EFFECTIVENESS TESTS</b>	<b>21</b>
4.1	<i>Applicability of the Societal Cost Test</i>	22
4.2	<i>Utility Cost Test</i>	22
4.3	<i>Rate Impact Measure</i>	22
4.4	<i>Applying the Cost-Effectiveness Tests</i>	22
<b>5.</b>	<b>HIGH-LEVEL EXAMPLES</b>	<b>24</b>
5.1	<i>Renewable Natural Gas Example (RNG)</i>	25
5.1.1	Example System Description	25
5.1.2	Considerations Surrounding BCA Parameters Associated with RNG Projects	25
5.2	<i>Local Storage – CNG</i>	27
5.2.1	Example System Description	27
5.2.2	Considerations Surrounding BCA Parameters Associated With CNG Projects	28
5.3	<i>Energy Efficiency Example</i>	29
5.3.1	Considerations Surrounding BCA Parameters Associated with EE Projects	29
5.4	<i>Demand Response</i>	31
5.4.1	Considerations Surrounding BCA Parameters Associated With DR Projects	31
5.5	<i>Gas To Electricity Conversion</i>	33
5.5.1	Considerations Surrounding BCA Parameters Associated with G2E Projects	33
5.6	<i>Derating Considerations Related To Duration of Supply / Load Impact</i>	34

## List of Tables

TABLE 4 - 1	COST-EFFECTIVENESS TESTS	21
TABLE 4 - 2	COMPONENTS APPLICABLE TO BCA TESTS	23
TABLE 5 - 1	KEY ATTRIBUTES OF SELECTED NPS TECHNOLOGIES	24
TABLE 5 - 2	APPLICABILITY OF EACH BCA CATEGORY TO NPS TECHNOLOGY	25

### I. ACRONYMS AND ABBREVIATIONS

Acronyms and abbreviations are used extensively throughout the Interim BCA Handbook and are presented here at the front of the Handbook for ease of reference.

BCA	Benefit-Cost Analysis
BCA Order	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit-Cost Analysis Framework (issued January 21, 2016).
CO <sub>2</sub>	Carbon Dioxide
Commodity Cost	The cost of natural gas at wholesale prices
CRG	Company Retained Gas, as further defined in Section 2.2.1.
Delivered Services	Gas supply services delivered to the city-gate acquired from a third-party (not a pipeline)
DR	Demand Response
Dth	A dekatherm of natural gas; an industry standard term referring to a quantity of natural gas containing 1 million British thermal units of energy, and represents about 1,000 cubic feet of natural gas
LBMP	Locational Based Marginal Prices
MMBtu	Million Btu's or one dekatherm
NO <sub>x</sub>	Nitrogen Oxides
NPS	Non-Pipeline Solutions
NYISO	New York Independent System Operator
O&M	Operations and Maintenance
Renewable Natural Gas	Pipeline quality gas (primarily methane) that has been recovered from a biological or other process (generally diverted from waste streams such as landfills, animal manure and waste treatment facilities) and upgraded to be compatible with other gas supplies delivered to customers
RIM	Rate Impact Measure
SCT	Societal Cost Test
SO <sub>2</sub>	Sulfur Dioxide
T&D	Transmission and Distribution
UCT	Utility Cost Test

## 1. INTRODUCTION

This handbook (“Interim BCA Handbook”) lays out a framework for calculating the benefits and costs of projects and investments associated with the procurement of Non-Pipeline Solutions, either through competitive acquisition programs or tariffs. Non-Pipeline Solutions are projects or programs that provide incremental gas supply, or displace or eliminate customers’ peak day requirements for gas, and do not involve the construction of new pipeline infrastructure. These investments can include the construction of on-system supply resources (e.g., CNG, LNG, or RNG) or the implementation of programs or technologies that reduce customer load requirements, with a focus on peak day needs. Con Edison is currently interested in investments and programs that have the benefit of reducing or eliminating Con Edison’s need to acquire upstream capacity and supply and may also reduce capital expenses related to on-system distribution requirements. An overriding principal is that any such investment or program produce results that do not fundamentally affect the core reliability of the service provided to Con Edison customers.

The BCA framework set out herein is guided by the principles that a BCA should, insofar as possible:

1. Be based on clear methodologies
2. Strive to identify and evaluate all benefits and costs, but recognize the need to use broader assumptions at times (e.g., when more granular details are not readily available or reasonably quantifiable)
3. Evaluate projects and programs within the broader context of a portfolio (rather than as individual measures or investments), allowing for consideration of potential synergies and economies across the portfolio
4. Address the full lifetime of each investment
5. Provide an assessment of the underlying risk of performance of an investment or program via sensitivity analysis on key assumptions
6. Compare benefits and costs to traditional alternatives instead of valuing them in isolation

The handbook reviews key considerations and methodologies affecting BCA as it relates to NPS. This includes a review of core valuation parameters applicable to the BCA of NPS, specific categories of costs and benefits associated with NPS, discussion of various input assumptions and possible sources for deriving these inputs, and associated modeling methodologies applicable to a broad range of such projects. Specific projects or portfolios will generally require additional, project-specific information, inputs, assumptions, and adjustments to the generic methodologies summarized herein.

The handbook also reviews the three key tests that will be used to assess the benefits and impacts of each proposed project/program. The results of these tests are used to arrive at overall recommendations regarding approval of portfolios of projects.

The methodology underlying the handbook is intended to be technology-agnostic and should be broadly applicable to all anticipated projects and portfolio types, with modest adjustments as necessary.

## Structure of the Handbook

The handbook is organized as follows:

- |                  |  |
|------------------|--|
| <b>Section 2</b> | Summarizes general BCA parameters and considerations applicable to any NPS project. These include the time horizon applicable to an associated NPV analysis, |
|------------------|--|



treatment of Company Retained Gas, and accounting for benefits and costs across multiple value streams.

- Section 3** Details a number of benefits and costs that are specific to NPS investments. Definitions are provided for each category as well as theoretical calculation methodologies and associated complexities surrounding such evaluations.
- Section 4** Reviews the three cost-effectiveness tests that will be used to evaluate each proposed project or investment once the various costs and benefits are identified, evaluated, and present valued.
- Section 5** Reviews the BCA framework and associated analytical challenges through its high-level application to five hypothetical examples: A) a baseload on-system supply via a renewable gas supply alternative, B) a dispatchable supply via a CNG storage alternative, C) a load-reduction option via a gas to electricity fuel switching technology, D) a load-reduction option via an energy efficiency program, and E) a load-reduction option via a demand response program.

## 2. GENERAL METHODOLOGICAL CONSIDERATIONS

Consistent with the guiding principles for BCA summarized in Section 1.1, there are numerous parameters and considerations applicable to any BCA. Likewise, any NPS specific project will have common characteristics that merit consideration in an associated BCA. This section reviews these considerations. Section 3 then provides a more detailed discussion of various benefits and costs that vary based on the specifics of a proposed NPS investment or project.

### 2.1 General BCA Considerations

#### ***2.1.1 Establishing Appropriate Time Horizon for Evaluation***

Any BCA analysis must consider the appropriate time horizon for evaluating associated benefits and costs. Programs and projects, such as those under consideration for NPS, have multiple components, including associated hardware, software, and related direct and indirect benefits and costs. Each component must be assessed independently and a relevant time horizon or associated effective useful lifetime established. For the purposes of this Interim BCA Handbook, the relevant timeframe for each BCA analysis will be the projected life of the specific program or project being evaluated. Authoritative sources and engineering judgment will be used to determine measure lives.

#### ***2.1.2 Performance Sensitivity Analysis***

Comparative analysis of projects, or portfolios of projects, can benefit from an assessment of their expected performance relative to each other under different conditions. To assist in this process, sensitivity analyses may be utilized to identify those assumptions and factors that are key to determining the overall net benefit of a project or portfolio.

### 2.2 Broad NPS Related BCA Considerations

The following reviews several analytical considerations that are generally applicable to any BCA analysis of a proposed NPS investment or project.

#### ***2.2.1 Incorporating Company Retained Gas into Analyses***

In calculating a benefit or cost resulting from an NPS program or investment, it is important to be cognizant of where such benefits or costs are measured relative to each other. In particular, the analysis must account for any between the point the gas is consumed at the customer's meter and the point the gas is originally acquired and avoided commodity or other savings measured at the city gate. Company Retained Gas can be accounted for either by adjusting the impact parameter (i.e., the benefit or cost measured on a unit of energy basis at the customer meter) or the valuation parameter (i.e., the benefit or cost measured on a unit of energy basis at the point of supply into the system). The following Company Retained Gas-related nomenclature is used in this Interim BCA Handbook:

- **Company Retained Gas** – The difference between the total quantity of gas sent-out or produced at a specific source of supply and the total quantity of gas utilized by an end-use (measured via customer revenue meters). This difference will primarily include fuel used for compressors and heaters, but will also include losses that represent natural gas that is delivered, but not properly measured by customer revenue meters.
- **Avoidable Company Retained Gas** – That Company Retained Gas quantity that may be avoided through the reduction of demand at the customer revenue meter or sourcing of supply at the customer delivery point. This differs from Con Edison's standard lost and unaccounted for percentage in that it refers only to the physical quantity of gas associated with Con Edison's fuel used to support system operations (e.g., for compressors and heaters). Losses related to leakage and inaccurately measured customer revenue meters are not directly avoidable via NPS programs or projects. The Avoidable Company Retained Gas is represented herein by the term CRG.

For consistency, the Interim BCA Handbook accounts for all Company Retained Gas by adjusting the impact parameter. As such, the per unit impact parameter must be increased by grossing up the impact parameter (measured at the customer's meter) for Company Retained Gas (i.e., dividing by  $(1 - \text{CRG})$ ). The key, however, is that calculations of benefits and costs should be presented and evaluated on a consistent basis with respect to such use.

### ***2.2.2 Accounting for Benefits and Costs across Multiple Value Streams***

Any given NPS project has the potential to provide benefits or impose costs across multiple value streams. For example, a CNG facility may provide the benefit of avoided upstream pipeline capacity, avoided city-gate supply and, based on its specific placement on the system, also allow the utility to avoid investment in incremental on-system distribution capacity. All three benefits should be incorporated into the BCA. Thus, a CNG project with 5 MMBtu/day of deliverability installed at location A may avoid the need to acquire incremental pipeline capacity, avoid the need for city-gate purchases of commodity (i.e., collectively, Avoided City Gate Costs) and also defer investment in on-system distribution capacity (i.e., Avoided Distribution Costs).

Care should be taken to avoid double counting of measured benefits or costs. Double counting can be avoided by: (1) careful tracking of the value streams resulting from multiple investment elements in a project, program, or portfolio; and, (2) clear definition and differentiation between the benefits and costs, and (3) careful consideration of how the related value propositions interact.

### 3. KEY NPS RELATED BENEFITS AND COSTS

The following reviews key benefits and costs that are specific to NPS investments and key to any associated BCA. Definitions are provided for each category, as well as theoretical calculation methodologies and complexities surrounding estimating associated future costs and benefits. While this section has been divided into a discussion of Benefits and a separate discussion of Costs, several of the items can fall into either category (e.g., negative benefit).

#### 3.1 Summary of NPS Related Benefits and Costs

##### 3.1.1 Main Benefit Categories

Benefits are divided into four main categories:

##### **Fixed and Variable Avoided**

##### **Upstream Supply:**

Benefits derived from avoiding the need to acquire or invest in infrastructure or incremental supply resources that deliver gas to Con Edison's city-gate (e.g., interstate pipeline capacity or Delivered Services). These generally consist of avoided fixed costs (e.g., capital expenses and/or demand charges) and associated avoided variable costs (e.g., volumetric charges for the costs associated with the physical delivery of natural gas molecules to the city-gate)

##### **Avoided Distribution Expense:**

Benefits derived from avoiding the need to invest in on-system distribution infrastructure. These generally consist of avoided carrying charges for capital additions necessary for expanding or upgrading the distribution system to accommodate new business and/or avoided O&M related to maintaining on-system infrastructure

##### **Reliability/Resiliency:**

Benefits that may be derived from specific NPS projects in the form of greater resiliency of the distribution system (e.g., those providing pressure support at key locations) or ability to avoid system outages or recover more quickly from any such outages.

##### **External Benefits:**

Indirect benefits associated with an NPS project or program, such as reduced emissions or other societal benefits not primarily recognized by the utility via customer bill charges or other payment mechanisms.

##### 3.1.2 Main Cost Categories

Costs are divided into six main categories:

##### **Program Administration:**

Administrative related costs directly associated with implementing an NPS project or program. These can include costs associated with setting up a program,

	ongoing costs associated with monitoring and accounting for a program, and incentives paid to participants.
<b>Incremental Distribution:</b>	Infrastructure costs incurred by the utility to support the implementation of the NPS project or program.
<b>Lost Utility Revenue</b>	Lost gas revenue from reduced NPS participant demand.
<b>Participant NPS Cost</b>	Costs incurred by NPS providers, including equipment and participation costs assumed by participants or providers, net of payments to provider or incentive/rebates to participants.
<b>Alternative Fuel Costs (Electricity):</b>	Cost of using an energy source other than gas as a replacement for the service previously provided by gas.
<b>External Costs:</b>	Indirect costs associated with an NPS project or program, such as increased emissions or other societal costs not primarily paid for by the utility or its customers, to the degree such costs are recognized in the broader market.

### 3.1.3 Applicable Units

Benefits and Costs are generally measured as either capacity related or volumetric related:

- **Capacity Measures** – These relate to impacts associated with peak day capacity to deliver gas to customers. These are generally represented as \$'s per Dth of peak day impact. Benefits or costs that are capacity in nature are those that can avoid or incur incremental capacity or deliverability.
- **Volumetric Measures** – These relate to impacts associated with consumption. They are generally represented as \$'s per Dth. Benefits or costs that are volumetric in nature are those that are associated with actual (or avoided) consumption. These may be realized on peak day but may also be realized on others days.

## 3.2 Timing of Impacts

For the purposes of BCA analysis of NPS projects, the timing of benefits and costs should be accounted for as follows:

- **Commodity and Operational** – Benefits and costs associated with commodity (e.g., increases or decreases in quantities consumed) or operational activities (e.g., associated O&M expenses) should be assumed to occur in the same year as the underlying projected impact. In other words, a program that reduces consumption in year X should be treated as having an associated benefit in year X.
- **Capacity and Infrastructure** – Direct costs associated with capital investments or infrastructure changes should be assumed to occur in the year incurred. Benefits (or costs) associated with such investments should be assumed to occur in the year that actual effects occur (i.e., the benefits or costs are actually realized). For example, if a project reduces system peak load in 2019 but the portfolio of assets cannot be modified in 2019 to account for this reduction (due to prior commitments to

upstream contracts) then no benefit should be recognized in that year. Any benefit should not be recognized until such time as the portfolio can be adjusted. However, to the degree NPS impacts are known ahead of time and accommodated into portfolio planning, the associated benefit should be credited to the project at the time the impacts are realized.

### 3.3 Key NPS Related Benefits

#### 3.3.1 *Avoided Upstream Supply Costs*

##### 3.3.1.1 *Definition*

A key focus of investing in NPS projects and programs is to avoid the cost of acquiring incremental supply resources (e.g., pipeline or Delivered Services) that deliver to Con Edison's city-gate. Upstream supply resources generally have two key cost components:

<b>Fixed Costs</b>	Fixed annual expenses, such as for pipeline demand charges or fixed demand fees, associated with securing the right to supply at the city-gate
<b>Commodity Costs</b>	Variable expenses associated with the delivery of actual physical commodity, generally on an as required basis

Upstream supply resources can be acquired through a variety of means. Much of Con Edison's gas transportation portfolio includes firm contractual rights to interstate pipeline capacity that may be used to ship gas from producing regions to Con Edison's city-gate. For a fixed annual cost (i.e., the underlying demand charge associated with the contract) these assets provide firm supply at Con Edison's city-gate based on the cost of commodity at the applicable upstream supply point (e.g., Gulf supplies or Appalachian basins) plus a small additional fee associated with the pipeline's variable shipping costs and fuel expenses. Alternatively, Con Edison may acquire Delivered Services from a third-party directly at Con Edison's interstate city-gate. In such cases the third-party holds upstream assets (either a single pipeline contract or a portfolio of assets) that enable it to provide firm supply directly to Con Edison.

NPS programs and investments that provide firm supply on peak days (or reduce peak day gas supply requirements) have the benefit of reducing Con Edison's need to acquire incremental pipeline or Delivered Services. As such, there is a direct benefit from such programs or investments in the form of avoided pipeline or Delivered Service expenses. BCA of NPS programs and investments should account for these avoided expenses.

##### 3.3.1.2 *Setting Baseline for Evaluation*

The specific Avoided Upstream Supply Cost associated with an NPS program or investment is a function of the contractual rights to a particular upstream pipeline capacity resource or Delivered Supply resources that Con Edison would otherwise acquire to meet the associated gas delivery requirements of its customers. As part of any NPS solicitation and/or program review, Con Edison must assess the portfolio of upstream pipeline capacity and supply alternatives available to it that it would otherwise acquire to cover its projected gas supply requirements. The costs associated with these upstream assets then determine the benefit of avoiding such services through the acquisition of NPS options.

At any given point it is unlikely Con Edison will be faced with one discrete option for acquiring incremental upstream supply. Rather, under most circumstances multiple options will be under consideration, each with its own set of fixed and variable costs. Each option will also have a unique set of associated characteristics, such as estimated time between the decision to acquire the asset and actual availability of the asset (i.e., pipeline permitting and construction lead times), timing risks (i.e., risks associated with meeting proposed in-service dates), trade-offs between fixed and variable costs, firmness of supply, duration of the asset (i.e., number of days it can perform), counterparty credit risk of the upstream provider, minimum contract size, and related factors.

Likewise, the ability of specific NPS projects or programs to defer or otherwise avoid the acquisition of the contractual rights to an upstream supply asset also depends on a number of characteristics, including timing of the proposed project, duration of the impact, relation to other NPS projects/programs and their associated characteristics, and cumulative size of the impact of the whole portfolio of NPS relative to any minimum commitments required by upstream suppliers. This is particularly true in the case of upstream pipeline resources which tend to require large and discrete commitments to be viable. As such, the combination of upstream supply options and NPS proposals must be evaluated as a portfolio to assess the overall potential for cost avoidance.

### 3.3.1.3 *Estimating Project Specific Benefits – Fixed Costs of Avoided Upstream Supply*

Project/program specific benefits associated with avoiding financial commitments to acquire contract rights to upstream pipeline capacity or Delivered Supply resources related in nature (i.e., \$/MMBtu-peak day). These can be calculated using the framework outlined in Equation 3-1 below. The key consideration will be the project's ability to provide supply or reduce demand on coincident peak days, allowing Con Edison to avoid acquiring or constructing an equivalent quantity of capacity.

#### Equation 3-1. Avoided Fixed Costs of Upstream Supply

$$\text{Benefit}_Y = \sum \left( \frac{\Delta \text{PeakLoad}_{Y,r}}{(1 - \text{CRG}_Y)} * \text{CoincidenceFactor}_{Y,r} * \text{DeratingFactor}_{Y,r} * \text{AUFC}_Y \right)$$

#### Where:

<b>Y</b>	The year that the benefit is recognized / realized through the actual avoidance of fixed costs associated with upstream pipeline capacity
<b><math>\Delta \text{PeakLoad}_Y</math></b>	The project's expected maximum demand reduction capability, or "nameplate" impact, measured in MMBtu/day at the retail delivery or connection point. This input is project or program specific. A positive value represents a reduction in peak load.
<b><math>\text{CRG}_Y</math></b>	The Avoidable Loss for the system applicable to year Y.
<b>r</b>	The specific retail delivery location.

<b>CoincidenceFactor<sub>y</sub></b>	Factor used to adjust the nameplate capacity of the project or program to account for the relationship between the coincidence of overall system peak requirements and the asset's expected contribution at such time. For example, a project with a nameplate demand reduction capacity of 100 Dth with a system coincidence factor of 0.8 would reduce system peak demand by only 80 Dth. This input is project specific.
<b>DeratingFactor<sub>y</sub></b>	Factor used to de-rate the coincident peak load benefit of the resource based on its expected availability during peak days. As opposed to the coincidence factor, the derate factor adjusts for broader availability considerations. For example, an on-system supply asset may have a coincidence factor of 0.8, reflecting expected reductions in deliverability on peak day due to the impact of cold weather on the asset's performance. But this asset could also have a restricted number of days on which it can be dispatched (either seasonally or over a sequence of days). The DeratingFactor would be used to account for this additional performance risk. This input is project specific.
<b>AUFC<sub>y</sub></b>	The annualized fixed cost of the avoidable capacity under the applicable scenario, measured in \$'s/Dth-Year, net of its capacity release value, if any.

### **Considerations on Equation Components**

#### ***PeakLoad<sub>y</sub>***

The nameplate capacity of a project is separate from its ability to impact coincident peak day requirements. The nameplate capacity is the underlying design capability of the asset or program, generally based on the associated underlying engineering principles.

#### ***CoincidenceFactor<sub>y</sub>***

The coincidence factor quantifies a project's contribution to peak day supply (or demand reductions) relative to its nameplate impact. This factor should be used to adjust the name plate capacity for various physical factors that affect the asset's ability to impact peak day and associated operational considerations that recognize how the program or asset impacts coincide with peak day requirements. For example, an asset's or program's performance may be negatively correlated with the factors that drive peak day demand (particularly temperature). The determination of the appropriate factor is project/program specific. However, consistent principles should be applied across all projects and programs.

#### ***DeratingFactor<sub>y</sub>***

The derating factor should be used to adjust for uncertainty-related factors that may affect the general availability of an asset, such as duration of service (e.g., one day or any day over the winter), or the likelihood that the asset or program will fail to perform, despite its physical capabilities. For example, an incremental supply may fail to perform because the facility is undergoing maintenance. The derating factor should also reflect distribution limitations that restrict the ability of an incremental supply (or demand reduction) at one point to fully reduce system requirements. Again, the specific factor adjustments will be project/program specific but should be consistently applied across all projects.



**AUFC<sub>r</sub>**

This value is generated as part of the analysis of the NPS programs and projects under consideration in the context of the utility's existing asset mix, projected load requirements (with and without the NPS program/project), and options for supplying incremental resource needs. In establishing a specific AUFC, consideration should be given to the net cost of the associated pipeline or Delivered Services asset, including (in the case of pipeline options) the reduction in the cost of commodity purchases resulting from the asset, if any, and the residual value associated with reselling excess deliverability / capacity to the secondary market when not required for on-system loads (e.g., capacity release value). This offsetting value should be evaluated based on forward spreads for the associated contract path less applicable variable costs (e.g., fuel and commodity).

**r**

'r' represents the specific location of the NPS program impact on the retail distribution system. Not all locations will have the same impact on the utility's ability to avoid upstream capacity or the specific upstream supply resource projected to be needed for overall system loads. Portfolio analysis of NPS programs will need to consider the location of the impact as it relates to specific upstream capacity commitments.

**3.3.1.4 Estimating Project Specific Benefits – Variable Cost of Avoided Upstream Supply**

Variable Avoided Upstream Supply costs are commodity in nature (i.e., \$/Dth of consumption). The specific avoided commodity related benefits of an NPS program or project are a result of the marginal commodity that can be avoided based on the supply portfolio. Establishing the appropriate marginal supply cost is a function of the existing portfolio and the impact of the project on that portfolio (both the mix of assets acquired and use of the assets). For example, if a project permits the avoidance of pipeline capacity, then the avoided commodity cost should recognize the impact of that the avoided asset would have had on the utility's commodity costs. Similarly, if the avoided upstream asset is Delivered Services, then the avoided commodity cost should reflect the commodity cost associated with including that service (more often a city-gate cost of gas) in the supply portfolio. In the final analysis a combination of upstream assets (e.g., pipeline capacity and Delivered Services) may be avoided by a portfolio of projects or programs. The combination of these assets should be assumed to be included in the portfolio when determining the avoided commodity cost.

Project/program specific benefits associated with avoiding variable upstream pipeline capacity costs can be calculated using the framework outlined in Equation 3-2 below. As opposed to the calculation of avoided fixed costs, which focuses on a project's ability to deliver supply or reduce demand on coincident peak days, the associated variable avoided pipeline capacity cost benefit may also be realized outside of the coincident peak period. For example, the addition of an on-system, baseload renewable supply would avoid allow the utility to avoid the acquisition of incremental peak day capacity. However, this project would generate avoidable commodity benefits all year round.

**Equation 3-2. Avoided Commodity Cost**

$$\text{Benefit}_Y = \sum_P \frac{\Delta \text{Commodity}_{P,Y,r}}{(1 - \text{CRG}_Y)} * \text{Commodity Cost}_{P,Y,r}$$

**Where:**

<b>Y</b>	The year that the benefit is recognized / realized through the actual avoidance of commodity costs associated with upstream pipeline capacity or Delivered Service.
<b>P</b>	The period within a given year when commodity costs are avoided (e.g., peak day, peak winter, summer).
<b><math>\Delta \text{Commodity}_{P,Y}</math></b>	The difference in the quantity of gas required at the applicable retail delivery point(s) (e.g., customer revenue meter) before and after the project or program is implemented, delineated by applicable years “Y” and periods “P” within each year.
<b><math>\text{CRG}_Y</math></b>	The Company Retained Gas for the system applicable to year Y.
<b>r</b>	The specific retail delivery location.
<b><math>\text{Commodity Cost}_{P,Y}</math></b>	The projected wholesale cost of gas at Con Edison’s city-gate (based on the applicable avoided upstream supply resource and the cost of transportation to Con Edison’s city gate, if any).

**Considerations on Equation Components**

Avoided Commodity Cost benefits are calculated using a forecast of Commodity Cost. The time differential for subscript P (period) will depend on the type of project, and could be peak, winter, summer, or another time interval. The user must ensure that the time-differentiation is appropriate for the project being analyzed and consistent with when impacts are anticipated to occur within a year. For example, it may be appropriate to use an annual average price and impact for a NPS that has a consistent load reduction at all hours of the year. However, using the annual average may not be appropriate for evaluating a demand response program that only reduces load during a few peak days.

**3.3.2 Distribution System Benefits****3.3.2.1 Avoided Distribution System Capacity Infrastructure**

**Avoided Distribution System Capacity Infrastructure** benefits result from distribution load reductions (or supply resources) that are valued at the marginal cost of distribution system infrastructure that is avoided or deferred by a NPS project or program. The project or program impact must be coincident with the distribution equipment peak or otherwise defer or avoid the need for incremental distribution infrastructure based on the characteristics of the specific project or program. Project/program specific benefits associated with Avoided Distribution System Capacity Infrastructure are capacity related (i.e., \$/Dth-peak day) and can be calculated using the framework outlined in Equation 3-3 below.

**Equation 3-3. Avoided Distribution System Capacity Infrastructure**

$$\text{Benefit}_Y = \sum_C \frac{\Delta \text{PeakLoad}_{Y,r}}{(1 - \text{CRG}_Y)} * \text{DistCoincFactor}_{C,Y,r} * \text{DeratingFactor}_Y * \text{MarginalDistCost}_{C,Y,r}$$

**Where:**

<b>Y</b>	The year that the benefit is recognized / realized through the actual avoidance of distribution system capacity infrastructure.
<b>r</b>	The specific retail delivery location.
<b>C</b>	The specific distribution system constraint affected.
<b><math>\Delta \text{PeakLoad}_{Y,r}</math></b>	The project's expected maximum demand reduction capability, or "nameplate" impact, measured in Dth/day at the retail delivery or connection point. This input is project or program specific. A positive value represents a reduction in peak load.
<b><math>\text{CRG}_Y</math></b>	The Company Retained Gas for the system applicable to year Y.
<b><math>\text{DistCoincFactor}_{C,Y,r}</math></b>	Factor used to adjust the nameplate capacity of the project or program to account for the relationship between the coincidence of the asset's expected contribution at the time the applicable section of distribution system experiences its peak load (this may differ from overall coincident system peak). The concept is similar to the CoincidenceFactor used for Avoided Supply costs. However, the peak requirement for the applicable section of distribution infrastructure may differ from the overall coincident system peak. This input is project specific.
<b><math>\text{DeratingFactor}_Y</math></b>	A generic factor used to de-rate the benefits of the program/project based on its anticipated availability during peak calls on the applicable section of the distribution system. For example, a demand response program may only be allowed to dispatch a maximum of 5 events per year, which could limit the availability of the resource during peak periods beyond the 5-day maximum. This input is project or program-specific.
<b><math>\text{MarginalDistCost}_{C,Y,r}</math></b>	The marginal cost of the distribution equipment that the project/program is relieving, measured in dollars per Dth-day. It is assumed that the marginal cost of service is based on the cost of expanding the applicable section of the distribution system. This variable is specific to the project/program location (r) and associated distribution system constraint (C).

**Considerations on Equation Components**

Project- and location-specific avoided distribution costs and deferral values should be used when and wherever possible. If the available marginal cost of service value is based on a different basis, then this parameter should first be converted to represent load at the pipeline and distribution line level prior to using in the equation above. In some circumstances use of the system average marginal cost may be

acceptable, for example, for evaluation of energy efficiency programs for which specific customer locations are not yet known.

Avoided distribution infrastructure benefits for a specific location are realized only if a NPS project or portfolio of NPS projects meets the engineering requirements for functional equivalence (i.e., NPS reliably reduces coincident load to a level that allows the deferral or avoidance of the distribution project).

Coincidence and derating factors could be determined by a project-specific engineering study, based on historical experience in Con Edison's service territory or elsewhere, or based on engineering judgements about potential performance limitations.

The timing of benefits realized from peak load reductions are project and/or program specific. It is assumed that a peak load reduction impact will produce benefits in the year of the impact. As with avoided supply costs, the impact of projects/programs should be evaluated on a 'with the program' and 'without the program' basis. An NPS project may contribute to avoiding distribution system capacity costs temporarily, but not permanently. In that case, avoided distribution system costs would be reflected as a benefit for a limited period.

### 3.3.2.2 *Avoided Distribution O&M*

**Avoided Distribution O&M** includes variable operation and maintenance benefits on the distribution system realized from a proposed program or project. Caution should be exercised in computing these benefits as O&M expenses related to distribution expansions and upgrades are often incorporated into marginal cost studies and the associated avoided cost may already be captured as part of the Avoided Distribution System Capacity Infrastructure cost.

Project/program specific benefits associated with Avoided Distribution O&M Costs are generally commodity related but can also have a capacity component. These can be calculated using the framework outlined in Equation 3-4 below.

#### Equation 3-4. Avoided Distribution O&M

$$\text{Benefit}_Y = \sum_{AT} \Delta \text{Expenses}_{AT,Y}$$

**Where:**

<b>Y</b>	The year that the benefit is recognized / realized through the actual avoidance of distribution system capacity infrastructure.
<b>AT</b>	The Activity Type or specific category of O&M expense (e.g., crews to replace equipment, pigging requirements, and other maintenance related expenses).
<b><math>\Delta \text{Expenses}_{AT,Y}</math></b>	Change in O&M expenses due to a project, including an appropriate allocation of administrative and common costs. In general, these costs would increase by inflation, where appropriate.

#### Considerations on Equation Components

Distribution O&M benefits from NPS may be limited where the O&M costs are already embedded in the marginal cost of service values. Some secondary impacts may be identifiable and quantifiable. For example, to the degree incremental supply on-system lowers utilization of upstream assets (e.g.,

components of the distribution designed to maintain pressure or provide other benefits), the associated reduction in O&M expense may be attributable to the program/project and would not be reflected in the calculation of Avoided Distribution Capacity Infrastructure costs. However, in general, these impacts are difficult to quantify and may be zero for most cases.

### 3.3.3 Reliability/Resiliency Benefits

Reliability/Resiliency benefits of NPS projects and programs reflect how these programs and projects affect overall system reliability and ability to maintain system standards and recover from system outages. For example, on-system NPS supply sources may provide pressure benefits depending on their location on the system. These can be leveraged to support system pressures during extreme events (increasing system reliability) and to provide faster recovery from disruption events.

Associated benefits are very program/project specific and highly influenced by the location of programs/projects on-system and their operational characteristics. NPS options that can be dispatched (i.e., ability to call on supply or demand reduction without limitation) have the greater potential to provide such benefits. The specific benefits are very project/program specific. To the degree these benefits exist but are not readily quantifiable, their impacts may be qualitatively assessed.

### 3.3.4 External Benefits

#### 3.3.4.1 Avoided Greenhouse Gas Emissions

**Avoided Greenhouse Gas Emissions** accounts for avoided CO<sub>2</sub> and other greenhouse gas emissions due to a net reduction in natural gas use or replacement of gas normally delivered by pipeline with Renewable Natural Gas (where greenhouse gas emissions are reduced via the creation of the fuel) or local supplies such as CNG or LNG (where additional emissions may occur in connection with the compression or liquefaction process).<sup>3</sup> In the case of reductions in natural gas use, project/program specific benefits associated with Avoided Greenhouse Gas Emissions can be calculated using the framework outlined in Equation 3-5 below.

#### Equation 3-5. Avoided Greenhouse Gas Emissions

$$\text{Benefit}_Y = \frac{\Delta \text{Emissions}_Y}{(1 - \text{CRG}_Y)} * \text{GHGIntensity}_Y * \text{SocialCostCO2}_Y$$

<sup>3</sup> The Avoided Greenhouse Gas Emissions benefit considers the avoided gas used at the city gate; i.e. including an adjustment to reflect Company Retained Gas.

**Where:**

<b>Y</b>	The year that the benefit is recognized / realized through the actual avoidance of distribution system capacity infrastructure.
<b><math>\Delta\text{Emissions}_Y</math></b>	For demand-side measures, the change in natural gas used on-site as a result of the program or project. This is measured in Dth at the customer delivery point or revenue meter and accounts for the net change in use related to the program or project over the entire year. For RNG and other local supplies, the change in emissions attributable to the specific process used to provide the local gas supplies.
<b><math>\text{CRG}_Y</math></b>	The Company Retained Gas for the system applicable to year Y.
<b><math>\text{GHGIntensity}_Y</math></b>	The GHG emission rate of natural gas emissions (i.e., for demand-side measures, 117 lbs/MMBtu or 0.0531 Metric Tons/Dt). <sup>4</sup>
<b><math>\text{SocialCostCO}_2</math></b>	An estimate of the total impacts to society associated with an incremental increase in carbon dioxide emissions, measured in dollars per ton of CO <sub>2</sub> equivalent.

**Considerations on Equation Components**

The net cost of greenhouse gas emissions will be taken into account with the intent to use a common cost of carbon across all aspects of the BCA. The  $\text{SocialCostCO}_2$  can be based on separate studies or on market indicators. One market indicator would be Renewable Energy Certificates (RECs). REC carbon allowances are priced in the form of \$/kWh. This \$/kWh value can be converted to an equivalent allowance price in \$/tCO<sub>2e</sub> for use in evaluating NPS or natural gas end use activity. Any valuation of this benefit should be based on generally accepted methodologies and sources for assessing avoided costs.

The benefit should be based on net changes in gas consumption at the customer site. Projects or programs that defer consumption to periods outside of the peak but do not otherwise reduce annual consumption will not realize benefits from reduction in greenhouse gas emissions. However, on-system supply sources, while not affecting end-use consumption, may have a small emissions benefit from avoiding on-system losses (depending on the project's location).

**3.3.4.2 Other Avoided Emissions**

**Other Avoided Emissions** accounts for the value of avoided pollutant emissions (excluding greenhouse gases emissions). Project/program specific benefits associated with these emissions are commodity related (i.e., \$/MMBtu) and can be calculated using the framework outlined in Equation 3-6 below.

**Equation 3-6. Other Avoided Emissions**

$$\text{Benefit}_Y = \sum_p \frac{\Delta\text{Emissions}_Y}{1 - \text{CRG}_Y} * \text{PollutantIntensity}_{p,Y} * \text{SocialCostPollutant}_{p,Y}$$

<sup>4</sup> 117 pnds/MMBtu \* 1 short ton/2000 pnds \* 1 metric ton/ 1.10231 short tons

**Where:**

<b>Y</b>	The year that the benefit is recognized / realized through the actual avoidance of distribution system capacity infrastructure.
<b>p</b>	Represents the applicable pollutant (e.g., SO <sub>2</sub> , NO <sub>x</sub> )
<b><math>\Delta\text{Emissions}_Y</math></b>	Change in natural gas used on-site as a result of the program or project. This is measured in MMBtu at the customer delivery point or revenue meter and accounts for the net change in use related to the program or project over the entire year.
<b>CRG<sub>Y</sub></b>	The Company Retained Gas for the system applicable to year Y.
<b>PollutantIntensity<sub>p,Y</sub></b>	The average pollutant emission rate for pollutant p at the customer site, measured in tons/Dth. This is project and technology-specific.
<b>SocialCostPollutant<sub>p,Y</sub></b>	An estimate of the cost to society associated with an incremental increase in pollutant p emissions in a given year.

**Considerations on Equation Components**

Pollutant impacts other than greenhouse gases emissions impacts are very project/program specific and may be zero depending on the project or program. Any valuation of this benefit should be based on generally accepted methodologies and sources for assessing avoided costs. To the degree these benefits exist but are not readily quantifiable, their impacts may be qualitatively assessed.

**3.3.4.3 Net Non-Energy Benefits**

This category covers other benefits (or reduced costs) accruing to the utility related to other non-commodity aspects of a proposed project or program. An example would be benefits from reduced costs to rendering a natural gas bill for a customer that switches to electric heat and terminates gas service entirely. To the degree these benefits exist but are not readily quantifiable, their impacts may be qualitatively assessed.

**3.3.4.4 Other External Benefits**

Other External Benefits may also include external benefits, such as land or water benefits associated with a project or program. In general, Other External Benefits would only apply to the Societal Cost Test. To the degree these benefits exist but are not readily quantifiable, their impacts may be qualitatively assessed.

**3.4 Costs Analysis****3.4.1 Program Administration Costs**

Program Administration Costs include the cost to administer and measure an NPS program or project. This may include the cost of incentives, measurement and verification, and other program administration costs

to start and maintain a specific program. These costs may include one-time or annual incentives such as rebates, one-time or annual payments to suppliers, and program administration costs related to marketing, evaluation, measurement and verification. These costs would increase by inflation, where appropriate. Program-specific details that are necessary to calculate the cost impact can include, but are not limited to, the scale of the activity, the types of participating technologies, and locational details. Sub-categories that could fall under Program Administration Costs include, but are not limited to, programmatic measurement & verification costs, and utility-specific rebates and/or incentives.

### **3.4.2 Incremental Distribution System Investments**

Incremental Distribution System Investments include those costs incurred by the utility to support the NPS project or program. These are distinct from Program Administration costs and can include incremental distribution system infrastructure costs, including O&M on the distribution system, any capital or other direct expenses (e.g., special meters, monitoring systems, and/or upgrades), opportunity costs associated with any utility owned land or infrastructure granted or dedicated to the project, and indirect administrative costs related to the program (i.e., its impact on broader administrative costs).

### **3.4.3 Lost Utility Revenue**

Lost Utility Revenue includes the distribution and other non-bypassable revenues that are shifted on to non-participating customers due to the normal process of establishing rates during a utility rate filing or the presence of revenue decoupling mechanisms. In both instances sales-related revenue shortfalls due to a decrease in natural gas sales or demand is recovered by marginally increasing delivery rates for all customers.

### **3.4.4 Participant NPS Costs**

Participant NPS Costs are costs that would be incurred by providers of NPS services, less incentives recognized in Program Administration Costs. This includes the equipment and participation costs assumed by NPS providers which need to be considered when evaluating the societal costs of a project or program. For the purpose of performing the BCA, Participant NPS costs are applied net of rebates and incentives which have been accounted for under Program Administration costs.

The Participant NPS Costs includes the installed cost of the device or system, as well as any ongoing operations and maintenance expenses to provide the solution. Installed costs include the capital cost of the equipment, other capital investments required by the installation, and labor for the installation. Operating costs include ongoing maintenance expenses. These can also include costs borne by participants, particularly related to programs designed to incentivize or having an impact on customer behavior and/or real or perceived benefits from service (e.g., the purchase and installation price of a smart thermostat required to participate in temperature reduction programs).

Actual Participant NPS costs will vary by project based upon factors including:

<b>Make and model:</b>	The NPS owner typically has an array of products to choose from, each of which has different combinations of cost and efficiency.
<b>Type of installation:</b>	The location of where the NPS would be installed influences the capital costs.
<b>Geographic location:</b>	Labor rates, property taxes, and other factors vary across utility service areas and across the state



**Available rebates  
and incentives:**

Include federal, state, and/or utility funding.

In general, Participant NPS Costs should be based on the incremental cost of the associated device or system relative to the costs the participant would have otherwise incurred. As such, Con Edison's competitive solicitations for NPS may require the disclosure of costs by the bidders, including but not limited to capital, installation, marketing, administrative, fixed and variable O&M and/or incentive costs. Con Edison will use the submitted costs in the project/program/portfolio BCA evaluation in conjunction with its technology-specific benchmark costs to assess the incremental capital and other costs to attribute to the proposed program or project. Due to the complexity of some programs and projects, including the existence of multiple revenue and cost streams, Con Edison may rely on the incentive payment or 'bid price' proposed by a respondent in the competitive solicitation process as the best estimate of incremental cost for the purpose of assessing Participant NPS Costs.

**3.4.5 Alternative Fuel Costs**

Alternative Fuel Costs include the cost of using an energy source other than gas. For example, fuel switching in the form of consumers installing electric heat pumps in place of traditional natural gas boilers, is a measure to reduce the demand for natural gas. If fuel switching is selected as a viable NPS, the cost of the alternative energy source should be considered in the BCA. The focus of the discussion here is on the use of electricity in place of natural gas. Although a variety of alternative energy sources can be considered, any analysis should consider the costs associated with the alternative (e.g., fuel costs, additional externalities). As an example, Equation 3-7 provides a framework for evaluating the energy costs associated with replacing gas with alternate fuels:

**Equation 3-7 Alt. Fuel Costs**

$$\text{Cost}_Y = \sum \frac{\Delta \text{Energy}_{Z,Y,r}}{1 - \text{Loss}\%_{Z,b \rightarrow r}} * \text{LBMP}_{Z,Y,b}$$

**Where:**

<b>Y</b>	The year that the cost is recognized / realized
<b>Z</b>	The applicable NYISO load zone where the incremental energy use occurs ("Zone")
<b>b</b>	The applicable Bulk System
<b>r</b>	The Retail Delivery or connection point
<b>Energy<sub>Z,Y,r</sub></b>	The difference at the retail delivery or connection point ("r") before and after project implementation by year. This parameter represents the energy impact at the project location and is <b>not</b> yet grossed up to the LBMP location based on the losses between those two points on the system. This input is project or program-specific. A positive value represents an increase in energy.

<b>Loss%<sub>z,b→r</sub></b>	The variable loss percent between transmission system and the retail delivery or connection point (“r”).
<b>LBMP<sub>z,y,b</sub></b>	The Locational Based Marginal Price, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level (“b”) for the Zone in which the project is located

The Standard BCA Handbook developed with the NYJU discussed the calculation of Capacity, Energy, and associated transmission and distribution expenses on the electric system as a result of pursuing non-wire solutions to incremental load requirements. To the degree NPS programs require an assessment of Alternative Fuel Costs, to the degree such costs are assessed to be substantive, they should be evaluated consistent with the framework and concepts established in the Standard BCA Handbook.

### 3.4.6 External Costs

#### 3.4.6.1 Alternative Fuel CO<sub>2</sub> Emissions

Alternative Fuel CO<sub>2</sub> Emissions include the emissions generated from production of the alternative fuel and from the end use of the alternative fuel by the consumer. For example, fuel switching in the form of consumers installing electric water heaters in place of traditional natural gas heaters is a measure to reduce the demand for natural gas. If the electricity is generated from a carbon emitting source, CO<sub>2</sub> emissions from the generation of the electricity needs to be accounted for. Equation 4-18 presents the cost equation for Alternative Fuel CO<sub>2</sub> Emissions:

**Equation 3-8 Alt. Fuel CO<sub>2</sub> Emissions**

$$\text{Cost}_Y = \left( \frac{\Delta \text{Energy}_{Y,r}}{1 - \text{Loss\%}_{Y,b \rightarrow r}} \right) * \text{CO}_2 \text{Intensity}_{Y,Z} * \text{SocialCostCO}_2_Y$$

**Where:**

<b>Y</b>	The year that the cost is recognized / realized
<b>Z</b>	The applicable NYISO load zone where the incremental energy use occurs
<b>r</b>	The Retail Delivery or Connection Point
<b>b</b>	The Bulk System
<b>ΔEnergy<sub>Y,r</sub></b>	The change in energy purchased at the retail delivery or connection point (“r”) as a result of the project. This parameter considers the impact at the project location, which is then grossed up to the bulk system level based on the <i>Loss%<sub>b→r</sub></i> parameter. A positive value represents a reduction in energy.
<b>Loss%<sub>Y,t→r</sub></b>	The variable loss percent from the bulk system level (“t”) to the retail delivery or connection point (“r”).

<b>CO<sub>2</sub>Intensity<sub>Y, Z</sub></b>	The CO <sub>2</sub> emissions rate of generation providing electricity to the applicable Zone.
<b>SocialCostCO<sub>2</sub><sub>Y</sub></b>	An estimate of the total impacts to society associated with an incremental increase in carbon dioxide emissions, measured in dollars per ton of CO <sub>2</sub> equivalent.

Any valuation of this benefit should be based on generally accepted methodologies and sources for assessing avoided costs, and should be consistent with the valuation of Avoided Greenhouse Gas Emissions.

### 3.4.6.2 *Alternative Fuel Other Emissions*

**Alternative Fuel Other Emissions** covers other emissions costs (other than greenhouse gases) associated with using an energy source other than gas to replace the service provided by gas. Equation 3-9 provides a framework for evaluating these costs:

**Equation 3-9. Alternative Fuel Other Emissions**

$$\text{Benefit}_Y = \sum_p \text{OnsiteEnergy}_{Y,r} * \text{PollutantIntensity}_{p,Y,Z} * \text{SocialCostPollutant}_{p,Y}$$

**Where:**

<b>Y</b>	The year that the cost is recognized / realized
<b>r</b>	The Retail Delivery or connection point
<b>p</b>	The applicable pollutant (e.g., SO <sub>2</sub> , NO <sub>x</sub> )
<b>Z</b>	The applicable NYISO load zone where the incremental energy use occurs
<b>OnsiteEnergy<sub>Y,r</sub></b>	The electricity used by customer-sited equipment.
<b>PollutantIntensity<sub>p,Y,Z</sub></b>	The pollutant emissions rate of the marginal generating unit providing electricity in the Zone.
<b>SocialCostPollutant<sub>p,Y</sub></b>	An estimate of the cost to society associated with an incremental increase in pollutant 'p' emissions in a given year.

Any valuation of this benefit should be based on generally accepted methodologies and sources for assessing avoided costs, and should be consistent with the valuation of Other Avoided Emissions.

### 3.4.6.3 *Net Non-Energy Costs*

Net Non-Energy Costs are other, non-commodity impacts on the utility's costs resulting from an NPS project. Like Net Non-Energy Benefits, this can include the impacts to customer billing costs. To the degree these benefits exist but are not readily quantifiable, their impacts may be qualitatively assessed.

#### 3.4.6.4 Other External Costs

This category covers external benefits not addressed in other categories, including land and water impacts associated with an NPS program or project. To the degree these benefits exist but are not readily quantifiable, their impacts may be qualitatively assessed.

## 4. RELEVANT COST-EFFECTIVENESS TESTS

Once project costs and benefits have been appropriately identified, evaluated, and present valued, three tests are used to assess the overall benefit of the project and to assess the relative benefits of competing projects. While there are similarities across all three tests, each focuses on a portfolio of solutions from a different perspective and considers different benefits and costs in its calculation. Table 4-1 summarizes these tests.

**Table 4 - 1 Cost-Effectiveness Tests**

Cost Test	Market Perspective	Key Question Assessed	Calculation Approach
Societal Cost Test (SCT)	Society	Is the State of New York better off as a whole?	Broadest measure. Includes direct costs and benefits of project (e.g., capital costs, Avoided Upstream Supply Costs, etc.) but also broader externalities associated with the program (e.g., carbon emissions and other net non-energy benefits). Calculation universe focuses broadly on New York residents as a whole.
Utility Cost Test (UCT)	Utility	How will utility costs be affected?	Utility focused. Includes costs and benefits applicable to the utility, such as Avoided Upstream Supply Costs, direct capital expenditures, administrative costs, direct incentives paid to participating customers or project participants. Excludes broader societal externalities (e.g., emissions and related costs where these are not a direct charge to the utility)
Ratepayer Impact Measure (RIM)	Ratepayer	How will utility rates be affected?	Customer focused. Recognizes impacts on customers, including non-participating customers. Incorporates secondary implications of projects (e.g., cross-subsidization effects) on non-participant bills.

Of these tests, the SCT is the primary measure of cost-effectiveness.

## 4.1 Applicability of the Societal Cost Test

A majority of the benefits included in the handbook can be evaluated under the SCT because their impact can be applied to society as a whole. This includes Fixed Costs of Avoided Upstream Supply, Commodity Costs of Avoided Upstream Supply, Avoided Distribution System Capacity Infrastructure, Avoided Distribution O&M, Reliability/Resiliency, Avoided Greenhouse Gas Emissions, and Avoided Other Emissions.

Lost Utility Revenue does not apply to the SCT, as these are considered transfers between stakeholder groups that have no net impact on society as a whole.

## 4.2 Utility Cost Test

The UCT looks only at impacts to the utility's direct costs. For this reason, external benefits such as Avoided Greenhouse Gas Emissions and Avoided Other Emissions do not apply to the UCT. Participant NPS Costs are not considered in the UCT because Participant NPS Costs are not a utility cost. Lost Utility Revenue is not included in the UCT, because any reduced revenues from NPS are assumed to be made up by non-participating NPS customers through future rate adjustments.

## 4.3 Rate Impact Measure

The RIM test can address rate impacts to non-participating customers of the utility. External benefits such as Avoided Greenhouse Gas Emissions, Avoided Other Emissions do not apply to the RIM because they do not directly affect customer rates. Reliability/Resiliency benefits have no predictable effect on rates.

Participant NPS cost does not apply to the RIM because the cost of an NPS solution not a utility cost that affects the rates of non-participating customers. However, any reduced revenues from NPS are included as increased costs to other ratepayers as Lost Utility Revenue because of revenue decoupling or other means that transfer costs from participants to non-participants.

## 4.4 Applying the Cost-Effectiveness Tests

Performing a cost-effectiveness test for a specific project or a portfolio of projects requires the following steps:

- **Select the relevant benefits** for the investment
- **Determine the relevant costs** from each cost included over the life of the investment
- **Estimate the impact** the investment will have in each of the relevant benefits in each year of the analysis period (i.e., how much will it change the underlying physical operation of the natural gas T&D system to produce the benefits)
- **Apply the benefit values** associated with the project impacts

- **Apply the appropriate discount rate** to perform a cost-effectiveness test for a specific project or portfolio. The discount rate is the utility-weighted average cost of capital to determine the present value of all benefits and costs<sup>5</sup>
- **Treat inflation consistently** by discounting real cash flow by real discount rates and nominal cash flows by nominal discount rates. A consistent annual inflation rate should be used where nominal values will be escalated

Table 4-2 summarizes the various costs and benefits discussed in this Interim BCA Handbook and which are generally relevant to which each test.

**Table 4 - 2 Components Applicable to BCA Tests**

Benefit/Cost	Section #	SCT	UCT	RIM
<b>Benefits</b>				
Fixed Costs of Avoided Upstream Supply	3.3.1.3	✓	✓	✓
Commodity Costs of Avoided Upstream Supply	3.3.1.4	✓	✓	✓
Avoided Distribution System Capacity Infrastructure	3.3.2.1	✓	✓	✓
Avoided Distribution O&M	3.3.2.2	✓	✓	✓
Reliability/Resiliency	3.3.3	✓	✓	✓
Avoided Greenhouse Gas Emissions	3.3.4.1	✓		
Avoided Other Emissions	3.3.4.2	✓		
Other Non-Energy Benefits	3.3.4.3	✓	✓	✓
Other External Benefits	3.3.4.4	✓		
<b>Costs</b>				
Program Administration Costs	3.4.1	✓	✓	✓
Incremental Distribution System Costs	3.4.2	✓	✓	✓
Lost Utility Revenue	3.4.3			✓
Participant NPS Cost	3.4.4	✓	✓	✓
Alt. Fuel Costs (Electric) *	3.4.5	✓	✓	✓
Alt. Fuel CO <sub>2</sub> Emissions	3.4.6.1	✓		
Alt. Fuel Other Emissions	3.4.6.2	✓		
Other Net Non-Energy Costs	3.4.6.3	✓	✓	✓
Other External Costs	3.4.6.4	✓		

<sup>5</sup> The currently approved discount rate is 6.81% (see: Joint Proposal settling CASE-16-E-0060, CASE-16-G-0061, CASE-15-E-0050, and CASE-16-E-0196)

## 5. HIGH-LEVEL EXAMPLES

As a means of illustrating the application of BCA to NPS alternatives, this section provides a high-level overview of five potential NPS programs and projects:

<b>RNG</b>	An incremental, baseload supply via an on-system renewable natural gas supply project
<b>CNG</b>	An incremental, dispatchable supply via an on-system CNG supply project
<b>EE</b>	Demand reduction via an energy-efficiency program
<b>DR</b>	Demand reduction via a dispatchable demand response program
<b>G2E</b>	Demand reduction via switching of existing gas-fired technology to electricity

These five examples cover a useful, illustrative range of impacts that NPS can have on the various benefit and cost categories in the Interim BCA Handbook. Each NPS technology has unique operating characteristics that allow it to accrue some benefits and costs but not others.

**Table 5 - 3 Key Attributes of Selected NPS Technologies**

Renewable Natural Gas (RNG)	Renewable Natural Gas production produces energy by using organic feedstock that would otherwise be deposited in a landfill. The RNG station can operate to supply a constant source of energy, reducing the load on the traditional natural gas supply system.
Local storage solutions (CNG)	Compressed natural gas storage (CNG) (alternatively could be liquefied natural gas) can be distributed in different areas to be readily available to the distribution system during periods of peak demand. The resource is dispatchable in nature but utilizes on-site supply and storage.
Energy Efficiency (EE)	EE reduces the energy consumption for delivery of a particular service use at customer premises.
Demand Response (DR)	DR reduces energy demand for a particular service (use) during specific hours or days. DR is typically available only for limited hours in a year (e.g., 5 days or 100 hours) and is dispatchable in nature. The operational objective of the DR determines how it may contribute to various benefit and cost categories.
Gas Conversion (G2E)	Gas conversions involve meeting the underlying service (use) requirements of the customer via a technology that utilizes a different fuel source (generally electricity). The application could be a complete replacement or designed to cover resource needs during specific hours (ideally peak). The example presumes the technology is not dispatchable.

**Table 5 - 4 Applicability of each BCA Category to NPS Technology**

Benefit/Cost	Section	RNG	CNG	EE	DR	G2E
<b>Benefits</b>						
Avoided Upstream Costs -- Fixed Costs	3.3.1.3	●	●	●	●	●
Avoided Upstream Costs -- Variable Costs	3.3.1.4	●	●	●	●	●
Avoided Distribution Costs -- Capital Related	3.3.2.1	○	○	◐	◐	◐
Avoided Distribution Costs -- O&M	3.3.2.2	○	○	◐	◐	◐
Reliability / Resiliency	3.3.3	◐	◐	◐	◐	◐
Avoided CO2	3.3.4.1	●	○	●	●	●
Avoided PM, NOX, SOX	3.3.4.2	◐	○	◐	◐	●
Other Net Non-Energy Benefits	3.3.4.3	◐	◐	◐	◐	◐
<b>Costs</b>						
Program Administration	3.4.1	●	●	●	●	●
Incremental Distribution System Investments/Costs	3.4.2	●	●	◐	◐	◐
Lost Utility Revenue	3.4.3	○	○	●	◐	●
Participant NPS Costs	3.4.4	●	●	●	●	●
Alternative Fuel Costs (Electric)	3.4.5	◐	◐	○	◐	●
CO2 Impacts	3.4.6.1	◐	◐	○	◐	●
PM, NOX, SOX Impacts	3.4.6.2	◐	◐	○	◐	●
Other Net Non-Energy Costs	3.4.6.3	◐	◐	◐	◐	◐

● Generally Applicable      ◐ Maybe Applicable      ○ Limited or No Applicability

## 5.1 Renewable Natural Gas Example (RNG)

Renewable Natural Gas production is selected to depict a *baseload* NPS, which is able to operate during peak periods as well as off-peak periods. The RNG production is assumed to be dependent on feedstock, which should be constantly supplied to enable a continuous production of gas.

### 5.1.1 Example System Description

Organic materials such as municipal solid waste, are rich in carbon, and can be converted to Renewable Natural Gas through anaerobic digestion or other means. The resulting gas can be processed into pipeline-quality gas and injected into a utility distribution system or pipeline. The byproducts resulting from the organic waste to gas conversion process can be a commodity and may be exported to other industries (ex. the use of slag in cement blends).

### 5.1.2 Considerations Surrounding BCA Parameters Associated with RNG Projects

#### Avoided Upstream Supply Costs – Fixed Costs



In general, the baseload nature of RNG projects implies these should provide on-system gas supply during periods required by the utility. Specific considerations in assessing their ability to avoid fixed costs associated with upstream supply (based on the framework provided in Section 3) include:

#### ***ΔPeakLoad***

$\Delta$ PeakLoad would generally be set at the facility's peak or nameplate capacity, recognizing any on-site uses of gas produced. However, as discussed below, many factors could affect the correlation of this capability to the underlying utility requirements. Any such issues are addressed in the applicable coincidence and derating factors.

#### **CoincidenceFactor**

The coincidence factor for an RNG facility could be influenced by a variety of factors. Depending on the underlying technology under consideration, production capabilities may be correlated with peak utility requirements or other factors. Adjustments to the coincidence factor should generally be based on underlying engineering realities (operational concerns are generally addressed in the derate coefficient). For example, the performance of the RNG technology may have a correlation to weather (e.g., better or worse performance during cold periods), that should be accounted for in establishing the appropriate factor.

#### **DeratingFactor**

The DeratingFactor should be used to adjust the project's capability to reflect operational risks. For example, if there is a known correlation between the availability of the feedstock during extreme weather events, it may be appropriate to derate the project's capability. For example, snow and icy conditions could result in reduced supply with a resulting impact on facility availability and performance. Any factors that would ameliorate set such concerns (such as on-site storage) should also be taken into consideration.

### **Avoided Upstream Supply Costs – Commodity Costs**

In this example, an RNG will supply gas throughout the year at a negotiated commodity rate with the utility. In evaluating such a project on an incremental basis, this commodity price will need to be compared with the price the utility would have otherwise paid for the equivalent quantity of gas supply. This differential represents avoided commodity supply costs which may, in fact, represent an incremental cost relative to the utility's options depending on the commodity rate paid to the RNG.

### **Avoided Distribution Costs – Fixed Costs**

RNG projects are discrete projects with specific and known delivery locations on the distribution system. If sufficient information is available, the BCA should assess the value of deferral or avoidance of distribution system investment as a result of the RNG project.

### **Reliability/Resiliency**

RNG projects may have the potential to provide reliability/resiliency benefits. Again, this is location specific. But incremental supply on-system at various points could help support on-system pressures and overall stability of the distribution system and thereby avoid distribution system capital expense. However, quantifying specific benefits is challenging. In general, these benefits should be considered in qualitative assessments of projects.

**External Benefits (Avoided Greenhouse Gas Emissions, Avoided Other Emissions)**

Any Avoided Greenhouse Gas or Avoided Other Emissions associated with an RNG project should be based on the net impact of the project. In general, impacts at the point such gas is ultimately consumed by the consumer are minimal to zero, given that the ultimate product consumed is still gas. However, benefits associated with the creation of the source fuel (e.g., capture of greenhouse gases as part of the RNG creation process) should be accounted for in the evaluation.

**Lost Utility Revenue**

As alternative supply sources, RNG projects do not create Lost Utility Revenue.

**Participant NPS Costs**

Participant NPS costs will be estimated based on any amount paid to the RNG developer by the utility in addition to any difference between the price of gas paid to the RNG plant and the price the utility would have otherwise paid for such supply. However, the overall investment may, in certain cases, be superior to the amount paid by the utility to the developer. The developer may be layering multiple other revenue streams in addition to amounts paid by the utility (e.g., compost sales, tipping fees, etc.), and the sum of all the cash streams is what makes the project worthwhile to the developer. The assumption is that only the cash streams paid to the developer by the utility are to be accounted for as incremental technology cost.

**Other Net Non-Energy Costs**

RNG projects may have water and land impacts (benefits and costs) due to landfill utilization. Any quantifiable land or water benefits would apply to the SCT test.

## **5.2 Local Storage – CNG**

Local storage is an example of a *dispatchable* NPS which is called upon to operate in response to system, pipeline, and distribution peaks.

***5.2.1 Example System Description***

Natural gas is compressed and stored in strategic locations where it can be re-introduced to the distribution system as required. Facilities can be constructed as full-cycle operations where gas is compressed on-site using supply directly from the distribution system and later re-injected into the system as required, or as satellite facilities where gas is compressed off-site (either at a separate full-cycle facility within the distribution system or from locations outside Con Edison's service territory, and transported to the site in off-peak periods for storage and later sendout into the distribution system.

The physical footprint of RNG facilities varies based on size and design. Full-cycle facilities require room for compression, storage, and regasification. While avoiding the need for compression facilities, satellite facilities require sufficient footprints to permit delivery of off-site supply (typically via tanker trucks). In general, CNG facilities will require a smaller footprint than LNG facilities (due to set back and dispersion requirements). At any given point a facility will have a limited number of days of deliverability based on the on-site storage capacity and on-site truck injection/replacement capacity.

Facilities can also be designed with secondary purposes, such as a refueling station for CNG vehicles. This creates additional societal benefits but may complicate call rights.

### 5.2.2 Considerations Surrounding BCA Parameters Associated With CNG Projects

#### **Avoided Upstream Supply Costs – Fixed Costs**

While CNG is dispatchable, these projects would generally have a limited number of days of operation or availability (limited by the on-site storage capacity of the facility). This has implications for derating factors affecting both avoidable upstream supply costs and distribution costs. Specific considerations in assessing their ability to avoid fixed costs associated with upstream supply (based on the framework provided in Section 3) include:

##### ***ΔPeakLoad***

This would generally be set at the facility's peak sendout or nameplate capacity, net of any on-site uses of natural gas.

##### **CoincidenceFactor**

The coincidence factor for a CNG project is anticipated to be at or near one. These projects provide equivalent commodity on-system as dispatched. The name plate capacity should reflect the full capability of the facility to deliver during design conditions.

##### **DeratingFactor**

Minimal 'on the day' operating conditions should impact the derating factor for a CNG facility. However, this factor should also be used to adjust the deliverability of the project to account for limitations related to on-site storage durations and refill/replacement considerations. Specifically, a facility capable of providing multiple contiguous days of full deliverability prior to refilling on-site supply has less value than a facility with many days of supply on-site.

Refill choices also affect the value of the asset to avoiding upstream capacity. A facility that can refill from off-site (off-system) resources (e.g., via trucked supply) may have more value than a facility that requires solely on-site supply to refill the facility as this increases loads and reduces availability during peak periods. Section 5.7 discusses ways to address the associated derate factor surrounding duration of supply considerations.

#### **Avoided Upstream Supply Costs – Commodity Costs**

As with an RNG facility, the utility may negotiate a specific commodity rate for purchases of gas from a CNG facility. Any such rate should be compared to the cost the utility would otherwise pay for supply on the days it anticipates calling on the CNG facility in order to assess the net avoided commodity cost associated with the project.

#### **Avoided Distribution Costs – Fixed Costs**

CNG projects are discrete projects with specific and known delivery locations on the distribution system. If sufficient information is available, the BCA should assess the value of deferral or avoidance of distribution system investment as a result of the RNG Project.

#### **Reliability/Resiliency**

CNG projects have the potential to provide reliability/resiliency benefits. While this is location specific, the on-system location and dispatchability of the projects is particularly attractive as a means of preserving systems pressures and overall stability. However, in assessing such benefits consideration should be made of any limitations on operations. For example, a project may have a minimum run time that exceeds the anticipated need for pressure stabilization at a given location. And each discrete use of the facility may have

an associated fixed start-up cost that would need to be incorporated into an assessment of the associated reliability/resiliency benefits. The net value of the asset will depend on its merits and costs relative to the alternative resources the utility would otherwise be installed.

#### **External Benefits (Avoided Greenhouse Gas Emissions or Avoided Other Emissions)**

Incremental Greenhouse Gas or Other Emissions associated with the operation of the facility, may be incorporated into the assessment to the degree they are substantive in nature. This would include incremental emissions associated with compressions of the natural gas (or liquefaction in the case of LNG).

#### **Lost Utility Revenue**

As an alternative supply source, RNG projects do not create Lost Utility Revenue.

#### **Participant NPS Costs**

Participant NPS costs will be estimated based on any amount paid to the CNG developer by the utility in excess of the price of natural gas supplied by the CNG plant.

#### **Incremental Distribution System Investments/Costs**

Utility costs related to a CNG facility may include the cost to connect such facility to the distribution system and any downstream improvements of the distribution system to allow full delivery of the associated supply.

### **5.3 Energy Efficiency Example**

An energy efficient furnace depicts a *load-reducing* project where the use of the technology decreases the customer's energy consumption as compared to what it would be without the technology or with the assumed alternative technology. As such it represents a reduction in demand relative to a pre-existing load expectation.

#### ***5.3.1 Considerations Surrounding BCA Parameters Associated with EE Projects***

##### **Avoided Upstream Supply Costs – Fixed Costs**

Evaluation of avoidable upstream supply costs related to an EE program requires assessment of the impacts of the specific technology under consideration and comparison of this technology to a base case (i.e., the current technology in place). Operational characteristics of both the before and after scenarios would be compared to provide the net impact from the energy efficiency program. Specific considerations in assessing their ability to avoid fixed costs associated with upstream supply (based on the framework provided in Section 3) include:

##### ***$\Delta$ PeakLoad***

This would be set at the difference in the peak load expectation before and after the new technology. Caution should be exercised to confirm that the operational characteristics of the new technology or measure will generally result in peak demands at the same time the prior technology experienced these conditions.  $\Delta$ PeakLoad value must be normalized for the blended types and sizes of the entire population of buildings participating in the EE program, and also accounts for the percentage unoccupied buildings, if applicable, or other behavioral considerations.

##### ***CoincidenceFactor***

The coincidence factor for an energy efficiency program depends on the nature of the technology being considered and the associated end use. For instance, a home furnace would tend to have a high coincidence factor as heating loads are a primary driver of peak demand. Coincidence factors should be determined based on evaluation, measurement and verification best practices.

#### **DeratingFactor**

The derating factor will be a measure of the level of uncertainty associated with the ex-ante impact forecast. For instance, more hands-on take-to-market approaches, such as direct install and/or conventional EE measures with a large ex-post evaluation, measurement and verification literature would generally have DeratingFactors closer to one. By contrast, innovative EE measures for which third-party evaluation is lacking, or for which delivery methods that are more hands-off, such as upstream or midstream rebate programs, will have a lower DeratingFactor due to the higher uncertainty about impacts.

#### **Avoided Upstream Supply Costs – Commodity Costs**

For most energy efficiency technologies the impact on volumetric demand will occur on more than peak day and generally throughout the year. As such, associated avoided commodity costs should be based on the broader cost of utility supply as opposed to a peak day commodity price. In general, this price will reflect the utility's overall portfolio of gas supply options and consist of a combination of peak and non-peak prices.

#### **Avoided Distribution Costs – Fixed Costs**

Energy efficiency programs are not discrete projects with specific and known delivery locations on the distribution. Rather, their impacts tend to be distributed across many customer locations not identified at the time the BCA is performed. As such, they will not generally realize a specific avoided distribution cost, but may in aggregate benefit long-term utility planning. Any such aggregate benefit should be incorporated into the BCA and socialized across the pool of potential participants. This would generally be limited to the marginal cost of distribution capacity for the broad portfolio.

#### **Reliability/Resiliency**

Energy Efficiency programs are not generally anticipated to provide quantifiable reliability or resiliency benefits.

#### **External Benefits (Avoided Greenhouse Gas Emissions or Avoided Other Emissions)**

External Benefits will occur as the result of reduced overall consumption of gas. The estimated annual reduction in consumption (relative to the baseline) should be used for this calculation.

#### **Program Administration Costs**

Administrative costs for an energy efficiency program, as opposed to an RNG or CNG program, are an important consideration. These costs cover implementation costs associated with designing the program (including the cost to develop appropriate estimates of penetration rates and population specific characteristics), participant incentives designed to induce selection of alternative technologies, costs associated with marketing programs, costs to monitor participation rates (including costs to verify proper application of rebates with the HVAC sub-contractors that will generally represent the front-line of the program), and costs to measure and verify impacts.

**Lost Utility Revenue**

Volumes used for estimating avoided commodity costs represent reduced gas sales. These quantities should be used for estimating the impact on lost utility revenue and the associated impact on non-participant rates.

**Participant NPS Costs**

Participant costs should be measured as a function of the incremental cost and not the gross cost of the technology. These should be measured net of rebates paid to the customer/participant, the cost of which is included in Program Administration Costs. This net cost should then be compared to the base case cost that would have otherwise been paid for the base technology. Given the program nature of this option, estimates of these differentials will need to be developed as part of the program design based on current market costs for technologies. Analysis should account for anticipated changes in costs over time (e.g., impact of technology improvements on relative costs of alternatives).

**5.4 Demand Response**

DR depicts an example of a *dispatchable* NPS where the resource can be called upon to respond to peak demand. For natural gas, the impact of a demand response program must be sustained for a period of time on the order of a few days to offset the load during a cold snap event, which might last for multiple days. Any such program would need to carefully address concerns regarding snap back effects (i.e., the tendency for a site to require more gas on the day following the day of interruption to make up for lost thermal benefits).

While this option does not provide incremental supply, the dispatchable nature of the asset creates parallels to CNG and storage alternatives. In particular, the benefit of the asset will depend on the duration of the impact that can be provided and the assets ability to sustain such impact over more than one peak period. Options capable of performing in multiple peak periods (after a specific recovery period) may have more value than options offering one single call. Considerations for addressing the duration and sustainability of calls are discussed in Section 5.7.

***5.4.1 Considerations Surrounding BCA Parameters Associated With DR Projects*****Avoided Upstream Supply Costs – Fixed Costs**

As with energy efficiency options, evaluation of avoidable upstream supply costs related to a demand response program requires assessment of the specific impact of the demand response resource relative to a base case (i.e., the customer's gas load if it had opted not to reduce demand). The key question is the difference between the quantity of gas required with and without the implementation of the demand response actions. Specific considerations in assessing their ability to avoid fixed costs associated with upstream supply (based on the framework provided in Section 3) include:

 **$\Delta$ PeakLoad**

This would be set at the difference in the peak load expectation with and without the demand response measure(s).  $\Delta$ PeakLoad value must be normalized for the blended types and sizes of the entire population of buildings participating in the DR program, account for snap back effect (if any), and also account for the percentage of unoccupied buildings, if applicable, or other behavioral considerations.  $\Delta$ PeakLoad must also be net of all market effects, such as free ridership, if applicable.

**CoincidenceFactor**

Given the dispatchable nature of the option, the coincidence factor will generally be one, assuming that  $\Delta\text{PeakLoad}$  accounts for any behavioral considerations.

**DeratingFactor**

The derating factor will be a measure of the level of uncertainty associated with the ex-ante impact forecast. For instance, more hands-on take-to-market approaches, such as direct install and/or conventional DR measures with a large ex-post evaluation, measurement and verification literature would generally have DeratingFactors closer to one. By contrast, more innovative DR measures for which third-party evaluation is lacking, or for delivery methods that are more hands-off, such as upstream or midstream rebate programs, a lower DeratingFactor may be appropriate to reflect higher uncertainty of performance.

**Avoided Upstream Supply Costs – Commodity Costs**

The starting point for assessing avoided commodity costs for a demand response asset or program will generally be the peak gas price of the utility. However, the net benefit associated with such technology should account for any snap back effects. To the degree the technology shifts demand from peak periods to other periods the net commodity benefit may be zero (or could be negative depending on how the technology operates and its impact on overall demand).

**Avoided Distribution Costs – Fixed Costs**

Demand response programs are typically not discrete projects with specific and known delivery locations on the distribution at the time the BCA is performed. Their impacts may be distributed across a wide area. As such, they will not generally realize a specific avoided distribution cost, but may in aggregate benefit long-term utility planning. Any such aggregate benefit should be recognized in the BCA. This would generally be limited to the marginal cost of distribution capacity for the broad portfolio. However, in the case of a single, large DR resource, it may be possible to determine a case-specific Avoided Distribution Cost.

**Reliability/Resiliency**

While demand response programs may be distributed across the utility, depending on the technology available for exercising the associated interruption right, there could be associated benefits with respect to reliability and resiliency. For example, if the technology permits the utility to direct activations to specific locations with sufficient aggregate participants, this may provide pressure stabilization benefits at times.

**External Benefits (Avoided Greenhouse Gas Emissions or Avoided Other Emissions)**

External Benefits may occur as a result of reduced overall consumption of gas, but should also account for the impact of the use of any alternative fuels (including electricity). The estimated annual reduction in demand (relative to the baseline) should be used for this calculation.

**Program Administration Costs**

Administrative costs for a demand response program will be similar to those associated with an energy efficiency program in many respects. Given the dispatchable nature of the asset, more effort and expense may be required with respect to validating impacts and/or pre-testing impacts on an annual or periodic basis.



**Lost Utility Revenue**

Volumes used for estimating avoided commodity costs represent reduced gas sales. These quantities should be used for estimating the impact on lost utility revenue and the associated impact on non-participant rates.

**Participant NPS Costs**

Participant costs should be measured as a function of the incremental cost and not the gross cost of the technology or measures. Given the program nature of this option, estimates of these differentials will need to be developed as part of the program design based on current market costs for technologies. The analysis should account for anticipated increases in costs over time (generally inflation) but also projected reductions in spreads between base technologies and higher efficiency options based on technology improvements over time. Con Edison may rely on the incentive payment or 'bid price' proposed by a respondent in a competitive solicitation process as the best estimate of incremental cost for the purpose of assessing Participant NPS Costs.

## **5.5 Gas To Electricity Conversion**

A gas to electric conversion involves the replacement of an existing gas application with a comparable resource powered by electricity. While this may completely eliminate the associated gas supply requirement, it creates an associated requirement on the power side that needs to be considered in the analysis.

### ***5.5.1 Considerations Surrounding BCA Parameters Associated with G2E Projects***

**Avoided Upstream Supply Costs – Fixed Costs**

Evaluation of avoidable upstream supply costs related to G2E program requires assessment of the technology / end-use being eliminated and also the details regarding the replacement technology with respect to associated power requirements. Specific considerations in assessing their ability to avoid fixed costs associated with upstream supply (based on the framework provided in Section 3) include:

 **$\Delta$ PeakLoad**

This would be set at the peak load of the gas asset being displaced.  $\Delta$ PeakLoad value must be normalized for the blended types and sizes of the entire population of buildings participating in the G2E program.  $\Delta$ PeakLoad must also be net of all market effects, such as free ridership, if applicable.

**CoincidenceFactor**

Coincidence factor shall be determined based on evaluation, measurement and verification best practices, which may entail computer-assisted building energy modeling or other approaches to establish the load profile of the gas usage (for instance space heating) being converted to electricity.

**DeratingFactor**

The derating factor will be a measure of the level of uncertainty associated with the ex-ante impact forecast. For instance, more established approaches, such as measures with a large ex-post evaluation, measurement and verification literature would generally have DeratingFactors closer to one. By contrast, more innovative approaches for which third-party evaluation is lacking, or delivery methods that are more hands-off, such as upstream or midstream rebate programs, may have a lower DeratingFactor due to the higher uncertainty.



**Avoided Upstream Supply Costs – Commodity Costs**

The commodity impact of a G2E program will depend on the associated end-use. In general, a G2E program will impact gas consumption throughout the winter season or year-round. As such, associated avoided commodity costs should be based on the broader cost of utility supply as opposed to a peak day commodity price. In general, this price will reflect the utility's overall portfolio of gas supply options and consist of a combination of peak and non-peak prices.

**Avoided Distribution Costs – Fixed Costs**

G2E programs are not necessarily discrete projects with specific and known delivery locations on the distribution system. Rather, their impacts tend to be distributed across a wide area. As such, they will not generally realize a specific Avoided Distribution Cost, but may in aggregate benefit long-term utility planning. Any such aggregate benefit should be recognized in the BCA. This would generally be limited to the marginal cost of distribution capacity for the broad portfolio.

**Reliability/Resiliency**

G2E programs are not generally anticipated to provide quantifiable reliability or resiliency benefits.

**External Benefits (Avoided Greenhouse Gas Emissions or Avoided Other Emissions)**

Net External Benefits should be computed for G2E programs. The programs reduce gas demand with associated emissions benefits, but increase electricity demand. The external impacts associated with the incremental electric load should be netted against the gas demand benefits.

**Program Administration Costs**

Administrative costs for a G2E program would likely be similar to those associated with an energy efficiency program.

**Lost Utility Revenue**

Volumes used for estimating avoided commodity costs represent reduced gas sales service revenues. These quantities should be used for estimating the impact on lost utility revenue and the associated impact on non-participant rates. However, these should be netted against incremental revenues associated with the replacement electric technology for an overall impact.

**Participant NPS Costs**

Administrative costs for a G2E program are consistent with those for an energy efficiency program.

## **5.6 Derating Considerations Related To Duration of Supply / Load Impact**

To receive credit for avoiding upstream fixed supply costs an NPS project or program(s) should provide both incremental deliverability (or decremental demand) during peak conditions, and provide this deliverability for a sufficient period of time to address the utility's projected design requirements. The specific duration of need required by the utility will be a function of the set of supply options in the utility's existing portfolio and the nature of the utility's projected loads on affected portions of its gas system. If the resource requirement calls for a quantity of gas on multiple days and the proposed project or program can provide deliverability on only some of those days, then the project or program cannot, in and of itself, avoid the acquisition of the upstream supply resource. However, this does not mean the project or program should be afforded no value toward avoiding the upstream asset.

To the degree a project or program can be combined with other proposals in such a combination to provide the needed supply resource, then the project or program may be afforded some credit toward avoided supply costs. In concept, if the utility requires an equal amount of supply or demand relieve on five days of supply and an asset only provides sufficient capacity to fulfill one day of that need, then the asset could arguably be credited for one-fifth of the avoided upstream asset cost. However, the actual dollar amount credited will be based on a portfolio assessment considering all alternative NPS programs and how they might, in combination with each other, effectively address the projected need.

To the degree a proposed project or program provides more than the required number of days of deliverability it has more value than an alternative that provides only the estimated number of days of relief. At a minimum, extra days provide the utility with greater security of supply and ability to respond to unforeseen load events (e.g., if actual consumption is higher than forecasted). Extra days of availability may also enable the utility to remarket other upstream assets (e.g., capacity release). In assessing NPS alternatives, those proposals providing more deliverability than requested should, at a minimum, be recognized qualitatively relative to shorter duration options.