Cost-Benefit Analysis of Electric Distribution Investments

PREPARED BY

T. Bruce Tsuchida
Dr. Linquan Bai
Dr. Goksin Kavlak
Sai Shetty
Sylvia Tang
Natalie Northrup

PREPARED FOR

Atlantic City Electric

Brattle

atlantic city electric℠
AN EXELON COMPANY

Notice

This report was prepared for Atlantic City Electric (ACE) by The Brattle Group, Inc. (Brattle), in accordance with Brattle's engagement terms, and is intended to be read and used as a whole and not in parts. The authors would like to thank ACE's subject matter experts and other staff for providing insights, experience, and data, which were all invaluable in completing this study. All results and any errors are the responsibility of the authors and do not necessarily reflect those of Brattle's clients or other consultants.

The analyses that we provide here are necessarily based on assumptions with respect to conditions that may exist or events that may occur in the future. Many of these assumptions are based on publicly-available industry data, if not directly provided by ACE. There is no guarantee that the assumptions and methodologies used will prove to be correct or that the forecasts will match actual results of planning or operations. Our analysis, and the assumptions used, are also dependent upon future events that are not within our control or the control of any other person, and do not account for regulatory uncertainties. Actual future results may differ, perhaps materially, from those indicated. Brattle does not make, nor intend to make, nor should anyone infer, any representation with respect to the likelihood of any future outcome, and cannot, and do not, accept liability for losses suffered, whether direct or consequential, arising out of any reliance on our analysis. While the analysis that Brattle is providing may assist ACE and others in rendering informed views of how ACE's investment in its distribution facilities could help the state of New Jersey achieve its goals, it is not meant to be a substitute for the exercise of anyone's own business judgments.

TABLE OF CONTENTS

Executive Summary

Atlantic City Electric (ACE) retained The Brattle Group, Inc. (Brattle) to develop a Cost-Benefit Analysis (CBA) for ACE's second Infrastructure Investment Program (IIP) filing, entitled Powering the Future, which includes a portfolio of distribution system investments.

Powering the Future includes 80 projects adding up to approximately \$380 million[1] of investments to ACE's distribution system over the next four years (from July 2023 through June 2027, over five calendar years). ACE groups the Powering the Future projects into the following five categories (and subprograms within each category):

1) Targeted Reliability Improvements (29 projects in 7 subprograms)
2) Smart Technology Upgrades (10 projects in 6 subprograms)
3) Infrastructure Renewals (7 projects in 6 subprograms)
4) Solar/Distributed Energy Resource (DER) Enablements (23 projects in 3 subprograms)
5) Substation Improvements (11 projects in 4 subprograms)

Load growth is the most common trigger for distribution investments. Powering the Future projects aimed for IIP are different. IIP projects are non-revenue producing projects that target modernizing and strengthening the grid to satisfy goals set forth by the New Jersey (State) Administrative Code. They also support the State's broader clean energy policy goals outlined in the 2019 Energy Master Plan (EMP).[2] The EMP aims to transition to a clean energy economy through electrification of transportation and buildings sectors and accelerated deployment of clean distributed energy resources. The New Jersey Board of Public Utilities (BPU) grid modernization initiative[3] targets higher volumes of DER deployment. Powering the Future projects in categories 1 (Targeted Reliability Improvements), 2 (Smart Technology Upgrades), 3 (Infrastructure Renewals), and 5 (Substation Improvements) directly support New Jersey's goals of modernizing the grid, while also preparing the grid for electrification of transportation and

1 Rounded to the nearest \$10 million.

2 2019 New Jersey Energy Master Plan: Pathway to 2050

3 New Jersey Board of Public Utilities, In The Matter of New Jersey Grid Modernization / Interconnection Process, Docket No. QO21010085.

higher volumes of DERs encouraged by the state policies and associated strategies. Projects in category 4 (Solar/DER Enablements) also support the State's goal by enabling new, low-carbon distributed energy resources to be added to system.

Table ES-1 below summarizes the project counts by the five project categories and their investment years.

TABLE ES-1: PROJECT COUNT BY CATEGORY BY START YEAR

Project Category		2023	2024	2025	2026	2027	2023-27
1	Targeted Reliability Improvements	11	10	5	1	2	**29**
2	Smart Technology Upgrades	9	1	0	0	0	**10**
3	Infrastructure Renewals	6	1	0	0	0	**7**
4	Solar/DER Enablements	23	0	0	0	0	**23**
5	Substation Improvements	6	2	3	0	0	**11**
	Total	**55**	**14**	**8**	**1**	**2**	**80**

This CBA analyzes 66 of the 80 projects individually (82.5% of all projects) where relevant data is available.[4] Table ES-2 summarizes the count of all projects and projects analyzed by the five categories.

4 We could not analyze 14 of the projects (17.5% of all projects). Nine of these projects, such as capacitor upgrades, provide benefits beyond those quantified in this CBA. The remaining five projects include those that lacked data because ACE has not yet developed the project to a sufficient levels of details for them to be analyzed.

TABLE ES-2: COUNT OF PROPOSED AND ANALYZED PROJECTS BY PROJECT CATEGORY AND START YEAR

Project Category		Count of Projects	2023	2024	2025	2026	2027	Total
1	Targeted Reliability Improvements	Proposed Projects	11	10	5	1	2	29
		Projects Analyzed	11	10	2	1	2	26
2	Smart Technology Upgrades	Proposed Projects	9	1	0	0	0	10
		Projects Analyzed	3	0	0	0	0	3
3	Infrastructure Renewals	Proposed Projects	6	1	0	0	0	7
		Projects Analyzed	4	1	0	0	0	5
4	Solar/DER Enablements	Proposed Projects	23	0	0	0	0	23
		Projects Analyzed	23	0	0	0	0	23
5	Substation Improvements	Proposed Projects	6	2	3	0	0	11
		Projects Analyzed	4	2	3	0	0	9
	Total	**Proposed Projects**	**55**	**14**	**8**	**1**	**2**	**80**
		Projects Analyzed	**45**	**13**	**5**	**1**	**2**	**66**

The 66 projects analyzed cover 22 out of the 26 subprograms. We assume the benefits of the 14 projects that are not analyzed are comparable to its peer projects (within the same subprogram, if not the same category) that we analyzed individually.

We perform the CBA and show results using three monetary terms:

- Nominal (in nominal dollars),
- Real (in real dollars after applying estimated future inflation rates of 2.35% to the nominal values), and
- Real-Discounted (in real dollars after applying estimated future inflation rates of 2.35% and a real discount rate of 2% to the nominal values). This metric tries to capture the value that society places on future benefits and costs.

Throughout this report, we will center the discussion on values shown in Real terms while providing ranges to show the Nominal and Real-Discounted values.

Table ES-3 below summarize the estimated investment by the five project categories and their investment years in Real terms.

TABLE ES-3: FORECASTED INVESTMENTS (REAL) BY PROJECT CATEGORY AND YEAR

Project Category		2023	2024	2025	2026	2027	2023-27
1	Targeted Reliability Improvements	$2.4	$23.7	$31.1	$23.7	$11.8	**$92.8**
2	Smart Technology Upgrades	$6.6	$16.9	$17.5	$18.1	$9.4	**$68.5**
3	Infrastructure Renewals	$3.6	$23.0	$24.3	$24.9	$11.7	**$87.5**
4	DER Enablements	$1.6	$8.4	$9.5	$9.5	$5.9	**$34.9**
5	Substation Improvements	$9.5	$15.5	$28.6	$33.2	$10.0	**$96.8**
	Total	**$23.7**	**$87.6**	**$111.1**	**$109.4**	**$48.8**	**$380.6**

Note: Numbers may not add up due to rounding. ($ million)

To analyze Powering the Future, we compare two scenarios—the IIP scenario where ACE makes these investments over the next four years (July 2023 – June 2027) as planned, and the Status Quo scenario where ACE does not move forward with the IIP investments as planned. We perform the analyses over a 20-year period (Study Period), consistent with other analyses of similar nature ACE has undertaken in the past. In the Status Quo scenario, ACE still makes necessary investments, which include many of the Powering the Future projects, but over the 20 year Study Period rather than the expedited 4 year-period proposed in ACE's Powering the Future. Given that the Powering the Future projects are non-revenue producing projects, the CBA assesses net benefits of the IIP scenario by analyzing future costs that would have accumulated if not for implementing the IIP projects (i.e., avoided, or reduced costs). Avoided or reduced future costs assessed include those for: operation and maintenance (O&M) costs; outage restoration costs; distribution system update costs; social cost of carbon emissions, electricity costs; costs incurred by outages (represented by value of lost load, and recovery costs); and future capital cost investments that can be quantified in monetary terms. The CBA compares the benefits against the initial investment costs for the individual Powering the Future projects where possible, looking at their payback over 20 years. We also compare the benefits analyzed against the initial capital investment needed (benefit to initial investment cost ratio, or B/I ratio).

The payback is positive in all three monetary terms for all categories and for the entire portfolio, as summarized in Figure ES-1 (in all three monetary terms) and Table ES-4 (representing results in Real terms) below.

FIGURE ES-1: COST-BENEFIT ANALYSIS RESULTS

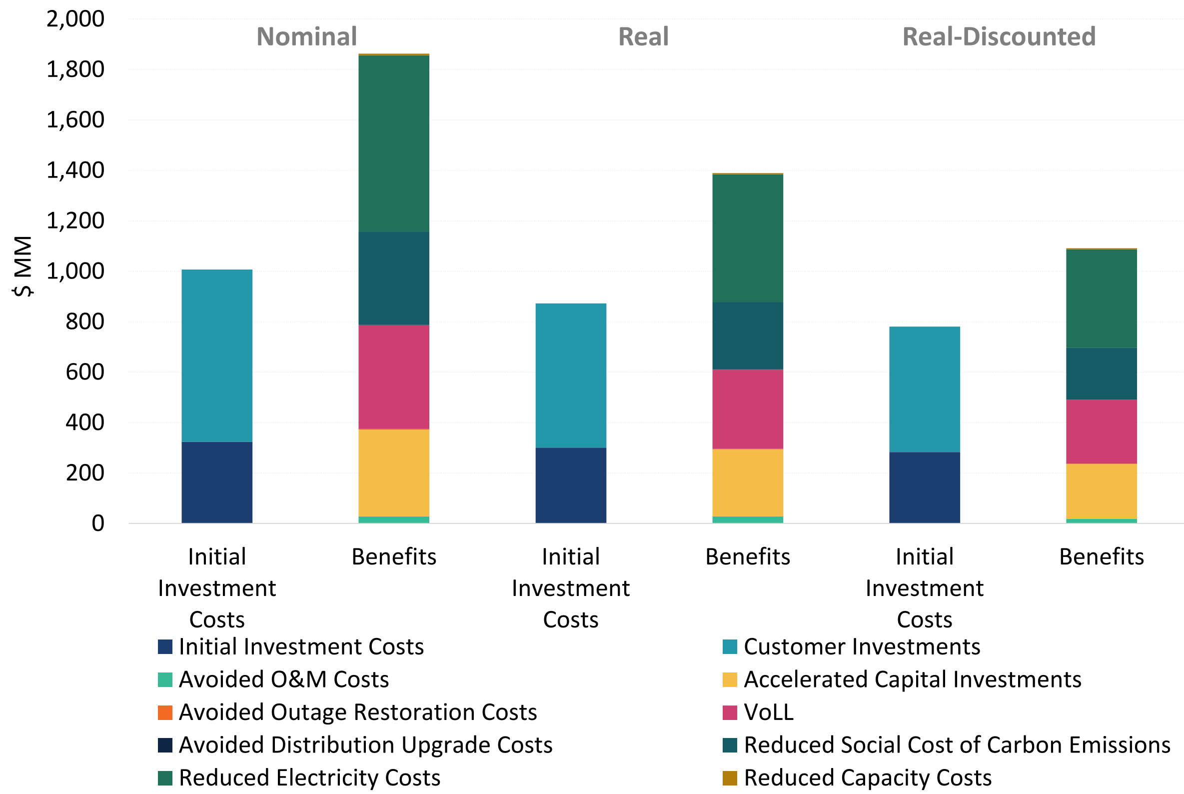


TABLE ES-4: COST BENEFIT RESULTS (REAL) BY PROJECT CATEGORY

Project Category	Project Counts	Initial Investment	Payback	B/I Ratio
1. Targeted Reliability Improvements	29	$92.8	$348.1	3.8
2. Smart Technology Upgrades	10	$68.5	$323.6	4.7
3. Infrastructure Renewals	7	$87.5	$146.2	1.7
4. Solar/DER Enablements	23	$34.9 + $572.3	$779.1	1.3
5. Substation Improvements	11	$96.8	$121.2	1.3

($ millions)

Overall, the CBA confirms that ACE's Powering the Future portfolio has a positive payback. The net positive payback for projects in categories 1 (Targeted Reliability Improvements), 2 (Smart Technology Upgrades), 3 (Infrastructure Renewals), and 5 (Substation Improvements) combined is $939 million in Real terms ($1,227 million in Nominal terms and $761 million in Real-Discounted terms), over the 20-year Study Period. This translates to a B/I ratio of 2.7 in Real terms (3.3 in Nominal terms and 2.3 in Real-Discounted terms).

Projects in category 4 (Solar/DER Enablements) will require investments from both ACE ($34.9 million shown in the table above) and individual customers ($572.3 million shown in the table above)[5], which could further provide economic stimulus that ACE customers and other New Jersey residents would benefit from. The CBA does not account for such secondary benefits because it is difficult to measure the contribution of the respective projects among other influential factors (e.g., tax incentives) that lead to them. Overall, projects in category 4 (Solar/DER Enablements) are estimated to provide a positive payback of $779 million in Real terms ($1,076 million in Nominal terms and $601 million in Real-Discounted terms), over the 20-year Study Period. This translates to a B/I ratio of 1.3 in Real terms (1.5 in Nominal terms and 1.1 in Real-Discounted terms) while the enabled DERs is estimated to reduce carbon emissions by 1.6 million metric tons (assuming the State's interim goals of DER deployments are reached).

These results indicate that Powering the Future will help New Jersey meet its clean energy goals while providing positive economic paybacks (i.e., with no overall costs to the society). The estimates for the initial investment costs include contingency cushions and, thereby, projects completed within the planned budget will see larger benefits. Further, the benefits brought by the IIP investments will likely last longer than the 20-years studied, indicating the actual economic benefits are larger than what the CBA calculated.

The remainder of this report is organized as follows:

- Section I (Introduction) provides an overview and background of New Jersey policies and IIP, and introduces ACE's Powering the Future portfolio;
- Section II (Cost-Benefit Analysis Methodology) discusses the calculation methodology and assumptions this CBA used;
- Section III (Cost-Benefit Analysis Results) reviews the CBA results, and finally;
- Section IV (Conclusion) summarizes the findings and observations.

Appendices include detailed descriptions of the assumptions, detailed analyses workbooks, and a glossary.

[5] Assuming current retail rates, we estimate customers who invest in DERs could recoup nearly $1.4 billion (in Real terms) in bill savings, encouraging the investments. This value is not included in our benefits calculation, which focuses on societal benefits.

I. Introduction

Atlantic City Electric (ACE) retained The Brattle Group (Brattle) to perform a cost benefit analysis (CBA) of its Powering the Future proposal that ACE plans to file with the state of New Jersey (State) as its second Infrastructure Investment Program (IIP). The IIP is a regulatory initiative intended to create a financial incentive for New Jersey utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing components that enhance reliability, resiliency, and/or safety.[6] Brattle, in collaboration with ACE subject matter experts, developed a CBA approach and calculated the costs and benefits of ACE's Powering the Future projects. This report presents the costs and benefits associated with the Powering the Future portfolio, analyzed over a 20-year time-horizon (Study Period) extending from 2023 to 2042.

ACE's Powering the Future portfolio includes 80 projects that are grouped into five categories through 26 subprograms:

1) Targeted Reliability Improvements (29 projects in 7 subprograms)
2) Smart Technology Upgrades (10 projects in 6 subprograms)
3) Infrastructure Renewals (7 projects in 6 subprograms)
4) Solar/DER Enablements (23 projects in 3 subprograms)
5) Substation Improvements (11 projects in 4 subprograms)

This CBA report provides a description and quantification of the costs and benefits associated with the Powering the Future projects on a project-by-project basis (to the extent possible), and summarizes the results for the entire portfolio, and by the five categories and 26 subprograms.

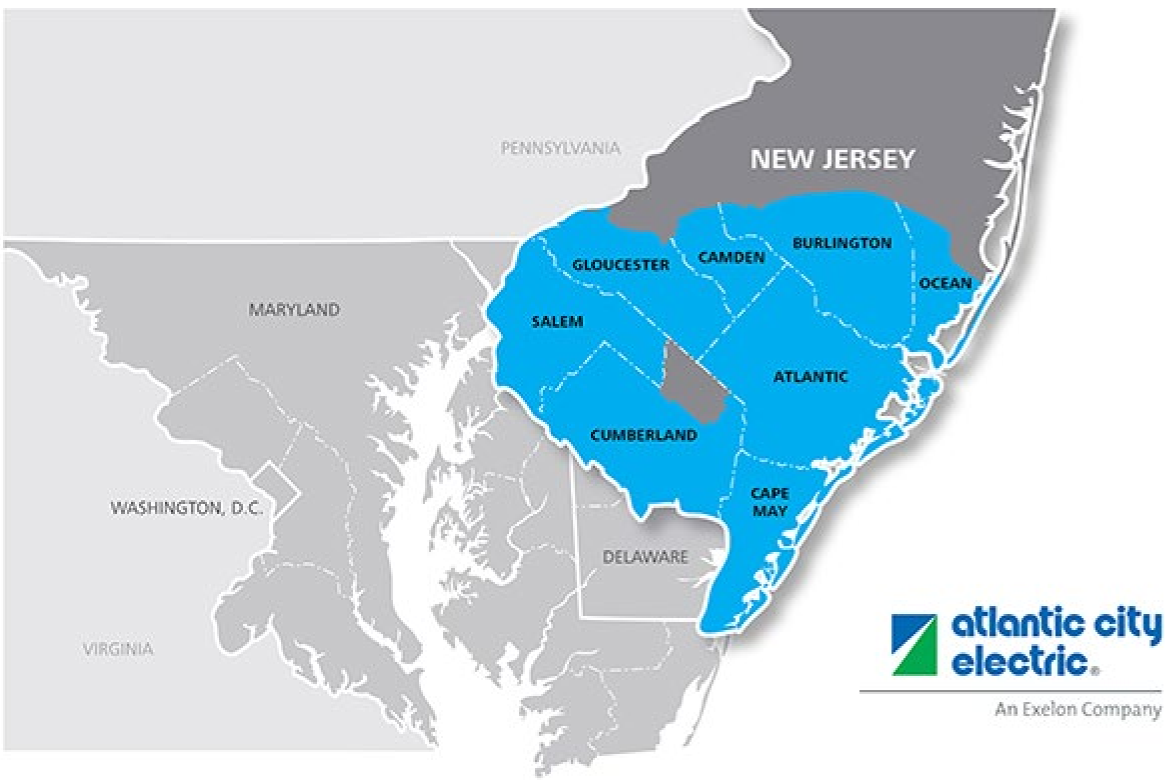
The remainder of this Section provides background information, including an overview of ACE, the policy landscape in New Jersey (State) and the IIP, and the Powering the Future portfolio.

[6] Pursuant to N.J.A.C. 14:3-2A.1 *et seq.*, which established the Infrastructure Investment Program.

A. Atlantic City Electric (ACE)

ACE, first incorporated in 1924, is a public utility with approximately 565,000 customers in southern New Jersey over a service territory that spans over 2,800 square miles. Within this service territory, ACE owns and operates over 90 substations and 300 feeders adding up to nearly 7,400 circuit miles of overhead lines and 3,000 circuit miles of underground cables as part of its distribution network.[7] ACE also owns over 1,100 circuit miles of transmission facilities. Figure 1 below shows the eight counties ACE serves.

FIGURE 1: ATLANTIC CITY ELECTRIC SERVICE TERRITORY



Source:
https://www.atlanticcityelectric.com/AboutUs/Pages/CompanyInformation.aspx?Origin=ACEBottomNavigation

ACE is engaged in electricity distribution and the provision of Basic Generation Service for residential, commercial, and industrial customers, delivering approximately 8.5 TWh of electricity annually. ACE represents 14% of the investor-owned utility customers and 12% of the annual electricity sales in New Jersey. ACE is a wholly owned subsidiary of Pepco Holdings LLC (PHI), which in turn, is a subsidiary of Exelon Corporation.

7 Exelon Form 10K filing for the year ending December 31, 2020.

B. New Jersey State Policies and Timeline

New Jersey is one of the states leading the energy transition with its ambitious clean energy and emission reduction goals. New Jersey has shaped its policy landscape through a series of legislation, especially over the last 15 years. More recently, Governor Phil Murphy's Administration accelerated climate action through executive orders and a comprehensive clean energy plan. Key milestones leading to New Jersey's current clean energy policy landscape include:

- 2007: Global Warming Response Act (GWRA) calls for reducing the State's greenhouse gas emissions by 80 percent below 2006 levels by 2050.[8]
- 2012: Solar Act of 2012[9] accelerates the solar carve-outs, which are part of the Renewable Portfolio Standard (RPS) targets. The Act mandates 3.47% of electricity sales in the energy year 2021 and 4.1% electricity sales in the energy year 2028 to be procured from solar electricity generation.
- 2018: Governor Murphy's Executive Order No. 8 calls for implementing the previously-enacted Offshore Wind Economic Development Act (OWEDA) to meet the goal of 3,500 MW of offshore wind energy generation by 2030.[10]
- 2018: Governor Murphy's Executive Order No. 28 directs the development of an updated Energy Master Plan to achieve 100% clean electricity by 2050.[11]
- 2018: Clean Energy Act[12] increases the State's RPS targets to 35% Class I renewables by 2025 and 50% by 2030.[13] The Act mandates the installation of 3,500 MW offshore wind and 2,000 MW energy storage by 2030. It also set energy efficiency targets for electric and natural gas utilities and mandates a transition to a new solar incentive program.

---

8 P.L. 2007 c.112, Global Warming Response Act of 2007, and New Jersey Global Warming Response Act 80 x 50 Report, 2020.

9 P.L. 2012, c.24, The Solar Act of 2012.

10 Executive Order No. 8.

11 Executive Order No. 28.

12 P.L. 2018, c.17, Clean Energy Act of 2018.

13 Class I renewables include all renewables except for hydro larger than 3 MW and municipal solid waste. Large hydro and solid waste are Class II renewables, which have an RPS target of 2.5% of electricity sales per year.

- 2019: Governor Murphy's Executive Order No. 92 increases the offshore wind goal to 7,500 MW by 2035.[14, 15]
- 2019: The Energy Master Plan (EMP) sets forth a strategic plan to achieve 100% clean energy by 2050.[16] The EMP projects a solar deployment of 12 GW by 2030 and 32 GW by 2050 from roughly 4 GW today with the support of the new solar incentive programs. To date, the 2019 EMP is the core state policy and provides the roadmap for achieving statewide decarbonization. We provide further details of the EMP in the section following.
- 2020: The Act concerning the use of plug-in electric vehicles (EVs) sets a goal of registering 330,000 EVs by 2025 and 2 million EVs by 2035 as well as developing the supporting charging infrastructure.[17] According to the Act, the State targets 85% of all new light-duty vehicles sold in the State to be EVs by 2040. The State and the utilities operating in the State provide rebates for vehicles and chargers to individuals, businesses, and other entities to encourage EV adoption.[18]
- 2021: Solar Act of 2021[19] directs the Board of Public Utilities to establish a program to incent the development of 3,750 MW of solar by 2026. The Act requires at least 300 MW of net metered solar, at least 150 MW of community solar, and an average of 300 MW of grid scale solar annually between 2021 and 2026.
- 2021: The legacy Solar Renewable Energy Certificate (SREC) program is closed to applications upon reaching 5.1% solar carve-out target for 2021. New Jersey starts providing incentives to solar energy producers through the Transition Incentive (TI) Program (May 1, 2020 - August 27, 2021) and the Successor Solar Incentive (SuSI) Program (August 28, 2021 – Current).

---

14 Executive Order No. 92.

15 New Jersey Offshore Wind Solicitations. Executive Order No. 92 increased the offshore wind target to 7,500 MW by 2035.

16 2019 New Jersey Energy Master Plan: Pathway to 2050 defines "100 percent clean energy by 2050" as 100 percent carbon-neutral electricity generation and maximum electrification of the transportation and building sectors with the goal of meeting or exceeding the 80 percent reduction in greenhouse gas emissions below 2006 levels by 2050 as outlined in the GWRA.

17 P.L. 2019, c. 362. An Act concerning the use of plug-in electric vehicles.

18 New Jersey Clean Energy Program Electric Vehicle Incentive Programs

19 P.L. 2021, c. 169. The Solar Act of 2021.

- 2021: Governor Murphy's Executive Order No. 274 adds an interim target to reduce greenhouse gas emissions to 50% below 2006 levels by 2030.[20]
- 2022: Executive Order No. 307 increases New Jersey's offshore wind goal to 11,000 MW by 2040.[21]

These policies have culminated to the following clean energy and climate goals for New Jersey:

- Reduce greenhouse gas emissions by 50% by 2030 and 80% by 2050 below 2006 levels.
- Supply 50% of electricity from renewables by 2030 and 100% of electricity from carbon-neutral resources by 2050.[22]
- Pursue large quantities of offshore wind procurements and generous solar incentives. Targets include installing 7,500 MW of offshore wind by 2035 and 11,000 MW by 2040, and approximately 450 MW of rooftop and community solar and 300 MW of grid-scale solar per year until 2026.

In line with these goals, New Jersey aims to plan for and implement distribution system upgrades in order to handle increased electrification and integration of DERs including rooftop solar, storage, EVs, and other technologies. The State urges electric utilities to develop plans to upgrade their distribution systems to handle the decentralized and bi-directional nature of evolving grid technology. Utilities are expected to meet these needs by adopting a coordinated approach to maximizing distribution level flexibility and replacing grid infrastructure that is not designed for the modern grid. The goal is to increase grid safety and reliability, while maximizing the cost savings and resilience that DERs provide.

C. 2019 Energy Master Plan (EMP)

New Jersey's EMP is the main energy policy leading the State's transition to a clean energy economy. The EMP comprehensively integrates and incorporates New Jersey's energy system goals including the production, distribution, consumption, and conservation of energy. Pursuant

20 Executive Order No. 274.

21 Executive Order No. 307.

22 2019 New Jersey Energy Master Plan: Pathway to 2050 defines "100 percent clean energy by 2050" as 100 percent carbon-neutral electricity generation and maximum electrification of the transportation and building sectors.

to statute,[23] EMP is a product of interagency collaboration and stakeholder process, and reflects a unified plan to achieve the State's goals.

The most recent EMP (2019 EMP) provides the blueprint for achieving 100% clean energy by 2050. It holistically considers the entire energy system in New Jersey with its associated greenhouse gas emissions. The EMP outlines seven key strategies to reach its 2050 clean energy goal:

- Strategy 1: Reducing Energy Consumption and Emissions from the Transportation Sector
- Strategy 2: Accelerating Deployment of Renewable Energy and Distributed Energy Resources
- Strategy 3: Maximizing Energy Efficiency and Conservation and Reducing Peak Demand
- Strategy 4: Reducing Energy Consumption and Emissions from the Building Sector
- Strategy 5: Decarbonizing and Modernizing New Jersey's Energy System
- Strategy 6: Supporting Community Energy Planning and Action in Underserved Communities
- Strategy 7: Expand the Clean Energy Innovation Economy

Through these seven EMP strategies, the State is pursuing an ambitious transition to a clean energy economy through electrification of transportation and buildings sectors, and accelerated deployment of clean DERs. As electrification increases the demand for electricity and the electricity system becomes more decentralized, there is a need for accelerated investments to improve the reliability, resiliency, and safety of the grid. The Infrastructure Investment Plan (IIP), discussed next, is an essential regulatory mechanism that helps utility investments to improve the reliability, resiliency, and safety of the grid, which then could indirectly support the EMP and associated policy goals.

D. Infrastructure Investment Program

The IIP is a regulatory mechanism established in the New Jersey Administrative Code[24] and enables utilities to accelerate its investments to build or remediate its plants and facilities to enhance safety, reliability, and/or resiliency. IIP also creates a rate recovery mechanism to

[23] *Ibid*

[24] N.J.A.C. 14:3-2A.1 *et seq.*

encourage and support the necessary accelerated investments in certain utility plants and equipment. As described in the regulation, these investments would occur in a systematic and sustained way to advance construction, installation, and rehabilitation of utility infrastructure needed for continued system safety, reliability, and resiliency, and sustained economic growth in the state of New Jersey.

To be eligible for IIP, projects must be non-revenue producing and related to safety, reliability, and/or resiliency. The approval from the New Jersey Board of Public Utilities (BPU) is required for projects to be implemented. For electric distribution companies, the eligible projects may include distribution automation investments, including, but not limited to, supervisory control and data acquisition equipment, cybersecurity investments, relays, reclosers, voltage and reactive power control, communications networks, and distribution management system integration.

E. ACE's Powering the Future Portfolio

ACE's Powering the Future portfolio features 80 capital projects that serve to improve ACE's reliability performance, increase system resiliency to adverse events, promote safe efficient operations of the distribution system, and advance technologies. ACE groups the Powering the Future portfolio projects into five categories:

1) Targeted Reliability Improvements
2) Smart Technology Upgrades
3) Infrastructure Renewals
4) Solar/Distributed Energy Resource Enablements
5) Substation Improvements

The five categories are further split into 26 subprograms. We discuss the five categories and subprograms within each category next.

Category 1 (Targeted Reliability Improvements): This category features projects that, once installed, will provide significant reliability improvements to ACE's distribution system. Substation based reliability projects, underground cable improvements, and removing abandoned and obsolete equipment on the overhead distribution system will be significant drivers of this category. Other investments include replacing aged open wire secondaries, and creating loops and redundant feeder sections in both overhead and underground facilities. In general, past operational events have led to identifying these projects.

This category includes 29 projects among the following seven subprograms:

- Long Radial Remediation (7 projects)
- New Feeders (2 projects)
- Priority Feeders (1 project)
- Rear Lot Conversions (6 projects)
- Reconductoring (11 projects)
- Unfused Laterals (1 project)
- URD Loop Feeds (1 project)

Category 2 (Smart Technology Upgrades): This category includes advancing the distribution automation (DA) system by installing advanced intelligent electronic devices in the substation and in the field. These devices are facilitated through established telecom networks, and work in concert with automation control programs to carry out the automatic sectionalizing and restoration (ASR) functions. This "self-healing" concept is the heart of DA. Feeders are designed with good segmentation using reclosers and smart switches and utilize one or more feeder tie switches to provide alternate power sources. Should a permanent fault occur, the appropriate protective device locks out as expected. This automatic isolation and restoration process normally takes less than two minutes. DA does not prevent faults or reduce their likelihood of occurring; however, DA can minimize the number of customers experiencing sustained outages and reduce restoration times by isolating the faulted line segment. Knowing the location of the fault also reduces patrol times and speeds up the restoration process for the customers impacted by the faulted section.

This category includes 10 projects among the following six subprograms:

- Capacitors (2 projects)
- Reclosers (1 projects)
- Smart Sensors (1 projects)
- Regulators (1 project)
- Fiber / Radio (2 projects)
- Distribution Automation (3 projects)

Category 3 (Infrastructure Renewals): Infrastructure renewals include an array of projects to upgrade, replace, or repair system infrastructure. Projects in this category primarily focus on the replacement of infrastructure at or near substations, which can have a significant effect on reliability for many customers. The category also includes projects to convert feeders to higher operating voltages, enabling the implementation of distribution automation schemes as well as creating greater hosting capacity for DERs. As infrastructure ages, the replacement of common infrastructure such as poles, underground cable, open wire secondary, reclosers, and other mission critical equipment is prudent to maintain system level reliability improvements to date, avoid future high impact failures, and provide increased resiliency in significant weather events. This category includes seven projects among the following six subprograms:

- Abandoned Line (1 project)
- Cable URD (1 project)
- Cutout Replacement (1 project)
- Network Renewal (2 projects)
- Open Wire Secondaries (1 project)
- Recloser Replacement (1 project)

Category 4 (Solar/DER Enablements): Solar/DER enablement projects prepare the distribution grid to accommodate more reverse power flow and accept more distributed generation, such as solar and storage, on the system. The projects in this category address system constraints that result in feeders being already saturated or restricted to additional generation. This category includes the following three subprograms which, in total, have 23 projects. Each of these projects can be part of multiple subprograms:

- Substation Reverse Power Protection – Capital
- Substation Reverse Power Protection – O&M
- DER Distribution Line Upgrades/Equipment Upgrades

Category 5 (Substation Improvements): Substation improvements include projects to install, upgrade, replace or repair substation infrastructure. Projects in this category are primarily focused on maintaining service reliability and safety of workers in substations, improving operating flexibility, and replacing or upgrading substation equipment due to age, condition or obsolescence. Accomplishing these improvements in a planned manner will help avoid unplanned outages or emergency repairs in the future. Work in this category includes building a new substation, transformer installations and replacements, switchgear replacement, bus and relay improvements, flood remediation and foundation and support replacements.
This category includes 11 projects among the following four subprograms:

- New Substation (1 project)
- Substation Additions (1 project)
- Substation Reliability (4 projects)
- Substation Renewal (5 projects)

The five categories of 80 projects consists of a total of $380.6 million ($379.0 million of distribution assets placed in service)[25] of investments (in Real terms, see discussion in Section III) planned over a four-year period (July 2023 – June 2027), as summarized in Table 1 and Table 2 below.

TABLE 1: PROJECT COUNT BY CATEGORY BY START YEAR

Project Category		2023	2024	2025	2026	2027	2023-27
1	Targeted Reliability Improvements	11	10	5	1	2	**29**
2	Smart Technology Upgrades	9	1	0	0	0	**10**
3	Infrastructure Renewals	6	1	0	0	0	**7**
4	DER Enablements	23	0	0	0	0	**23**
5	Substation Improvements	6	2	3	0	0	**11**
	Total	**55**	**14**	**8**	**1**	**2**	**80**

TABLE 2: FORECASTED INVESTMENTS (IN REAL TERMS) BY PROJECT CATEGORY AND YEAR

Project Category		2023	2024	2025	2026	2027	2023-27
1	Targeted Reliability Improvements	$2.4	$23.7	$31.1	$23.7	$11.8	**$92.8**
2	Smart Technology Upgrades	$6.6	$16.9	$17.5	$18.1	$9.4	**$68.5**
3	Infrastructure Renewals	$3.6	$23.0	$24.3	$24.9	$11.7	**$87.5**
4	DER Enablements	$1.6	$8.4	$9.5	$9.5	$5.9	**$34.9**
5	Substation Improvements	$9.5	$15.5	$28.6	$33.2	$10.0	**$96.8**
	Total	**$23.7**	**$87.6**	**$111.1**	**$109.4**	**$48.8**	**$380.6**

Note: Numbers may not add up due to rounding. ($ million)

These interrelated projects replace aging infrastructure, improve system reliability, implement distribution automation, introduce new technologies and comply with the IIP rules. In addition, they align with the EMP goals. Specifically, the Powering the Future projects support EMP Strategies 1, 2, and 5, listed below.

[25] This slight difference occurs because the Powering the Future portfolio includes two telecom related projects where part of the cost is allocated outside the distribution account.

Strategy 1 (Reducing Energy Consumption and Emissions from the Transportation Sector): This strategy calls for decarbonizing the transportation sector by EV adoption. As discussed earlier, New Jersey has a goal of registering 330,000 light duty EVs by 2025 and 2 million light duty EVs by 2035. New Jersey also plans to deploy the necessary charging infrastructure. Distribution system upgrades will be needed to enable the charging infrastructure. Increasing EV adoption will increase the need for reliability, as customers' transportation needs will also depend on availability of electricity and power outages will be more costly.

Strategy 2 (Accelerating Deployment of Renewable Energy and Distributed Energy Resources): New Jersey mandates increased quantities of renewable energy through its RPS targets, offshore wind, solar, and energy storage goals. New Jersey also incentivizes further development of distributed solar through the Solar Act of 2021 and a distributed solar program that provides fixed incentives over the 15-year lifetime of projects. Adding higher volumes of distributed solar to the system will require enhancing the distribution system.

Strategy 5 (Decarbonizing and Modernizing New Jersey's Energy System): This strategy specifies goals for the necessary distribution system upgrades to handle increased electrification and integration of DERs. The EMP recommends utilities to modernize the grid to support new technologies and establish plans to support distributed energy resources and electric vehicle charging on the electric distribution system.[26]

Specifically, projects in categories 1 (Targeted Reliability Improvements), 2 (Smart Technology Upgrades), 3 (Infrastructure Renewals), and 5 (Substation Improvements) directly support EMP Strategy 5 by modernizing the grid, while also preparing the grid for electrification of transportation and higher volumes of DERs encouraged by EMP Strategies 1 and 2, respectively. Projects in category 4 (Solar/DER Enablements) directly supports EMP Strategy 2 and 5 by enabling new, low-carbon distributed energy resources to be added to system.

[26] The EMP Ratepayer Impact Study for NJBPU finds that adopting electric vehicles for transportation and electric heat pumps for heating can reduce energy bills for New Jersey ratepayers by 10-20% in 2030 compared to 2020 levels. See New Jersey Energy Master Plan Ratepayer Impact Study, conducted by The Brattle Group for New Jersey Board of Public Utilities, August 2022.

II. Cost-Benefit Analysis Methodology

This Section details the methodology used for the CBA for the Powering the Future projects by categories and describes the types of costs and benefits included in the analysis.

A. CBA Approach Overview

The CBA compares the costs between two scenarios: the IIP scenario where ACE makes these investments over the next four years (July 2023 – June 2027) as planned, and the Status Quo scenario where ACE does not move forward with the Powering the Future projects as planned. In the Status Quo scenario, ACE will still make necessary investments, which include many of the Powering the Future projects, over a 20 year-period[27] rather than the expedited schedule over the next four years as ACE proposes in its IIP application. The CBA applies this scenario approach to all Powering the Future projects we analyze, regardless of their project categories or subprograms. Through this approach, the CBA analyzes projects' payback of their initial investment costs over the 20-year Study Period. The analysis results are also used to develop the projects' benefit to initial investment cost ratio (B/I ratio). We assess these metrics in three monetary terms defined as:

- Nominal (in nominal dollars),
- Real (in real dollars after applying estimated future inflation rates of 2.35% to the nominal values), and
- Real-Discounted (in real dollars after applying estimated future inflation rates of 2.35% and a real discount rate of 2% to the nominal values). This metric tries to capture the value that society places on future benefits and costs.

Throughout this report, we will center the discussion on values shown in Real terms while providing ranges to show the Nominal and Real-Discounted values. We then summarize the results by subprogram, categories, and for the Powering the Future portfolio as a whole.

[27] The 20-year time horizon is a reasonable and conservative estimate of the lifetime of assets in each project. The benefits of the assets likely extend beyond 20 years; however, those benefits are not included in the CBA, therefore leading to a conservative estimate of benefits.

Benefits will vary among projects analyzed. In general, IIP projects are non-revenue producing projects. Thereby, the benefits of the IIP scenario are future costs that would have accumulated if not for implementing the Powering the Future projects (i.e., under the Status Quo scenario). In other words, the benefits are largely avoided or reduced costs in the IIP scenario. Projects in categories 1 (Targeted Reliability Improvements), 2 (Smart Technology Upgrades), 3 (Infrastructure Renewals), and 5 (Substation Improvements) will directly lead to benefits, such as by reducing outages (occurrence, duration once it happens, and number of customers it impacts) or ongoing operation and maintenance costs, while also avoiding future investments. Benefits for projects in category 4 (Solar/DER Enablements) rely on customers' actions, specifically their DER investments, that are largely outside of ACE's control.[28] We limit the benefits to societal benefits and do not include those that may occur for individual entities (e.g., profitability for ACE, utility bill savings for customers who install DERs, etc.) The assessed benefits will then be compared against the initial investment costs of the Powering the Future projects, as discussed earlier. If the resulting B/I ratio is 1.0 or higher (i.e., benefits are equal to or higher than the initial investment costs), the project is considered economically advantageous.

We perform the CBA on an individual project basis, to the extent practically possible. Overall, we analyze 66 out of 80 projects (82.5% of all projects). Table 3 below summarizes the count of projects by categories we analyzed in this CBA.

[28] Benefits of category 4 (Solar/DER Enablements) will vary with the volume of DER installations. DER installations are investment decisions made by individual customers and outside of ACE's control. These decisions will also be impacted by federal, state, and perhaps local (i.e., cities, towns, etc.) policies, such as incentives. The benefits of the DER enablement projects will vary based on the volume of DER installations that occur in the IIP scenario.

TABLE 3: COUNT OF PROPOSED AND ANALYZED PROJECTS BY PROJECT CATEGORY AND START YEAR

Project Category			2023	2024	2025	2026	2027	Total
1	Targeted Reliability Improvements	Proposed Projects	11	10	5	1	2	29
		Projects Analyzed	11	10	2	1	2	26
2	Smart Technology Upgrades	Proposed Projects	9	1	0	0	0	10
		Projects Analyzed	3	0	0	0	0	3
3	Infrastructure Renewals	Proposed Projects	6	1	0	0	0	7
		Projects Analyzed	4	1	0	0	0	5
4	Solar/DER Enablements	Proposed Projects	23	0	0	0	0	23
		Projects Analyzed	23	0	0	0	0	23
5	Substation Improvements	Proposed Projects	6	2	3	0	0	11
		Projects Analyzed	4	2	3	0	0	9
	Total	**Proposed Projects**	**55**	**14**	**8**	**1**	**2**	**80**
		Projects Analyzed	**45**	**13**	**5**	**1**	**2**	**66**

The 66 projects analyzed cover 22 out of the 26 subprograms. We assume the benefit of projects that are not analyzed are comparable to its peer projects (within the same subprogram, if not same category) that we analyzed individually. The 14 unanalyzed projects spread over eight subprograms.[29] Four of these subprograms have other projects analyzed within the subprogram and we assume the benefits of projects not analyzed are comparable to the other projects within the subprogram. For the remaining four subprojects without any projects analyzed, we assume the benefits are comparable to analyzed projects within the same category.

The sections following discuss detailed methodology for each type of costs and benefits.

B. Costs

The CBA recognizes two types of costs—those associated with capital investments and those that are not investment related but rather ongoing costs. The first cost type (investment related costs) include those associated with ACE's capital investment for the Powering the Future projects and investments made by others—for example, customers' DER investments. We compare the

29 We could not analyze 14 of the projects (17.5% of all projects). Nine of these projects, such as capacitor upgrades, provide benefits beyond those quantified in this CBA. The remaining five projects include those that lacked data because ACE has not yet developed the project to a sufficient levels of details for them to be analyzed.

Powering the Future projects' benefits against these initial investment costs to analyze the net cash flow and the B/I ratio.

ACE Capital Investments: ACE provided Powering the Future projects and their estimated investment costs. Through these projects, ACE is proposing to remove obsolete equipment, upgrade substations, feeders, cables, and other equipment as well as install new equipment.

Customer Investments: This cost is largely specific to projects in category 4 (Solar/DER Enablements). In addition to the investment by ACE, individuals, businesses, or other entities could also incur costs to install DER. For this analysis, we characterize these costs as the capital costs incurred by ACE's retail customers who install rooftop solar panels. The average cost of rooftop solar installation before federal tax credits in New Jersey is summarized in Table 4 below:

TABLE 4: PROJECTION OF ROOFTOP SOLAR INSTALLATION COSTS IN NEW JERSEY

Year	Rooftop Solar CapEx Projection for New Jersey ($/W in 2022 USD)
2022	2.88
2023	2.67
2024	2.46
2025	2.24
2026	2.03
2027	1.82
2028	1.61
2029	1.40
2030	1.19
2031	1.17
2032	1.16
2033	1.15
2034	1.13
2035	1.12
2036	1.11
2037	1.09
2038	1.08
2039	1.07
2040	1.05
2041	1.04
2042	1.03

Notes: Cost projections do not include federal tax credits or other incentives.

As this table shows, we assume future cost reduction in solar photovoltaics, reflecting the Moderate Projection from the National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) report.[30] Further details are included in Appendix A.

The second cost type is costs other than investments, such as ongoing operational costs that repeat every year going forward. We use this second cost type to analyze potential benefits by comparing the changes in these costs between the IIP and Status Quo scenarios. For example, if the Powering the Future investments would lower operational costs (compared to the Status Quo scenario), we will consider that cost reduction as a benefit. We discuss these costs in the benefits section next.

C. Benefits Analyzed

Powering the Future projects are non-revenue producing programs related to safety, reliability, and/or resiliency. Given these characteristics, we analyze the potential benefits largely as a measure of increased safety, reliability, or resiliency, or decreased costs to provide the same level of safety, reliability, or resiliency, assuming such costs would go down with the IIP investments. These benefits include:

- Avoided O&M Costs
- Avoided Outage Restoration Costs
- Avoided Distribution Upgrade Costs
- Reduced Social Cost of Carbon Emissions
- Reduced Electricity Costs
- Value of Lost Load (VoLL)
- Accelerated Capital Investments

Any given individual project analyzed in this CBA may not offer all these benefits. For example, projects in categories 1 (Targeted Reliability Improvements), 2 (Smart Technology Upgrades), 3 (Infrastructure Renewals), and 5 (Substation Improvements) would likely produce VoLL benefits since they could reduce the effects of outages and economic losses associated with outages. Projects in these categories also lead to avoided future capital costs due to the accelerating the

[30] NREL, Electricity Annual Technology Baseline (ATB) Data, 2022, available at: https://atb.nrel.gov/electricity/2022/data

investments required for upgrading and modernizing the distribution system. Projects in category 4 (Solar/DER Enablements) would lead to reduced social cost of carbon, reduced electricity costs, and avoided distribution system upgrades by enabling higher quantities of distributed solar installations. Table 5 below summarizes the project counts by category that exhibited the benefits listed above.

TABLE 5: COUNT OF PROJECTS OFFERING BENEFITS

	Project Category	Count of Projects	Count of Analyzed Projects	BENEFIT TYPES						
				Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Reduced Social Cost of Carbon Emissions	Reduced Electricity Costs	Avoided Distribution Upgrade Costs	Accelerated Capital Investments
1	Targeted Reliability Improvements	29	26	29	8	22	0	0	0	26
2	Smart Technology Upgrades	10	3	10	0	3	0	0	0	3
3	Infrastructure Renewals	7	5	7	3	5	0	0	0	5
4	Solar/DER Enablements	23	23	0	0	0	23	23	2	23
5	Substation Improvements	11	9	11	0	9	0	0	0	9

Each of the benefit types is summarized briefly next.

Avoided O&M Costs: Replacing older infrastructure assets with new infrastructure typically lowers O&M expenditures. Thereby, the IIP scenario would require lower O&M costs due to replacement of aging equipment and reduction of the associated corrective maintenance needs (which would also likely go down with the technological improvements brought by the Powering the Future projects). The avoided O&M costs under the IIP scenario are estimated by comparing the O&M cost projections against those of the Status Quo scenario. For this CBA, we calculate annual O&M costs to be approximately 4% of the gross plant value (capital investment amounts) and assumed new equipment would reduce the O&M costs by 25%, compared to older equipment, and thereby commanding approximately 3% of the gross plant value added as annual O&M expenses. We developed these assumptions by observing historical data from ACE's FERC Form 1 filings, as discussed in Appendix A.

Avoided Outage Restoration Costs: A portion of IIP investments leads to lower outage restoration costs, since newer infrastructure will have fewer equipment failures and lower equipment restoration costs. The avoided costs under the IIP scenario can be estimated by comparing the cost projections against that of the Status Quo scenario. ACE provided the avoided outage restoration costs for 14 projects over the 20-year Study Period by comparing the IIP and Status Quo scenarios.

Avoided Distribution Upgrade Costs: Several projects allow for more customers to invest in DERs. The deployment of the DERs then reduces peak load growth (if generation from DERs coincide with peak load hours) and leads to delayed distribution upgrade costs. We calculate the monetary value of this benefit by multiplying the contribution of DER installations to reducing peak load and overloading of transformers by the distribution upgrade cost per MW. The distribution upgrade cost per MW is estimated to be $52,824 (in 2022 dollars) based on the difference of the demand cost components in ACE's 2018 and 2020 vintage Cost of Service studies.

To quantify the peak reduction effect, we obtain the maximum solar hosting capacity of each transformer over the 20-year Study Period under the Status Quo and IIP scenarios. The transformers' hosting capacities are already saturated and do not provide any room for new solar interconnections in the Status Quo scenario. Under the IIP scenario, the hosting capacities of the transformers will increase and new solar can be added until the new hosting capacity is saturated. We assume solar installations under the IIP scenario to grow at the rate of 15% per year in 2023 and 9% per year afterwards, based on historical solar installations in ACE's service territory and statewide distributed solar goals. This value is aligned with ACE's internal forecast. This analysis also considers the expected gross load growth rate, which is estimated to be 1.10% per year based on the forecasted growth rates of net load and DER installations. Appendix A provides further detail on this analysis.

Reduced Social Cost of Carbon Emissions: Several Powering the Future projects, in particular those in category 4 (Solar/DER Enablements), lead to increased DERs (e.g., rooftop solar installations). More DERs leads to reduction in generation from other sources. This in turn reduces greenhouse gas emissions from these other emitting resources. The Social Cost of Carbon (SCC) is a commonly used metric to estimate such avoided damages and inform investment and policy decisions. SCC represents the societal benefits of reducing CO_2 emissions by one ton. In this analysis, we use the SCC values for the 2023-2042 period based on the 2% discount rate, as summarized in Table 6 below.[31] [32] [33]

TABLE 6: SOCIAL COST OF CARBON

Year	Social Cost of Carbon ($/metric tons of CO_2 in 2022 USD)
2023	$143
2024	$145
2025	$146
2026	$149
2027	$150
2028	$152
2029	$154
2030	$155
2031	$158
2032	$160
2033	$161
2034	$163
2035	$166
2036	$167
2037	$169
2038	$171
2039	$172
2040	$175
2041	$177
2042	$179

[31] New York State Energy Research and Development Authority and Resources for the Future. "Estimating the Value of Carbon: Two Approaches." Revised April 2021. This report uses the results from the U.S. Government report U.S. Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990, February 2021.

[32] We use the same SCC values used in previous PHI filings. See Pepco's Climate Solutions 5-Year Action Plan: Benefits and Costs, January 2022, submitted to the Public Service Commission of the District of Columbia for Formal Case No. 1167

[33] Recent scientific updates show SCC values to be much higher and thereby the SCC values used in this analysis are conservative. See Rennert, K., Errickson, F., Prest, B.C. *et al.* Comprehensive Evidence Implies a Higher Social Cost of CO2. *Nature* (2022). https://doi.org/10.1038/s41586-022-05224-9

To quantify the carbon reduction by the solar power generation, we use the Energy Information Administration's (EIA) estimate of 537 lb/MWh as the average carbon dioxide emission rate for New Jersey.[34] Further details are included in Appendix A.

Reduced Electricity Costs: The additional DER installations enabled by projects would also reduce the net-demand of electricity and, therefore, the electricity generation costs to the utility. We estimate the generation cost reduction by multiplying the amount of electricity generated by the incremental solar installations in the IIP scenario by the recent wholesale energy prices—i.e., the locational marginal prices (LMPs) observed in the ACE region on an hourly basis.[35] This is a conservative approach because we are not accounting for any losses associated with power purchased through the wholesale energy market. Table 7 below summarizes the wholesale energy prices assumed by showing monthly averages. We assume hourly energy prices to remain constant in real terms through the Study Period.

TABLE 7: WHOLESALE ENERGY PRICES

Month	Monthly Average LMP ($/MWh in 2022 USD)
January	$67.53
February	$46.66
March	$39.78
April	$55.63
May	$62.51
June	$64.36
July	$82.68
August	$94.33
September	$93.34
October	$109.28
November	$107.83
December	$69.68

34 EIA New Jersey Electricity Profile 2020, https://www.eia.gov/electricity/state/newjersey/

35 LMPs reflect the marginal cost of generation and, thereby, we use it as a proxy of the avoided generation costs. We obtained the historical hourly LMPs observed for the first 8 months of 2022 from PJM. For the last 4 months of 2022, we estimate the LMPs by scaling the LMPs observed for the last 4 months of 2021 by the ratio of 2022 and 2021 LMPs observed for the first 8 months of 2022. We assume LMPs in a given hour to remain constant in real terms in the future.

If the generation from DERs coincide with peak load hours, the additional DER installations enabled also reduce ACE's system peak demand and the need for the capacity of resources. We estimate the reduced capacity costs by multiplying the peak load reduction by the recent clearing prices of the PJM capacity market. Capacity price is set at $66/MW-Day (in 2022 USD) based on the recent PJM Base Residual Auction (BRA), [36] and assumed to remain constant in real terms through the Study Period. Please see Appendix A for further details.

Table 8 shows the impact of DER generation in Year 5 (2027) and Year 20 (2042) for each project analyzed under category 4 (Solar/DER Enablements). Most IIP projects lead to peak load reduction compared to Status Quo and a reduction in annual generation due to increased quantity of DERs. We assume the annual solar generation in the Status Quo scenario to stay constant through the Study Period since the transformers are closed to new solar interconnections.

[36] For avoided capacity costs, we used the average of capacity price from PJM 2022/2023 BRA for EMACC, which was $97.86/MW-day and PJM 2023/2024 BRA for RTO, which was $34.13/MW-day, as the 2023 capacity price.

TABLE 8: PEAK LOAD REDUCTION AND ANNUAL SOLAR GENERATION BY TRANSFORMER

Transformer	Peak Load Reduction *Under IIP Compared to Status Quo in Year 20* (MW)	Annual Solar Generation *Status Quo* (GWh) (Constant through Study Period)	Annual Solar Generation in Year 5 *IIP* (GWh)	Annual Solar Generation in Year 20 *IIP* (GWh)
Barnegat T1	2.64	12.66	20.56	34.75
Cardiff_T3	1.28	10.09	16.38	42.85
Dorothy_T2	0.35	11.52	18.70	37.13
Franklin_T1	0.07	12.41	20.15	32.12
High Street_T1	0.75	11.52	18.69	36.79
Mantua_T2	0.07	8.41	13.65	32.27
Mickleton_T2	0.15	10.90	17.69	35.09
Mickleton_T5	0.44	7.95	12.91	33.23
Moss Mill_T2	1.35	6.16	9.99	31.04
Motts Farm_T3	2.55	10.10	16.40	34.90
Motts Farm_T5	1.67	11.78	19.12	32.66
Rio Grande_T6	0.14	10.98	17.82	36.80
Rio Grande_T7	1.26	9.73	15.79	34.47
Rio Grande_T8	0.14	11.10	18.02	37.46
Roadstown_T2	0.14	8.67	14.07	32.85
Searstown_T2	0.00	8.62	13.99	30.13
Sickler_T3	0.85	8.52	13.82	35.36
Tansboro_T1	0.00	9.52	15.45	31.29
Tansboro_T2	0.24	5.33	8.65	30.90
Upper Pittsgrove_T1	0.00	8.84	14.35	33.57
Williamstown_T4	0.20	13.21	21.44	36.85
Williamstown_T5	0.08	19.84	32.21	33.29
Winslow_T2	0.49	3.15	5.12	12.69
Total	**14.84**	**231.01**	**374.98**	**768.47**

Value of Lost Load (VoLL): The CBA calculates the avoided customer outage cost using VoLL, which represents a proxy for the economic costs that customers incur due to a power outage. Alternatively, one can think about it as the average customer's willingness to pay to avoid an outage. Investments and upgrades to aging infrastructure can significantly reduce the likelihood of outages, thereby representing an implicit benefit that can be realized across different customer classes. Given that the electricity use cases vary largely across different customer classes, the costs incurred from an outage can vary widely based on the customer class under consideration. We quantify the benefits of the IIP scenario over the Status Quo scenario for different customer classes by applying VoLL data from past studies and ACE's customer characteristics. We first obtain the "Unserved kWh due to Outage" in a year by analyzing the annual number of outages, duration of outage events, and the electricity consumption per hour by the customers affected. The VoLL factor is specific to customer class and refers to the outage cost incurred by the customer per unserved kWh. The product of unserved kWh and the VoLL for each customer class factor gives us the VoLL for that class. VoLL from customer classes are added up to obtain the total VoLL. Table 9 below shows the VoLL factors used for each customer class in the CBA. Appendix A provides a detailed explanation of the VoLL analysis.

TABLE 9: VOLL FACTORS: INTERRUPTION COST PER UNSERVED KWH

Interruption Duration (Minutes)	Cost per Unserved kWh ($/ in 2022 USD)		
	Residential	Small C&I	Medium/Large C&I
Momentary	$38.94	$2,841.14	$240.31
0.5	$7.43	$597.44	$47.13
0.75	$5.80	$484.59	$37.30
1	$4.16	$371.75	$27.47
1.25	$3.98	$363.27	$26.45
1.5	$3.80	$354.80	$25.43
1.75	$3.62	$346.32	$24.42
2	$3.44	$337.85	$23.40
2.25	$3.27	$329.37	$22.38
2.5	$3.09	$320.90	$21.36
2.75	$2.91	$312.42	$20.34
4	$2.73	$303.95	$19.32

Accelerated Capital Investments: The Powering the Future projects, in particular those that are in categories 1 (Targeted Reliability Improvements), 2 (Smart Technology Upgrades), 3 (Infrastructure Renewals), and 5 (Substation Improvements) are related to safety, reliability, and/or resiliency. By nature, these are necessary investments, and, thereby, we understand they will eventually be built. With this understanding, we assume that investments for these projects would still occur in the Status Quo scenario, albeit over a longer time horizon. The IIP scenario effectively accelerates these investments and the benefits they provide. To analyze this effect, we estimate the Status Quo scenario's annual cash flows for each individual project by distributing the total IIP investment over a 20-year horizon. Both the IIP and Status Quo scenarios assume that cash flows start with the proposed IIP project investment year. Projects under category 4 (Solar/DER Enablements) do not have this benefit because utilities may not need to invest in such projects under the Status Quo scenario.

Appendix A include further details of the assumptions discussed above.

D. Benefits Not Analyzed

There are other benefits that the CBA does not directly analyze. These include:

- Avoided Cost Increase
- Reputational Benefits
- Economic Stimulus

This section briefly discuss these potential benefits.[37]

Avoided Cost Increase: In calculating the Accelerated Capital Investments, we assume that investments for Powering the Future projects would still occur in the Status Quo scenario, albeit over a longer time horizon. To analyze this effect, we estimate the Status Quo scenario's annual cash flows for each individual project by distributing the total Powering the Future investment over a 20-year horizon without any cost increase (in Real terms). However, recent history indicates that costs for industrial materials (and associated labor force) could increase sharply. For example, the Federal Reserve Economic Data[38] shows the compound annual growth rate (CAGR) for Global Price of Industrial Materials Index and PPI by Commodity (Materials and Components for Construction) for the 2020-2022 period to be 23% and 20%, respectively. These values are much higher than the CAGR experienced in the last decade (2012-2022), which were 2% for Global Price of Industrial Materials Index and 5% for PPI by Commodity (Materials and Components for Construction).

Reputational Benefits: The Powering the Future projects that enable more renewables also provide reputational values for both the State and utilities, including ACE. A strong reputation could potentially lead to further investments by Commercial and Industrial (C&I) customers, among others, as discussed next.

[37] We also did not measure operational benefits brought by some projects. For example, capacitor upgrades provide operational benefits that are difficult to measure in monetary terms. Operational benefits are akin to the benefits of "power steering" in automobiles—everyone recognizes the benefits, such as making driving easier, and are willing to pay for it. However, the direct economic benefits are hard to assess. Similarly, benefits for maintaining voltage and power factors—both which are increasingly becoming more challenging with increased DERs and electrification—are difficult to measure using the benefit metrics developed in this CBA.

[38] https://fred.stlouisfed.org/

Economic Stimulus: Associated with the reputational benefits is the economic stimulus triggered by the Powering the Future projects, in particular those that enable DERs, which could lead to further investments. For example, C&I customers' interest in procuring renewable energy has increased steadily since 2016, by 48% annually through 2021. The Clean Energy Buyers Association (CEBA), a community of energy buyers accelerating the zero-carbon energy future, shows that over 350 companies across various industries have made commitments to procure 100% of electricity from renewables. Examples include Apple (already achieved its 100% renewable energy transition in operations), General Motors (accelerated 100% renewable energy transition from 2030 to 2025), Walmart (over 33% complete with its 100% renewable energy goal by 2035), and Bank of America (achieved 100% renewable energy in operations).[39] Renewable goals are often factored into company environmental, social, and governance (ESG) scores and can impact corporate credit ratings. Other motivations include demonstrating leadership, reducing energy expenses, diversifying supply, responding to investor demand, long-term price stability and building resilient systems.[40] CEPA expects renewable procurement growth to continue.[41] This could lead to the growth of local solar industry that both ACE customers and other New Jersey residents would benefit from them. In addition, a better reliability and stronger infrastructure brought by the Powering the Future projects would help attract economic development in the region. The CBA does not account for these benefits because it is difficult to measure the contribution of the respective projects among other influential factors (e.g., tax incentives) that lead to them.

---

[39] Apple, GM, Walmart, Bank of America

[40] Policies for Enabling Corporate Sourcing of Renewable Energy Internationally", NREL, May 2017, Policies for Enabling Corporate Sourcing of Renewable Energy Internationally: A 21st Century Power Partnership Report (nrel.gov)

[41] See Factsheet-2.15.22.pdf (cebuyers.org)

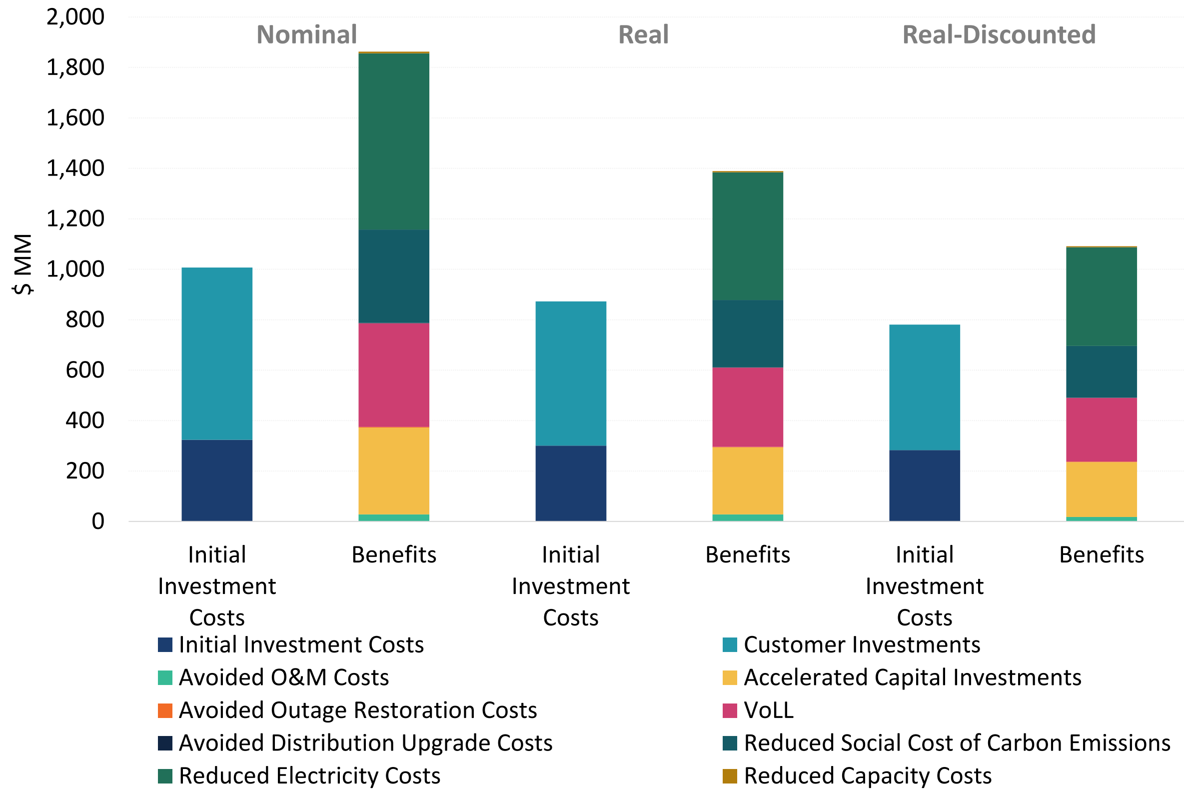
III. Cost-Benefit Analysis Results

This Section summarizes the results of the CBA for the entire portfolio, project category, and subprograms. This section presents the projects' payback and the B/I ratios that we obtained following the methodology described in the earlier Section. Note that there are caveats that lead to a conservative estimate of payback and B/I ratios. First, the initial project investment values include contingencies, which accounts for potential cost increases. For projects completed within (or below) the planned budget, B/I ratios will be higher than shown in this Section. Second, the analyses assumes a 20-year Study Period. Many of the benefits identified are likely to continue beyond the Study Period. Third, we do not analyze a number of potential benefits such as economic stimulus, reputational benefits, and avoided cost increases, as we discussed in the earlier Section. Fourth, we generally use conservative assumptions (e.g., future electricity prices, social cost of carbon), which may underestimate the benefits. Finally, we understand many of the Powering the Future projects will likely be pursued by ACE for reliability purposes regardless of the BPU approval for IIP, and thereby, not avoidable. We did not assume any cost increase for future material and labor in Real terms. If these are to increase (as recent history has indicated), the benefits (specifically, those associated with Accelerated Capital Investment benefits) could increase as well.

A. Portfolio Results

We analyzed 66 out of the 80 projects. Figure 2 compares the investment costs to benefits by type for the 66 projects we analyzed.

FIGURE 2: RESULTS SUMMARY FOR PORTFOLIO



This figure shows the portfolio having a healthy mix of benefit types, indicating the robustness of the portfolio (i.e., the benefits are diversified and changes in the value of any given benefit type alone will likely not drive down the total benefits to the level where the portfolio becomes economically infeasible in Real terms).

Table 10 through Table 12 show the CBA results in all three monetary terms (Nominal in Table 10, Real in Table 11, and Real-Discounted in Table 12), respectively, for the entire portfolio (including the 14 projects not analyzed) and the five categories. We assume the B/I ratio of projects not analyzed are comparable to its peer projects (same subprogram, if not same category) that we analyzed individually.

TABLE 10: RESULTS SUMMARY BY CATEGORY AND ENTIRE PORTFOLIO (NOMINAL)

Category	Total Investments ($ million)	Total Benefits ($ million)	*B/I Ratio*
1 - Targeted Reliability Improvements	$100.0	$454.8	*4.5*
2 - Smart Technology Upgrades	$73.7	$426.0	*5.8*
3 - Infrastructure Renewals	$94.3	$190.6	*2.0*
5 - Substation Improvements	$104.3	$155.9	*1.5*
Categories 1, 2, 3, 5 Total	$372.3	$1,227.4	*3.3*
4 - Solar/DER Enablements	$721.1	$1,076.0	*1.5*
Portfolio Total	$1,093.4	$2,303.4	*2.1*

TABLE 11: RESULTS SUMMARY BY CATEGORY AND ENTIRE PORTFOLIO (REAL)

Category	Total Investments ($ million)	Total Benefits ($ million)	*B/I Ratio*
1 - Targeted Reliability Improvements	$92.8	$348.1	*3.8*
2 - Smart Technology Upgrades	$68.5	$323.6	*4.7*
3 - Infrastructure Renewals	$87.5	$146.2	*1.7*
5 - Substation Improvements	$96.8	$121.2	*1.3*
Categories 1, 2, 3, 5 Total	$345.7	$939.0	*2.7*
4 - Solar/DER Enablements	$607.2	$779.1	*1.3*
Portfolio Total	$952.9	$1,718.1	*1.8*

TABLE 12: RESULTS SUMMARY BY CATEGORY AND ENTIRE PORTFOLIO (REAL-DISCOUNTED)

Category	Total Investments ($ million)	Total Benefits ($ million)	*B/I Ratio*
1 - Targeted Reliability Improvements	$87.2	$282.0	*3.2*
2 - Smart Technology Upgrades	$64.6	$260.3	*4.0*
3 - Infrastructure Renewals	$82.3	$118.6	*1.4*
5 - Substation Improvements	$91.0	$99.5	*1.1*
Categories 1, 2, 3, 5 Total	$325.1	$760.5	*2.3*
4 - Solar/DER Enablements	$530.8	$600.7	*1.1*
Portfolio Total	$855.9	$1,361.2	*1.6*

As these tables summarize, all five categories individually and the portfolio as a whole show positive paybacks.

The net positive payback for projects in categories 1 (Targeted Reliability Improvements), 2 (Smart Technology Upgrades), 3 (Infrastructure Renewals) and 5 (Substation Improvements) combined is $939 million in Real terms ($1,227 million in Nominal terms and $761 million in Real-Discounted terms), over the 20-year Study Period. This translates to a B/I ratio of 2.7 in Real terms (3.3 in Nominal terms and 2.3 in Real-Discounted terms).

Projects in category 4 (Solar/DER Enablements) will require investments from both ACE and individual customers (e.g., the $607 million investment shown in Table 11 is a combination of $34.9 million by ACE and $572.3 million by customers). Category 4 (Solar/DER Enablements) is estimated to provide a positive payback of $779 million in Real terms ($1,076 million in Nominal terms and $601 million in Real-Discounted terms), over the 20-year Study Period. The payback is the result of both investments (ACE and customers) and translates to a B/I ratio of 1.3 in Real terms (1.5 in Nominal terms and 1.1 in Real-Discounted terms) while the enabled DERs reduce carbon emissions by 1.6 million metric tons (assuming the State's interim goals of DER deployments are reached).

The benefits shown in the three tables for category 4 (Solar/DER Enablements) are the societal benefits and do not account for any potential bill savings by customers who installed DERs. The total bill saving over 20 years for these customers is estimated around $1.4 billion in Real Terms ($2 billion in Nominal terms and $1.1 billion in Real-Discounted terms) before any federal tax credits and other state incentives, and is much larger than their initial investment amount, indicating such paybacks would likely encourage customer investments.

The comparatively lower B/I ratio for projects in category 4 (Solar/DER Enablements) or category 5 (Substation Improvements) by itself is not a negative sign. The B/I ratio metric should be looked at in conjunction with the absolute value of the benefits, rather than alone. This is because projects with higher initial investment costs tend to have lower B/I ratios while the absolute values of the net benefits are still larger. The dotted lines in Figure 3 and Figure 4 show this trend for the projects we analyzed.

FIGURE 3: B/I RATIO TREND BY INITIAL INVESTMENT COSTS (IN REAL TERM)

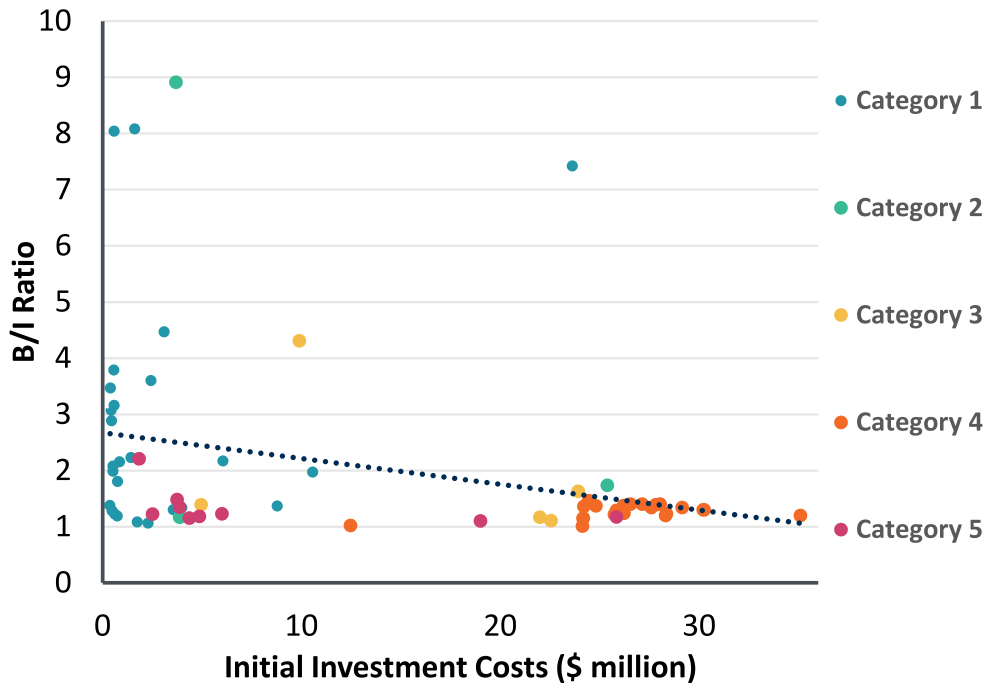
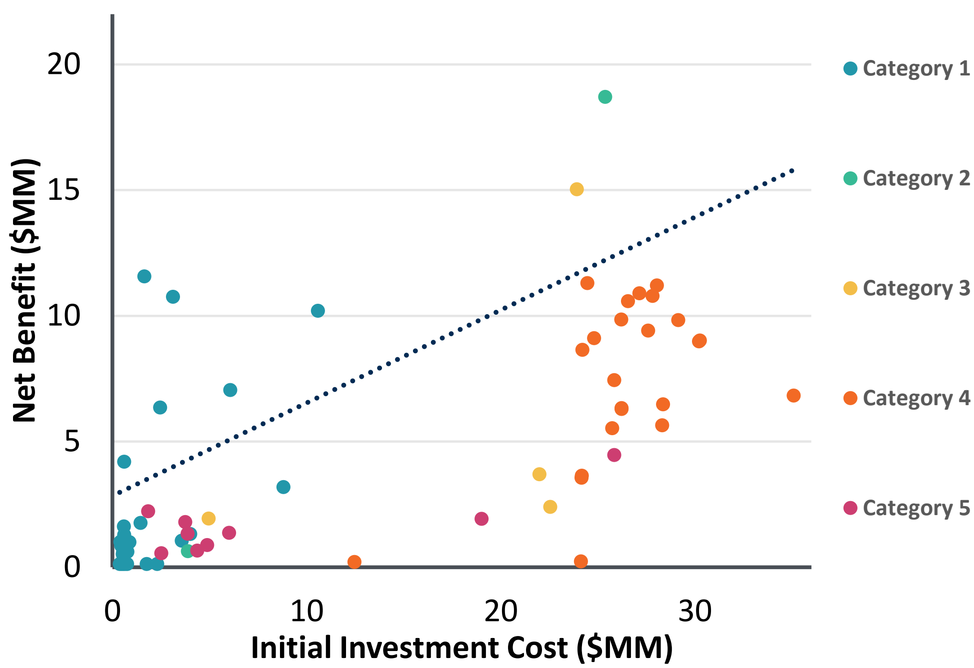


FIGURE 4: NET BENEFIT TREND BY INITIAL INVESTMENT COST (IN REAL TERM)



Overall, the analyses show that ACE's Powering the Future portfolio is providing a strong positive cash flow in all three monetary terms, without excessively relying on one or two specific benefit types, indicating it is a well-balanced portfolio that could help New Jersey achieve its state goals with minimal costs to the society. The portfolio of projects would also reduce the total carbon emissions over next 20 years by 1.6 million metric tons.

B. Results by Categories and Subprograms

This subsection shows the results by categories and associated subprograms.

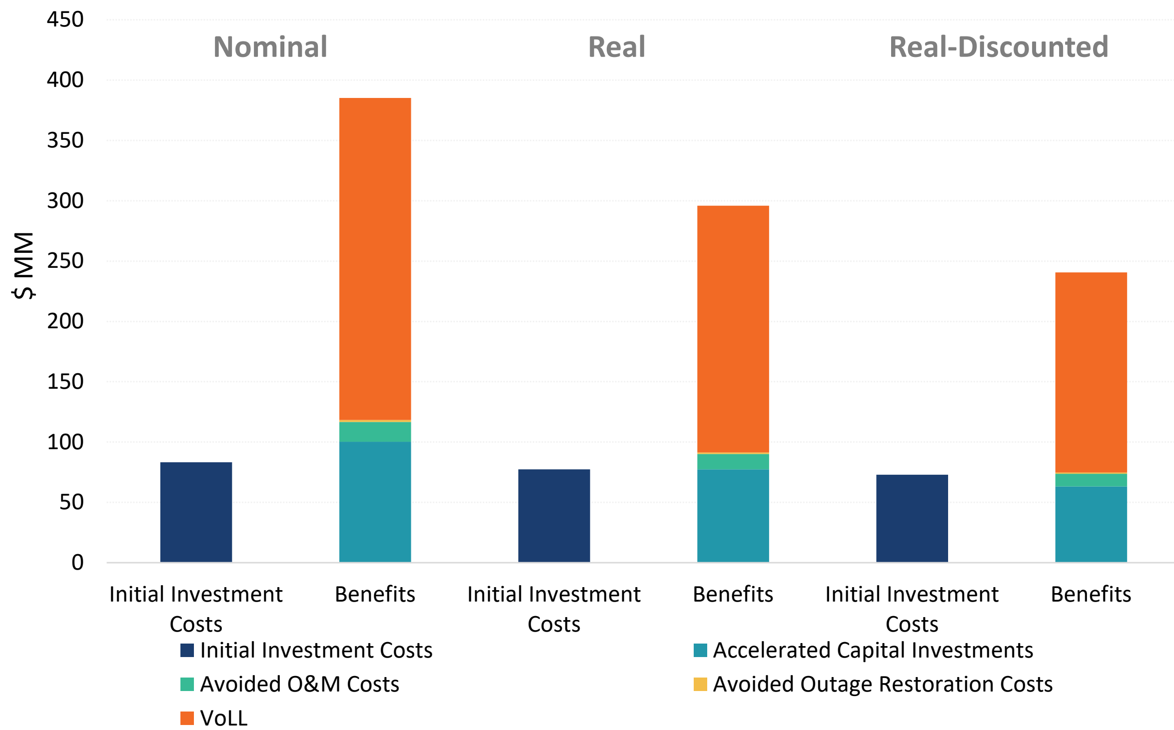
a. Category 1: Targeted Reliability Improvements

This category includes 29 projects among the following seven subprograms:

- Long Radial Remediation (7 projects)
- New Feeders (2 projects)
- Rear Lot Conversions (6 projects)
- Reconductoring (11 projects)
- URD Loop Feeds (1 project)
- Unfused Laterals (1 project)
- Priority Feeders (1 project)

We analyzed 26 out of the 29 projects. Figure 5 compares the investment costs to benefits by type for the 26 projects we analyzed.

FIGURE 5: RESULTS SUMMARY FOR PROJECTS ANALYZED - CATEGORY 1



Benefits are largely associated with Accelerated Capital Investments and outage reduction related (VoLL), followed by Avoided O&M costs. We did not assume any cost increase for future material and labor in real terms. If these are to increase (as recent history has indicated), the benefits associated with Accelerated Capital Investment could increase as well.

Table 13 shows the CBA results for the seven subprograms for category 1 (Target Reliability Improvements), including the three projects we did not analyze. We assume the B/I ratio of the three projects not analyzed are comparable to its peer projects (same subprogram, if not same category) that we analyzed individually.

TABLE 13: RESULTS SUMMARY FOR CATEGORY 1 AND SUBPROGRAMS

Subprogram	Initial Investment Costs (Nominal)	Total Benefits (Nominal)	*B/I Ratio (Nominal)*	Initial Investment Costs (Real)	Total Benefits (Real)	*B/I Ratio (Real)*	Initial Investment Costs (Real-Discounted)	Total Benefits (Real-Discounted)	*B/I Ratio (Real-Discounted)*
Long Radial Remediation	$15.5	$64.4	*4.1*	$14.3	$48.4	*3.4*	$13.4	$38.6	*2.9*
New Feeders	$15.0	$33.0	*2.2*	$14.1	$25.4	*1.8*	$13.4	$20.7	*1.5*
Rear Lot Conversions	$6.9	$9.3	*1.3*	$6.3	$7.1	*1.1*	$5.9	$5.8	*1.0*
Reconductoring	$21.0	$87.5	*4.2*	$19.5	$66.7	*3.4*	$18.4	$53.8	*2.9*
URD Loop Feeds	$9.5	$15.5	*1.6*	$8.8	$12.0	*1.4*	$8.3	$9.8	*1.2*
Unfused Laterals	$6.5	$17.1	*2.6*	$6.1	$13.1	*2.2*	$5.7	$10.7	*1.9*
Priority Feeders	$25.6	$228.2	*8.9*	$23.6	$175.4	*7.4*	$22.2	$142.6	*6.4*
Category 1 Total	**$100.0**	**$454.8**	***4.5***	**$92.8**	**$348.1**	***3.8***	**$87.2**	**$282.0**	***3.2***

($ million)

The average B/I ratio is 3.8 in Real terms (4.5 in Nominal terms and 3.2 in Real-Discounted terms) indicating a great return on investment. The smallest B/I ratio is 1.0 (slightly below) in Real-Discounted terms for the Rear Lot Conversion subprogram. Considering this subprogram commands one of the smallest initial investment amounts, the B/I ratio is 1.1 in Real terms, and the conservativeness of the assumptions we used for the analyses, this may not be a significant risk. The B/I ratio for all other subprograms are higher with a healthy payback.

Detailed CBA results for each subprogram in category 1 (Target Reliability Improvements) are summarized next.

SUBPROGRAM 1: LONG RADIAL REMEDIATION

This subprogram includes seven projects as listed in Table 14. We analyzed six of the seven projects.[42] We assumed the B/I ratio for the seventh project (the project we did not analyze) to be similar to the other six projects (i.e., average of the six projects we analyzed).

[42] ACE typically develops distribution projects on two year-cycles, and rarely five years ahead. We could not analyze one of the seven projects because ACE has not yet developed project details for it.

TABLE 14: CBA RESULTS (NOMINAL) FOR PROJECTS IN CATEGORY 1, SUBPROGRAM 1

(Nominal $ million)

Project Name	Project Analyzed	Initial Investment Costs	Accelerated Capital Investments	Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
TBD_ACE Long Radial Remediation - NJ0213	TRUE	$0.4	$0.5	$0.1	$0.0	$1.2	$1.9	*4.2*
TBD_ACE Long Radial Remediation - NJ0305	TRUE	$0.6	$0.7	$0.1	$0.0	$0.6	$1.5	*2.6*
TBD_ACE Long Radial Remediation - NJ1734	TRUE	$0.5	$0.6	$0.1	$0.0	$1.1	$1.8	*3.8*
TBD_ACE Long Radial Remediation - NJ1981	TRUE	$0.6	$0.8	$0.2	$0.0	$5.3	$6.2	*9.9*
TBD_ACE Long Radial Remediation - NJ2393	TRUE	$0.6	$0.7	$0.1	$0.0	$0.5	$1.4	*2.4*
TBD_ACE Long Radial Remediation - NJ2623	TRUE	$0.8	$1.0	$0.2	$0.0	$0.6	$1.8	*2.2*
Average of Analyzed Projects								***4.1***
TBD_ACE Long Radial Remediation	FALSE	$12.0	NA	NA	NA	NA	$50.0	*4.1*
Total		**$15.5**					**$64.4**	***4.1***

Table 15 summarize the results for this subprogram. The B/I ratio is 3.4 in Real terms (4.1 in Nominal terms and 2.9 in Real-Discounted terms), suggesting a very strong return on investment. The largest benefit is associated with reduction in outages (VoLL), followed by Accelerated Capital Investment. The subprogram's payback will remain positive, even if one of these benefit types were not accounted for on its entirety.

TABLE 15: CBA RESULTS FOR CATEGORY 1, SUBPROGRAM 1

($ million)	Initial Investment Costs	Avoided O&M Costs	Accelerated Capital Investments	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Nominal	$3.5	$0.9	$4.3	$0.0	$9.4	$14.5	*4.1*
Real	$3.3	$0.7	$3.3	$0.0	$7.2	$11.2	*3.4*
Real-Discounted	$3.2	$0.5	$2.7	$0.0	$5.9	$9.1	*2.9*

SUBPROGRAM 2: NEW FEEDERS

This subprogram includes two projects as listed in Table 16 below. We analyzed both projects.

TABLE 16: CBA RESULTS (NOMINAL) FOR PROJECTS IN CATEGORY 1, SUBPROGRAM 2

(Nominal $ million)

Project Name	Project Analyzed	Initial Investment Costs	Accelerated Capital Investments	Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
CHURCHTOWN SUBSTATION 2 NEW FEEDER TERMINALS	TRUE	$11.3	$13.6	$2.7	$0.0	$10.6	$27.0	*2.4*
Mickleton - New Feeder	TRUE	$3.8	$4.6	$0.9	$0.0	$0.5	$6.0	*1.6*
Total		**$15.0**					**$33.0**	***2.2***

Table 17 summarizes the results for this subprogram. The B/I ratio is 1.8 in Real terms (2.2 in Nominal terms and 1.5 in Real-Discounted terms), suggesting this a good subprogram with solid returns. The benefits are split among three benefit types, and the reduction in outages (VoLL) and Avoided O&M Costs combined are of similar magnitude to Accelerated Capital Investments, indicating these projects are fairly well-balanced projects (from a benefits-perspective).

TABLE 17: CBA RESULTS FOR CATEGORY 1, SUBPROGRAM 2

($ million)	Initial Investment Costs	Avoided O&M Costs	Accelerated Capital Investments	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Nominal	$15.0	$3.6	$18.2	$0.0	$11.1	$33.0	*2.2*
Real	$14.1	$2.8	$14.1	$0.0	$8.4	$25.4	*1.8*
Real-Discounted	$13.4	$2.3	$11.6	$0.0	$6.8	$20.7	*1.5*

SUBPROGRAM 3: REAR LOT CONVERSION

This subprogram includes six projects as listed in Table 18 below. We analyzed all six projects.

TABLE 18: CBA RESULTS FOR PROJECTS (NOMINAL) IN CATEGORY 1, SUBPROGRAM 3

(Nominal $ million)

Project Name	Project Analyzed	Initial Investment Costs	Accelerated Capital Investments	Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Rear Lot Conversion 1	TRUE	$0.4	$0.5	$0.0	$0.2	$0.0	$0.7	*1.7*
Rear Lot Conversion 2	TRUE	$0.6	$0.7	$0.0	$0.2	$0.0	$0.8	*1.5*
Rear Lot Conversion 3	TRUE	$0.7	$0.8	$0.0	$0.2	$0.0	$1.0	*1.4*
Rear Lot Conversion 4	TRUE	$0.8	$1.0	$0.0	$0.2	$0.0	$1.2	*1.4*
Rear Lot Conversion 5	TRUE	$1.9	$2.3	$0.0	$0.2	$0.0	$2.5	*1.3*
Rear Lot Conversion 6	TRUE	$2.5	$3.0	$0.0	$0.2	$0.0	$3.2	*1.3*
Total		**$6.9**					**$9.3**	***1.3***

Table 19 summarizes the results for this subprogram. The B/I ratio is 1.1 in Real terms (1.3 in Nominal terms and 1.0 in Real-Discounted terms), suggesting the subprogram more than pays for itself. The largest benefit type is Accelerated Capital Investment, followed by reduction in outages related benefits (VoLL and Avoided Outage Restoration). We understand that projects within this subprogram will likely be pursued by ACE for reliability purposes regardless of the BPU approval for IIP, and thereby, not avoidable. We did not assume any cost increase for future material and labor in real terms. If these are to increase (as recent history has indicated), the benefits associated with Accelerated Capital Investment could increase as well.

TABLE 19: CBA RESULTS FOR CATEGORY 1, SUBPROGRAM 3

($ million)	Initial Investment Costs	Avoided O&M Costs	Accelerated Capital Investments	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Nominal	$6.9	$0.0	$8.2	$1.0	$0.0	$9.3	*1.3*
Real	$6.3	$0.0	$6.3	$0.8	$0.0	$7.1	*1.1*
Real-Discounted	$5.9	$0.0	$5.1	$0.7	$0.0	$5.8	*1.0*

SUBPROGRAM 4: RECONDUCTORING

This subprogram includes 11 projects as listed in Table 20. We analyzed nine of the 11 projects.[43] We assumed the B/I ratio for the tenth and eleventh project (the two projects we did not analyze) to be similar to the other nine projects (i.e., average of the nine projects we analyzed).

TABLE 20: CBA RESULTS FOR PROJECTS (NOMINAL) IN CATEGORY 1, SUBPROGRAM 4

(Nominal $ million)

Project Name	Project Analyzed	Initial Investment Costs	Accelerated Capital Investments	Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Cape May Coast Guard Reconductor NJ0236	TRUE	$0.5	$0.6	$0.1	$0.0	$1.0	$1.7	*3.5*
Egg Harbor Green Bank - Reconductor	TRUE	$1.5	$1.9	$0.4	$0.0	$1.9	$4.2	*2.8*
New Feeder Ties NJ1111 and NJ1166	TRUE	$4.4	$5.2	$1.0	$0.0	$0.7	$6.9	*1.6*
New Feeder Ties NJ1112 and NJ1114	TRUE	$0.9	$1.1	$0.2	$0.0	$1.1	$2.5	*2.6*
Reconductor Harbor Beach Feeders	TRUE	$2.6	$3.2	$0.0	$0.0	$8.3	$11.5	*4.4*
Reconductor Marven Feeders	TRUE	$3.3	$4.0	$0.0	$0.2	$14.0	$18.2	*5.6*
Recondutor Ontario Feeders	TRUE	$1.8	$2.1	$0.0	$0.2	$15.0	$17.3	*9.9*
South Millville- NJ0415 conductor upgrade	TRUE	$0.6	$0.8	$0.2	$0.0	$2.0	$2.9	*4.7*
Upgrade Feeder Ties NJ0211 to NJ0415	TRUE	$0.6	$0.8	$0.2	$0.0	$1.5	$2.4	*3.8*
Average of Analyzed Projects								***4.2***
Mickleton Sub Feeder NJ1162 - Upgrade Feeder Conductor	FALSE	$3.1	NA	NA	NA	NA	$13.0	*4.2*
Upgrade Feeder Ties NJ2061 and NJ2062	FALSE	$1.6	NA	NA	NA	NA	$6.8	*4.2*
Total		**$21.0**					**$87.5**	***4.2***

Table 21 summarizes the results for this subprogram. The B/I ratio is 3.4 in Real terms (4.2 in Nominal terms and 2.9 in Real-Discounted terms), suggesting a very strong return. The largest benefit is associated with reduction in outages (VoLL), followed by Accelerated Capital Investment. The subprogram’s payback will remain positive, even if one of these benefit type are not accounted for on its entirety.

[43] ACE typically develops distribution projects on two year-cycles, and rarely five years ahead. We could not analyze two of the eleven projects because ACE has not yet developed project details for them.

TABLE 21: CBA RESULTS FOR CATEGORY 1, SUBPROGRAM 4

($ million)	Initial Investment Costs	Avoided O&M Costs	Accelerated Capital Investments	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Nominal	$16.2	$2.1	$19.6	$0.4	$45.5	$67.7	*4.2*
Real	$15.2	$1.6	$15.2	$0.3	$34.6	$51.7	*3.4*
Real-Discounted	$14.3	$1.3	$12.4	$0.3	$27.9	$41.9	*2.9*

SUBPROGRAM 5: URD LOOP FEEDS

This subprogram includes one projects as listed in Table 22 below. We analyzed this project.

TABLE 22: CBA RESULTS FOR PROJECTS (NOMINAL) IN CATEGORY 1, SUBPROGRAM 5

(Nominal $ million)

Project Name	Project Analyzed	Initial Investment Costs	Accelerated Capital Investments	Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Create loops in radial URD developments	TRUE	$9.5	$11.3	$2.3	$0.0	$1.9	$15.5	*1.6*
Total		**$9.5**					**$15.5**	***1.6***

Table 23 summarizes the results for this subprogram. The B/I ratio is 1.4 in Real terms (1.6 in Nominal terms and 1.2 in Real-Discounted terms), suggesting a decent payback. The largest benefit is Accelerated Capital Investment. We understand that projects within this subprogram will likely be pursued by ACE for reliability purposes regardless of the BPU approval for IIP, and thereby, not avoidable. We did not assume any cost increase for future material and labor in real terms. If these are to increase (as recent history has indicated), the benefits associated with Accelerated Capital Investment could increase as well.

TABLE 23: CBA RESULTS FOR CATEGORY 1, SUBPROGRAM 5

($ million)	Initial Investment Costs	Avoided O&M Costs	Accelerated Capital Investments	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Nominal	$9.5	$2.3	$11.3	$0.0	$1.9	$15.5	*1.6*
Real	$8.8	$1.8	$8.8	$0.0	$1.4	$12.0	*1.4*
Real-Discounted	$8.3	$1.4	$7.2	$0.0	$1.2	$9.8	*1.2*

SUBPROGRAM 6: UNFUSED LATERALS

This subprogram includes one project as listed in Table 24. We did not analyze this specific project and assumed the B/I ratio for this project (and, thereby, the subprogram) to be similar to the other subprograms (i.e., average of the other subprograms where we analyzed projects) within category 1 (Targeted Reliability Improvements).

TABLE 24: CBA RESULTS FOR PROJECTS (NOMINAL) IN CATEGORY 1, SUBPROGRAM 6
(Nominal $ million)

Project Name	Project Analyzed	Initial Investment Costs	Accelerated Capital Investments	Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Unfused Laterals	TRUE	$6.5	$7.8	$1.6	$0.0	$7.7	$17.1	*2.6*
Total		**$6.5**					**$17.1**	***2.6***

As shown in Table 25, the B/I ratio is 2.2 in Real terms (2.6 in Nominal terms and 1.9 in Real-Discounted terms), suggesting a strong subprogram with solid returns. The largest benefit is associated with reduction in outages (VoLL), followed by Accelerated Capital Investment. The subprogram's payback will remain positive, even after one of these benefit type vanishes on its entirety.

TABLE 25: CBA RESULTS FOR PROJECTS IN CATEGORY 1, SUBPROGRAM 6

($ million)	Initial Investment Costs	Avoided O&M Costs	Accelerated Capital Investments	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Nominal	$6.5	$1.6	$7.8	$0.0	$7.7	$17.1	*2.6*
Real	$6.1	$1.2	$6.1	$0.0	$5.8	$13.1	*2.2*
Real-Discounted	$5.7	$1.0	$5.0	$0.0	$4.7	$10.7	*1.9*

SUBPROGRAM 7: PRIORITY FEEDERS

This subprogram includes one project as listed in Table 26. We analyzed this specific project.

TABLE 26: CBA RESULTS FOR PROJECTS (NOMINAL) IN CATEGORY 1, SUBPROGRAM 7
(Nominal $ million)

Project Name	Project Analyzed	Initial Investment Costs	Accelerated Capital Investments	Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Priority Feeders	TRUE	$25.6	$30.8	$6.1	$0.0	$191.3	$228.2	*8.9*
Total		**$25.6**					**$228.2**	***8.9***

As shown in Table 27, the B/I ratio is 7.4 in Real terms (8.9 in Nominal terms and 6.4 in Real-Discounted terms), suggesting an extremely strong payback. The largest benefit is associated with reduction in outages (VoLL), followed by Accelerated Capital Investment. The subprogram's payback will remain positive, even after one of these benefit type vanishes on its entirety.

TABLE 27: CBA RESULTS FOR PROJECTS IN CATEGORY 1, SUBPROGRAM 7

($ million)	Initial Investment Costs	Avoided O&M Costs	Accelerated Capital Investments	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Nominal	$25.6	$6.1	$30.8	$0.0	$191.3	$228.2	*8.9*
Real	$23.6	$4.7	$23.6	$0.0	$147.0	$175.4	*7.4*
Real-Discounted	$22.2	$3.9	$19.2	$0.0	$119.5	$142.6	*6.4*

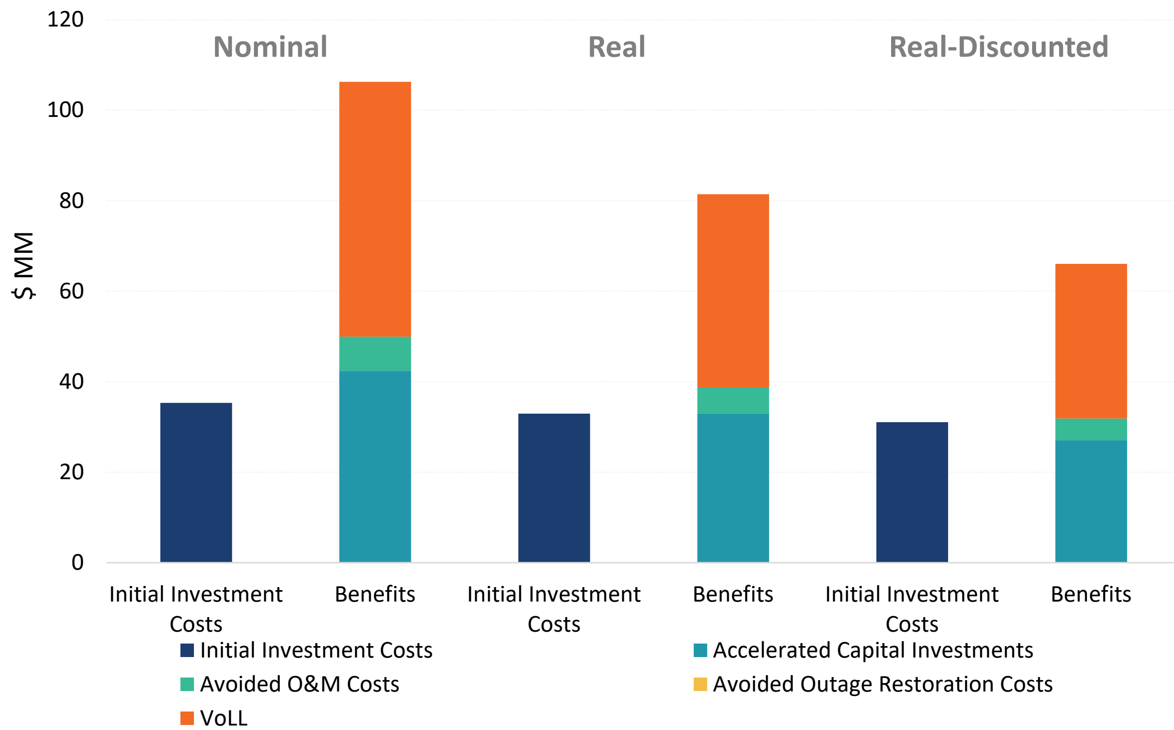
b. Category 2: Smart Technology Upgrades

This category includes 10 projects among the following six subprograms:

- Capacitors (2 projects)
- Reclosers (1 projects)
- Smart Sensors (1 projects)
- Regulators (1 project)
- Fiber / Radio (2 project)
- Distribution Automation (3 project)

We analyzed three out of the 10 projects. Figure 6 compares the investment costs to benefits by type for the three projects we analyzed.

FIGURE 6: RESULTS SUMMARY FOR PROJECTS ANALYZED - CATEGORY 2



Benefits are largely associated with Accelerated Capital Investments and outage related (VoLL). The subprogram is robust enough that it could maintain a positive payback, even if one of these benefits are not accounted for on it's entirely.

Table 28 shows the CBA results by the six subprograms for category 2 (Smart Technology Upgrades) including the seven projects we did not analyze. We assume the B/I ratio of the seven projects not analyzed are comparable to its peer projects (same subprogram, if not same category) that we analyzed individually.

TABLE 28: RESULTS SUMMARY FOR CATEGORY 2 AND SUBPROGRAMS

Subprogram	Initial Investment Costs (Nominal)	Total Benefits (Nominal)	*B/I Ratio (Nominal)*	Initial Investment Costs (Real)	Total Benefits (Real)	*B/I Ratio (Real)*	Initial Investment Costs (Real-Discounted)	Total Benefits (Real-Discounted)	*B/I Ratio (Real-Discounted)*
Capacitors	$4.4	$25.5	*5.8*	$4.1	$19.5	*4.7*	$3.9	$15.7	*4.0*
Reclosers	$27.2	$57.4	*2.1*	$25.4	$44.1	*1.7*	$23.9	$35.9	*1.5*
Smart Sensors	$4.2	$5.8	*1.4*	$3.9	$4.5	*1.2*	$3.7	$3.7	*1.0*
Regulators	$2.3	$13.2	*5.8*	$2.1	$10.1	*4.7*	$2.0	$8.1	*4.0*
Fiber / Radio	$12.6	$72.6	*5.8*	$11.6	$54.8	*4.7*	$10.9	$43.9	*4.0*
Distribution Automation	$23.0	$251.5	*10.9*	$21.4	$190.6	*8.9*	$20.2	$153.0	*7.6*
Category 2 Total	**$73.7**	**$426.0**	***5.8***	**$68.5**	**$323.6**	***4.7***	**$64.6**	**$260.3**	***4.0***

($ million)

The average B/I ratio is 4.7 in Real terms (5.8 in Nominal terms and 4.0 in Real-Discounted terms), indicating a strong return on investment. The smallest B/I ratio is 1.2 in Real terms (1.4 in Nominal terms and 1.0 in Real-Discounted terms) for the Smart Sensors subprogram. This subprogram has one of the smallest investment costs within this category, indicating limited risks associated with investment in this subprogram.

Detailed CBA results for each subprogram in Category 2 (Smart Technology Updates) are summarized next.

SUBPROGRAM 1: CAPACITORS

This subprogram includes two projects as listed in Table 29. We did not analyze either projects because updating capacitors provide benefits beyond those we measured in this CBA. Thereby, we assumed the B/I ratio for these projects (and, thereby, the subprogram) to be similar to the other subprograms (i.e., average of the other subprograms where we analyzed projects) within category 2 (Smart Technology Upgrades).

TABLE 29: CBA RESULTS FOR PROJECTS IN CATEGORY 2, SUBPROGRAM 1

($ million)

	Nominal			Real			Real-Discounted		
Project Name	Initial Investment Costs	Total Benefits	*B/I Ratio*	Initial Investment Costs	Total Benefits	*B/I Ratio*	Initial Investment Costs	Total Benefits	*B/I Ratio*
Capacitor Bank Upgrade Program	$2.4	$3.4	*1.4*	$2.2	$2.6	*1.2*	$2.1	$2.2	*1.0*
Capacitor Controller Upgrade Program - Continued from IIP1	$2.1	$3.0	*1.4*	$1.9	$2.3	*1.2*	$1.8	$1.9	*1.0*

SUBPROGRAM 2: RECLOSERS

This subprogram includes one project as listed in Table 30. We analyzed this specific project.

TABLE 30: CBA RESULTS FOR PROJECTS (NOMINAL) IN CATEGORY 2, SUBPROGRAM 2

(Nominal $ million)

Project Name	Project Analyzed	Initial Investment Costs	Accelerated Capital Investments	Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
ACE NJ Recloser Installation	TRUE	$27.2	$32.7	$6.5	$0.0	$18.1	$57.4	*2.1*
Total		**$27.2**					**$57.4**	***2.1***

Table 31 summarizes the results for this subprogram. The B/I ratio is 1.7 in Real terms (2.1 in Nominal terms and 1.5 in Real-Discounted terms), suggesting a good subprogram with a solid payback. The largest benefit is Accelerated Capital Investment, followed by reduced outages benefits (VoLL and Avoided Outage Restoration). We understand that projects within this subprogram will likely be pursued by ACE for reliability purposes regardless of the BPU approval for IIP, and thereby, not avoidable. We did not assume any cost increase for future material and labor in real terms. If these are to increase (as recent history has indicated), the benefits associated with Accelerated Capital Investment could increase as well.

TABLE 31: CBA RESULTS FOR CATEGORY 2, SUBPROGRAM 2

($ million)	Initial Investment Costs	Avoided O&M Costs	Accelerated Capital Investments	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Nominal	$27.2	$6.5	$32.7	$0.0	$18.1	$57.4	*2.1*
Real	$25.4	$5.1	$25.4	$0.0	$13.6	$44.1	*1.7*
Real-Discounted	$23.9	$4.2	$20.8	$0.0	$10.9	$35.9	*1.5*

SUBPROGRAM 3: SMART SENSORS

This subprogram includes one project as listed in Table 32.

TABLE 32: CBA RESULTS FOR PROJECTS (NOMINAL) IN CATEGORY 2, SUBPROGRAM 3

(Nominal $ million)

Project Name	Project Analyzed	Initial Investment Costs	Accelerated Capital Investments	Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
ACE NJ Distribution Smart Fault Sensors	TRUE	$4.2	$5.0	$0.0	$0.0	$0.8	$5.8	*1.4*
Total		**$4.2**					**$5.8**	***1.4***

Table 33 summarizes the results for this subprogram. The B/I ratio is 1.2 in Real terms (1.4 in Nominal terms and 1.0 in Real-Discounted terms), indicating the subprogram more than pays for itself. This B/I ratio is the lowest amongst subprograms within this category. It also requires one of the lowest amount of capital investments, indicating minimal risk. The benefit is largely associated with Accelerated Capital Investment. We understand that projects within this subprogram will likely be pursued by ACE for reliability purposes regardless of the BPU approval for IIP, and thereby, not avoidable. We did not assume any cost increase for future material and labor in real terms. If these are to increase (as recent history has indicated), the benefits associated with Accelerated Capital Investment could increase as well. This suggests there is very little benefit in delaying the subprogram.

TABLE 33: CBA RESULTS FOR CATEGORY 2, SUBPROGRAM 3

($ million)	Initial Investment Costs	Avoided O&M Costs	Accelerated Capital Investments	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Nominal	$4.2	$0.0	$5.0	$0.0	$0.8	$5.8	*1.4*
Real	$3.9	$0.0	$3.9	$0.0	$0.6	$4.5	*1.2*
Real-Discounted	$3.7	$0.0	$3.2	$0.0	$0.5	$3.7	*1.0*

SUBPROGRAM 4: REGULATORS

This subprogram includes one project as listed in Table 34. We did not analyze this specific project because the benefits of upgrading the regulator controller are beyond those we measured in this CBA. Thereby, we assumed the B/I ratio for this project (and, thereby, the subprogram) to be similar to the other subprograms (i.e., average of the other subprograms where we analyzed projects) within category 2 (Smart Technology Upgrades).

TABLE 34: CBA RESULTS FOR PROJECTS IN CATEGORY 2, SUBPROGRAM 4

($ million)

	Nominal			**Real**			**Real-Discounted**		
Project Name	Initial Investment Costs	Total Benefits	*B/I Ratio*	Initial Investment Costs	Total Benefits	*B/I Ratio*	Initial Investment Costs	Total Benefits	*B/I Ratio*
Regulator Controller Upgrade Program - Continued from IIP1	$2.3	$3.3	*1.4*	$2.1	$2.6	*1.2*	$2.0	$2.1	*1.0*

SUBPROGRAM 5: FIBER/RADIO

This subprogram includes two projects as listed in Table 35. We did not analyze either projects because these projects provide benefits beyond those we measured in this CBA. Thereby, we assumed the B/I ratio for these projects (and, thereby, the subprogram) to be similar to the other subprograms (i.e., average of the other subprograms where we analyzed projects) within category 2 (Smart Technology Upgrades).

TABLE 35: CBA RESULTS FOR PROJECTS IN CATEGORY 2, SUBPROGRAM 5

($ million)

	Nominal			**Real**			**Real-Discounted**		
Project Name	Initial Investment Costs	Total Benefits	*B/I Ratio*	Initial Investment Costs	Total Benefits	*B/I Ratio*	Initial Investment Costs	Total Benefits	*B/I Ratio*
Fiber Optic Network Reliability Improvement	$3.3	$4.7	*1.4*	$3.0	$3.6	*1.2*	$2.8	$3.0	*1.1*
Telecom Security Lifecycle Demand	$9.3	$13.4	*1.4*	$8.6	$10.3	*1.2*	$8.0	$8.4	*1.0*

SUBPROGRAM 6: DISTRIBUTION AUTOMATION

This subprogram includes three projects as listed in Table 36. We analyzed one of the three projects.[44] We assumed the B/I ratio for the two projects we did not analyze to be similar to the project we analyzed.

TABLE 36: CBA RESULTS FOR PROJECTS (NOMINAL) IN CATEGORY 2, SUBPROGRAM 6

(Nominal $ million)

Project Name	Project Analyzed	Initial Investment Costs	Accelerated Capital Investments	Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Next DA Substation Upgrades	TRUE	$3.9	$4.7	$0.9	$0.0	$37.4	$43.1	*10.9*
Average of Analyzed Projects								***10.9***
Next DA Implement - Feeder Improvements Progr	FALSE	$5.9	NA	NA	NA	NA	$64.6	*10.9*
Strengthen DA Feeder Ties	FALSE	$13.2	NA	NA	NA	NA	$143.9	*10.9*
Total		**$23.0**					**$251.5**	***10.9***

Table 37 summarizes the results for this subprogram. The B/I ratio is 8.9 in Real terms (10.9 in Nominal terms and 7.6 in Real-Discounted terms) indicating an extremely beneficial subprogram. The largest benefit is associated with reduction in outages (VoLL), with Accelerated Capital Investment following as a distant second. The project is likely to provide a significant boost to reliability.

TABLE 37: CBA RESULTS FOR CATEGORY 2, SUBPROGRAM 6

($ million)	Initial Investment Costs	Avoided O&M Costs	Accelerated Capital Investments	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Nominal	$3.9	$0.9	$4.7	$0.0	$37.4	$43.1	*10.9*
Real	$3.7	$0.7	$3.7	$0.0	$28.4	$32.8	*8.9*
Real-Discounted	$3.5	$0.6	$3.0	$0.0	$22.9	$26.5	*7.6*

c. Category 3: Infrastructure Renewals

This category includes seven projects among the following six subprograms:

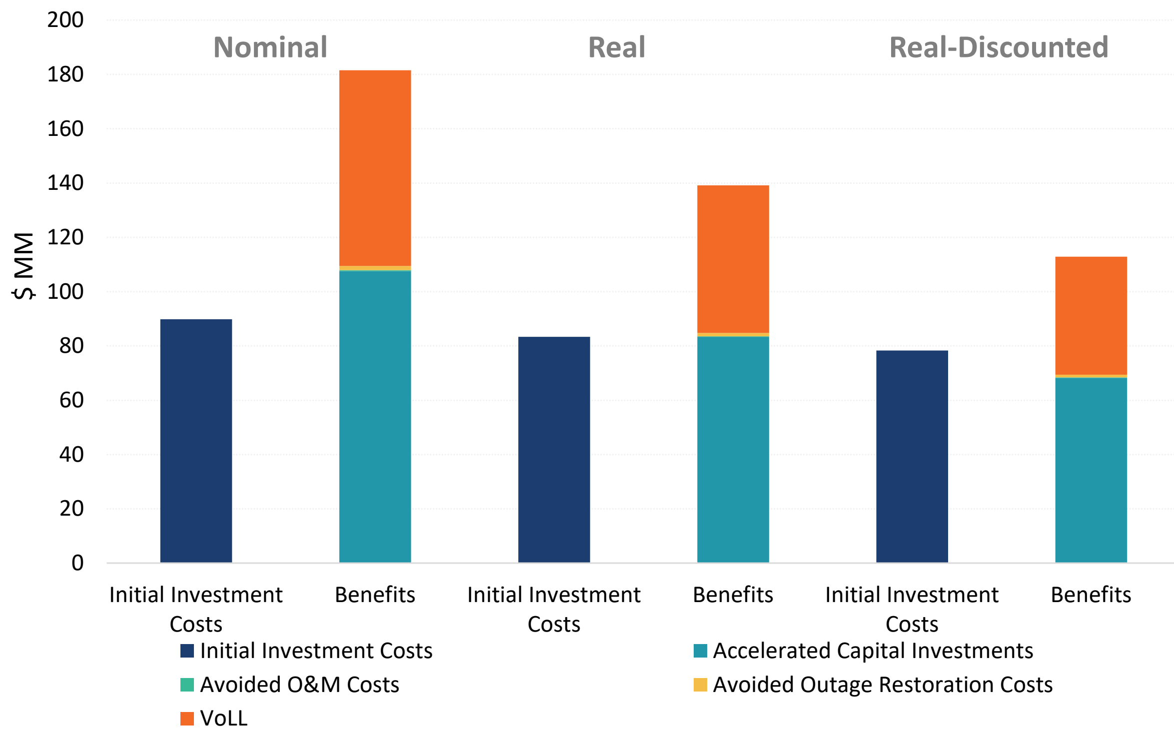
- Abandoned Line (1 project)
- Cable URD (1 project)
- Network Renewal (2 projects)
- Open Wire Secondaries (1 project)

[44] ACE typically develops distribution projects on two year-cycles, and rarely five years ahead. We could not analyze two of the three projects because ACE has not yet developed project details for them.

- Cutout Replacement (1 project)
- Recloser Replacement (1 project)

We analyzed five out of the seven projects. Figure 7 compares the investment costs to benefits by type for the five projects we analyzed.

FIGURE 7: RESULTS SUMMARY FOR PROJECTS ANALYZED - CATEGORY 3



Benefits are largely associated with Accelerated Capital Investments, followed by reduction in outages (VoLL). We did not assume any cost increase for future material and labor in real terms. If these are to increase (as recent history has indicated), the benefits associated with Accelerated Capital Investment could increase.

Table 38 shows the CBA results in Real terms by the six subprograms for category 3 (Infrastructure Renewals).

TABLE 38: RESULTS SUMMARY FOR CATEGORY 3 AND SUBPROGRAMS

Subprogram	Initial Investment Costs (Nominal)	Total Benefits (Nominal)	*B/I Ratio (Nominal)*	Initial Investment Costs (Real)	Total Benefits (Real)	*B/I Ratio (Real)*	Initial Investment Costs (Real-Discounted)	Total Benefits (Real-Discounted)	*B/I Ratio (Real-Discounted)*
Abandoned Line	$23.8	$33.4	*1.4*	$22.0	$25.7	*1.2*	$20.6	$20.9	*1.0*
Cable URD	$24.3	$32.2	*1.3*	$22.6	$25.0	*1.1*	$21.2	$20.4	*1.0*
Network Renewal	$4.5	$9.1	*2.0*	$4.2	$7.0	*1.7*	$4.0	$5.7	*1.4*
Open Wire Secondaries	$5.3	$8.9	*1.7*	$5.0	$6.9	*1.4*	$4.7	$5.7	*1.2*
Cutout Replacement	$10.6	$56.2	*5.3*	$9.9	$42.6	*4.3*	$9.3	$34.2	*3.7*
Recloser Replacement	$25.7	$50.8	*2.0*	$23.9	$39.0	*1.6*	$22.5	$31.6	*1.4*
Category 3 Total	**$94.3**	**$190.6**	***2.0***	**$87.5**	**$146.2**	***1.7***	**$82.3**	**$118.6**	***1.4***

($ million)

The average B/I ratio is 1.7 in Real terms (2.0 in Nominal terms and 1.4 in Real-Discounted terms) indicating a good return on investment. Two subprograms, namely, Abandoned Line and Cable URD show B/I ratios of 1.1 and 1.2 in Real terms, respectively, with B/I ratios in Real-Discounted terms falling to 1.0 (slightly under). Considering the conservativeness applied in our assumptions, this may not be a significant concern. In particular, there is no loss in removing the abandoned line, which could wreak havoc in the future if left unattended.

Detailed CBA results for each subprogram in category 3 (Infrastructure Renewal) are summarized next.

SUBPROGRAM 1: ABANDONED LINE

This subprogram includes one projects as listed in Table 39. We analyzed the project.

TABLE 39: CBA RESULTS FOR PROJECTS (NOMINAL) IN CATEGORY 3, SUBPROGRAM 1

(Nominal $ million)

Project Name	Project Analyzed	Initial Investment Costs	Accelerated Capital Investments	Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Abandoned Line Removal	TRUE	$23.8	$28.6	$0.0	$0.2	$4.5	$33.4	*1.4*
Total		**$23.8**					**$33.4**	***1.4***

Table 40 summarizes the results for this subprogram. The B/I ratio is 1.2 in Real terms (1.4 in Nominal terms and 1.0 in Real-Discounted terms), indicating the projects would more than pay for itself. There is no loss in removing the abandoned line, which could wreak havoc in the future if left unattended. The largest benefit is associated with Accelerated Capital Investment. We understand that there is little excuse in leaving abandoned lines as is, and, thereby, this project (and subprogram) will likely be pursued by ACE for reliability purposes regardless of the BPU approval for IIP, and thereby, not avoidable. We did not assume any cost increase for future material and labor in real terms. If these are to increase (as recent history has indicated), the benefits associated with Accelerated Capital Investment could increase as well.

TABLE 40: CBA RESULTS FOR CATEGORY 3, SUBPROGRAM 1

($ million)	Initial Investment Costs	Avoided O&M Costs	Accelerated Capital Investments	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Nominal	$23.8	$0.0	$28.6	$0.2	$4.5	$33.4	*1.4*
Real	$22.0	$0.0	$22.0	$0.2	$3.5	$25.7	*1.2*
Real-Discounted	$20.6	$0.0	$17.9	$0.1	$2.9	$20.9	*1.0*

SUBPROGRAM 2: CABLE URD

This subprogram includes one project as listed in Table 41. We analyzed the project.

TABLE 41: CBA RESULTS FOR PROJECTS (NOMINAL) IN CATEGORY 3, SUBPROGRAM 2

(Nominal $ million)

Project Name	Project Analyzed	Initial Investment Costs	Accelerated Capital Investments	Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
70894_URD Cable ACE	TRUE	$24.3	$29.0	$0.0	$0.7	$2.5	$32.2	*1.3*
Total		**$24.3**					**$32.2**	***1.3***

Table 42 summarize the results for this subprogram. The B/I ratio is 1.1 in Real terms (1.3 in Nominal terms and 1.0 in Real-Discounted terms), suggesting the subprogram pays for itself. The largest benefit is associated with Accelerated Capital Investment. We understand this project (and subprogram) will likely be pursued by ACE for reliability purposes regardless of the BPU approval for IIP, and thereby, not avoidable. We did not assume any cost increase for future material and labor in real terms. If these are to increase (as recent history has indicated), the benefits associated with Accelerated Capital Investment could increase as well.

TABLE 42: CBA RESULTS FOR CATEGORY 3, SUBPROGRAM 2

($ million)	Initial Investment Costs	Avoided O&M Costs	Accelerated Capital Investments	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Nominal	$24.3	$0.0	$29.0	$0.7	$2.5	$32.2	*1.3*
Real	$22.6	$0.0	$22.6	$0.5	$1.8	$25.0	*1.1*
Real-Discounted	$21.2	$0.0	$18.5	$0.4	$1.5	$20.4	*1.0*

SUBPROGRAM 3: NETWORK RENEWAL

This subprogram includes two projects as listed in Table 43. We did not analyze either projects because replacing these equipment provides benefits beyond those we measured in this CBA. Thereby, we assumed the B/I ratio for these projects (and, thereby, the subprogram) to be similar to the other subprograms (i.e., average of the other subprograms where we analyzed projects) within category 3 (Infrastructure Renewals).

TABLE 43: CBA RESULTS FOR PROJECTS IN CATEGORY 3, SUBPROGRAM 3

($ million)

	Nominal			Real			Real-Discounted		
Project Name	Initial Investment Costs	Total Benefits	*B/I Ratio*	Initial Investment Costs	Total Benefits	*B/I Ratio*	Initial Investment Costs	Total Benefits	*B/I Ratio*
Network Cable Replacements	$1.3	$1.9	*1.4*	$1.2	$1.5	*1.2*	$1.2	$1.2	*1.0*
Network Transformer Replacements	$3.2	$4.6	*1.4*	$3.0	$3.6	*1.2*	$2.8	$2.9	*1.0*

SUBPROGRAM 4: OPEN WIRE SECONDARIES

This subprogram includes one project as listed in Table 44. We analyzed the project.

TABLE 44: CBA RESULTS FOR PROJECTS (NOMINAL) IN CATEGORY 3, SUBPROGRAM 4

(Nominal $ million)

Project Name	Project Analyzed	Initial Investment Costs	Accelerated Capital Investments	Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Replace open wire secondaries	TRUE	$5.3	$6.4	$0.0	$0.0	$2.4	$8.9	*1.7*
Total		**$5.3**					**$8.9**	***1.7***

Table 45 summarize the results for this subprogram. The B/I ratio is 1.4 in Real terms (1.7 in Nominal terms and 1.2 in Real-Discounted terms), suggesting a decent payback. The largest benefit is associated with Accelerated Capital Investment, followed by reduction in outages (VoLL). We understand that projects within this subprogram will likely be pursued by ACE for reliability purposes regardless of the BPU approval for IIP, and thereby, not avoidable. This suggests there is no benefit in delaying the subprogram. We did not assume any cost increase for future material and labor in real terms. If these are to increase (as recent history has indicated), the benefits associated with Accelerated Capital Investment could increase as well.

TABLE 45: CBA RESULTS FOR CATEGORY 3, SUBPROGRAM 4

($ million)	Initial Investment Costs	Avoided O&M Costs	Accelerated Capital Investments	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Nominal	$5.3	$0.0	$6.4	$0.0	$2.4	$8.9	*1.7*
Real	$5.0	$0.0	$5.0	$0.0	$1.9	$6.9	*1.4*
Real-Discounted	$4.7	$0.0	$4.1	$0.0	$1.5	$5.7	*1.2*

SUBPROGRAM 5: CUTOUT REPLACEMENT

This subprogram includes one project as listed in Table 46. We analyzed this project.

TABLE 46: CBA RESULTS FOR PROJECTS (NOMINAL) IN CATEGORY 3, SUBPROGRAM 5

(Nominal $ million)

Project Name	Project Analyzed	Initial Investment Costs	Accelerated Capital Investments	Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Porcelain Cutout Replacement	TRUE	$10.6	$12.7	$0.1	$0.6	$42.8	$56.2	*5.3*
Total		**$10.6**					**$56.2**	***5.3***

Table 47 summarizes the results for this subprogram. The B/I ratio is 4.3 in Real terms (5.3 in Nominal terms and 3.7 in Real-Discounted terms), indicating an extremely beneficial subprogram. The largest benefit is associated with reduction in outages (VoLL), followed by Accelerated Capital

Investment. The subprogram's payback will remain positive, even after one of these benefit type is not accounted for on its entirety. We did not assume any cost increase for future material and labor in real terms. If these are to increase (as recent history has indicated), the benefits associated with Accelerated Capital Investment could increase as well.

TABLE 47: CBA RESULTS FOR CATEGORY 3, SUBPROGRAM 5

($ million)	Initial Investment Costs	Avoided O&M Costs	Accelerated Capital Investments	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Nominal	$10.6	$0.1	$12.7	$0.6	$42.8	$56.2	*5.3*
Real	$9.9	$0.1	$9.9	$0.5	$32.2	$42.6	*4.3*
Real-Discounted	$9.3	$0.1	$8.1	$0.4	$25.7	$34.2	*3.7*

SUBPROGRAM 6: RECLOSER REPLACEMENT

This subprogram includes one project as listed in Table 48. We analyzed the project.

TABLE 48: CBA RESULTS FOR PROJECTS (NOMINAL) IN CATEGORY 3, SUBPROGRAM 6

(Nominal $ million)

Project Name	Project Analyzed	Initial Investment Costs	Accelerated Capital Investments	Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
NOVA Recloser Replacement - Technology Upgrade in DA Circuit Plan	TRUE	$25.7	$30.8	$0.1	$0.0	$19.9	$50.8	*2.0*
Total		**$25.7**					**$50.8**	***2.0***

Table 49 summarize the results for this subprogram. The B/I ratio is 1.6 in Real terms (2.0 in Nominal terms and 1.4 in Real-Discounted terms), suggesting a good subprogram with solid paybacks. The largest benefit is associated with Accelerated Capital Investment, followed by reduction in outages (VoLL). We understand that projects within this subprogram will likely be pursued by ACE for reliability purposes regardless of the BPU approval for IIP, and thereby, not avoidable. We did not assume any cost increase for future material and labor in real terms. If these are to increase (as recent history has indicated), the benefits associated with Accelerated Capital Investment could increase as well.

TABLE 49: CBA RESULTS FOR CATEGORY 3, SUBPROGRAM 6

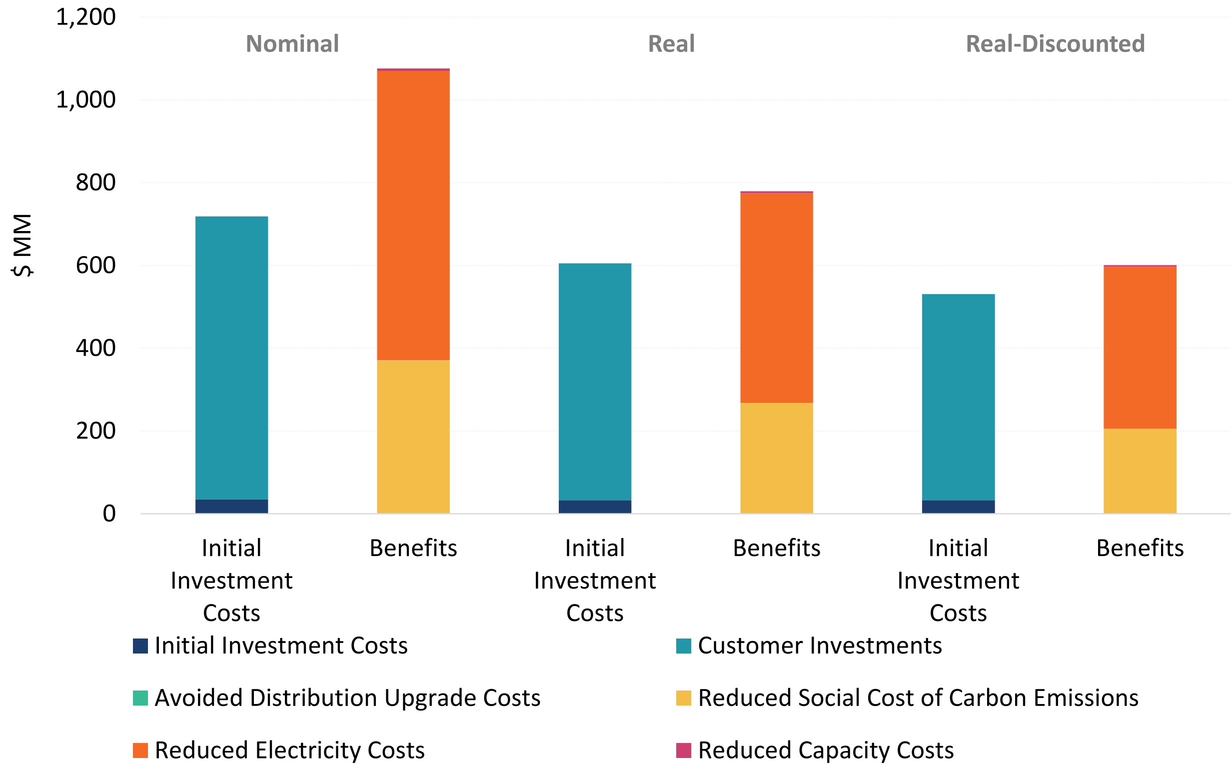
($ million)	Initial Investment Costs	Avoided O&M Costs	Accelerated Capital Investments	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Nominal	$25.7	$0.1	$30.8	$0.0	$19.9	$50.8	*2.0*
Real	$23.9	$0.1	$23.9	$0.0	$14.9	$39.0	*1.6*
Real-Discounted	$22.5	$0.1	$19.6	$0.0	$11.9	$31.6	*1.4*

d. Category 4: Solar/DER Enablements

Through 23 projects listed under this category, ACE is proposing to invest $34.9 million in upgrading relay protection and other equipment on transformers and feeders to enable DER installations. The $34.9 million ACE investment will allow for approximately $670 million customer-side investments on DERs (e.g., rooftop solar installations), resulting in $779 million benefits (all in real 2022 dollars) to the society including avoided distribution system upgrade, reduced social cost of carbon emissions, reduced electricity cost, and reduced capacity cost. These benefit calculations assume a 10% CAGR in DER installments, in line with state policy goals. If the adoption rate is higher, the benefits will also increase.

We analyzed all 23 projects. Figure 8 compares the investment costs to benefits by type for this category.

FIGURE 8: RESULTS SUMMARY FOR PROJECTS ANALYZED - CATEGORY 4



Since projects in category 4 (Solar/DER Enablement) can bridge over multiple subprograms, we summarize the CBA results by each transformer as a project instead of by each subprogram. As shown in Table 50, the average B/I ratio is 1.3 in Real terms (1.5 in Nominal terms and 1.1 in Real-Discounted terms), indicating the benefits are more than the cost of the IIP investment and customer investment combined. Customer investment costs do not reflect any federal tax credits available.[45] Accounting for such benefits could reduce the customer investment costs by 30%. There are other incentives offered as well, which could further reduce customers' costs. In addition to the economic benefits, all the investments are necessary for ACE to achieve the renewable energy goal of New Jersey. The investments on feeder upgrades are allocated to the transformers that the feeder is connected to. We have not quantified the benefits of feeder investment separately, which indicates that the actual benefit of IIP investment on the projects in this category would results in more benefits than our conservative estimation.

45 If the scope of societal benefits considered is defined as those within New Jersey, federal tax credits can largely be considered as a cost reduction to the State, rather than a shift of costs that would occur for state led incentives.

Real $ millions

TABLE 50: RESULTS SUMMARY FOR PROJECTS (REAL) IN CATEGORY 4

Project Name	Avoided Distribution Upgrade Costs	Reduced Social Cost of Carbon Emissions	Reduced Electricity Costs	Reduced Capacity Costs	Total Benefits	Initial Investment Costs	Customer Investments	Total Costs	*B/I Ratio*
Barnegat T1	$0.2	$12.7	$24.3	$0.9	$38	$1.8	$25.3	$27.1	*1.4*
Cardiff T3	$0.0	$14.4	$27.2	$0.4	$42	$3.0	$32.1	$35.1	*1.2*
Dorothy T2	$0.0	$13.5	$25.7	$0.1	$39	$2.8	$27.4	$30.3	*1.3*
Franklin T1	$0.0	$11.6	$22.3	$0.0	$34	$0.9	$23.9	$24.8	*1.4*
High Street T1	$0.0	$13.4	$25.4	$0.2	$39	$1.2	$28.0	$29.1	*1.3*
Mantua T2	$0.0	$11.3	$21.3	$0.0	$33	$1.5	$24.8	$26.2	*1.2*
Mickleton T2	$0.0	$12.8	$24.2	$0.0	$37	$0.9	$26.7	$27.6	*1.3*
Mickleton T5	$0.0	$11.2	$21.2	$0.1	$33	$0.7	$25.6	$26.2	*1.2*
Moss Mill T2	$0.0	$9.5	$17.8	$0.4	$28	$0.9	$23.2	$24.2	*1.1*
Motts Farm T3	$0.0	$12.5	$23.8	$0.8	$37	$0.7	$25.9	$26.6	*1.4*
Motts Farm T5	$0.5	$11.9	$22.8	$0.5	$36	$0.7	$23.8	$24.5	*1.5*
Rio Grande T6	$0.0	$13.3	$25.3	$0.0	$39	$0.9	$26.9	$27.8	*1.4*
Rio Grande T7	$0.0	$12.3	$23.4	$0.3	$36	$0.9	$25.3	$26.2	*1.4*
Rio Grande T8	$0.0	$13.5	$25.7	$0.0	$39	$0.7	$27.4	$28.0	*1.4*
Roadstown T2	$0.0	$11.5	$21.7	$0.0	$33	$0.7	$25.2	$25.9	*1.3*
Searstown T2	$0.0	$10.8	$20.5	$0.0	$31	$3.4	$22.4	$25.7	*1.2*
Sickler T3	$0.0	$12.0	$22.6	$0.2	$35	$1.5	$26.9	$28.4	*1.2*
Tansboro T1	$0.0	$11.3	$21.5	$0.0	$33	$0.7	$23.6	$24.2	*1.4*
Tansboro T2	$0.0	$8.5	$15.9	$0.0	$24	$0.7	$23.5	$24.1	*1.0*
Upper Pittsgrove T1	$0.0	$11.8	$22.2	$0.0	$34	$2.6	$25.8	$28.3	*1.2*
Williamstown T4	$0.0	$13.5	$25.7	$0.1	$39	$2.6	$27.6	$30.2	*1.3*
Williamstown T5	$0.0	$9.5	$18.3	$0.0	$28	$2.6	$21.6	$24.2	*1.2*
Winslow T2	$0.0	$4.4	$8.2	$0.1	$13	$2.8	$9.6	$12.5	*1.0*
Total	**$0.7**	**$267.1**	**$506.9**	**$4.5**	**$779.1**	**$34.9**	**$572.3**	**$607.2**	***1.3***

In addition to the societal benefits identified and quantified, customers who invested in DERs are likely to see reduction in their utility bills. Assuming an average residential rate offered to ACE customers of $0.22/kWh, a reduction of 6,589 GWh of electricity supply from utility due to the increased residential solar generation enabled by the investment on category 4 (DER Enablements) projects over the Study Period would lead to a $1.4 billion of benefits in real 2022 dollars.

e. Category 5: Substation Improvements

This category includes 11 projects among the following four subprograms:

- New Substation (1 project)
- Substation Additions (1 project)
- Substation Reliability (4 projects)
- Substation Renewal (5 projects)

We analyzed nine out of the 11 projects. Figure 9 compares the investment costs to benefits by type for the nine projects we analyzed.

FIGURE 9: RESULTS SUMMARY FOR PROJECTS ANALYZED - CATEGORY 5

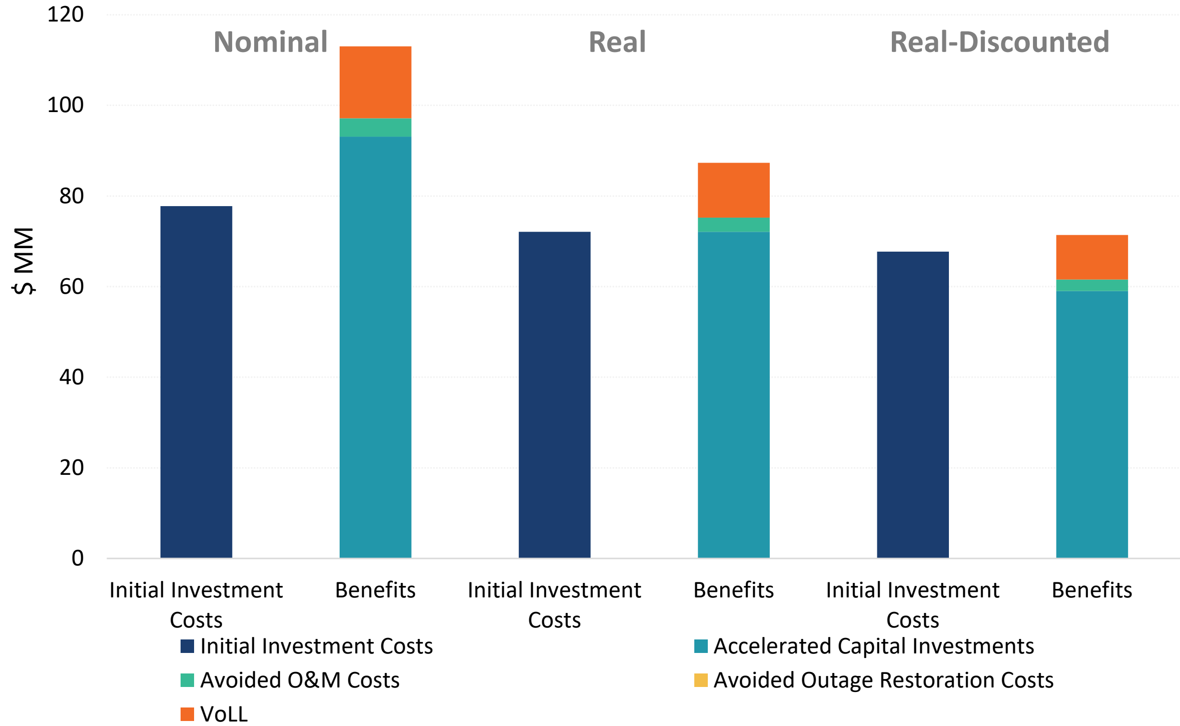


Table 51 shows the CBA results in real terms by the four subprograms for category 5 (Substation Improvements).

TABLE 51: RESULTS SUMMARY FOR CATEGORY 5 AND SUBPROGRAMS

Subprogram	**Initial Investment Costs (Nominal)**	**Total Benefits (Nominal)**	***B/I Ratio (Nominal)***	**Initial Investment Costs (Real)**	**Total Benefits (Real)**	***B/I Ratio (Real)***	**Initial Investment Costs (Real-Discounted)**	**Total Benefits (Real-Discounted)**	***B/I Ratio (Real-Discounted)***
New Substation	$20.3	$27.0	*1.3*	$19.0	$20.9	*1.1*	$18.0	$17.1	*1.0*
Substation Additions	$27.6	$39.2	*1.4*	$25.8	$30.3	*1.2*	$24.5	$24.8	*1.0*
Substation Reliability	$22.7	$41.9	*1.8*	$20.9	$32.7	*1.6*	$19.5	$27.0	*1.4*
Substation Renewal	$33.6	$47.8	*1.4*	$31.1	$37.2	*1.2*	$29.1	$30.6	*1.0*
Category 5 Total	**$104.3**	**$155.9**	***1.5***	**$96.8**	**$121.2**	***1.3***	**$91.0**	**$99.5**	***1.1***

($ million)

The average B/I ratio is 1.3 in Real terms (1.5 in Nominal terms and 1.1 in Real-Discounted terms), indicating a positive return on investment. Compared to projects in other subprograms, the investment costs of projects in this subprogram is large. Projects with larger initial investments tend to show lower B/I ratios, even if their benefits in absolute values are larger than smaller investment opportunities. Thereby, the smaller B/I ratio should not be a concern.

Detailed CBA results for each subprogram in Category 5 (Substation Improvements) are summarized next.

SUBPROGRAM 1: NEW SUBSTATION

This subprogram includes one project as listed in Table 52. We analyzed this project.

TABLE 52: CBA RESULTS FOR PROJECTS (NOMINAL) IN CATEGORY 5, SUBPROGRAM 1

(Nominal $ million)

Project Name	Project Analyzed	Initial Investment Costs	Accelerated Capital Investments	Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
New Logan Substation	TRUE	$20.3	$24.5	$0.3	$0.0	$2.2	$27.0	*1.3*
Total		**$20.3**					**$27.0**	***1.3***

Table 53 summarizes the results for this subprogram. The B/I ratio is 1.1 in Real terms (1.3 in Nominal terms and 1.0 in Real-Discounted terms), indicating the project will more than pay for itself. The largest benefit is associated with Accelerated Capital Investment. We understand that projects within this subprogram will likely be pursued by ACE for reliability purposes regardless of the BPU approval for IIP, and thereby, not avoidable. This suggests there is no benefit in delaying the subprogram. We did not assume any cost increase for future material and labor in real terms. If these are to increase (as recent history has indicated), the benefits associated with Accelerated Capital Investment could increase as well.

TABLE 53: CBA RESULTS FOR CATEGORY 5, SUBPROGRAM 1

($ million)	Initial Investment Costs	Avoided O&M Costs	Accelerated Capital Investments	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Nominal	$20.3	$0.3	$24.5	$0.0	$2.2	$27.0	*1.3*
Real	$19.0	$0.2	$19.0	$0.0	$1.7	$20.9	*1.1*
Real-Discounted	$18.0	$0.2	$15.6	$0.0	$1.3	$17.1	*1.0*

SUBPROGRAM 2: SUBSTATION ADDITIONS

This subprogram includes one project as listed in Table 54. We analyzed the project.

TABLE 54: CBA RESULTS FOR PROJECTS (NOMINAL) IN CATEGORY 5, SUBPROGRAM 2

(Nominal $ million)

Project Name	Project Analyzed	Initial Investment Costs	Accelerated Capital Investments	Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Lambs - ADD 2ND XFMR (Substation and distribution lines)	TRUE	$27.6	$33.3	$0.3	$0.0	$5.6	$39.2	*1.4*
Total		**$27.6**					**$39.2**	***1.4***

Table 55 summarizes the results for this subprogram. The B/I ratio is 1.2 in Real terms (1.4 in Nominal terms and 1.0 in Real-Discounted terms), indicating the project will pay for itself. The largest benefit is associated with Accelerated Capital Investment. We understand that projects within this subprogram will likely be pursued by ACE for reliability purposes regardless of the BPU approval for IIP, and thereby, not avoidable. This suggests there is no benefit in delaying the subprogram. We did not assume any cost increase for future material and labor in real terms. If these are to increase (as recent history has indicated), the benefits associated with Accelerated Capital Investment could increase as well.

TABLE 55: CBA RESULTS FOR CATEGORY 5, SUBPROGRAM 2

($ million)	**Initial Investment Costs**	**Avoided O&M Costs**	**Accelerated Capital Investments**	**Avoided Outage Restoration Costs**	**VoLL**	**Total Benefits**	***B/I Ratio***
Nominal	$27.6	$0.3	$33.3	$0.0	$5.6	$39.2	*1.4*
Real	$25.8	$0.2	$25.8	$0.0	$4.2	$30.3	*1.2*
Real-Discounted	$24.5	$0.2	$21.2	$0.0	$3.4	$24.8	*1.0*

SUBPROGRAM 3: SUBSTATION RELIABILITY

This subprogram includes four projects as listed in Table 56 below. We analyzed three of the four projects. We assumed the B/I ratio for the fourth project (the project we did not analyze) to be similar to the other three projects (i.e., average of the six projects we analyzed).

TABLE 56: CBA RESULTS FOR PROJECTS (NOMINAL) IN CATEGORY 5, SUBPROGRAM 3

(Nominal $ million)

Project Name	Project Analyzed	Initial Investment Costs	Accelerated Capital Investments	Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Cedar Substation	TRUE	$2.0	$2.4	$0.5	$0.0	$2.4	$5.3	*2.6*
Fairton Relay _ Bus Upgrades	TRUE	$4.1	$4.9	$1.0	$0.0	$1.4	$7.2	*1.8*
Laurel	TRUE	$4.3	$5.0	$1.0	$0.0	$0.7	$6.8	*1.6*
Average of Analyzed Projects								***1.8***
66433_ACE NJ - Distribution - Flood remediation	FALSE	$12.3	NA	NA	NA	NA	$22.6	*1.8*
Total		**$22.7**					**$41.9**	***1.8***

Table 57 summarizes the results for this subprogram. The B/I ratio is 1.6 in Real terms (1.8 in Nominal terms and 1.4 in Real-Discounted terms), suggesting this is a good subprogram with a solid payback. The benefits are split among three benefit types, namely Accelerated Capital Investment, followed by the reduction in outages (VoLL) and Avoided O&M Costs. All three of these benefits are material indicating these projects are well-rounded and balanced (from a benefits-perspective) projects. We did not assume any cost increase for future material and labor in real terms. If these are to increase (as recent history has indicated), the benefits associated with Accelerated Capital Investment could increase as well.

TABLE 57: CBA RESULTS FOR CATEGORY 5, SUBPROGRAM 3

($ million)	Initial Investment Costs	Avoided O&M Costs	Accelerated Capital Investments	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Nominal	$10.4	$2.4	$12.3	$0.0	$4.5	$19.2	*1.8*
Real	$9.5	$1.9	$9.5	$0.0	$3.5	$14.8	*1.6*
Real-Discounted	$8.7	$1.6	$7.7	$0.0	$2.9	$12.1	*1.4*

SUBPROGRAM 4: SUBSTATION RENEWAL

This subprogram includes five projects as listed in Table 58. We analyzed four of the five projects. We assumed the B/I ratio for the fifth project (the project we did not analyze) to be similar to the other four projects (i.e., average of the four projects we analyzed).

TABLE 58: CBA RESULTS FOR PROJECTS (NOMINAL) IN CATEGORY 5, SUBPROGRAM 4

(Nominal $ million)

Project Name	Project Analyzed	Initial Investment Costs	Accelerated Capital Investments	Avoided O&M Costs	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
68606 - ACE NJ Clayton_69_12kv T2 Transformer Replacement	TRUE	$4.7	$5.6	$0.3	$0.0	$0.5	$6.5	*1.4*
ACE NJ Berlin_Upgrade Switchgear A	TRUE	$2.7	$3.2	$0.0	$0.0	$0.7	$4.0	*1.5*
Corson T3 Upgrade	TRUE	$6.6	$7.8	$0.3	$0.0	$1.5	$9.6	*1.5*
Lenox	TRUE	$5.4	$6.3	$0.3	$0.0	$0.8	$7.5	*1.4*
Average of Analyzed Projects								***1.4***
63657_ACE NJ - Dist - Sub Infrastructure	FALSE	$14.3	NA	NA	NA	NA	$20.3	*1.4*
Total		**$33.6**					**$47.8**	***1.4***

Table 59 summarizes the results for this subprogram. The B/I ratio is 1.2 in Real terms (1.4 in Nominal terms and 1.0 in Real-Discounted terms), suggesting the project will more than pay for itself. The largest benefit is associated with Accelerated Capital Investment. We did not assume any cost increase for future material and labor in real terms. If these are to increase (as recent history has indicated), the benefits associated with Accelerated Capital Investment could increase as well.

TABLE 59: CBA RESULTS FOR CATEGORY 5, SUBPROGRAM 4

($ million)	Initial Investment Costs	Avoided O&M Costs	Accelerated Capital Investments	Avoided Outage Restoration Costs	VoLL	Total Benefits	*B/I Ratio*
Nominal	$19.4	$1.0	$23.0	$0.0	$3.5	$27.5	*1.4*
Real	$17.8	$0.8	$17.8	$0.0	$2.7	$21.3	*1.2*
Real-Discounted	$16.5	$0.6	$14.5	$0.0	$2.3	$17.3	*1.0*

IV. Conclusions

ACE's Powering the Future portfolio includes 80 projects adding up to approximately $380 million (in Real terms) of investments to ACE's distribution system over the next four years (from July 2023 through June 2027, over five calendar years). ACE groups the Powering the Future projects into the following five categories (and subprograms within each category):

1) Targeted Reliability Improvements (29 projects in 7 subprograms)
2) Smart Technology Upgrades (10 projects in 6 subprograms)
3) Infrastructure Renewals (7 projects in 6 subprograms)
4) Solar/DER Enablements (23 projects in 3 subprograms)
5) Substation Improvements (11 projects in 4 subprograms)

New Jersey is one of the states leading the energy transition with its ambitious clean energy and emission reduction goals. The State outlines its broader clean energy policy goals in the 2019 Energy Master Plan (EMP). The EMP aims to transition to a clean energy economy through electrification of transportation and buildings sectors and accelerated deployment of clean distributed energy resources. The New Jersey Board of Public Utilities (BPU) grid modernization initiative targets higher volumes of DER deployment.

In parallel, New Jersey's Infrastructure Investment Program (IIP) provides a rate recovery mechanism for non-revenue producing projects that target modernizing and strengthening the grid to satisfy goals set forth by the New Jersey (State) Administrative Code. ACE plans to file the Powering the Future portfolio with the BPU for IIP application. ACE's Powering the Future proposal satisfies the criteria set forth in the rules. All projects are either related to reliability, resiliency, and safety, and are non-revenue producing investments.

The Powering the Future portfolio also aligns well with the State's goals. Projects in categories 1 (Targeted Reliability Improvements), 2 (Smart Technology Upgrades), 3 (Infrastructure Renewals), and 5 (Substation Improvements) directly support the EMP's goals of modernizing the grid, while also preparing the grid for electrification of transportation and higher volumes of DERs encouraged by the state policies and associated strategies. Projects in category 4 (Solar/DER Enablement) supports the State's goal by enabling new, low-carbon DERs to be added to system.

This CBA quantifies the economic benefits of ACE's IIP projects by analyzing individual projects to the extent possible. IIP projects are non-revenue producing projects. Thereby, the benefits of the IIP projects are future costs that would have accumulated if not for implementing the Powering the Future projects. In other words, the benefits are largely avoided or reduced costs under the IIP scenario. Projects in categories 1 (Targeted Reliability Improvements), 2 (Smart Technology Upgrades), 3 (Infrastructure Renewals), and 5 (Substation Improvements) will directly lead to such benefits, through reducing outages (occurrence, duration once it happens, and number of customers it impacts) or ongoing operation and maintenance costs, while also avoiding future investments. Benefits for projects in category 4 (Solar/DER Enablements) rely on customers' actions, specifically their DER investments, that are largely outside of ACE's control. We analyze 66 out of the 80 projects.

Overall, the CBA confirms that ACE's Powering the Future projects have a positive payback, as summarized in Table 60 (in Real terms) below. All five categories individually, and the portfolio as a whole show positive paybacks.

TABLE 60: RESULTS SUMMARY BY CATEGORY AND ENTIRE PORTFOLIO (REAL)

Category	Total Investments ($ million)	Total Benefits ($ million)	*B/I Ratio*
1 - Targeted Reliability Improvements	$92.8	$348.1	*3.8*
2 - Smart Technology Upgrades	$68.5	$323.6	*4.7*
3 - Infrastructure Renewals	$87.5	$146.2	*1.7*
5 - Substation Improvements	$96.8	$121.2	*1.3*
Categories 1, 2, 3, 5 Total	$345.7	$939.0	*2.7*
4 - Solar/DER Enablements	$607.2	$779.1	*1.3*
Portfolio Total	$952.9	$1,718.1	*1.8*

The net positive payback for projects in categories 1 (Targeted Reliability Improvements), 2 (Smart Technology Upgrades), 3 (Infrastructure Renewals) and 5 (Substation Improvements) combined, is $939 million in Real terms ($1,227 million in Nominal terms, and $761 million in Real-Discounted terms) over the 20-year Study Period. This translates to a B/I ratio of 2.7 in Real terms (3.3 in Nominal terms and 2.3 in Real-Discounted terms).

Projects in category 4 (Solar/DER Enablements) will require investments from both ACE (approximately $35 million of the $607 million shown in the table above) and individual customers (approximately $572 million of the $607 million shown in the table above), which could further provide economic stimulus that ACE customers and other New Jersey residents would benefit from. The CBA does not account for such benefits because it is difficult to measure the contribution of the respective projects among other influential factors (e.g., tax incentives) that lead to them. Overall, projects in category 4 (Solar/DER Enablements) are estimated to provide a positive payback of $779 million in Real terms ($1,076 million in Nominal terms and $601 million in Real-Discounted terms), over the 20-year Study Period. This translates to a B/I ratio of 1.3 in Real terms (1.5 in Nominal terms, and 1.1 in Real-Discounted terms) while the enabled DERs reduce carbon emissions by 1.6 million metric tons (assuming the State's interim goals of DER deployments are reached).

These results indicate that ACE's Powering the Future portfolio that comply with IIP regulations will help New Jersey meet its clean energy goals while providing positive economic paybacks (i.e., with no overall costs to the society).

Appendix

Appendix A: Assumptions

This appendix discusses the various assumptions used for this CBA:

a. Inflation Rate and Discount Rate
b. Customer Investment
c. Avoided O&M Costs
d. Avoided Outage Restoration Costs
e. Avoided Distribution Upgrade Costs
    - Distribution Marginal Cost
    - Solar Installation Rate
    - Solar Profiles
    - Load Growth
f. Reduced Social Cost of Carbon Emissions
g. Reduced Electricity Costs
    - Locational Marginal Prices (LMP)
    - Capacity Prices
h. Value of Lost Load (VoLL)

a. Inflation Rate and Discount Rate

In this CBA, we calculate projects' payback and the benefits to initial investment ratio (B/I ratio) using three monetary terms:

- Nominal (in nominal dollars),
- Real (in real dollars after applying estimated future inflation rates of 2.35% to the nominal values), and
- Real-Discounted (in real dollars after applying estimated future inflation rates of 2.35% and a real discount rate of 2% to the nominal values).

We use historical and forward-looking inflation rates to convert real dollars to nominal dollars and vice versa. We assume forward-looking inflation rates of 2.35% per year, based on the average of consumer price index (CPI) for five-year averages (2024-2028, 2029-2033) from Blue

Chip's long-range Consensus survey.[46] For historical inflation rates, we use the average annual inflation rate measured by changes in CPI, as shown in Table A-1.[47] [48]

TABLE A-1: HISTORICAL INFLATION RATES FOR THE UNITED STATES (2013-2022)

Year	Inflation Rate
2013	1.5%
2014	1.6%
2015	0.1%
2016	1.3%
2017	2.1%
2018	2.5%
2019	1.8%
2020	1.2%
2021	4.7%
2022*	8.3%

Notes: 2022 value is the average of the monthly rates reported for January- August 2022 by the U.S. Bureau of Labor Statistics. Monthly rates represent percent changes from 12 months ago.

When calculating the Real-Discounted benefits and costs, we use a real discount rate of 2%. This leads to a nominal discount rate of 4.35% after adding the 2.35% inflation rate. The 2% real discount rate was chosen to reflect the social discount rate, since this CBA focuses on benefits and costs at societal scale including those that are associated with the utility system (e.g. accelerated capital investments) and society as a whole (e.g. customer investments in DER, and avoided carbon dioxide emissions costs). This discount rate accounts for the value of enabling reliable, resilient, and safe utility service over the long term while aligning with important policy goals of the state (e.g. EMP goals). The 2% real discount rate is also being used for valuing costs and benefits to society in regulatory analyses performed by other Exelon utilities.[49]

---

46 Blue Chip Financial Forecasts, Vol. 41, No. 6, June 1, 2022.

47 World Bank, Inflation, consumer prices for the United States [FPCPITOTLZGUSA], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/FPCPITOTLZGUSA, October 9, 2022.

48 U.S. Bureau of Labor Statistics (BLS), Consumer Price Index Historical Tables for U.S. City Average Consumer Price Index Historical Tables for U.S. City Average : Mid–Atlantic Information Office : U.S. Bureau of Labor Statistics (bls.gov)

49 For example, PSC Maryland Order No. 90261 directs Maryland utilities to use 2% real discount rate plus inflation to discount future societal costs and benefits for EmPOWER Maryland program (Case 9648). Also, see Future Programming Working Group Report for further details.

For consistency, we apply the same discount rate to all cost and benefit types in this study, including the Reduced Social Cost of Carbon Emissions as explained in more detail next.

b. Customer Investments

We estimate customer investments based on the DER installation capacity and the capital cost for rooftop solar systems in New Jersey.

We estimate the average installation cost of rooftop solar panels in New Jersey to be $2.88/W in 2022.[50] This value does not include federal tax credits or other state and local incentives.

Starting with this 2022 value, we project the cost of rooftop solar installations over the next 20 years. We expect the cost of solar panels to decline in the future. We obtain the expected decline in rooftop solar system costs from the National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) study. We rely on the projections under the Moderate Technology Innovation Scenario (Moderate Scenario), which is at the middle-level of the three scenarios (Advanced, Moderate and Conservative Scenarios) ATB presents. The Moderate Scenario assumes R&D investment will continue at today's levels, and current industry technology roadmaps will be achieved, but no substantial innovations or new technologies will be introduced to the market.[51]

Table A-2 shows the calculations of future solar costs. Based on the NREL data on annual rooftop PV installation costs (column B), we calculate the percentage change in costs from 2022 levels (column C). We then apply these percentages to the average 2022 New Jersey rooftop solar cost of $2.88/W (column D). Column D (shaded light blue) shows the final values used in the CBA.

Although not included in this CBA, federal tax credits and other incentives could reduce the costs further. When the federal solar investment tax credit (ITC) is applied, installation cost decreases by 30% between 2023 and 2032, 26% in 2033, 22% in 2034, and 0% thereafter (column E).[52] Column F shows the projected rooftop solar cost in New Jersey after ITC. However, in this CBA, we use the values without ITC shown in column D.

---

[50] Solar Panel Cost in New Jersey, updated 6/25/2022 https://www.energysage.com/local-data/solar-panel-cost/nj/

[51] NREL, Electricity Annual Technology Baseline (ATB) Data, 2022, https://atb.nrel.gov/electricity/2022/data

[52] US Department of Energy, Solar Energy Technologies Office. Homeowner's Guide to the Federal Tax Credit for Solar Photovoltaics, September 2022.

TABLE A-2: ROOFTOP PV INSTALLATION COST (CAPEX) BASED ON NREL ATB MODERATE SCENARIO

Year	Rooftop Solar CapEx Projection Based on NREL *Without ITC* ($/W in 2020 USD)	Percentage reduction from 2022	Rooftop Solar CapEx Projection for New Jersey *Without ITC* ($/W in 2022 USD) FINAL VALUES USED IN THE CBA	Reduction in Cost Due to ITC	Rooftop Solar CapEx Projection for New Jersey *With ITC* ($/W in 2022 USD)
A	B	C	D	E	F
2022	2.47		2.88		
2023	2.29	7.4%	2.67	30%	1.87
2024	2.11	14.7%	2.46	30%	1.72
2025	1.92	22.1%	2.24	30%	1.57
2026	1.74	29.4%	2.03	30%	1.42
2027	1.56	36.8%	1.82	30%	1.27
2028	1.38	44.1%	1.61	30%	1.13
2029	1.20	51.5%	1.40	30%	0.98
2030	1.02	58.8%	1.19	30%	0.83
2031	1.01	59.3%	1.17	30%	0.82
2032	0.99	59.7%	1.16	30%	0.81
2033	0.98	60.2%	1.15	26%	0.85
2034	0.97	60.6%	1.13	22%	0.88
2035	0.96	61.1%	1.12	0%	1.12
2036	0.95	61.6%	1.11	0%	1.11
2037	0.94	62.0%	1.09	0%	1.09
2038	0.93	62.5%	1.08	0%	1.08
2039	0.92	62.9%	1.07	0%	1.07
2040	0.90	63.4%	1.05	0%	1.05
2041	0.89	63.8%	1.04	0%	1.04
2042	0.88	64.3%	1.03	0%	1.03

c. Avoided O&M Costs

New equipment is likely to reduce O&M costs for two reasons. First, there is a general trend of O&M costs going up with equipment age. Second, the advancements in both technology and design typically lead to lower O&M costs. These changes are equipment specific and we did not have access to such data for all projects analyzed in this CBA.

The table below shows the total avoided O&M costs for the projects where ACE quantified the avoided O&M costs.

TABLE A-3: AVOIDED O&M COSTS

Category	Sub-program	Project Name	Total Avoided O&M Cost Over 20 years ($)
1 - Targeted Reliability Improvements	Abandoned Line	Abandoned Line Removal	$9,450
1 - Targeted Reliability Improvements	Open Wire Secondaries	Replace open wire secondaries	$18,900
1 - Targeted Reliability Improvements	Rear Lot Conversions	Rear Lot Conversion	$34,650
1 - Targeted Reliability Improvements	Cable URD	70894: URD Cable ACE	$25,200
1 - Targeted Reliability Improvements	New Substation	New Logan Substation	$256,500
1 - Targeted Reliability Improvements	Substation Additions	Lambs - ADD 2ND XFMR (Substation and distribution	$256,500
2 - DA / Telecom	Smart Sensors	ACE NJ Distribution Smart Fault Sensors	$35,625
3 - Infrastructure Renewal	Reclosers	NOVA Recloser Replacement - Technology Upgrade in	$103,950
3 - Infrastructure Renewal	Substation Renewal	Corson T3 Upgrade	$256,500
3 - Infrastructure Renewal	Substation Renewal	Lenox T2 Replacement and Relay Upgards	$256,500
3 - Infrastructure Renewal	Reconductoring	Reconductor Marven Feeders	$2,363
3 - Infrastructure Renewal	Reconductoring	Reconductor Harbor Beach Feeders	$1,575
3 - Infrastructure Renewal	Reconductoring	Recondutor Ontario Feeders	$2,363
3 - Infrastructure Renewal	Cutout Replacement	Porcelain Cutout Replacement	$78,750
3 - Infrastructure Renewal	Substation Renewal	68606 - ACE NJ Clayton: 69/12kv T2 Transformer	$256,500
3 - Infrastructure Renewal	Substation Renewal	Carney's Point Substation Rebuild	$256,500
3 - Infrastructure Renewal	Substation Renewal	ACE NJ Berlin: Upgrade Switchgear A	$22,680
3 - Infrastructure Renewal	Substation Renewal	ACE NJ Berlin Exit Cable Modification/Upgrades	$1,418

For projects related to distribution lines, if a project prevents outages from occurring (equipment replacement/removals), ACE uses the number of expected outages per year times duration of the outage times hourly cost of $150 to determine the amount of O&M saved by avoiding trouble response/switching.

For substation related projects, such as the transformer replacements/new substations, ACE assumes that the project will alleviate the need for a mobile unit in the event of a failure, which is likely to occur over the next 20 years. In this instance, we spread the cost for the transportation/installation/disconnection of the mobile unit ($250K) over 20 years to estimate the yearly amounts.

For other projects where such data are not available, we relied on empirical evidence and estimated the annual O&M expenses for distribution as a function of the gross plant value for distribution assets using historical observations. We then looked at the same data on an incremental basis for recent years.

Historical observations over the past four years (2018 through 2021) shows ACE's annual investment in its distribution related assets add up to around $180 million annually. This expenditure is composed of:

- Corrective maintenance (nearly a third of the annual investments)
- Adding new business (roughly 10% of the annual investments)

- Facility relocation and others (about 1% of the annual investments)
- Capacity Expansion (roughly 10% of the annual investments)
- System performance updates and telecommunication upgrades (the balance, or around 45% of the annual investments)

The first three expenditure types in this list, which add up to nearly 45% (closest 5%) of the total do not contribute to reducing O&M costs. The last two expenditure types do contribute, and the Powering the Future projects are all of the last type.

Figure A-1 compares the gross distribution plant value (in solid navy line, units are on the left Y-axis) to the annual O&M costs (in dotted blue line, units are on the right Y-axis), as reported in ACE's FERC Form 1 filings.[53] It shows that the annual O&M costs and gross distribution plant value are correlated. While the annual O&M costs (blue dotted line) drop in recent years, on average, the annual O&M cost is about 4% of the gross plant value.

FIGURE A-1: GROSS DISTRIBUTION PLANT AND O&M COST (2014-2021)

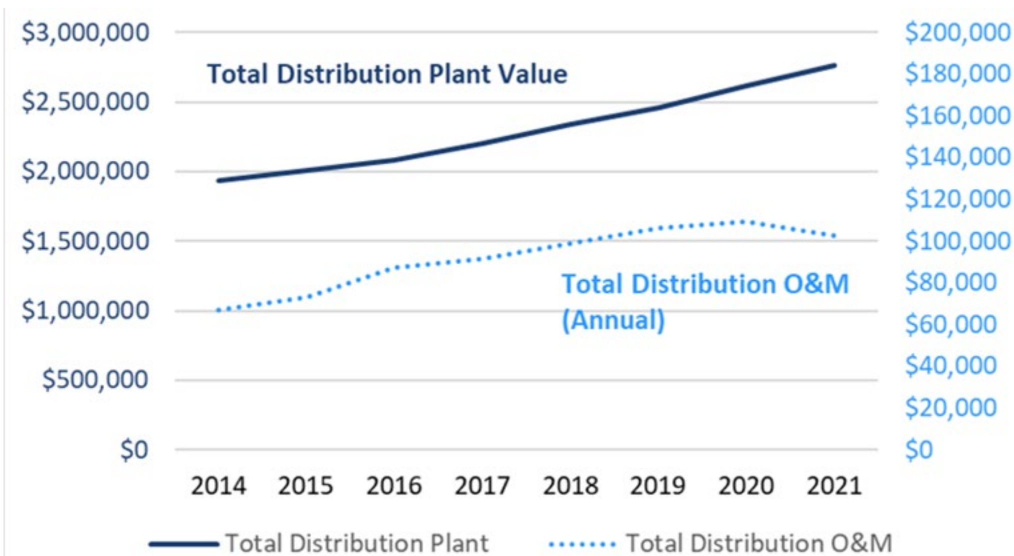
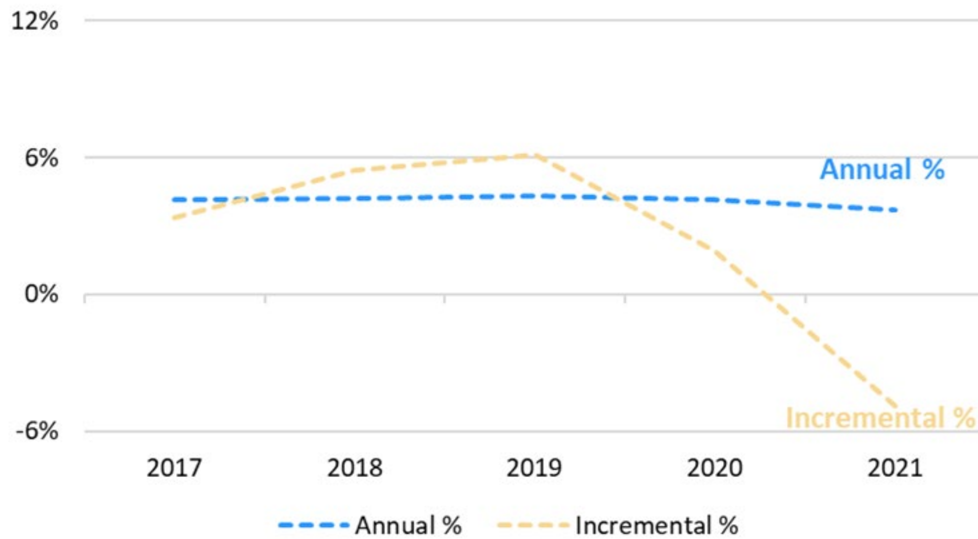


Figure A-2 compares the annual O&M costs share (%) against the gross plant cost. The dotted blue line shows the average share being around 4%, as discussed above in Figure A-1. The blue dotted line in Figure A-2 is the blue dotted line from Figure A-1 divided by the solid navy line from Figure A-1. The orange dotted line in Figure A-2 shows the incremental (i.e., per respective year) O&M costs share (%) against the incremental change in gross plant cost.

---

[53] FERC Form 1 Company Financial and Operating Details, Downloaded from S&P Capital IQ Pro Excel Template Library. Accessed October 5, 2022.

FIGURE A-2: ANNUAL O&M COSTS (% OF GROSS PLANT VALUE) (2017-2021)



We then compare these incremental annual O&M costs of recent years against those from past years.[54] Table A-4 below summarizes our observations. The second row labeled Annual in the Metrics column shows the historically observed ratio of total O&M costs to gross plant—these are what we showed above in Figure A-1 and Figure A-2. The average value of 4% is shown in the Average column. The second row labeled Incremental in the Metrics column shows the historically observed ratio of incremental O&M costs to incremental increase in gross plant—these are what we showed above in Figure A-2. The last 3 rows show the cumulative incremental O&M costs shares against a historical base year (i.e., 2016, 2017, or 2018), as shown in the Base Year column. Taking the sixth row with the Base Year of 2016 as an example, the sixth column labeled 2017 compares the incremental costs of 2017 against the 2016 costs. The seventh column labeled 2018 compares the incremental costs of 2017 and 2018 combined (hence cumulative) against the 2016 costs. The Ratio to Base Year column shows the comparison of the cumulative values through 2021 against the respective Base Years (i.e., 2016, 2017, or 2018). It shows a ratio of ~50% for Base Year 2016 and 2017, and ~20% for Base Year 2018.

[54] For example, if the FERC Form 1 for a given year shows $10 million in gross plant value for distribution assets and the annual O&M expense is $1 million, we assume annual O&M costs are 10% of gross plant. Then, in the following year, if the gross plant value changes to $11 million ($1 million incremental growth) and the annual O&M expenses to $1.06 million ($60,000 incremental growth), we calculate the incremental annual O&M costs to be 6% of the incremental gross plant (the $60,000 incremental O&M costs growth divided by the $1 million incremental in gross plant growth).

TABLE A-4: OBSERVATION SUMMARIES

Metrics	Base Year	2016	2017	2018	2019	2020	2021	Average	Ratio to Base Year
Annual	NA	4.2%	4.2%	4.2%	4.3%	4.2%	3.7%	4.1%	
Incremental	NA	20.0%	3.4%	5.5%	6.1%	1.9%	-4.9%	2.4%	
Incremental	2016		3.4%	4.5%	5.0%	4.1%	2.2%		52%
Incremental	2017			5.5%	5.8%	4.3%	1.9%		47%
Incremental	2018				6.1%	3.7%	0.8%		18%

Using these observations, we developed the following assumptions:

1. Historical O&M costs were about 4% of gross plant value.
2. Annual O&M costs of new equipment installed in the past few years (including the IIP projects from 2018) have lowered the O&M costs by about half, when compared to historically observed 4% of gross plant.
3. To be conservative, we assumed the new projects would reduce annual O&M costs by 25% (half of the 50% observed), which is roughly 1% of the gross plant being added. Considering that only half of all new projects is assumed to contribute to O&M savings, and that all Powering the Future projects fall under such projects (that reduce O&M), this is extremely conservative.

d. Avoided Outage Restoration Costs

Similar to O&M costs, new equipment is likely to reduce outage restoration costs as well. For this CBA, ACE provided the avoided outage restoration costs over the 20-year Study Period by comparing the IIP and Status Quo scenarios for 14 projects (the Rear Lot Conversion project listed in this table accounts for 6 separate projects), as listed in Table A-5:

TABLE A-5: AVOIDED OUTAGE RETORATION COSTS

Category	Sub-program	Project Name	Total Avoided Restoration Cost over 20 years ($)
1 - Targeted Reliability Improvements	Abandoned Line	Abandoned Line Removal	$185,850
1 - Targeted Reliability Improvements	Open Wire Secondaries	Replace open wire secondaries	$37,800
1 - Targeted Reliability Improvements	Rear Lot Conversions	Rear Lot Conversion	$837,375
1 - Targeted Reliability Improvements	Cable URD	70894: URD Cable ACE	$571,200
3 - Infrastructure Renewal	Reconductoring	Reconductor Marven Feeders	$165,900
3 - Infrastructure Renewal	Reconductoring	Reconductor Harbor Beach Feeders	$28,613
3 - Infrastructure Renewal	Reconductoring	Recondutor Ontario Feeders	$165,900
3 - Infrastructure Renewal	Cutout Replacement	Porcelain Cutout Replacement	$498,750
3 - Infrastructure Renewal	Substation Renewal	ACE NJ Berlin Exit Cable Modification/Upgrades	$315,000

For projects related to distribution lines, if the project prevents outages from occurring (equipment replacement/removals), ACE uses the number of expected outages per year, duration of the outage and times hourly cost of $150 (assumed a 3 person crew and $2,500 for material) to determine the amount of restoration cost saved by avoiding trouble response/switching.

e. Avoided Distribution Upgrade Costs

We calculate the avoided distribution upgrade costs through four different variables. First, we analyze the load and solar profiles to see how solar can reduce peak load. We then analyze the solar installation rate and peak load growth rate to assess the growth rate for net peak load (i.e., peak load offset by solar generation). This net peak load would delay the investments needed for accommodating load growth for the distribution network. Thereby, we develop the following four assumptions:

- Distribution Marginal Cost
- Solar Installation Rate
- Solar Profiles
- Load Growth

Each of these are discussed next.

Distribution Marginal Cost: We calculate the distribution marginal cost for upgrades on a $/MW basis. We rely on ACE's previous cost of service studies (vintage 2018 and 2020) to compare the demand related distribution costs.

The 2018 study shows the total distribution assets' cost to be $444 million. The 2020 cost of service study shows the total distribution assets' costs as $469 million and demand related distribution costs as $330 million, indicating that demand related costs are approximately 70% of the total costs. We then apply this 70% ratio to the total distribution cost of $444 million from the 2018 study and calculate the demand related distribution costs as $312 million (for the 2018 study). The difference in demand related distribution costs between the 2018 and 2020 study is $17.7 million.

We then compared the maximum secondary demand between the two studies (2,323 MW in the 2018 study and 2,707 MW in the 2020 study). The difference in maximum secondary demand between the 2018 and 2020 study is 384 MW.

Taking the $17.7 million (difference in demand related distribution costs) and the 384 MW (difference in maximum secondary demand), we calculate the marginal demand cost to be $46/kW (in 2019 dollars), which we then inflate to $53/kW in 2022 dollars.

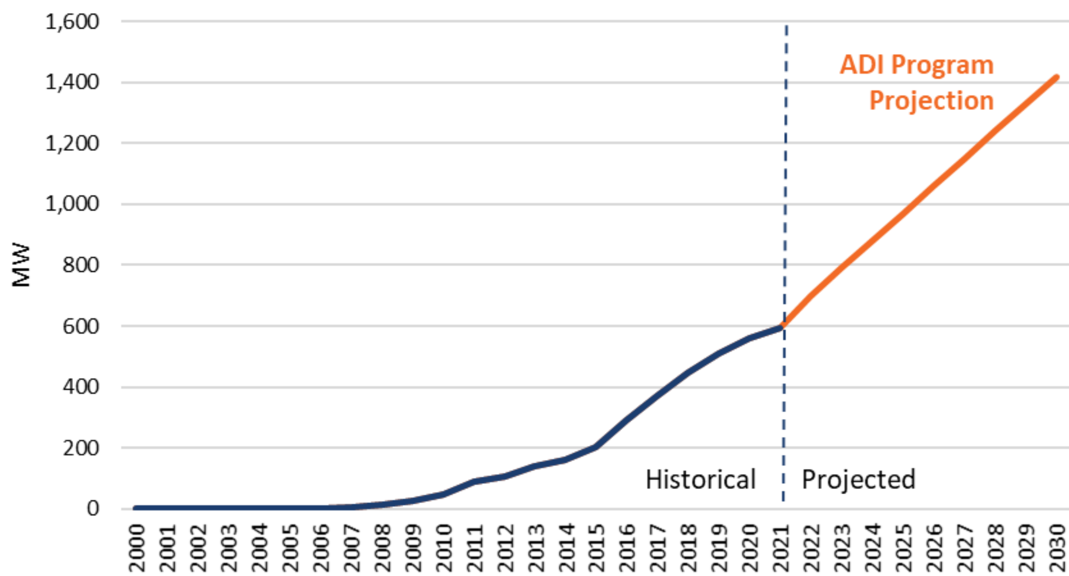
Table A-6 below summarizes the calculations discussed above.

TABLE A-6: AVOIDED DISTRIBUTION UPGRADE COSTS

	2018	2020	Marginal Increase
Costs for All Components (2019 $)	$444,198,197	$469,352,151	$25,153,954
% of Demand Component	N/A	70%	
Demand Component (2019 $)	$312,156,272	$329,832,986	$17,676,714
Maximum Secondary Demand (kW)	2,323,221	2,707,466	384,245
Marginal Demand Cost (2019 $/MW)			$46,004
Marginal Demand Cost (2022 $/MW)			$52,823

Solar Installation Rate: We estimate the compound annual growth rate (CAGR) of solar installations based on the State's policy goals. We base these on historical and projected solar installations in ACE's service territory, as shown in Figure A-3: Cumulative Distributed Solar Installations In Ace Service Territory.

FIGURE A-3: CUMULATIVE DISTRIBUTED SOLAR INSTALLATIONS IN ACE SERVICE TERRITORY



Data from New Jersey Solar Activity Reports[55] and Installation Data through May 31, 2022 show installations in ACE's service territory represent roughly 20% of annual statewide installations in the last 10 years. New Jersey provides incentives to distributed solar (net-metered projects smaller than 5 MW and community solar) through the "Administratively Determined Incentive"

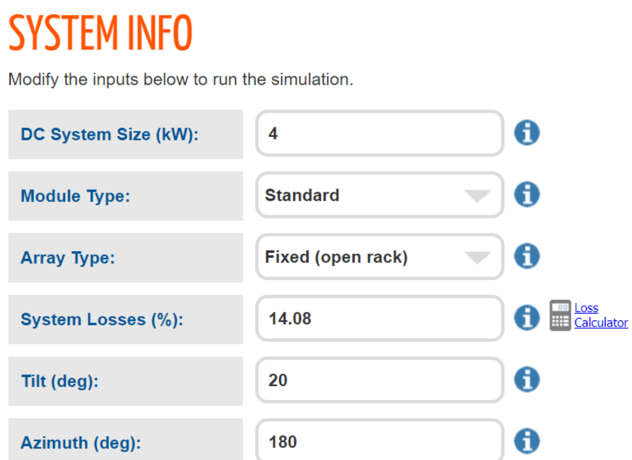
55 New Jersey Solar Activity Reports | NJ OCE Web Site (njcleanenergy.com)

(ADI) program. The plot below ADI statewide capacity goal is 525 MW per year for 2022 and 450 MW per year through 2026.[56] The plot assumes that the statewide capacity goal remains constant at 450 MW/year through 2030 and ACE will continue to represent 20% of annual statewide installations.

The CAGR is **15% per year between 2021 and 2023**. This assumes that ACE installs 20% of the statewide goal of 525 MW in 2022 and 20% of the statewide goal of 450 MW in 2023. The CAGR is **9% per year for 2024 and onwards**. We calculate this based on the cumulative installations between 2023 and 2030, assuming ACE continues to install 20% of the statewide goal of 450 MW/per year.

Solar Profiles: Hourly solar profiles are based on NREL's PV Watts Calculator,[57] using the default PV settings and the zip code where the transformers are located at in New Jersey. The default PV setting in NREL's PV Watts Calculator is shown in Figure A-4.

FIGURE A-4: NREL PV WATTS DEFAULT ASSUMPTIONS



Each of the 23 transformers analyzed under category 4 (Solar/DER Enablements) is located in one of the following four planning areas in ACE's service territory: Cape May, Glassboro, Pleasantville, Winslow. We use data for these four areas to develop the hourly (8,760) solar profiles with PVWatts. ACE also provided hourly (8760) solar generation "multipliers" for each of the four planning areas. The solar generation multipliers are values between 0 and 1, and are meant to represent the hourly solar generation as a share of the capacity of the installed solar panels. We

56 Statewide solar deployment quantities are based on the Solar Act of 2021 as implemented under the ADI program

57 https://pvwatts.nrel.gov/

use the hourly solar profiles and multipliers to project future years' solar generation. The underlying assumption is that solar generation retains the same hourly profiles in future years.

Gross Load Growth: We estimate the expected gross load growth rate for ACE as 1.10% per year. We calculate this value based on forecasts of future net load and DER in ACE's service territory. Table A-7 below illustrates the calculation and shows the data sources. As shown in the table, we obtain the 2022 net load, and DER adjustments (distributed solar, energy storage, and plug-in electric vehicles) for ACE from the PJM Load Forecast report.[58] PJM's net load value represents the peak load after reductions for solar and energy storage and additions for plug-in electric vehicles. To obtain gross load, we add back the solar and energy storage load and subtract the plug-in vehicle load. We project the net load and DER adjustments separately for the next 10 years by applying ACE's internal projected growth rates. We then sum the projected net load and DER adjustments to obtain the projected gross load. We finally calculate the CAGR between 2022 and 2031 to obtain the average growth rate for gross load.

We assume the gross load growth rate and DER growth rate above apply to all transformers, which we use to estimate the net peak load of each transformer in future years.

[58] PJM Load Forecast Report, January 2022 https://www.pjm.com/-/media/library/reports-notices/load-forecast/2022-load-report.ashx. ACE is represented as the AE Locational Deliverability Area within PJM.

TABLE A-7: CALCULATION OF GROWTH RATE FOR GROSS LOAD

	Unit			2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Net Load	MW	[1]		2,691									
DER Adjustments													
Distributed Solar	MW	[2]		232									
Distributed Battery Storage	MW	[3]		0									
Plug-In Electric Vehicle	MW	[4]		-10									
Total	MW	[5]		222									
ACE Forecasted Net Load Growth Rate	%	[7]	**0.08%**										
ACE Forecasted Net Load	MW	[8]		2,691	2693	2695	2697	2699	2701	2703	2705	2707	2709
ACE Forecasted DER Growth Rate	%	[9]	**9.56%**										
ACE Forecasted DER Adjustment	MW	[10]		222	243	266	292	320	350	384	421	461	505
Gross Load	MW	[11]		2,913	2,936	2,962	2,989	3,019	3,052	3,087	3,126	3,168	3,214
Gross Load CAGR	%	[12]	**1.10%**										

Sources and Notes:

[1]: PJM 2022 Load Forecast Report Table D-1 for AE

[2]: PJM 2022 Load Forecast Report Table B8-a for AE

[3]: PJM 2022 Load Forecast Report Table B8-b for AE

[4]: PJM 2022 Load Forecast Report Table B8-c for AE

[5]= [2] + [3] + [4]

[6]= [1] + [5]

[7]: From ACE

[8]: 2022 value is from Row [1]. After 2022, Row [1] x [7]

[9]: From ACE

[10]: 2022 value is from Row [5]. After 2022, Row [5] x [9]

[11]= [8] + [10]

[12]: CAGR = Compound Annual Growth Rate between 2022 and 2031

f. Reduced Social Cost of Carbon Emissions

We obtain the amount of reduced greenhouse gas emissions due to each MWh of solar generation based on the emission intensity of New Jersey electricity grid. The Energy Information Administration (EIA) estimates the carbon dioxide emission intensity of New Jersey to be 537 lb/MWh.[59] We multiply the emission intensity value by the MWh of solar generated in a given year to obtain the total amount of carbon dioxide (converted from pounds to metric tons) avoided in that year. We multiply the total amount of carbon dioxide avoided by the social cost of carbon to obtain the economic value of reduced emissions.

[59] EIA New Jersey Electricity Profile 2020, https://www.eia.gov/electricity/state/newjersey/

We obtain the social cost of carbon from a report by Resources for the Future (RFF) for valuing the change in GHG emissions using the 2% real discount rate (see Table A-8).[60] The values were recently adopted by the New York Department of Environmental Conservation (DEC) for estimating the costs of changes in GHG emissions.[61] The RFF study uses the results from the same models for estimating the damages caused by climate change as the U.S. Interagency Working Group in the most recent report released in February 2021, but assumes a lower discount rate of 2% based on updated analysis of available market data and reports the values.

TABLE A-8: US SOCIAL COST OF CARBON DIOXIDE BY DISCOUNT RATE (2020$ PER METRIC TON OF CO2)

	Recommended Range of Discount Rates			
Emissions Year	3% Average	2% Average (Central Rate)	1% Average	0% Average
2020	51	121	406	2,130
2021	52	123	409	2,125
2022	53	124	411	2,119
2023	54	126	414	2,114
2024	55	128	416	2,108
2025	56	129	418	2,103
2026	57	131	421	2,098
2027	59	132	423	2,093
2028	60	134	426	2,088
2029	61	136	428	2,083
2030	62	137	430	2,077
2031	63	139	433	2,072
2032	64	141	435	2,067
2033	65	142	437	2,061
2034	66	144	440	2,056
2035	67	146	442	2,050
2036	69	147	444	2,045
2037	70	149	446	2,040
2038	71	151	449	2,035
2039	72	152	451	2,030
2040	73	154	453	2,024
2041	74	156	456	2,020
2042	75	158	459	2,015

60 New York State Energy Research and Development Authority and Resources for the Future. "Estimating the Value of Carbon: Two Approaches." Revised April 2021. This report uses the results from the U.S. Government report U.S. Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990, February 2021.

61 New York Department of Environmental Conservation, Establishing a Value of Carbon: Guidelines for Use by State Agencies, October 2021. The projected social cost of carbon is available here: https://www.dec.ny.gov/docs/administration_pdf/vocguid22.pdf

The values in Table A-8 above are in 2020 dollars. We apply historical inflation rate of 4.7% to convert 2020 dollars to 2021 dollars, and 8.3% to convert 2021 dollars to 2022 dollars (See the discussion on inflation rate in the beginning of this appendix.) Based on this conversion, we obtain the following values used in this CBA as shown in Table A-9.

TABLE A-9: SOCIAL COST OF CARBON

Year	Social Cost of Carbon ($/metric tons of CO2 in 2022 USD)
2023	$143
2024	$145
2025	$146
2026	$149
2027	$150
2028	$152
2029	$154
2030	$155
2031	$158
2032	$160
2033	$161
2034	$163
2035	$166
2036	$167
2037	$169
2038	$171
2039	$172
2040	$175
2041	$177
2042	$179

g. Reduced Electricity Costs

Locational Marginal Prices (LMP): We obtained historical hourly LMPs observed for the first 8 months of 2022 from PJM.[62] For the last 4 months of 2022, we estimated 2022 LMPs by scaling the LMPs observed for the last 4 months of 2021 by the ratio of the average of hourly LMPs in 2022 to the average of hourly LMPs in 2021 for the first 8 months. LMPs are assumed

[62] PJM, https://www.pjm.com/markets-and-operations/energy/real-time/historical-bid-data

to remain constant in real terms in the future years. Table A-10 summarizes the monthly average LMPs for 2022. Note that the reduced electricity cost is calculated on an hourly basis by multiplying the hourly LMP with hourly solar generation.

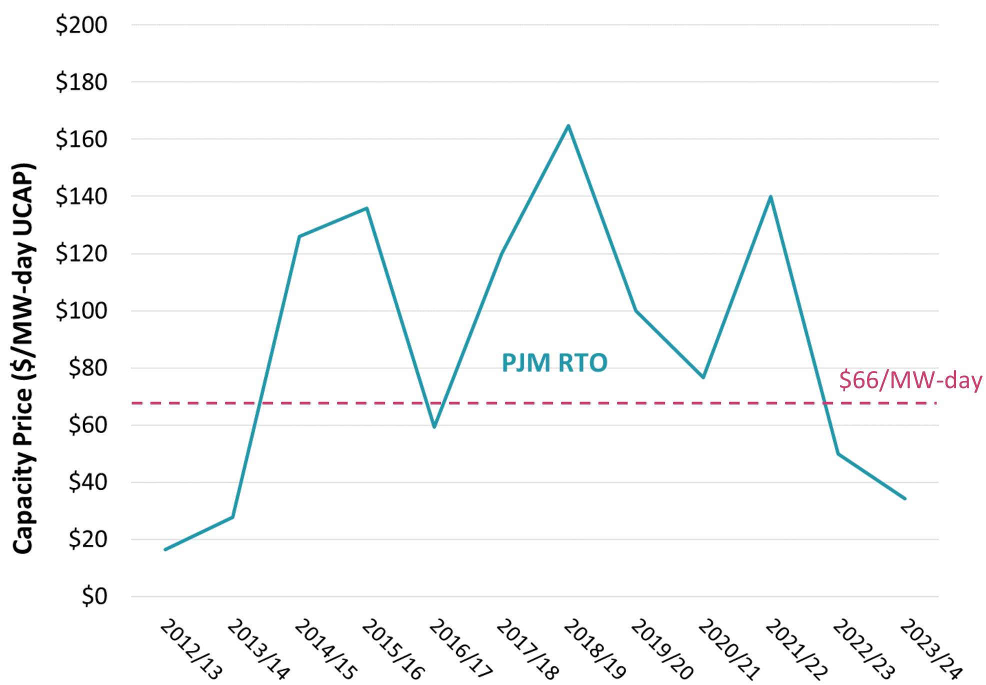
TABLE A-10: MONTHLY AVERAGE LMPS IN 2022

Year 2022	Monthly Average LMP ($/MWh)
January	$67.53
February	$46.66
March	$39.78
April	$55.63
May	$62.51
June	$64.36
July	$82.68
August	$94.33
September	$93.37
October	$109.28
November	$107.83
December	$69.68

Capacity Prices: The average of the clearing price in PJM's 2022/2023 Base Residual Auction (BRA) (EMACC: $97.86/MW-day) and 2023/2024 BRA (RTO: $34.13/MW-day) are used as the capacity price of 2023 in order to estimate the avoided capacity cost by peak load reduction due to increased DER installations. This results in a capacity price of $66/MW-day (2022 USD).[63] Capacity prices are assumed to remain constant in real terms through the Study Period. A 2.35% inflation rate is applied to the capacity prices in future years to obtain the nominal prices (see earlier discussion on inflation rates in this appendix). As shown in Figure A-5 below, using the latest BRA prices for future years leads to a conservative assumption compared to the capacity prices in the last decade where significantly higher prices were observed.

[63] For avoided capacity costs, we used the average of capacity price from PJM 2022/2023 BRA for EMACC, which was $97.86/MW-day and PJM 2023/2024 BRA for RTO, which was $34.13/MW-day, as the 2023 capacity price.

FIGURE A-5: HISTORICAL PJM RTO CAPACITY PRICES (NOMINAL)



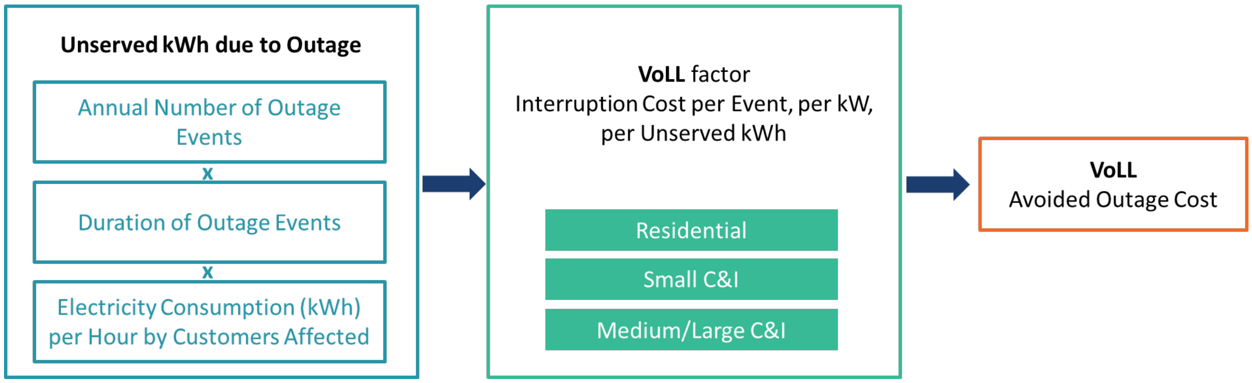
Utility Bills: We assumed a residential rate of $0.22/kWh to estimate the reduced utility bills to customers who installed DERs. We obtained this average residential rate from ACE's previous base rate case filings.[64]

h. Value of Lost Load (VoLL)

We estimate the benefits associated with reduced outages using the Value of Lost Load (VoLL). Figure A-6 presents an overview of the process to calculate VoLL in this CBA.

[64] Direct Testimony Of Kristin M. McEvoy on Behalf of Atlantic City Electric Company Before The New Jersey Board of Public Utilities. BPU Docket Number ER20120746

FIGURE A-6: OVERVIEW OF VOLL ESTIMATION



We refer to the general methodology of VoLL calculation adopted in a prior study, though some assumptions may be different in this CBA.[65] For VoLL factors, we rely on the Lawrence Berkeley National Laboratory's (LBNL) 2015 meta study (LBNL VoLL Study),[66] a source that has been widely cited in past VoLL studies. The 2015 LBNL VoLL Study is an econometric study that estimates VoLL using past survey data from electric utilities across the United States. We do not reproduce the econometric analysis as part of this CBA but rather use the results from the LBNL VoLL Study to calculate outage reduction related benefits for ACE.

For each project, we calculate VoLL separately for each customer class. Given that the electricity use cases differ largely across different customer classes, the costs incurred from an outage can vary widely based on the customer class under consideration. For an industrial customer, this may involve a slew of labor and production related costs while for the typical residential customer, it may largely involve inconveniences of not having power.

Note that customer classes used for the VoLL analysis have been defined as per the 2015 LBNL VoLL Study. The 2015 LBNL VoLL Study defines small commercial and industrial (C&I) customers as those having less than 50,000 kWh of consumption annually, and medium and large C&I customers are those with an annual consumption greater than 50,000 kWh.

We calculate the VoLL values separately for each customer class in a given year by multiplying the unserved kWh due to outage and the corresponding VoLL factor. Annual VoLL values for each customer class are then added to obtain the total VoLL for each project in a given year.

---

65 Peter Fox-Penner, William P. Zarakas, Analysis of Benefits: PSE&G's Energy Strong Program, 2013.

66 Michael J. Sullivan, Josh Schellenberg and Marshall Blundell, Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States, January 2015 (LBNL-6941E).

We obtain the "Unserved kWh due to Outage" in a year by analyzing the annual number of outages, duration of outage events, and the electricity consumption per hour by the customers affected. ACE provided the estimated annual count of outage events and their durations for the Status Quo and IIP scenarios, respectively. These estimates were provided by project over the 20-year time horizon. The IIP projects proposed by ACE that offer VoLL benefits are expected to either reduce or completely eliminate outages. The duration of outages may or may not decrease.

For each project, we obtain the number of outages from ACE under the Status Quo and IIP scenarios. We then allocate the total outages to each customer class based on the system-wide proportions of customer counts in each customer class. We obtain the number of customers by customer class from ACE's cost of service study. We then map the customers onto the three classes (residential, small C&I, and medium/large C&I classes) based on their average energy consumption to match the 2015 LBNL VoLL Study assumptions (e.g., the split between small C&I and medium/large C&I is 50,000 kWh per year). Table A-11 below shows the count of customers by customer class. For example, if the total customer-outage number is 1,500, then we assume 1,337 (89.1%) of this total is experienced by residential customers; 153 (10.2%) are allocated to small C&I customers; and 10 (0.6%) are allocated to medium/large C&I customers.

TABLE A-11: COUNT OF ACE CUSTOMERS BY CUSTOMER CLASS

Customer Class	Number of Customers	Percentage
Residential Customers	494,884	89.1%
Small C&I Customers	56,730	10.2%
Medium/Large C&I Customers	3,506	0.6%

We also obtain the average annual energy consumption as shown in Table A-12 below from ACE's 2020 cost of service study. By using the annual average consumption, we can calculate the average consumption in a given period of time, such as one hour, for each customer class.

TABLE A-12: ANNUAL AVERAGE ELECTRICITY CONSUMPTION FOR EACH CUSTOMER CLASS

Customer Class	Annual Average Electricity Consumption (kWh)
Residential Customers	7,924
Small C&I Customers	21,997
Medium/Large C&I Customers	930,151

We calculate the "Unserved kWh due to Outage" for each project by customer class under the Status Quo and IIP scenarios, and obtain the incremental effect of IIP. "Unserved kWh due to

Outage" is obtained by multiplying the count of customer outages, outage duration, and average kWh consumption had there not been an outage.

The VoLL factor refers to the outage cost incurred by the customer per unserved kWh. We leverage VoLL factors for different customer classes from the 2015 LBNL VoLL Study.[67] For this CBA, we utilize the "cost per unserved kWh" values provided in Table A-13. We convert the VoLL factors provided in 2013 dollars to 2022 dollars based on historical inflation rates. For outages that fall between the specified interruption durations given in the LBNL report, we use linear interpolation to estimate the cost per unserved kWh. The final values used are shown in Table A-14.

TABLE A-13: VOLL FACTORS[68]
INTERRUPTION COST PER EVENT, AVERAGE KW AND UNSERVED KWH (U.S.2013$) BY DURATION AND CUSTOMER CLASS

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Medium and Large C&I (Over 50,000 Annual kWh)						
Cost per Event	$12,952	$15,241	$17,804	$39,458	$84,083	$165,482
Cost per Average kW	$15.9	$18.7	$21.8	$48.4	$103.2	$203.0
Cost per Unserved kWh	$190.7	$37.4	$21.8	$12.1	$12.9	$12.7
Small C&I (Under 50,000 Annual kWh)						
Cost per Event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per Average kW	$187.9	$237.0	$295.0	$857.1	$2,138.1	$4,128.3
Cost per Unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0
Residential						
Cost per Event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per Average kW	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per Unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3

Notes: The CBA utilizes data in the rows "Cost per Unserved kWh"

[67] Michael J. Sullivan, Josh Schellenberg and Marshall Blundell, Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States, January 2015 (LBNL-6941E).

[68] Table obtained from Michael J. Sullivan, Josh Schellenberg and Marshall Blundell, Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States, January 2015 (LBNL-6941E).

TABLE A-14: VOLL FACTORS: INTERRUPTION COST PER UNSERVED KWH (2022 USD)

Interruption Duration (Minutes)	Cost per Unserved kWh ($/kWh in 2022 USD)		
	Residential	Small C&I	Medium/Large C&I
Momentary	$38.94	$2,841.14	$240.31
0.5	$7.43	$597.44	$47.13
0.75	$5.80	$484.59	$37.30
1	$4.16	$371.75	$27.47
1.25	$3.98	$363.27	$26.45
1.5	$3.80	$354.80	$25.43
1.75	$3.62	$346.32	$24.42
2	$3.44	$337.85	$23.40
2.25	$3.27	$329.37	$22.38
2.5	$3.09	$320.90	$21.36
2.75	$2.91	$312.42	$20.34
4	$2.73	$303.95	$19.32

Appendix B: CBA Analyses Details

This appendix includes two detailed CBA workbooks, provided as separate Excel files.

Appendix B - CBA Analyses Workbook for Categories 1, 2, 3, and 5

CBA for Power the Future (PTF) Projects in Category 1-3 and 5

Rationale for Quantifying Benefits

Four benefit components including Accelerated Capital Investments, Avoided O&M Costs, Avoid Outage Restoration Costs, and Value of Lost of Load (VoLL) are quantified.

- Accelerated Capital Investments: Accelerated Capital Investments are considered as benefits.
- Avoided O&M Costs: Replacing older infrastructure assets with new infrastructure results in lower O&M expenditures.
- Avoided Outage Restoration Costs: New infrastructure will have fewer equipment failures and lower equipment restoration costs.
- Value of Lost Load (VoLL): Avoided customer outage costs based on VoLL.

Model Description

Accelerated Capital Investments:

<u>Step 1:</u> Lay out assumptions for Status Quo and Infrastructure Investment Program (IIP) scenarios.

Status Quo: The project will be completed in 20 years. As a conservative assumption, we allocate the project capital investments over 20 years evenly.

***IIP*:** The project will be completed in the next 5 years.

<u>Step 2:</u> Calculate the Accelerated Capital Investments in Nominal, Real, and Real-Discounted terms.

Other Avoided Costs:

Calculate Avoided O&M Costs and Avoided Outage Restoration Costs based on ACE provided data and relevant assumptions in Nominal, Real, and Real-Discounted terms.

VoLL:

<u>Step 1:</u> Lay out assumptions for Status Quo and IIP scenarios below.

Status Quo: In the absence of the project, count of residential, small C&I (less than 50,000 MWh annual consumption), and medium/large C&I customers (above 50,000 MWh annual consumption) affected; count and duration of outage events.

IIP: If the project is implemented, count of residential, small C&I, and medium/large C&I customers affected; count and duration of outage events.

<u>Step 2:</u> Estimate the reduced annual customer interruption minutes and unserved energy in MWh based on the data in Step 1.

<u>Step 3:</u> Calculate interruption cost $/MWh using VoLL factors and calculate VoLL by multiplying the reduced unserved energy (MWh) and interrruption cost ($/MWh).

Finally, B/I Ratio is calculated considering the initial investment costs and the quantified benefits above for each

Appendix B - CBA Analyses Workbook for Category 4

CBA for Power the Future (PTF) Projects in Category 4

Benefits

- Avoided Distribution Upgrade Costs due to peak load reduction resulting from higher level of DER installations in the Infrastructure Investment Program (IIP) Scenario, in comparison to the Status Quo scenario where feeders are closed to new DER installations.
- Avoided or Reduced Capacity Costs due to peak load reduction in the IIP scenario.
- Reduced Social Cost of Carbon Emissions due to increased solar generation in the IIP scenario.
- Reduced Electricity Costs of power production due to increased solar generation in the IIP scenario.

Costs

- IIP Investment Costs to upgrade the transformer and feeders.
- Customer DER Investments to install rooftop solar systems.

Model Description

Step 1: Lay out assumptions for Status Quo and IIP scenarios

Status Quo: No solar increase in future years since feeders are closed to new solar installations.

IIP: Installed solar capacity grows year by year until new maximum hosting capacity of the transformer is reached.

Step 2: Obtain incremental peak load reduction (in MW) achieved under IIP compared to Status Quo to calculate the Avoided Distribution Upgrade Costs and Avoided Capacity Costs.

Step 3: Calculate the increased solar generation achieved under IIP compared to Status Quo to calculate

Appendix C: Glossary

ACE	Atlantic City Electric
ASR	Automatic Sectionalizing and Restoration
ATB	Annual Technology Baseline
B/I ratio	Benefit to Initial Investment Cost Ratio
BPU	New Jersey Board of Public Utilities
BRA	PJM Base Residual Auction
C&I	Commercial and Industrial
CAGR	Compound Annual Growth Rate
CBA	Cost-Benefit Analysis
CEBA	Clean Energy Buyers Association
CPI	Consumer Price Index
DA	Distribution Automation
DEC	New York Department of Environmental Conservation
EIA	Energy Information Administration's
EMP	Energy Master Plan
ESG	Environmental, Social, and Governance
EV	Electric Vehicle
GWRA	Global Warming Response Act
IIP	Infrastructure Investment Program
ITC	Investment Tax Credits
LBNL	Lawrence Berkeley National Laboratory
LMP	Locational Marginal Prices
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
OWEDA	Offshore Wind Economic Development Act
PHI	Pepco Holdings LLC
RFF	Resources for the Future
RPS	Renewable Portfolio Standard
SREC	Solar Renewable Energy Certificate
SuSI	Successor Solar Incentive
TI	Transition Incentive
VoLL	Value of Lost Load

NORTH AMERICA | EUROPE | ASIA-PACIFIC

THE Brattle GROUP