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Natural Gas Benefit Cost Analysis (BCA) Handbook

Version 1.0

July 14, 2025

NYSEG/RG&E Natural Gas Benefit-Cost Analysis (BCA) Handbook

COMMONLY USED TERMS

Acronyms and abbreviations are used extensively throughout this Benefit-Cost Analysis (BCA) Handbook and are presented here for ease of reference.

BCA	Benefit-Cost Analysis
Btu	British thermal units of energy
Capacity	Space on a pipeline allowing the Company to move gas from a receipt point to citygate for distribution on the Company's system
CH_4	Methane
Citygate	The interconnection point between an upstream pipeline and the local facilities through which the Company receives deliveries from that pipeline
CO_2	Carbon dioxide
Commodity cost	The cost of natural gas at wholesale prices
Company	New York State Electric & Gas Corporation and/or Rochester Gas and Electric Corporation where applicable, or any successor agency thereto
Cost of Gas	The Company's total cost of gas upstream of the Company's citygate. The cost is composed of the commodity cost of gas, all pipeline capacity costs, and all storage capacity costs
Dekatherm (Dth)	10 therms, which is the quantity of heat energy equal to 1,000,000 BTUs
Delivered services	Gas supply services delivered to the citygate acquired from a third-party (not a pipeline)
DR	Demand response
Losses	The loss of gas, resulting from its transportation over the Distribution System, between the Distribution Point(s) of Receipt and the Distribution Point(s) of Delivery
LAUF Gas	Lost and Unaccounted For Gas. The difference between the quantity of gas available from all sources (purchased, transported, and locally produced) and the quantity accounted for by Company sales or deliveries
NEI	Non-energy impacts
N_2O	Nitrous oxide
NYISO	New York Independent System Operator

NYSDPS	New York State Department of Public Service (also referred to as the New York State Public Service Commission)
NYSEG	New York State Electric & Gas Corporation
NYSERDA	New York State Energy Research & Development Authority
O&M	Operations and maintenance
Point of Supply	The point (or connection) where the Company's gas mains and/or Service Lines end and customer-owned Service Lines end and customer-owned facilities begin
RECC	Real economic carrying charge
RG&E	Rochester Gas and Electric Corporation
RIM	Ratepayer impact measure
SCC	Social cost of carbon
SCT	Societal cost test
T&D	Transmission and distribution
UCT	Utility cost test
WACC	Weighted average cost of capital

1. INTRODUCTION

The New York State Electric & Gas Corporation (NYSEG) and Rochester Gas and Electric (RG&E)[1] Natural Gas Benefit-Cost Analysis (BCA) Handbook (Handbook) lays out a framework for calculating the benefits and costs to evaluate the cost-effectiveness of natural gas energy efficiency projects, programs, and portfolio investments, as directed by the State of New York Public Service Commission's (NYSDPS) Order Regarding Long-Term Natural Gas Plan and Directing Further Actions.[2]

Evaluating cost-effectiveness is a complex task that requires consideration of many factors, some of which are easier to quantify than others. The BCA framework set out in this Handbook is guided by the principles that, when possible, a BCA should:

- Use clear methodologies;
- Strive to identify and evaluate all benefits and costs, but recognize the need to use broad assumptions at times (e.g., when more granular details are not readily available or reasonably quantifiable);
- Evaluate project proposals within the broader context, allowing for consideration of potential synergies, interactive effects, and economic impacts across the portfolio;
- Address the full lifetime of a project or program;
- Assess the underlying risk of a project's or program's performance via sensitivity analysis on key assumptions; and
- Compare benefits and costs to traditional alternatives instead of valuing them in isolation.

The BCA Handbook addresses general BCA considerations and highlights significant issues related to data collection for impact assessments. It reviews the Societal Cost Test (SCT), Utility Cost Test (UCT), and Rate Impact Measure (RIM) cost-effectiveness tests, deemed relevant by the NYSDPS's Order Establishing the Benefit Cost Analysis Framework (BCA Order),[3] and identifies the pertinent benefits and costs associated with each test.

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

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[1] NYSEG and RG&E are fully owned subsidiaries of Avangrid, Inc.

[2] Case 23-G-0437 – In the Matter of a Review of the Long-Term Gas System Plan of New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation, Order Regarding Long-Term Natural Gas Plan and Directing Further Actions (issued January 23, 2025).

[3] 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)

1.1 Structure of the BCA Handbook

The remainder of the Handbook is divided into four chapters that detail the BCA methodology and assumptions.

Section 2. General Methodological Considerations summarizes the general BCA considerations to ensure consistency and rigor across various analyses.

Section 3. Relevant Cost-Effectiveness Tests defines the three (3) cost-effectiveness tests that will be used to evaluate each proposed project or program once the various benefits and costs are identified, evaluated, and appropriately discounted.

Section 4. Key Benefits and Costs details the key impacts specific to natural gas benefit-cost analysis. Definitions and theoretical calculation methodologies are provided for each impact.

Section 5. Selected Input Parameters provide the current values of selected parameters that will be used to assess the cost-effectiveness analysis.

2. GENERAL METHODOLOGICAL CONSIDERATIONS

Many methodological considerations apply to any BCA to ensure consistency and rigor across various analyses. Some considerations are common across most analyses, while others are specific to a given project. These considerations serve as a foundation for creating robust BCA models tailored to specific projects, enabling a comprehensive assessment of benefits and costs while addressing the nuances of proposed natural gas investments.

This section presents the general methodological considerations that underpin the BCA methodology.

2.1 Establish Appropriate Time Horizon for Evaluation

The duration over which the costs and benefits of new investments are realized can vary significantly. As such, the time horizon for the analysis must consider the different expected useful lifetimes of the measures across multiple projects. The analysis timeframe should be based on the longest asset lifetime of the project or program under consideration.

2.2 Discount Cash Flows

Determine the present value of all benefits and costs by applying the discount rate (i.e., the utility-weighted average cost of capital). Inflation should be treated consistently by discounting real cash flow by real discount rates and nominal cash flows by nominal discount rates.

2.3 Perform Sensitivity Analysis

Comparative analysis of projects or portfolios can benefit from an assessment of their expected performance relative to each other under different conditions. Sensitivity analyses may identify the assumptions and factors key to determining the overall net benefit of a project or program.

2.4 Incorporating Avoidable Losses into the Analysis

The BCA must account for variable losses occurring upstream from the load impact to determine the total energy or demand impact. The savings from an energy efficiency program are measured at the point of consumption (i.e., the customer's meter). However, commodity savings measured at the point of consumption underestimate the total supply savings measured at the citygate due to losses in the transmission and distribution system between the citygate and the point of consumption. To accurately capture the total savings from the energy efficiency program, the savings measured at the point of consumption must be "grossed up" to account for these system losses.

The BCA Handbook accounts for all avoidable losses (represented as AvdLoss in this document) by adjusting the impact parameter. As such, the per unit impact parameter (measured at the customer's meter) must be grossed up for avoidable losses (i.e., dividing by (1 – AvdLoss)). It is crucial that the calculations of benefits and costs are presented and evaluated on a consistent basis with respect to losses.

2.5 Accounting for Multiple Benefits and Costs

Projects have the potential to offer various benefits or to incur multiple costs, all of which should be included in the BCA. For example, an energy efficiency program may provide the benefits of avoided commodity cost, avoided citygate supply, and avoided investment in incremental on-system distribution capacity (based on its specific placement within the system). Additionally, some impacts may be considered either a benefit or a cost, depending on the program or project type. For example, energy efficiency program benefits include energy savings across all fuel types with limited exceptions. Alternatively, fuel switching programs involve the decrease or elimination of one fuel (a benefit) and the increase of an alternative fuel (a cost). These distinctions should be considered when assessing a project, and impacts should be appropriately accounted for as either a benefit or a cost in the BCA.

To avoid double-counting or miscounting project impacts that have been measured:

- Carefully track the benefits and costs resulting from various investments in a project, program, or portfolio;
- Clearly define and differentiate between the benefits and costs; and
- Carefully consider how the related value propositions interact.

2.6 Timing of Impacts

For the purposes of BCA analysis, 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 have 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 same year that actual effects occur (i.e., the benefits or costs are realized). For example, if a project reduces system peak load in 2025 but the portfolio of assets cannot be modified in 2025 to account for this reduction (due to prior commitments to upstream contracts), then there are no benefits in 2025. The benefit should not be recognized until the portfolio can be adjusted. However, to the degree 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.

2.7 Appropriate Granularity of Data

Ideally, the BCA should use locational and temporal information specific to the program or project. If more detailed data are not available, an applicable annual average or system average can be employed to represent the anticipated benefits or costs associated with the project.

2.8 Data Sources

Table lists the sources for selected data that will be used to implement the Handbook. The current values for these selected input parameters are provided in Section 5.

TABLE 1. SOURCES FOR SELECTED INPUT PARAMETERS

Parameter	Source
Weighted Average Cost of Capital (WACC)	2020-2025 System Energy Efficiency Plan: NYSEG/RG&E Appendix B—Benefit Cost Analysis Working Papers
Avoidable Gas Loss Factor	Lost and Unaccounted For (LAUF) Gas Value: NYSEG = 0.216% (Case 22-G-0033); RG&E = 0.729% (Case 22-G-0320)
Upstream Supply Cost (Cost of Gas)	Avangrid Multi-Source Market Forecast
Social Cost of Carbon	2025 Update, NYS Value of Carbon Guidance, Appendix: Annual Social Cost Estimates

3. RELEVANT COST-EFFECTIVENESS TESTS

The BCA Order states that the SCT, UCT, and RIM make up the relevant cost-effectiveness tests to be used in the BCA. These cost-effectiveness tests are summarized in Table . 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 2. COST-EFFECTIVENESS TESTS

Cost Test	Perspective	Key Question Answered	Calculation Approach
Societal Cost Test (SCT)	Society	Is society as a whole better off?	Compares the costs associated with designing and delivering projects and customer expenses to the benefits of avoided natural gas, other supply-side resource costs, and the cost of externalities (e.g., carbon emissions).
Utility Cost Test (UCT)	Utility	How will utility costs be affected?	Compares the utility costs associated with designing, delivering, and managing projects to the benefits of avoided natural gas supply-side resource costs.
Ratepayer Impact Measure (RIM)	Ratepayer	How will utility rates be affected?	Compares the utility costs associated with designing, delivering, and managing projects as well as lost revenue due to reduced energy bills to the benefits of avoided natural gas supply-side resource costs.

3.1 Societal Cost Test

The SCT is designed to capture the full range of economic, environmental, and operational impacts of a program or project on society as a whole. The impacts include fixed and commodity costs associated with avoided upstream supply, avoided investments in distribution infrastructure, reduced distribution operations and maintenance (O&M) costs, improvements in reliability and resiliency, and reductions in both CO_2e and other pollutant emissions. Lost utility revenue and program incentive costs are excluded from the SCT because they represent a financial transfer between participants and non-participants, resulting in no net societal gain or loss.

3.2 Utility Cost Test

The UCT focuses solely on the direct financial impacts to the natural gas utility. The impacts include fixed and commodity costs associated with avoided upstream supply, avoided investments in distribution infrastructure, reduced distribution O&M costs, improvements in reliability and resiliency, program costs, and participant incentives. External benefits, such as avoided CO_2e emissions and other pollutant reductions are not included in this test unless there are associated monetized compliance costs, as they do not directly affect customer rates. Participant costs and lost natural gas utility revenues are excluded since they are not incurred by the utility and any reduced revenues are assumed to be made up by non-participating customers through future rate adjustments.

3.3 Ratepayer Impact Measure

The RIM test assesses the rate impacts on non-participating customers of the natural gas utility. The impacts include fixed and commodity costs associated with avoided upstream supply, avoided investments in distribution infrastructure, reduced distribution O&M costs, improvements in reliability and resiliency, program costs, participant incentives, and lost utility revenues. External benefits, such as avoided CO_2e emissions and other pollutant reductions, are excluded from this test unless there are associated monetized compliance costs, as they do not directly affect customer rates. Improvements in reliability and resiliency are omitted because their effects on rates are unpredictable and difficult to quantify. Participant costs are not considered because the customer's expense to implement a project is not a natural gas utility cost that influences non-participating customers' rates.

3.4 Applying the Cost Effectiveness Tests

Table summarizes and identifies which benefits and costs are relevant to each cost-effectiveness test.

TABLE 3. SUMMARY OF COST-EFFECTIVENESS TESTS BY BENEFIT AND COST

Section #	Impacts (Benefit/Cost)	SCT	UCT	RIM
Benefit				
4.2.1	Gas System Capacity Impacts	✓	✓	✓
4.2.2	Gas Commodity Impacts	✓	✓	✓
4.2.3 Error! Reference source not found.	Gas Distribution System Infrastructure Impacts	✓	✓	✓
4.2.4	Gas Distribution System O&M Impacts	✓	✓	✓
4.2.5	Reliability/Resiliency/Safety Impacts	✓	✓	
4.2.6	Natural Gas CO_2e Emission Impacts	✓		
4.2.7	Natural Gas Other Emissions Impacts	✓		
4.2.8	Participant Incentives		✓	✓
4.2.17	Participant Non-Energy Impacts	✓		
4.2.18	Other Non-Energy Impacts	✓	✓	✓
4.2.19	Other External Impacts	✓		
Cost				
4.2.9	Federal Incentives	✓		
4.2.10	Program Administration Costs	✓	✓	✓
4.2.11	Incremental Distribution Systems Investments	✓	✓	✓
4.2.12	Lost Utility Revenue			✓
4.2.13	Participant Costs	✓		
4.2.14	Alternative Fuel Impacts			
	Alternative Fuel Impacts – Electric	✓	✓	✓
	Alternative Fuel Impacts – Non-Electric	✓		✓
4.2.15	Alternative Fuel CO_2e Emissions Impacts (Electric and Non-Electric)	✓		
4.2.16	Alternative Fuel Other Emissions Impacts (Electric and Non-Electric)	✓		
4.2.18	Other Non-Energy Impacts	✓	✓	✓
4.2.19	Other External Impacts	✓		

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

- Select the relevant benefit for the investment.

- Determine the relevant costs from each cost included over the life of the investment.
- Estimate the impact of the investment on each relevant benefit for every year of the analysis period (i.e., how much it will alter the underlying physical operation of the natural gas T&D system to generate the benefits).
- Apply the benefit values associated with project impacts.
- Apply the appropriate discount rate to conduct 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.
- Treat inflation consistently by discounting real cash flow with real discount rates and nominal cash flows with nominal discount rates. An annual inflation rate of 2% should be assumed unless stated otherwise.
- Compare the discounted lifetime benefits to the discounted lifetime costs to get a benefit-cost ratio.

4. KEY BENEFITS AND COSTS

This section reviews the key impacts specific to natural gas BCAs. Definitions and theoretical calculation methodologies, as well as complexities surrounding the estimation of associated future costs and benefits, are provided for each category.

4.1 Summary of Key Impacts

A summary of the key impacts specific to natural gas BCAs is presented in Table . The impacts are typically considered a cost or benefit within a specific BCA test but may fall into either category depending on the project and program.

TABLE 4. SUMMARY OF KEY IMPACTS

IMPACT	BRIEF DESCRIPTION
Gas System Capacity Impacts	Impacts resulting from avoiding the need to increase or decrease gas utilization on peak days. The impact will lag based on when peaking services contracts are procured and the load impacts are realized.
Gas Commodity Impacts	Impact resulting from reducing or increasing the need for supply resources.
Gas Distribution System Infrastructure Impacts	Impacts resulting from avoiding or deferring the need to invest in the distribution system infrastructure. The impacts take into account that a project or program may only defer the investment rather than completely eliminating the need for investment.
Gas Distribution System O&M Impacts	The variable operation and maintenance impacts on the distribution system resulting from a proposed project or program. O&M expenses related to distribution expansions and upgrades are often incorporated into marginal cost studies, and the associated avoided costs may be captured in the Gas Distribution System Infrastructure Impacts.
Reliability/ Resiliency/ Safety	These impacts reflect how projects and programs affect overall system reliability, the ability to maintain system standards despite disruptions, and the ability to recover from system malfunctions or outages. Projects essential for meeting reliability, resiliency, and safety requirements typically do not fit well into traditional economic evaluations, such as benefit-cost analyses, since they are critical prerequisites for delivering gas service to customers and are heavily context-dependent. However, the results of such analyses

	can still be useful for comparing and prioritizing different programs or projects that offer similar benefits.
Natural Gas CO_2e Emissions Impacts	The impacts account for avoided carbon dioxide equivalent (CO_2e) emissions (including CO_2, CH_4, and N_2O) due to a net reduction in natural gas use.
Natural Gas Other Emissions Impacts	These impacts are derived from reducing pollutant emissions—excluding CO_2e—that result from decreased natural gas consumption.
Program Administration Costs	Administrative costs directly associated with implementing a project or program, including program delivery, marketing, and evaluation.
Incremental Distribution System Investments	Incremental distribution system investments include the costs incurred by the utility to support the implementation of the project or program.
Lost Utility Revenue	Lost distribution and other non-by-passable revenue from decreased natural gas sales or demand.
Participant Costs	Costs incurred by customers, including incremental equipment and ongoing maintenance costs.
Participant Incentives	Direct or indirect payments to customers to offset participant costs of equipment or other costs associated with participation in a program.
Federal Incentives	Federal rebates or tax incentives paid to customers for the purchase and installation of qualifying equipment or completion of qualifying projects.
Alternative Fuel Impacts	Impact of using electricity (or a non-electric fuel) as a replacement for the service previously provided by natural gas.
Alternative Fuel CO_2e Emissions Impacts	CO_2e emissions produced from using a fuel other than natural gas (electric or non-electric fuel).
Alternative Fuel Other Emissions Impacts	Non-CO_2e pollutant emissions produced from using a fuel other than natural gas (electric or non-electric fuel).
Participant Non-Energy Impacts	Additional impacts beyond direct energy savings, such as improved safety, enhanced thermal comfort, and health benefits.
Other Non-Energy Impacts	Additional impacts (or cost reductions) for the natural gas utility associated with various non-commodity aspects of a proposed project or program. If these impacts exist but are difficult to measure, they can be assessed qualitatively.

Other External Impacts	Impacts not captured in other categories, such as environmental effects. If these impacts exist but are difficult to measure, they can be assessed qualitatively.

4.2 Key Impacts (Benefits/Costs)

This section details the key impacts included in the BCA Handbook. Definitions are provided for each impact, along with the theoretical calculation methodologies and complexities involved in quantifying their benefits or costs.

4.2.1 Gas System Capacity Impacts

NYSEG and RG&E may be able to adjust their capacity portfolio if a project leads to a decrease in natural gas utilization on peak demand days. The capacity-related benefits depend on the marginal supply that can be avoided when peak demand decreases. Determining the correct marginal supply cost relies on the specifics of the natural gas utilization reduction, the existing supply portfolio, and how the project influences that portfolio in terms of timing. Based on these considerations, NYSEG and RG&E may recognize delivered services or components of their pipeline or storage delivery capacity as the marginal supply for a particular project analysis.

To receive credit for reduced peak gas demand, a project must either increase supply or decrease demand during peak conditions for a sufficient magnitude and duration, allowing NYSEG and RG&E to modify their procurement strategies. The required magnitude and duration depend on the existing contracts in NYSEG and RG&E's portfolios, as well as the projected demands on the relevant parts of their gas system. For instance, if the needed gas quantity spans multiple days but the project can only offer benefits on a few, it will not avoid the complete marginal supply resource.

EQUATION 1. GAS SYSTEM CAPACITY IMPACTS

$$Impact_Y = \sum_P \left(\frac{\Delta PeakLoad_Y}{\left(1 - AvdLoss_Y\right)} * DistCoincFactor_Y * DeratingFactor_Y * MCOPS_Y \right)$$

Where:

Y	The year that the benefit is recognized/realized.
P	If applicable and data are available, the period within a given year when capacity costs are impacted (e.g., winter, shoulder, or summer).

$\Delta PeakLoad_Y$	The project's expected maximum demand impact capability, or nameplate impact. This input is project- or program-specific. A positive value represents a reduction in peak load.
$AvdLoss_Y$	The avoidable loss for the system applicable to year Y.
$DistCoincFactor_Y$	Factor 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 the distribution system experiences its peak load (this may differ from the overall coincident system peak). The input is project-specific.
$DeratingFactor_Y$	A factor to derate the impacts of the program/project based on its anticipated availability during peak calls on the applicable section of the distribution system. For example, a DR program may be limited to dispatching a maximum of five events per year, which could limit the availability of the resource during peak periods beyond the 5-day maximum. The input is project or program-specific.
$MCOPS_Y$	The marginal cost of peaking services is the fixed reservation fee component of the avoidable peaking services supply under the applicable scenario, measured in $/Dth for the number of days of avoided peaking service purchases.

Considerations on Equation Components

The impact will lag based on when peaking services contracts are procured and when the peak load impact is realized.

4.2.2 Gas Commodity Impacts

Commodity supply costs result from projects or programs that reduce or increase the need for supply resources throughout the year. Commodity supply costs are variable in nature (i.e., $/Dth of consumption). The impacts associated with avoiding commodity supply costs can be calculated using the framework outlined in **Error! Reference source not found.**.

EQUATION 2. GAS COMMODITY IMPACTS

$$Impact_Y = \sum_P \left(\frac{\Delta Commodity_{P,Y}}{(1 - AvdLoss_Y)} * CostofGas_{P,Y,r} \right)$$

Where:

Y	The year that the benefit is recognized/realized.
P	If applicable and data are available, the period within a given year when commodity costs are impacted (e.g., winter, shoulder, or summer).
$\Delta\mathbf{Commodity}_{P,Y}$	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.
$\mathbf{AvdLoss}_Y$	The avoidable loss for the system applicable to year Y.
r	The specific retail delivery location; this may differ by transmission, high, medium, or low-pressure customers.
$\mathbf{CostofGas}_{P,Y,r}$	The commodity cost of gas.

Considerations on Equation Components

Commodity impacts are calculated using a commodity cost forecast. The time differential for subscript P (period) will depend on the type of project and interval (winter, shoulder, summer, or another time interval). The benefit-cost analysis must accurately capture when the impacts are expected to occur within a given year. For example, it may be appropriate to use an annual average price and impact for a project that has a consistent load reduction at all hours of the year. However, using the annual average may not be appropriate for evaluating a DR program that only reduces load during a few peak days, if the commodity cost on peak days is available.

4.2.3 Gas Distribution System Infrastructure Impacts

Distribution infrastructure impacts result from projects or programs that reduce distribution load (or supply resources) to avoid or defer investments in the distribution system infrastructure.[4] The 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- or program-specific benefits

[4] Note that this section pertains to the benefits of avoiding gas distribution infrastructure. In some cases, gas-to-electricity programs may result in the need to upgrade electricity distribution infrastructure to accommodate energy services that were previously provided by gas. If fuel switching from gas to electricity causes an incremental need for a distribution upgrade, that upgrade should be considered a cost in the analysis.

associated with avoided distribution infrastructure are capacity-related and can be calculated using the framework outlined in Equation .

EQUATION 3. GAS DISTRIBUTION SYSTEM INFRASTRUCTURE IMPACTS

$$Impact_Y = \sum_C \left(\frac{\Delta PeakLoad_{Y,r}}{(1 - AvdLoss_Y)} * DistCoincFactor_{C,Y,r} * DeratingFactor_Y * MarginalDistCost_{C,Y,r} \right)$$

In many situations, a project or program may only defer the investment in the distribution system infrastructure rather than completely offset the need for the investment. There are industry-recognized methods to estimate the deferral value over time, which are well-suited to represent the marginal cost of the distribution equipment. The deferral method (sometimes called the rental value method) converts capital investments into annual costs using a real economic carrying charge (RECC). The RECC is the current dollar value that, when escalated over time at the inflation rate, results in the same present value as the present value of the infrastructure investments.

EQUATION 4. MARGINAL COST OF DISTRIBUTION EQUIPMENT

$$MarginalDistCost_{C,Y,r} = \frac{\sum_A RECC_{C,r,A}}{Capacity_{C,r}} * (1 + Inflation)^{Y - Y_0}$$

To calculate the marginal cost of distribution equipment, the RECC values are summed across all assets associated with a given system constraint and retail delivery location. The sum is divided by the increase in peak capacity, expressed in Dth/day, resulting from the investment in additional distribution system infrastructure. Lastly, the quotient is escalated at the inflation rate to provide a time series of marginal costs.

EQUATION 5. REAL ECONOMIC CARRYING CHARGE

$$RECC_{C,r,A} = \frac{PVAssetCost_{C,r,A}}{PV\left(RealDiscntRate,\ Lifetime_{C,r,A},\ \frac{-1}{1 + Inflation}\right)}$$

And

$$RealDiscntRate = \frac{1 + NomDiscntRate}{1 + Inflation} - 1$$

Where:

Y	The year that the impact is recognized/realized. Y_0 is the current year.
r	The specific retail delivery location; this may differ by transmission, high, medium, or low-pressure customers.

C	The specific distribution system constraint was affected.
A	An asset required in the infrastructure investment.
$\Delta \mathbf{PeakLoad}_{Y,r}$	The expected maximum demand reduction capability, or nameplate impact. This input is project/program-specific. A positive value represents a reduction in peak load.
$\mathbf{AvdLoss}_{Y}$	The avoidable loss for the system applicable to year (Y).
$\mathbf{DistCoincFactor}_{C,Y,r}$	Factor to adjust the nameplate capacity of the project/program to account for the relationship between the coincidence of the asset's expected contribution at the time the applicable section of the distribution system experiences its peak load (this may differ from the overall coincident system peak). The input is project/program-specific.
$\mathbf{DeratingFactor}_{Y}$	A factor to derate 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 (DR) program may be limited to dispatching a maximum of five events per year, which could limit the availability of the resource during peak periods beyond the 5-day maximum. The input is project/program-specific.
$\mathbf{MarginalDistCost}_{C,Y,r}$	The marginal cost of the distribution equipment that the project/program is relieving is assumed to be based on the cost of expanding the applicable section of the distribution system. The variable is specific to the location (r) and distribution system constraint (C).
$\mathbf{RECC}_{C,r,A}$	The real economic carrying charge for asset (A) associated with the distribution system constraint (C) and retail delivery location (r), measured in dollars.
$\mathrm{Capacity}_{C,r}$	The increase in peak capacity resulting from the investment in all distribution system assets associated with system constraint (C) and retail delivery location (r), measured in Dth/day of capacity.
Inflation	The inflation rate in units of %/year.

$AssetCost_{C,r,A}$	Investment cost for each asset (A) associated with system constraint (C) and retail delivery location (r), measured in dollars.
$Lifetime_{C,r,A}$	Equipment lifetime in years based on utility cost accounting for asset (A) associated with system constraint (C) and retail delivery location (r).
NomDiscntRate	The nominal discount rate in units of %/year.
RealDiscntRate	The real discount rate in units of %/year.
PV( )	The present value function, as defined in Microsoft Excel.

Considerations on Equation Components

Project- and location-specific distribution system infrastructure costs and deferral values should be utilized whenever 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 it in Equation . In some circumstances, the system average marginal cost may be acceptable—for instance, when evaluating energy efficiency programs for which specific customer locations are not yet identified. The distribution infrastructure impacts for a specific location are only realized if a project or program meets the engineering requirements for functional equivalence (i.e., reliably reduces coincident load to a level that enables the deferral or avoidance of the distribution project in each hour for which a coincident load reduction is necessary).

Coincidence and derating factors may be determined through a project-specific engineering study based on historical experience in NYSEG and RG&E's service territory or elsewhere or derived from engineering judgments about potential performance limitations. The timing of impacts resulting from peak load reductions is project- or program-specific. It is assumed that a peak load reduction impact will yield benefits in the year the impact occurs. As with avoided supply costs, the benefit-cost analysis must accurately capture when the impacts are expected to occur within a given year. A 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.

4.2.4 Gas Distribution System O&M Impacts

Distribution system O&M encompasses the variable operation and maintenance impacts on the distribution system resulting from a proposed program or project. Caution should be exercised when computing these impacts, as O&M expenses related to distribution expansions and upgrades are often incorporated into marginal cost studies, and the associated avoided costs may be captured in the avoided distribution system infrastructure costs.

Project- or program-specific benefits associated with distribution system O&M costs are generally commodity-related but can also have a capacity component.

EQUATION 6. GAS DISTRIBUTION SYSTEM O&M IMPACTS

$$Impact_Y = \sum_{AT} \left(\Delta Expenses_{AT,Y}\right)$$

Where:

Y	The year that the benefit is recognized/realized.
AT	The activity type or specific category of O&M expense (e.g., crews to replace equipment, inspections and surveys, and other maintenance-related expenses).
$\Delta \mathbf{Expenses}_{\mathbf{AT,Y}}$	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 impacts from a project or program 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 distribution infrastructure impacts. However, in general, these impacts are difficult to quantify and may be zero for most cases.

4.2.5 Reliability/Resiliency/Safety Impacts

Reliability, resiliency, and safety impacts reflect how projects and programs affect overall system reliability, the ability to maintain system standards despite disruptions, and the ability to recover from system malfunctions or outages. Measuring these impacts ensures that investments in the system will strengthen it under stress, not just at peak use. These impacts are project- and program-specific and especially influenced by their location on the system and operational characteristics. Projects that can be dispatched (i.e., the ability to call on supply or demand reduction without limitation) tend to offer greater potential for delivering these benefits because context significantly affects these impacts. A qualitative assessment may be appropriate when they cannot be easily measured.

As an example of estimating these impacts, on-system supply sources may provide pressure benefits depending on their location on the system. These benefits can be leveraged to support system pressures during extreme events (increasing system reliability) and to facilitate faster recovery from disruptions. Incremental on-system supply from local resources may also provide pressure benefits based on their location. These can be utilized to support system pressures during extreme events (enhancing system reliability) and to promote quicker recovery from disruptions.

Projects essential for meeting reliability, resiliency, and safety standards typically do not fit well into traditional economic evaluations, such as benefit-cost analyses, since they are critical prerequisites for delivering gas service to customers and are heavily context-dependent. However, the results of such analyses can still be useful for comparing and prioritizing different programs or projects that offer similar benefits.

Projects and programs that alter how customers utilize alternative fuels (either by converting oil and propane customers to natural gas or by electrifying existing gas end uses) can impact the reliability of the energy service that individual customers receive. The effect on individual customers will depend on both their energy use, with winter space heating being more critical than hot water and other applications, as well as the performance of alternative fuel service providers. While these customer impacts may not be easily quantifiable within this Handbook, they can still be qualitatively assessed.

4.2.6 Natural Gas CO_2e Emissions Impacts

Natural gas CO_2e emissions impacts account for avoided CO_2e emissions (including CO_2, CH_4, and N_2O) due to a net reduction in natural gas use. Project- and program-specific impacts associated with avoided CO_2e emissions can be calculated using the framework outlined in Equation 7. Note that the net CO_2e emissions are calculated using the same cost of carbon throughout the entire BCA.

The impacts should be determined by net changes in gas consumption at the customer site. Projects or programs that shift consumption to periods outside of the peak but do not reduce annual consumption will not realize benefits from reducing CO_2e.

EQUATION 7. NATURAL GAS CO_2e EMISSIONS IMPACTS

$$Impact_Y = \frac{\Delta OnsiteEnergy_Y}{(1 - AvdLoss_Y)} * CO2eIntensity_Y * SocialCostCO2e_Y$$

Where:

Y	The year that the impact is recognized/realized.

$\Delta \mathbf{OnsiteEnergy_Y}$	Change in natural gas used onsite as a result of the program or project measured in Dth at the customer delivery point or revenue meter and accounts for the net change in use over the entire year.
$\mathbf{AvdLoss_Y}$	The avoidable loss for the system applicable to year (Y).
$\mathbf{CO2eIntensity_Y}$	The total equivalent (CO_2e) emission rate, including upstream and end-user emissions from burning Appalachian Basin natural gas, using AR5 20-Year Global Warming Potential Factors.[5]
$\mathbf{SocialCostCO2e_Y}$	An estimate of the total monetized damages to society associated with an incremental increase in CO_2e emissions, based on the Social Cost of Carbon, measured in dollars per metric ton of CO_2e.

Considerations on Equation Components

The net cost of CO_2e emissions will be considered with the intention of utilizing a common carbon cost across all aspects of the BCA. The SocialCost CO_2e can be derived from generally accepted methodologies and the NYS Value of Carbon Guidance.[6] The impact should result from net changes in gas consumption at the customer site. Projects or programs that shift consumption to off-peak periods but do not otherwise reduce annual consumption will not realize benefits from decreased CO_2e emissions. However, on-system supply sources, while not affecting end-use consumption, may provide a small CO_2e benefit by avoiding on-system losses (depending on the project's location).

4.2.7 Natural Gas Other Emissions Impacts

Other emissions impacts refer to the value derived from reducing pollutant emissions—excluding CO_2e—that result from decreased natural gas consumption. The specific impacts associated with these emissions are related to the commodity itself (e.g., measured in $/Dth) and can be estimated using the methodology provided in Equation 8. This approach allows for

[5] Case 23-G-0437, "Final Gas Long-Term Plan, New York State Electric & Gas and Rochester Gas and Electric," April 24, 2024. Appendix E: Tables E-6, E-25, and E-28.
[6] New York State Department of Environmental Conservation. Establishing a Value of Carbon. Guidelines for Use by State Agencies. Appendix: Annual Social Cost Estimates.

a consistent and quantifiable way to capture the environmental value of reducing pollutants beyond greenhouse gases.

Pollutant impacts aside from CO_2e vary by project or program and may, in some cases, be negligible or nonexistent. Any attempt to assign value to these impacts should rely on widely accepted methods and reputable sources for calculating avoided costs. When such impacts are present but cannot be easily quantified, a qualitative assessment may still provide meaningful insights.

EQUATION 8. NATURAL GAS OTHER EMISSIONS IMPACTS

$$Impact_Y = \sum_{pP} \left(\frac{\Delta OnsiteEnergy_Y}{(1 - AvdLoss_Y)} * PollutantIntensity_{P,Y} * SocialCostPollutant_{P,Y}\right)$$

Where:

Y	The year that the impact is recognized/realized.
P	The applicable pollutant.
$\mathbf{\Delta OnsiteEnergy_Y}$	Change in natural gas used onsite as a result of the program or project measured in Dth at the customer delivery point or revenue meter and accounts for the net change in use over the entire year.
$\mathbf{AvdLoss_Y}$	The avoidable loss for the system applicable to year (Y).
$\mathbf{PollutantIntensity_{P,Y}}$	The average pollutant emission rate for pollutant (P) at the customer site, measured in tons/Dth. This is project and technology-specific.
$\mathbf{SocialCostPollutant_{P,Y}}$	An estimate of the total monetized damages to society associated with an increase in pollutant (P) emissions in year (Y), measured in $/ton of pollutant.

Considerations on Equation Components

Pollutant impacts other than CO_2e are project-/program-specific and may be zero depending on the project or program. Any valuation of the impact should be based on generally accepted methodologies and the NYS Value of Carbon Guidance. To the degree these impacts exist but are not readily quantifiable, their impacts may be qualitatively assessed.

4.2.8 Participant Incentives

Participant incentives consist of one-time or annual direct customer payments or indirect payments to help offset the costs associated with purchasing and installing qualifying equipment or participating in a program (such as conducting a study).

4.2.9 Federal Incentives

The federal rebates or tax incentives paid to customers for the purchase and installation of qualifying equipment or completion of qualifying projects.

4.2.10 Program Administration Costs

Program administration costs are the expenses natural gas utilities incur to deliver, market, and evaluate projects or programs. These costs may be adjusted for inflation and depend on factors such as project scale, technology type(s), and location. Subcategories include measurement and verification expenses, delivery strategy, and marketing strategies.

4.2.11 Incremental Distribution System Investments

Incremental distribution system investments include the costs incurred by the utility to support the project or program. These differ from program administration costs and may 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 associated with the program (i.e., its impact on broader administrative costs).

4.2.12 Lost Utility Revenue

Lost utility revenue includes the distribution and other non-by-passable revenues that are shifted onto non-participating customers due to the presence of revenue decoupling mechanisms or the standard process of establishing rates during a utility rate filing. This occurs when reduced revenues from decreased natural gas sales or demand are recovered by marginally increasing rates for all customers.

4.2.13 Participant Costs

The costs incurred by participating customers reflect the additional expense incurred compared to what the participant would have otherwise spent without the program (also known as the incremental cost). Incremental costs include the costs to purchase and install the equipment (as compared to non-efficient equipment), building upgrades needed to support the new equipment, and ongoing maintenance. Actual incremental costs can vary depending on the make and model of the equipment, how and where it is installed, and local labor rates.

4.2.14 Alternative Fuel Impacts

When a project involves switching from natural gas to another energy source—like electricity—the impacts of that alternative fuel must be included in the BCA. This section focuses on the impact of using electricity instead of natural gas at the retail delivery point (where the customer receives the energy). However, these impacts can be realized from switching to other energy sources as well. The equation can be modified to consider fuel prices, change in energy usage, and energy losses for the other non-electric energy sources.

The impact of using electricity as an alternative fuel is calculated using the following formula:

EQUATION 9. ALTERNATIVE FUEL IMPACTS (ELECTRICITY)

$$Impact_Y = \sum_r \left(\frac{\Delta Energy_{Z,Y,r}}{(1 - AdvLoss_{Z,b \rightarrow r})} * LBMP_{Z,Y,b}\right)$$

Where:

Y	The year that the cost is recognized/realized.
Z	The applicable NYISO zones where the incremental energy use occurs.
B	The applicable bulk system.
r	The retail delivery or connection point.
$\boldsymbol{\Delta Energy_{Z,Y,r}}$	Change in electricity use at the retail delivery point (r), in NYISO zone (Z), during period (P) (e.g., monthly or peak/off-peak).
$\boldsymbol{AdvLoss_{Z,b \rightarrow r}}$	Percentage of energy lost between the bulk system (b) and the retail point (r) in the applicable NYISO zone (Z).
$\boldsymbol{LBMP_{Z,Y,b}}$	Locational-Based Marginal Price in zone (Z), year (Y), and bulk system (b). This includes: • Energy price • Congestion costs • Losses • Installed capacity • Ancillary services • Renewable energy credits

This formula quantifies the impact of electricity displacing natural gas, accounting for energy losses and market-based pricing.

4.2.15 Alternative Fuel CO_2e Emissions Impacts

Alternative fuel CO_2e emissions impacts account for CO_2e emissions (including CO_2, CH_4, and N_2O) that result from using an alternative fuel, such as electricity. In the case of electricity, some of these emission-related costs are already included in wholesale market prices. However, this is not true for fuels such as propane or fuel oil, so additional emissions impacts must be considered when evaluating fuel-switching projects.

The cost of CO_2e emissions from alternative fuel use is calculated using the following formula:

EQUATION 10. ALTERNATIVE FUEL CO_2e EMISSIONS IMPACT

$$Impact_Y = \frac{\Delta Energy_Y}{(1 - AdvLoss_Y)} * CO2eIntensity_Y * SocialCostCO2e_Y$$

Where:

Y	The year that the cost is recognized/realized.
$\mathbf{\Delta Energy_Y}$	Change in alternative energy use in year (Y) as a result of the program or project.
$\mathbf{AdvLoss_Y}$	The avoidable loss for the system applicable to year (Y).
$\mathbf{CO2eIntensity_Y}$	The total equivalent (CO_2e) emission rate, including upstream and end-user emissions from burning Appalachian Basin natural gas, using AR5 20-Year Global Warming Potential Factors.[7]
$\mathbf{SocialCostCO2e_Y}$	An estimate of the total monetized damages to society associated with an incremental increase in CO_2e emissions, based on the Social Cost of Carbon, measured in $/ton of CO_2e.

This approach should follow accepted methods for valuing avoided emissions. If some benefits cannot be easily measured, they may still be described qualitatively.

[7] Case 23-G-0437, "Final Gas Long-Term Plan, New York State Electric & Gas and Rochester Gas and Electric." April 24, 2024. Appendix E: Tables E-6, E-25, and E-28.

4.2.16 Alternative Fuel Other Emissions Impacts

Other emissions impacts refer to the value of pollutant emissions—excluding CO_2e— derived from using a fuel other than natural gas, such as electricity. In the case of electricity, some of these emission-related costs are already included in wholesale market prices. However, this is not true for fuels such as propane or fuel oil, so additional emissions impacts must be considered when evaluating fuel-switching projects.

The following formula estimates the cost of these other emissions:

EQUATION 11. ALTERNATIVE FUEL OTHER EMISSIONS IMPACT

$$Impact_Y = \sum_P \left(\frac{\Delta Energy_Y}{(1 - AvdLoss_Y)} * PollutantIntensity_{P,Y} * SocialCostPollutant_{P,Y}\right)$$

Where:

Y	The year that the cost is recognized/realized.
P	The applicable pollutant.
$\mathbf{\Delta Energy_Y}$	Change in alternative energy use in year (Y) as a result of the program or project.
$\mathbf{AvdLoss_Y}$	The avoidable loss for the system applicable to year (Y).
$\mathbf{PollutantIntensity_{P,Y}}$	The average pollutant emission rate for pollutant (P) at the customer site.
$\mathbf{SocialCostPollutant_{P,Y}}$	An estimate of the total monetized damages to society associated with an increase in pollutant (P) in year (Y), measured in $/ton of pollutant.

Valuing these emissions should follow the standard, widely accepted methods and be consistent with how other avoided emissions are assessed. If some benefits are difficult to quantify, they can be described qualitatively.

4.2.17 Participant Non-Energy Impacts

Participant non-energy impacts (NEIs) are the additional effects of energy efficiency or electrification measures beyond direct energy savings. These include positive benefits, such as improved safety (e.g., reducing risks of carbon monoxide leaks or gas fires), enhanced thermal comfort (more consistent indoor temperatures and better air quality), and health benefits (for instance, fewer respiratory issues due to improved indoor air quality).

4.2.18 Other Non-Energy Impacts

Other NEIs encompass additional impacts (or cost reductions) for the natural gas utility associated with various non-commodity aspects of a proposed project or program. For example, savings can be realized when a customer switches to electric heating and discontinues natural gas service, eliminating the need for billing related to gas usage. Other expenses may similarly decrease, including reduced service calls or a lesser need for account maintenance. If these impacts exist but are difficult to measure, they can be qualitatively assessed.

4.2.19 Other External Impacts

Other external impacts include those not captured in other categories. These may involve environmental effects such as land and water use. If these impacts exist but are difficult to measure, they can be qualitatively assessed.

5. SELECTED INPUT PARAMETERS

This section includes the current values of selected parameters that will be used to assess the cost-effectiveness analysis.

5.1 Weighted Average Cost of Capital

The BCA will apply the latest approved weighted average cost of capital (WACC) for each utility. The WACC is sourced from the 2020-2025 System Energy Efficiency Plan: NYSEG/RG&E Appendix B—Benefit Cost Analysis Working Papers. For reference, the current nominal discount rates are NYSEG – 6.68% and RG&E – 7.48%.

5.2 Avoidable Gas Loss Factor

Avoidable gas losses are represented by a rolling three-year average of each utility's Lost and Unaccounted For (LAUF) gas, along with applicable upstream pipeline capacity losses where appropriate. For reference, the current LAUF gas value for NYSEG is 0.216% (Case 22-G-0033) and for RG&E is 0.729% (Case 22-G-0320).

5.3 Upstream Supply Cost

The upstream supply cost represents the Company's total cost of gas commodity prior to delivery at the Company's citygate, excluding all associated fixed and variable pipeline and storage costs. The commodity cost used in BCA calculations reflects the wholesale market price of natural gas and its seasonal pricing differentials, which capture fluctuations in gas prices between winter and summer due to demand variability; locational basis adjustments, which account for procurement cost differences arising from pipeline access, proximity to market hubs, and transportation constraints; and project-specific cost modifiers, which incorporate adjustments related to infrastructure investments, regulatory compliance, and regional delivery limitations.

The commodity cost forecasts to be used for BCA for NYSEG and RG&E are described as "multi-source market forecasts," drawing from the following list of data sources:

- **Comparison of Data Sources Used:** Evaluating S&P MI, NYISO CARIS, NYISO SRO, WoodMac, EIA projections, NYMEX Henry Hub Futures Price, adjusted by the Appalachia Eastern Gas, South forward basis.
- **NYISO System and Resource Outlook:** A critical tool for integrating gas market trends into system planning.

- **Additional Resources:** Other utilities may incorporate proprietary data sources or independent market analysis to refine their methodologies.

5.4 Social Cost of Carbon

The BCA will use the Social Cost of CO_2 in nominal (escalated) dollars in each year. A table of values in 2020 dollars appears below, sourced from the 2025 Update, NYS Value of Carbon Guidance, Appendix: Annual Social Cost Estimates.

Year	SCC*
2025	$130
2030	$144
2035	$158
2040	$173
2045	$189
2050	$205

*(Table A1: Social cost of carbon dioxide (CO2), 2020-2050 (in 2020 dollars per metric ton CO2), 2.5% Discount Rate)