New Jersey Cost Test

Triennium 3 Straw Proposal

New Jersey Board of Public Utilities
Division of Clean Energy
44 S. Clinton Ave.
Trenton, NJ 08625

Introduction

The Clean Energy Act of 2018[1] ("CEA" or "the Act") included requirements to increase the energy savings enjoyed by New Jersey consumers through a new generation of efficiency ("EE") and peak demand reduction ("PDR") programs. Key to the legislation was the concept that the Board of Public Utilities ("Board" or "BPU") shall "ensure investment in *cost-effective* energy efficiency measures," while also ensuring "universal access to energy efficiency measures" and serving "the needs of low-income communities . . . ." (emphasis added). This summary describes the primary benefit-cost test for the third three-year program cycle ("Triennium 3") of EE and PDR investments in New Jersey that is designed to carefully steward ratepayer dollars by ensuring that these investments are cost-effective, while also ensuring universal access and serving the needs of low-income communities. The CEA requires that:

> *The energy efficiency programs and peak demand reduction programs shall have a benefit-to-cost ratio greater than or equal to 1.0 at the portfolio level, considering both economic and environmental factors, and shall be subject to review during the stakeholder process established by the board pursuant to subsection f. of this section. The methodology, assumptions, and data used to perform the benefit-to-cost analysis shall be based upon publicly available sources and shall be subject to stakeholder review and comment. A program may have a benefit-to-cost ratio of less than 1.0 but may be appropriate to include within the portfolio if implementation of the program is in the public interest, including, but not limited to, benefiting low-income customers or promoting emerging energy efficiency technologies.*[2]

The Act specifically requires that each portfolio of EE and PDR programs must have a benefit-to-cost ratio ("BCR") greater than or equal to 1.0, which means that the portfolio yields positive net benefits (i.e., benefits less costs) to the New Jersey economy and is therefore "cost-effective." The Act allows (and in fact, for the purposes of serving low-income communities or ensuring universal access to EE, requires) that every program may not meet this cost-effectiveness standard. However, reasonable policy interests should support the adoption of programs with BCRs below 1.0, as their inclusion in a portfolio will reduce overall net benefits achieved. Similarly, individual efficiency measures do not need to be cost-effective, although the cost-effectiveness of individual measures may be considered during the review of program filings. As with programs, non-cost-effective measures should typically only be included for good reason, such as to promote health and safety, to ensure equitable access, or to spur innovation, the adoption of other measures, or longer-term market transformation.

While the CEA is not explicit in prescribing a cost-effectiveness test beyond requiring the inclusion of economic and environmental factors, it is clear that such a test is needed to achieve the purpose of the state's EE and PDR programs and serve the public interest of all New Jersey residents. As such, the primary cost-effectiveness test used to evaluate these programs should reflect the impacts of the programs on the state's overall economy and environment, including not only energy but also non-energy benefits ("NEBs") that EE and PDR programs can provide to the residents of New Jersey. This summary outlines the primary cost test for New Jersey's EE

---

[1] P.L. 2018, c. 17 (N.J.S.A. 48:3-87.8 et al.).

[2] N.J.S.A. 48:3-87.9(d)(2).

and PDR programs, including the costs, benefits, sources for such inputs, and guidelines for the use of the test.

Executive Summary

New Jersey has historically used five (5) standard benefit-cost tests to evaluate the costs and benefits of EE programs: the Total Resource Cost Test ("TRC"), Societal Cost Test ("SCT"), Program Administrator Cost Test ("PACT"), Participant Cost Test ("PCT"), and Ratepayer Impact Measure Test ("RIM"), which are described in more detail in the "Background" section below.

In order to implement the CEA's requirement that EE and PDR portfolios have BCRs greater than or equal to 1.0, all program administrators shall use a primary benefit-cost test. BPU staff ("Staff") worked with stakeholders to design an initial New Jersey Cost Test ("NJCT") to fulfill the CEA's requirements to consider economic and environmental factors, ensure universal access to EE, and serve the needs of low-income communities.[3] It was anticipated that the Triennium 1 NJCT, which applied to the first three (3)-year term of EE and PDR programs,[4] would evolve over time through the efforts of the EM&V Working Group ("EM&V WG") and could include additional or different impacts as they are studied further and evaluated for use in New Jersey.

In considering which impacts to include in the Triennium 1 NJCT, Staff used the TRC as a foundation and added inputs, including non-energy impacts ("NEIs"), that are both relevant to New Jersey's policy goals and can be applied based on readily available research and industry consensus. Staff also identified near-term and potential long-term sources for the values for each cost and benefit included in the NJCT.

For Triennium 2, Staff worked with the Statewide Evaluator ("SWE"), EM&V WG, and NJCT Committee to discuss potential revisions to the NJCT. After soliciting and reviewing comments from public stakeholders about the proposed NJCT, Staff prepared final recommendations to the Board for the NJCT.[5] As part of the negotiation process for Triennium 2 utility programs, the utility companies agreed to include additional costs in the Triennium 3 NJCT – namely, financial returns to the utilities and the administrative costs of servicing loans.

For Triennium 3, Staff worked with the Center for Urban Policy Research ("CUPR") at Rutgers University, as well as the EM&V WG and SWE, to propose the updates to the NJCT contained herein. As proposed, the NJCT remains mostly the same compared to Triennium 2, except for minor changes in the wholesale electricity cost and emission rates, as well as a more substantive change to the value of the social cost of carbon and the addition of three costs:

---

[3] *See* In re the Implementation of P.L. 2018, c. 17 Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs, BPU Docket No. QO19010040 (Order dated June 10, 2020) ("June 10, 2020 Order"), at 3.

[4] Each program year will commence on July 1 and end on June 30 of the following year, in alignment with State fiscal years. The third three-year term will include Program Year 7 (July 1, 2027 – June 30, 2028), Program Year 8 (July 1, 2028 – June 30, 2029), and Program Year 9 (July 1, 2029 – June 30, 2030).

[5] The Triennium 2 NJCT Memo is available on the "Program Evaluations, Market Analysis and TRMs" page in the"Cost Effectiveness Analysis & Avoided Cost" section at https://njcleanenergy.com/main/public-reports-and-library/market-analysis-protocols/market-analysis-baseline-studies/market-an.

financial returns to the utilities, administrative costs of servicing loans, and any recovery of the revenue impact of sales losses resulting from implementation of the programs (i.e., effective revenue incentive). As adopted by the Board, the Triennium 3 NJCT shall be used by all program administrators for the third program cycle and will be reviewed by the SWE, EM&V WG, NJCT Committee, and public stakeholders for potential future updates. Table 1 summarizes the various inputs and methodologies that are proposed for implementation by program administrators in Triennium 3.

Table 1: Summary of New Jersey Cost Test Inputs and Values

	Input	Description	Calculation method or value
Utility System Costs	Measure incremental costs	Total costs associated with the efficiency measure implemented (i.e., material and labor) less the costs of the baseline measure	Monetized
	Program administration costs	Non-measure costs, including program-specific (such as overhead, marketing, and data tracking costs) and non-program-specific costs (such as administration and planning; and evaluation, monitoring, and verification costs)	Monetized
	Utility Return	Performance-based return on EE & PDR program investment	Determined from performance incentive mechanism curves
	Cost to Service Loans	The ratepayer cost for loan administration and interest rate buydown (third-party institution or "TPI") or return on unpaid balance (on-bill repayment or "OBR")	TPI – total annual fees charged by the third-party institution OBR – return on unpaid loan balance amortized over the length of the loan
	Effective Revenue Incentive	Revenue incentive for reduced energy sales	If weather normalized three (3)-year moving average retail sales increase, then no adjustment is made. Otherwise, the revenue adjustment is equal to energy savings times a representative tariff.
Utility System Benefits	Avoided wholesale electric energy costs	Value of electric energy directly avoided by reductions in energy consumption	Calculated using the most recent PJM Locational Marginal Pricing ("LMP") data and then inflated based on annual percent change in U.S. Energy Information Administration ("EIA") Annual Energy Outlook ("AEO").

Avoided wholesale electric capacity costs	Value of electric capacity directly avoided by reductions in electric consumption	Calculated by multiplying the demand offered into, and cleared in, the PJM Reliability Pricing Model ("RPM") by the relevant zonal clearing price in the Base Residual Auction using the actual clearing price, as appropriate, or a three-year rolling average
Avoided wholesale electric transmission and distribution ("T&D") capacity costs	Value of future T&D capacity costs avoided by reductions in electric consumption	Avoided transmission costs are calculated by using the most recent Network Integration Transmission Service ("NITS") Rate as applicable to individual utility service territories. Avoided distribution costs are calculated by determining the total annual distribution charges that the customer would have paid before participation in the program and then subtracting the total distribution charges the customer paid after implementation of EE measures.
Avoided wholesale electric ancillary costs	Value of avoided electric ancillary services (e.g., spinning reserves, frequency regulation, black start capability, reactive power, etc.) required for safe and effective grid operation	Calculated using a three-year rolling average of PJM Market Monitor prices.
Avoided wholesale natural gas supply costs	Value of natural gas supply costs avoided by reductions in natural gas consumption	Calculated using New York Mercantile Exchange ("NYMEX") futures contracts plus delivery basis
Avoided delivered fuel costs	Avoided costs of delivered fuels such as propane or fuel oil	Calculated using a three-year rolling average of historic EIA NJ residential fuel oil and propane prices escalated using an annual growth rate derived from AEO projections
Electric energy demand reduction induced price effects ("DRIPE")	Value of price effects resulting from reduced demand in the electric energy market	Included as an adder calculated as 5% of the avoided wholesale electric energy costs
Electric capacity DRIPE	Value of price effects resulting from reduced demand in the electric capacity market	Included as an adder calculated as 5% of the avoided wholesale electric capacity costs

	Natural Gas DRIPE	Value of lower natural gas costs due to wholesale natural gas market price suppression from diminished demand	Included as an adder calculated as 5% of the avoided wholesale natural gas supply cost
Non-Energy Impacts	Avoided emissions impacts	Carbon dioxide (CO_2): Avoided damages for each ton of CO_2 avoided SO_2 and NO_x: Avoided damages for each ton of SO_2 and NO_x avoided	CO_2: Calculated for electric and natural gas using the mean SCC value from a comprehensive study performed by Kevin Rennert et al. (2022); EPA eGrid emission rates. Other emissions: calculated for electric and natural gas using the 3% case from the EPA report (updated in January 2022) entitled *Estimating the Benefit per Ton of Reducing Directly-Emitted PM2.5, PM2.5 Precursors and Ozone Precursors from 21 Sectors*; EPA eGrid emission rates.
Low-income benefits		Adder applied to account for additional benefits (including health and safety) to low-income ("LI") participants and community	30% (15% NEBs + 15% additional LI) applied to avoided wholesale energy costs
Non-energy benefits		Adder applied to all non-LI programs to account for NEBs not already included in the NJCT that are currently difficult to quantify (including public health, water and sewer benefits, economic development, etc.)	15% applied to avoided wholesale energy costs
Global Inputs	Discount rate	Interest rate that calculates the present value of expected yearly benefits and costs	3%
Electric line losses		Electric marginal line losses, using approved line loss factor in utility's tariff	Utility-specific line loss factor grossed up for marginal losses by 1.5
Natural gas losses		Natural gas marginal losses, using approved losses factor in utility's tariff	Utility-specific loss factor

Background

New Jersey has historically used five (5) standard cost-effectiveness tests, based on the California Standard Practice Manual ("CSPM"),[6] to review the costs and benefits of EE programs. More specifically, the BPU's Division of Clean Energy ("DCE") has required New Jersey's electric and gas public utilities to evaluate their EE programs using the five (5) tests. The DCE has also used the five (5) tests to evaluate New Jersey Clean Energy Program ("NJCEP") offerings, which in turn use avoided cost assumptions developed by the Rutgers CUPR.[7]

These five (5) basic cost-effectiveness tests, as defined below by the CSPM, reflect varying perspectives and include different costs and benefits. Of the jurisdictions that have a primary test, many leading states rely on the SCT or a modified TRC, both of which consider costs and benefits from the entire jurisdiction's economy.

- **Total Resource Cost Test ("TRC")** and **Societal Cost Test ("SCT")**: The TRC measures the combined impacts of a resource option based on the total costs and benefits of the program, including for the participants and the utility. The SCT is a variant of the TRC. It goes beyond the TRC in that it attempts to quantify the change in the total resource costs to society as a whole rather than to only the service territory (the utility and its ratepayers). The SCT uses essentially the same input variables as the TRC test, but they are defined with a broader societal point of view. For example, the SCT includes the effects of externalities (e.g., environmental, national security), excludes tax credit benefits, and applies a social discount rate. As noted in the CSPM, traditionally, implementing agencies have independently determined the details of the SCT, such as the components of the externalities, the externality values, and the policy rules that specify the contexts in which the externalities and tests are used.
- **Program Administrator Cost Test ("PACT")[8]**: The PACT measures the net costs of a demand-side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant.

---

[6] California Public Utilities Commission, "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects" (October 2001), *available at* https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf. As noted on page 6 of the manual, the tests are not intended to be used individually or in isolation. Rather, the manual suggests that the results of tests must compared and that there are tradeoffs between the various tests. The manual provides a description of the strengths and weaknesses of each test to assist users in qualitatively weighing test results.

[7] *See*, *for example*, *Energy Efficiency Cost-Benefit Analysis Avoided Cost Assumptions Technical Memo: May 1, 2019 Update* ("2019 CUPR Avoided Cost Memo"). For a list of recent CUPR Avoided Cost Memos, *see* https://njcleanenergy.com/main/public-reports-and-library/market-analysis-protocols/market-analysis-baseline-studies/market-an.

[8] It is also referred to as the "utility cost test" ("UCT"); however, PACT is preferred because program administrators may not always be utilities, and it is reasonable to consider the entire costs and benefits on both gas and electric systems (which may reflect different utilities) when programs are addressing both fuels.

- **Participant Cost Test ("PCT")**: The PCT measures quantifiable benefits and costs to the customer due to participation in a program. As noted in the CSPM, since many customers do not base their decision to participate in a program entirely on quantifiable benefits, this test cannot be a complete measure of the benefits and costs of a program to a customer.
- **Ratepayer Impact Measure Test ("RIM")**: The RIM measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills will go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.

There are also other methods for developing primary cost tests, such as through the methods described in the National Standard Practice Manual ("NSPM"). The NSPM method results in a state-specific test, referred to as a Resource Value Test ("RVT"), that is based on a jurisdiction's articulated policy and other objectives.

New Jersey Cost Test Framework

The NJCT is the State's primary test for determining cost-effectiveness of EE and PDR programs, to be used in plan development, approval, and evaluation assessments. The NJCT shall be used to determine compliance with the CEA's 1.0 BCR requirement. The NJCT has been designed to include all costs and benefits relevant to a proposed portfolio of EE programs that are reasonably quantifiable or otherwise important considerations and that align with the policies articulated in the CEA, as well as additional public interest goals of the BPU and the State of New Jersey.

As adopted by the Board, program administrators will use the NJCT as the primary cost-effectiveness test. In addition to the NJCT, the results of the existing TRC, SCT, PACT, PCT, and RIM will be reported for informational purposes.

Efficiency programs can provide additional benefits to society beyond the ratepayer cost savings directly resulting from using less energy. Including appropriate NEIs to adequately capture the full range of impacts that these programs have on participants and society helps to ensure that benefit-cost screening is balanced and symmetrical. Given the requirements of the CEA and the participant and societal benefits provided by EE programs, the NJCT includes NEIs.

The SWE, EM&V WG, and NJCT Committee will review the overall NJCT framework on an ongoing basis and consider recommendations for modifications in collaboration with Staff. In addition, the Board has tasked the EM&V WG with developing a process for all EE and PDR programs through which the methodologies for developing the value of relevant costs and benefits are appropriately updated and memorialized ahead of each program cycle and/or as needed. All NJCT changes will be adopted by the Board before being considered final.

The methods and policies used to administer the NJCT shall be consistent across all program administrators. Inputs should be established according to the process described above prior to each three (3)-year program cycle and for retrospective evaluation of program performance related to a given cycle. In addition, most input values should reflect average statewide estimates, rather than be utility-specific. This will ensure fair comparisons of all BCA results across program administrators and for statewide co-managed and BPU-administered programs. However, utility-specific values may be used for certain inputs where deemed appropriate by the Board and where the use of such values is in keeping with the CEA's requirement that input values be publicly available.[9] Table 2 shows the costs and benefits that are included in each of the California Standard Practice Manual tests, in the Triennium 2 NJCT, and proposed for the Triennium 3 NJCT. Please note that program administrators would not add additional costs or benefits to the NJCT beyond those listed in Table 2.

Table 2: Costs and Benefits Included in the Various Cost Tests

	California Standard Cost Tests					NJCT	
	PCT	RIM Test	UCT	TRC Test	SCT	Tri 2	Tri 3
Energy Efficiency Program Benefits:							
Avoided Wholesale Electric Energy Costs	--	Yes	Yes	Yes	Yes	Yes	Yes
Avoided Wholesale Electric Capacity Costs	--	Yes	Yes	Yes	Yes	Yes	Yes
Avoided Wholesale Electric Transmission and Distribution Costs	--	Yes	Yes	Yes	Yes	Yes	Yes
Wholesale Market Price Suppression Effects	--	Yes	Yes	Yes	Yes	--	--
Avoided Cost of Environmental Compliance	--	Yes	Yes	Yes	Yes	Emissions	Emissions
Non-Energy Benefits (utility)	--	Yes	Yes	Yes	Yes	--	--
Non-Energy Benefits (participant)	Yes	--	--	Yes	Yes	--	--
Non-Energy Benefits (societal)	--	--	--	--	Yes	Adder	Adder
Customer Bill Savings	Yes	--	--	--	--	--	--
Avoided Wholesale Electric Ancillary Costs	--	--	--	--	--	Yes	Yes
Avoided Wholesale Nat. Gas Supply Costs	--	--	--	--	--	Yes	Yes
Avoided Delivered Fuel Costs	--	--	--	--	--	Yes	Yes
Electric and/or Nat. Gas DRIPE	--	--	--	--	--	Adder	Adder
Electric Capacity DRIPE	--	--	--	--	--	Adder	Adder

[9] N.J.S.A. 48:3-87.9(d)(2).

Avoided Line Losses	--	--	--	--	--	Yes	Yes
Energy Efficiency Program Costs:							
Program Administrator Costs, Including Return	--	Yes	Yes	Yes	Yes	Yes (no ROE)	Yes
EE Measure Cost: Incentives, Return on Loan Balance	--	Yes	Yes	Yes	Yes	Yes (no loan costs)	Yes
EE Measure Cost: Participant Contribution	Yes	--	--	Yes	Yes	--	--
EE Measure Cost: Incremental Cost		Yes		Yes	Yes	Yes	Yes
Effective Revenue Incentive (for reduced energy sales)	--	Yes	--	--	--	--	Yes

As a result of stakeholder comments, Staff recommends that DRIPE and T&D be studied in advance of Triennium 4.

Global NJCT Inputs

Most of the key inputs for conducting the NJCT are variable and measure-, program-, or portfolio-specific, such as the actual stream of annual costs and savings. Others are consistent statewide ("global") but updated with each EE and PDR program cycle. This section outlines the key global inputs or methods used by the NJCT.

Discount Rate

EE measures typically have relatively high upfront costs that need to be recovered by savings over the life of the measure. Benefit-cost analyses for programs or projects with streams of costs or benefits over more than one (1) to two (2) years use the standard accounting practice of discounting the value of future benefits and costs using discount rate to calculate the present value of expected yearly benefits and costs. Discounting is especially important when comparing projects or programs with different lifespans. Discounting to a present value therefore allows a more apples-to-apples comparison of projects with various lifespans.

As explained by the Office of Management and Budget ("OMB") in Circular A-94, "[the] higher the discount rate, the lower is the present value of future cash flows."[10] For example, as described in EPA *Guidelines for Preparing Economic Analyses*, if the benefits of a given program occur 30 years in the future and are valued in real terms at $5 billion at that time, the rate at which the $5 billion in future benefits is discounted can dramatically alter the economic

[10] U.S. Office of Management and Budget, *Circular A-94: Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs* (October 29, 1992) at 8, *available at* https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A94/a094.pdf.

assessment of the policy. $5 billion 30 years in the future discounted at 1% is $3.71 billion, at 3% it is worth $2.06 billion, at 7% it is worth $657 million, and at 10% it is worth $287 million.[11]

Many other states that promote EE programs, especially utility-administered programs, use the utility weighted-average cost of capital ("WACC") as the discount rate, although several states have employed lower discount rates. OMB Circular A-94 indicates that a real discount rate of 7% should be used as a base-case for regulatory analysis, as that rate approximates the marginal pretax rate of return on an average investment in the private sector, and that a rate higher than 7% should be used if the "main cost is to reduce business investment."[12] OMB also states that a lower discount rate is appropriate "when regulation primarily and directly affects private consumption (e.g., through higher consumer prices for goods and services)."[13] The lower rate that is most often used to reflect the "social rate of time preference" is the rate at which "society" discounts future consumption flows to their present value, which can be estimated according to the real rate of return on long-term government debt.[14]

A nominal discount rate of 7% for the PCT, RIM, UCT, and TRC tests will be applied to EE programs. The Societal Cost discount rate is updated to 3% for Triennium 3 to better align with best practices.

Staff proposes that the Triennium 3 NJCT continue to use a 3% real discount rate to align with public policy in the state and account for how implementation of the EE programs will significantly and directly affect private consumption (e.g., reduce energy consumption by utility customers), as well as result in costs and benefits that impact not only utilities and program participants but New Jersey ratepayers, residents, and society at large over many years.

Line Losses

Due to electric line losses, a kWh saved from efficiency at site translates to more than one kWh saved at generation. The higher the load on the electric system, the higher the line losses. This means that the line losses from energy saved through efficiency, which saves energy at the margin, are significantly higher than average system losses.

Electric line losses are calculated by using the average line loss factor in each electric utility's tariff. A factor of 1.5 is used to convert average line losses to marginal line losses.[15] For state-run programs, distribution marginal line loss rate multiplier for avoided energy (kWh) is 8.25% (i.e. 1.5 times the 5.5% portion of T&D losses that are assumed).

---

[11] U.S. Environmental Protection Agency, *Guidelines for Preparing Economic Analyses* (2016) at 75.

[12] U.S. Office of Management and Budget, *Circular A-94: Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs* (October 29, 1992) at 9.

[13] U.S. Office of Management and Budget, *Circular A-4* (September 17, 2003), *available at* https://obamawhitehouse.archives.gov/omb/circulars_a004_a-4.

[14] Id.

[15] Lazar, J, X Baldwin, RAP, "Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements" (2011).

Natural gas losses are calculated by using the losses factor in each natural gas utility's tariff. Public Service Electric & Gas Company ("PSE&G") and New Jersey Natural Gas Company[16] use a natural gas loss factor of 2%,[17] South Jersey Gas Company uses a natural gas loss factor of 1.43%,[18] and Elizabethtown Gas Company uses 1.5%.[19] Staff recommends the usage of a weighted average by delivery volume of 1.9% for natural gas loss factor for State-run programs.

Consideration of a multiplier for converting average energy losses to marginal losses during times of peak demand may be explored in the next update to the NJCT.

Costs

Utility Return

Utility return is determined annually through a performance incentive mechanism. The net present value of the annual return shall be included as a cost in the NJCT. For EE and PDR program plan filings, the utility shall assume the average return (not the maximum return) from the performance incentive mechanism curve.

Cost to Service Loans

Utilities may offer EE and PDR loans either by engaging third-party institutions ("TPIs") to administer the loans or by administering on-bill repayment loans. For TPIs, the cost to service loans includes all administrative fees and any fees to buy down interest rates. This cost, treated as investment and amortized with a rate of return, shall be included in the NJCT as a net present value. For utility-run OBR, the unpaid balance of loan principal may be amortized for the length of the loans. The utility may earn a return on the unpaid balance. This cost-to-service OBR shall be included in the NJCT as a net present value.

Effective Revenue Incentive

The net present value of the annual revenue derived from the effective revenue incentive (revenue incentive for reduced energy sales) shall be included as a cost in the NJCT. The incentive is based on whether the weather-normalized three (3)-year moving average retail sales is increasing or decreasing. For the EE and PDR program plan filings, the utility shall determine the incentive based on whether the filed retail sales are increasing or decreasing.

---

[16] Personal Communication.

[17] https://nj.pseg.com/-/media/pseg/public-site/documents/current-gas-tariff/gas-tariff-16-bgssrsg-balancing-cip-sbcusf-10012023.ashx.

[18] https://southjerseygas.com/SJG/media/pdf/pdf-regulatory/SJG-Tariff-No-14.pdf?ver=20231212.

[19] https://www.elizabethtowngas.com/Elizabethtown/media/PDF/Regulatory%20Info/Elizabethtown-Gas-TARIFF-NO-18.pdf?version=20231129.

Efficiency Measure Incremental Costs

Efficiency measure incremental costs are the total costs (to the utility, installer, participant, etc.) associated with the measure implemented (i.e., material and labor) less the costs of the baseline measure. Specific values for measure incremental costs were recently determined in a literature review study from DNV and should be used for the NJCT calculations.[20] Any new incremental measure cost studies completed prior to the program filings for Triennium 3 should be used in NJCT calculations.

Currently, equipment operation and maintenance ("O&M") are not explicitly defined in the incremental measure cost study data described above. As estimates or actual values are developed for New Jersey using primary research, they may be documented and incorporated more explicitly in the NJCT.

Program Administration Costs

All non-measure program costs (i.e., those costs that do not directly cover some portion of the incremental measure costs) are included in calculation of overall portfolio level cost-effectiveness. Non-measure costs can generally be divided into two broad categories: non-measure program-specific costs and non-program-specific costs.

Non-Measure Program Costs

Non-measure specific program costs include those costs attributable to specific programs but not individual measures. Such costs may include, but are not limited to, overhead, marketing, and data tracking costs.

Non-Measure, Non-Program-Specific Costs

Non-program specific costs include, but are not limited to, non-program-specific administration, market transformation, planning and analysis, EM&V, and regulatory costs. Non-program costs that cannot be reasonably allocated or assigned to a specific program should only be included at the portfolio level.

Benefits

Energy Savings

EE investments provide two main types of energy savings that need to be quantified in any cost-benefit analysis. First, program participants enjoy *direct* savings associated with lower utility bills when they consume less electricity or other forms of energy. Second, New Jersey residents may benefit from *indirect* savings because of the reduced generation and transmissions costs that result when energy consumption decreases. The economic benefits to society from reduced consumption of energy are the sum of these direct and indirect savings

[20] Energy Efficiency Triennium 2 Incremental Measure Cost Values (2023): https://njcleanenergy.com/files/file/BPU/2023/Energy%20Efficiency%20Triennium%202%20Incremental%20Measurement%20Costs%20Values%20(2023).xlsx.

values. There are numerous components to avoided costs to account separately for energy and peak capacity reductions and to reflect electric generation, T&D, and natural gas and delivered fuels avoided costs.

Avoided Energy Costs

Avoided energy costs are created when utilities do not have to purchase electricity or natural gas because a consumer has invested in EE infrastructure and reduced its total consumption. The reductions in wholesale purchases by the utility represent a net savings to society equal to the quantity of avoided electricity or natural gas multiplied by the wholesale cost of procuring that energy, including capacity and other associated costs. For purposes of measuring these benefits, the NJCT considers the following factors:

- Avoided wholesale electric energy costs using PJM LMP data (in $/MW-hour);
- Avoided wholesale electric capacity costs using the PJM capacity rate (in $/MW-day);
- Avoided wholesale electric T&D capacity costs (in $/kw-year);
- Avoided wholesale electric ancillary costs;
- Avoided wholesale natural gas supply costs using NYMEX futures contract prices; and
- Avoided delivered fuel costs.

Avoided Wholesale Electric Energy Costs Using PJM LMP Data:

Avoided wholesale electric energy costs should be calculated using PJM LMP data. Table 3 shows Historic Day-ahead Locational Marginal Prices from PJM escalated based on the annual percent change in the *EIA 2025 Annual Energy Outlook* using the PJM/East Electricity Generation Prices.[21] Note that the 2024 wholesale electricity price is the three (3)-year average of 2022, 2023, and 2024 LMPs. The seasonal peak and off-peak factors were derived using historic 2024 PJM LMP data.[22] Summer is defined as May through September, winter is defined as October through April, on-peak is defined as Monday through Friday 8am-8pm (hour beginning or "HB"), and off-peak is defined as Monday-Friday 8pm-8am (HB) and weekends and holidays.

[21] Wholesale electricity prices are not weather normalized. https://www.eia.gov/outlooks/aeo/data/browser/#/?id=62-AEO2025&region=5-10&cases=ref2025&start=2023&end=2050&f=A&sourcekey=0

[22] http://www.pjm.com/markets-and-operations/energy.aspx

Table 3: Triennium 3 Wholesale Energy Prices (Nominal Dollars)

	Summer Peak	*Summer Off-Peak*	*Non-Summer Peak*	*Non-Summer Off-Peak*
2024	$42.51*	$38.86*	$40.18*	$36.70*
2025	$41.50	$37.93	$39.22	$35.83
2026	$40.99	$37.47	$38.74	$35.39
2027	$31.11	$28.44	$29.41	$26.86
2028	$33.75	$30.85	$31.90	$29.14
2029	$34.00	$31.08	$32.14	$29.36
2030	$34.43	$31.47	$32.54	$29.72
2031	$38.20	$34.92	$36.10	$32.98
2032	$37.12	$33.93	$35.09	$32.05
2033	$40.37	$36.90	$38.16	$34.85
2034	$40.70	$37.21	$38.47	$35.14
2035	$40.45	$36.98	$38.23	$34.92
2036	$38.39	$35.09	$36.29	$33.14
2037	$41.44	$37.89	$39.17	$35.78
2038	$41.08	$37.56	$38.83	$35.47
2039	$39.42	$36.04	$37.26	$34.03
2040	$39.27	$35.90	$37.11	$33.90
2041	$40.23	$36.77	$38.02	$34.73
2042	$41.44	$37.88	$39.17	$35.78
2043	$42.48	$38.83	$40.15	$36.67
2044	$43.42	$39.69	$41.04	$37.49
2045	$44.37	$40.56	$41.94	$38.31
2046	$45.56	$41.65	$43.06	$39.33
2047	$46.71	$42.70	$44.15	$40.33

Avoided Wholesale Electric Capacity Costs Using the PJM Capacity Rate:

The NJCT calculates avoided wholesale capacity costs using PJM Base Residual Auction data. For periods where actual PJM auctions have occurred, the actual jurisdictional-specific auction clear price should be used. For periods after when actual auctions have occurred, the average of the three (3) most recent utility-specific auction clearing prices should be used, escalated by an inflation rate consistent with that discussed in the Discount Rate section of these recommendations. Utilities should use utility-specific data if available; State programs should use a weighted average of clearing prices, weighted based upon the Preliminary Zonal Peak Load Forecast less Fixed Resource Requirement ("FRR") load for each utility in New Jersey from PJM's most current planning parameters.

To calculate the values in Table 4, New Jersey Utility PJM Reliability Pricing Model ("RPM") prices for the four (4) electric distribution companies (Atlantic City Electric Company, Jersey Central Power & Light Company, PSE&G and Rockland Electric Company) out to 2025 were weighted by each utility's historic 2024 peak load to estimate an average New Jersey capacity price.[23] For 2026 to 2047, the capacity prices were escalated based on the EIA projected annual change in U.S. GDP Chain-type Price Index, which is reported in Table 6. PJM's Forecast Pool Requirement ("FPR") is provided in Table 3; the FPR is a multiplier that converts load values into capacity obligation.[24]

Table 4: Triennium 3 Capacity Price (Nominal $/kW-year)

	Capacity $/kW-year
2024	$18.93
2025	$65.94
2026	$67.05
2027	$68.17
2028	$69.46
2029	$70.69
2030	$72.01
2031	$73.49
2032	$75.04
2033	$76.67
2034	$78.37
2035	$80.07
2036	$81.73
2037	$83.43
2038	$85.15
2039	$86.90
2040	$88.72
2041	$90.62
2042	$92.60
2043	$94.66
2044	$96.77
2045	$98.95
2046	$101.19
2047	$103.49

Avoided Wholesale Electric Transmission and Distribution Capacity Costs

The NJCT estimates the direct benefits of avoided wholesale PJM transmission costs using the most recent Network Integration Transmission Service ("NITS") Rate, as measured in dollars per

[23] Downloaded from Data Miner 2, https://dataminer2.pjm.com/feed/hrl_load_metered/definition.

[24] 2023 PJM Reserve Requirement Study, October 3, 2023, PJM Staff at 9 for FPR values and at 40 for definition of FPR, https://www.pjm.com/-/media/committees-groups/committees/mrc/2023/20231025/20231025-item-02---2-2023-pjm-reserve-requirement-study-report-final.ashx.

kW-year, as applicable to individual utility service territories.[25] The NJCT calculates the direct benefits of avoided electric distribution costs by determining the applicable distribution rate for each customer enrolled in the program based on the customer's specific customer class and usage. The savings is determined by determining the total annual distribution charges that the customer would have paid before its participation in the program and then subtracting the total distribution charges the customer paid after the implementation of the EE measures. Table 5 below shows the NITS Rate from January 2024 by utility service territory.[26]

Table 5: NITS Rate by Utility

	$/MW-yr	$/kW-yr
ACE	$103,398	$103.40
JCPL	$37,937	$37.94
PSEG	$180,898	$180.90
RECO	$53,766	$53.77

Actual utility-specific distribution cost values for Triennium 3 should be used as per the NJCT.

Avoided Wholesale Electric Ancillary Costs

The NJCT calculates the avoided wholesale electric energy and ancillary services ("E&AS") costs using a three (3)-year rolling average taken from PJM's most recent State of the Market Report. This rate should be escalated at the same rate as the avoided electric energy cost over the long-term.

Ancillary services cost in 2021 was $1.16/MWh, 2022 was $1.43/MWh, and 2023 was $1.30/MWh.[27] Please note that the historical ancillary services prices have not been updated since 2023. The three (3)-year rolling average is $1.30/MWh and is escalated based on the annual percent change in the *EIA AEO 2025* using the PJM/East Electricity Generation Prices. Table 4 shows ancillary services prices from 2024 to 2047.

[25] See, for example, https://www.pjm.com/-/media/markets-ops/settlements/network-integration-trans-service-september-2022.ashxTh.

[26] https://www.pjm.com/-/media/markets-ops/settlements/network-integration-trans-service-january-2024.ashx.

[27] Monitoring Analytics, LLC, 2023 State of the Market Report, at 466 (Table 10-4), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023/2023q2-som-pjm-sec10.pdf

Table 6: Ancillary Service Price $/MWh

	Ancillary $/MWhs
2024	$1.36
2025	$1.33
2026	$1.31
2027	$1.00
2028	$1.08
2029	$1.09
2030	$1.10
2031	$1.22
2032	$1.19
2033	$1.29
2034	$1.30
2035	$1.30
2036	$1.23
2037	$1.33
2038	$1.32
2039	$1.26
2040	$1.26
2041	$1.29
2042	$1.33
2043	$1.36
2044	$1.39
2045	$1.42
2046	$1.46
2047	$1.50

Avoided Wholesale Natural Gas Supply Costs

The NJCT includes avoided natural gas consumption costs, taken from the New York Mercantile Exchange ("NYMEX") forward trading prices for Henry Hub in 2024[28] and are escalated using Henry Hub prices in the *EIA AEO 2025*.[29] The utilities may include actual gas transportation rates and any local distribution company transportation rates to determine the full delivered cost of gas for any individual customer. The winter and summer prices were derived from the 1994 to 2024 historic average ratio of summer and winter prices to Henry Hub.[30] The summer average ratio was 99.3%, and the winter average ratio was 100.7%.

[28] https://www.eia.gov/dnav/ng/ng_pri_fut_s1_a.htm.

[29] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2025&region=0-0&cases=ref2025&start=2023&end=2050&f=A&sourcekey=0.

[30] https://www.eia.gov/dnav/ng/hist/rngc1m.htm.

Table 7: Wholesale Natural Gas Prices (Nominal $/MMBtu)

	Average Price	*Summer*	*Winter*
2024	2.19	$2.17	$2.21
2025	2.94	$2.92	$2.96
2026	2.84	$2.82	$2.86
2027	2.76	$2.74	$2.78
2028	2.93	$2.91	$2.95
2029	3.16	$3.14	$3.18
2030	3.43	$3.41	$3.45
2031	3.67	$3.64	$3.69
2032	4.30	$4.27	$4.33
2033	4.86	$4.83	$4.90
2034	5.26	$5.22	$5.29
2035	5.48	$5.44	$5.52
2036	5.59	$5.55	$5.63
2037	5.64	$5.60	$5.68
2038	5.67	$5.63	$5.71
2039	5.70	$5.66	$5.74
2040	5.86	$5.82	$5.90
2041	6.09	$6.05	$6.13
2042	6.33	$6.29	$6.37
2043	6.67	$6.62	$6.72
2044	6.94	$6.89	$6.99
2045	7.19	$7.14	$7.24
2046	7.48	$7.43	$7.54
2047	7.73	$7.68	$7.79

Avoided Delivered Fuel Costs

The value of avoided delivered fuel costs (propane or fuel oil) should be included in the NJCT. Avoided costs for #2 fuel oil and propane should be calculated using a three (3)-year rolling average of historic EIA New Jersey residential fuel oil and propane prices escalated using an annual growth rate derived from the Mid-Atlantic Region EIA AEO projections.[31]

Propane Prices: An average of 2022, 2023, and 2024 historic EIA New Jersey residential propane prices[32] were escalated using an annual growth rate derived from the Mid-

[31] For example: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2023&region=1-2&cases=ref2023&start=2021&end=2050&f=A&linechart=ref2023-d020623a.3-3-AEO2023.1-2&map=ref2023-d020623a.4-3-AEO2023.1-2&sourcekey=0.

[32] https://www.eia.gov/dnav/pet/pet_pri_wfr_dcus_sNJ_w.htm.

Atlantic Region *EIA AEO 2025* propane price forecasts[33] (Residential Prices). EIA defines Residential Propane Prices as the price charged for home delivery of consumer-grade propane intended for use in space heating, cooking, or hot water heaters in residences. Propane prices initially were presented as weekly averages during the period of January to March and October to December[34] and were averaged to develop an annual price. In addition, CUPR added the 6.625% Sales and Use Tax.[35]

Heating Oil Prices: An average of 2022, 2023, and 2024 historic EIA New Jersey residential heating oil prices were escalated using an annual growth rate derived from the Mid-Atlantic Region *EIA AEO 2025* heating oil price forecast (Residential Prices).[36] EIA defines Residential Heating Oil as the price charged for home delivery of No. 2 heating oil, exclusive of any discounts such as those for prompt cash payment. Heating oil prices were presented as weekly averages from January to March and October to December and were averaged to develop an annual price. In addition, CUPR added the 6.625% Sales and Use Tax.[37]

Table 8: Residential Propane and Heating Oil Prices (Nominal $/Gallon)

	Propane Residential	*Heating Oil Residential*
2024*	$3.64	$4.06
2025	$3.60	$3.90
2026	$3.68	$3.97
2027	$3.71	$4.15
2028	$3.78	$4.38
2029	$3.88	$4.62
2030	$4.02	$4.88
2031	$4.17	$4.99
2032	$4.39	$5.08
2033	$4.66	$5.25
2034	$4.92	$5.39
2035	$5.14	$5.56
2036	$5.32	$5.69

[33] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2025&region=1-2&cases=ref2025&start=2023&end=2050&f=A&sourcekey=0.

[34] CUPR used weekly Wholesale/Resale propane prices from the Central Atlantic region from October to December 2019 because the data was not reported for New Jersey. The Central Atlantic region includes NJ, MD, NY, and PA. All other data was for NJ.

[35] Based upon communications with the U.S. EIA, CUPR assumes that EIA does not include the 6.875% sales and use tax because it is unclear whether utilities include the sales tax when submitting this data to the EIA.

[36] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2025&region=1-2&cases=ref2025&start=2023&end=2050&f=A&sourcekey=0.

[37] Based upon communications with the U.S. EIA, CUPR assumes that EIA does not include the 6.875% sales and use tax because it is unclear whether utilities include the sales tax when submitting this data to the EIA.

2037	$5.47	$5.85
2038	$5.60	$5.99
2039	$5.72	$6.14
2040	$5.85	$6.32
2041	$6.01	$6.50
2042	$6.18	$6.67
2043	$6.39	$6.89
2044	$6.59	$7.09
2045	$6.80	$7.26
2046	$7.01	$7.49
2047	$7.28	$7.78

*2024 value is average of 2022, 2023, and 2024 historical values as per the NJCT.

Additional Indirect Energy Benefits

In addition to the direct and indirect energy benefits resulting from the avoided costs outlined above, the reduced load associated with EE and PDR deployment also may reduce indirect energy and capacity prices for all New Jersey consumers. PJM operates a single-clearing price market, and the price is set at the point that supply and demand meet. PJM determines the clearing price by creating a "supply stack" of all eligible resources based on their strike price. The least expensive resources are lower on the supply stack and are selected first. The next least expensive resource is selected next, and so on, until supply matches the anticipated demand. The theory describing the impact of decreasing demand on wholesale energy prices is often referred to as the Demand-Reduction-Induced Price Effect ("DRIPE") and may occur in both the PJM energy and capacity markets.

DRIPE effects are relatively small when expressed in terms of an impact on market prices. However, DRIPE impacts can be significant when expressed in absolute dollar terms when applied to all wholesale purchases by New Jersey consumers.

As literature has been updated over the past few years, and given a lack of consensus on calculating the various DRIPE benefits, Staff proposes that Electric Energy DRIPE, Electric Capacity DRIPE, and Natural Gas DRIPE impacts should remain the same for Triennium 3. In other words, Staff proposes continuing a DRIPE adder of 5% of avoided wholesale and capacity costs for electricity and 5% of the avoided wholesale natural gas supply cost.

Non-Energy Impacts

There are three (3) general types of NEIs: (1) utility NEIs, such as reduced arrearages and debt collection costs; (2) participant NEIs, such as reduced operations and maintenance costs; impacts on occupant health and productivity; and increased property values; and (3) societal NEIs, such as economic development, environmental, and public health impacts. Including NEIs will ensure that the NJCT reflects a symmetrical treatment of costs and benefits and accounts for the full range of benefits that are not captured in traditional avoided costs.

It is common practice for jurisdictions to account for NEIs in their cost-effectiveness tests. NEIs are typically included through measured values, adders, or a combination of these two approaches. Measured NEIs are derived from independent studies of efficiency programs or measures that use methodologies such as utility data analysis, engineering models, or surveys and interviews. NEI adders apply a multiplier to total energy or resource benefits, thereby serving as a proxy for impacts that have yet to be evaluated in a jurisdiction. While measured NEIs are more precise than adders, the studies needed to develop values can be costly, time consuming, and difficult for hard to quantify impacts. Adders provide a simpler method to account for NEIs in the absence of specific evaluations that precisely measure their values.

Many jurisdictions have approved the use of adders to account for general NEBs. General NEB adders range from 5% in Washington D.C. to 20% in Colorado. Nevada, New Hampshire, and Montana use a general adder of 10% to account for the range of benefits attributable to EE programs.[38] These adders reflect a range of impacts including public health, water resources, and economic development.

Jurisdictions also often include separate adders for specific programs such as those that serve low-income customers. Low-income programs provide many difficult to quantify benefits beyond energy savings, which include improved household health and safety, improved comfort, reduced energy burden, and others. States that include additional adders in their cost-effectiveness tests to account for hard to measure low-income program benefits are Colorado (25%), Nevada (25%), New Mexico (20%), New Hampshire (20%), and Vermont (15%).[39] It is important that these benefits are captured in the NJCT, given the CEA's focus on serving the needs of the state's low-income customers and communities.

Adders may serve as interim proxies for NEBs and be updated and refined as more precise values become available. The adders included in the NJCT will continue to be evaluated during the Triennium 3 and refined or replaced with measured values as the EM&V WG undertakes state-specific NEI studies.

Avoided Emissions Impacts

Emission Rates

Electric emission rates for CO_2, NO_x, and SO_x are shown in Table 7 in lb/MWh. The NJ-specific 2023 quantity of avoided electric (CO_2, SO_2, NO_X) emissions are taken from the EPA eGRID 2023 Summary Table.[40] The emission rates are projected forward using the

[38] National Efficiency Screening Project, Database of State Efficiency Screening Practices, *available at* https://www.nationalenergyscreeningproject.org/state-database-dsesp/

[39] *Id.*

[40] https://www.epa.gov/egrid/summary-data (ST23 tab).

previous emission rate calculation (based upon the average of on-peak and off-peak in the most recent PJM Emissions rate report,[41] de-escalated to a value equivalent to a 50 percent reduction in emissions rate by 2050, as compared to the initial 2022 PJM-based value. Emission rates are linearly interpolated from 2022 to 2050. The quantity of avoided natural gas emissions should be calculated based upon the Natural Gas Emissions Values published by EIA (11.7 pounds per therm saved of CO_2[42]), un-escalated into the future.

Table 9: Electric Emission Rates (lbs/MWh)

	CO_2	NO_x	SO_2
2025	840	0.29	0.11
2026	824	0.28	0.10
2027	808	0.28	0.10
2028	792	0.27	0.10
2029	776	0.27	0.10
2030	760	0.26	0.10
2031	743	0.26	0.09
2032	727	0.25	0.09
2033	711	0.24	0.09
2034	695	0.24	0.09
2035	679	0.23	0.09
2036	663	0.23	0.08
2037	646	0.22	0.08
2038	630	0.22	0.08
2039	614	0.21	0.08
2040	598	0.21	0.08
2041	582	0.20	0.07
2042	566	0.19	0.07

[41] PJM 2018–2022 CO_2, SO_2, and NO_x Emission Rates (April 2023).

[42] https://www.eia.gov/environment/emissions/co2_vol_mass.php.

2043	549	0.19	0.07
2044	533	0.18	0.07
2045	517	0.18	0.07
2046	501	0.17	0.06
2047	485	0.17	0.06

Carbon dioxide (CO_2)

The proposed updated SCC value uses the mean SCC value from a comprehensive study performed by Kevin Rennert et al. (2022).[43] The Rennert Study recommends a mean value of $185/ton CO_2 in 2020 U.S. dollars using the 2% discount rate scenario. The value in September 2025 dollars is $233/ton using the Bureau of Labor Statistics CPI calculator.[44] To calculate total avoided CO_2 damages, the avoided carbon emissions in tons should be discounted and then multiplied by the SCC value in current dollars.

SO_2, NO_X, & $PM_{2.5}$

Values were calculated using the 3% case estimates from the EPA report (updated in April 2023) entitled "Estimating the Benefit per Ton of Reducing Directly-Emitted PM2.5, PM2.5 Precursors and Ozone Precursors from 21 Sectors." Years between 2025, 2030, 2035, and 2040 were linearly interpolated. Values beyond 2045 were escalated using the GDP deflator.

Table 10: Avoided Damages (Nominal $/metric ton) and U.S. GDP Chain-type Price Index

	NOx	SO_2	Social Cost of CO_2	GDP Chain-type
2024			$246	1.34
2025	$9,118	$67,379	$256	1.37
2026	$9,414	$69,673	$264	1.39
2027	$9,710	$71,967	$274	1.42
2028	$10,006	$74,261	$284	1.44
2029	$10,302	$76,554	$293	1.47
2030	$10,598	$78,848	$304	1.50
2031	$11,115	$82,763	$315	1.53
2032	$11,632	$86,679	$326	1.56
2033	$12,150	$90,594	$339	1.59
2034	$12,667	$94,509	$352	1.63
2035	$13,185	$98,424	$364	1.66

[43] Rennert, K., Errickson, F., Prest, B.C. *et al.*, Comprehensive evidence implies a higher social cost of CO_2, *Nature* 610, 687–692 (2022), https://doi.org/10.1038/s41586-022-05224-9 ("Rennert Study").

[44] https://www.bls.gov/data/inflation_calculator.htm.

2036	$13,723	$102,571	$378	1.70
2037	$14,261	$106,719	$392	1.73
2038	$14,799	$110,866	$404	1.77
2039	$15,337	$115,014	$419	1.81
2040	$15,874	$119,161	$434	1.84
2041	$16,213	$121,706	$450	1.88
2042	$16,567	$124,360	$467	1.92
2043	$16,936	$127,129	$484	1.97
2044	$17,313	$129,961	$502	2.01
2045	$17,704	$132,893	$521	2.06
2046	$18,104	$135,899	$540	2.10
2047	$18,517	$138,997	$562	2.15

Economic Development Benefits

Economic development benefits are included in the General NEB adder as described below. Staff proposes that the Board take more time to consider a recommended input for Triennium 4, especially given the large weight that a proposed economic developments input may have relative to the overall NJCT.

Non-Energy Benefits & Low-Income Benefits

Using the findings of SERA's *Non-Energy Benefits / Non-Energy Impacts (NEBs/NEIs): Analysis of Alternatives for The State of New Jersey Updates* and other sources, the NJCT should incorporate a General NEB adder of 15% (applied to avoided wholesale energy cost) for all programs. This General NEB adder represents the average adder from the Top 16 American Council for an Energy Efficient Economy ("ACEEE") Scorecard states (excluding New Jersey) in the SERA study (Figure 0.2).

Low- and moderate-income programs should have a total adder of 30% (applied to avoided wholesale energy costs), comprised of the 15% NEB adder plus an additional 15% for low- and moderate-income customers. This Low Income adder represents the average adder from the Top 16 ACEEE Scorecard states (excluding NJ) in the SERA study (Figure 0.2).