REDACTED

UNITIL ENERGY SYSTEMS, INC.

JOINT SUPPLEMENTAL TESTIMONY

OF

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(Kingston Solar Project Panel)

Exhibit SP-1 (Supplemental)

New Hampshire Public Utilities Commission

Docket No. DE 22-073

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Exhibits:

I. INTRODUCTION

Q. Please introduce the members of the Kingston Solar Project Panel.

A. The members of the Kingston Solar Project Panel ("SP") and the sponsors of this Supplemental Testimony are Kevin E. Sprague, Jacob S. Dusling, Andre J. Francoeur, Todd R. Diggins, Christopher J. Goulding, and Jeffrey M. Pentz on behalf of Unitil Energy Systems, Inc. ("Unitil" or the "Company").

Q. Have you previously submitted testimony in this proceeding?

A. Yes. We submitted direct testimony (individually and jointly) to the New Hampshire Public Utilities Commission (the "Commission") on October 31, 2022, in support of the Company's proposed 4.99 megawatt ("MW") alternating current ("AC")[1] utility-scale photovoltaic ("PV" or "solar") generating facility located in Kingston, New Hampshire (the "Kingston Solar Project," or the "Project"). We also appeared at the Commission's prehearing conference on January 18, 2023 and the technical session that followed immediately thereafter.

Q. Why is the Company filing Supplemental Testimony?

A. At the January 18, 2023 prehearing conference, the Commission expressed an interest in obtaining additional information concerning potential risks associated with the Kingston Solar Project. The Commission and intervenors also expressed

[1] Solar cells produce direct current ("DC") electricity, which is then converted to AC electricity by a solar power inverter, which allows the electricity to be delivered to the electric distribution system. The Project assumptions in both the initial filing and this supplemental update for system capacity are based on the proposal identified as the best overall value in each stage of the Company's two-stage competitive solicitation. As discussed herein, the updated design for the Project is 6.50 MW (DC) / 4.88 MW (AC).

an interest in understanding the sensitivity of the Benefit-Cost Analysis to certain assumptions and inputs. That interest is consistent with New Hampshire Revised Statutes Annotated ("RSA") 374-G:5 which requires, among other things, a discussion of the potential risks associated with a proposed project. Accordingly, this Supplemental Testimony provides additional qualitative and quantitative information concerning potential project risks, and a discussion of the ways in which Unitil is measuring, managing, and mitigating those risks.

In addition, Unitil explained in its initial filing that it planned to issue a final Engineering, Procurement and Construction ("EPC") Request for Proposals ("RFP") based on responses to its Preliminary EPC RFP.[2] As discussed in Section II, the Company has received and evaluated responses to its Final EPC RFP and has selected a winning bidder. Accordingly, the Company has revised its Benefit-Cost Analysis with updated cost and performance estimates drawn from the winning Final EPC RFP proposal. Our Supplemental Testimony explains how that information has been reflected in the Company's updated Benefit-Cost Analysis.

Based on updated information and analyses discussed throughout our testimony, the Project is highly likely to create positive net benefits for customers in particular, and the State of New Hampshire in general. That is the case looking solely at direct

[2] Exh. JSD-1, at Bates pages 000051-000053.

benefits; it is even more so considering indirect benefits.[3] In keeping with the Company's proposed two-stage process,[4] the updated information and analyses further support the Company's request for a Commission finding that the Project is in the public interest.

Q. How is the balance of your testimony organized?

A. The remainder of our testimony is organized as follows:

- Section II updates the status of the EPC RFP process;
- Section III discusses the specific updates to the Benefit Cost Analysis, explains the increased Benefit-Cost ratio in the context of those updates, and provides an updated Bill Impact analysis;
- Section IV presents the stress test and a simulation analysis the Company performed to quantitatively assess Project risk; and
- Section V summarizes and concludes our testimony.

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3 *See generally* Exhs. GPP-1 and GPP-2 (quantifying $11.2 million (on an NPV basis) of direct, indirect, and induced economic benefits to New Hampshire, $1.9 million (on an NPV basis) in avoided CO2 and NOx benefits, and $566,963 in aggregate Demand Reduction Induced Prices Effects (DRIPE) benefits to New Hampshire load).

4 Exhibit KES-1, at Bates pages 000033-000035.

II. STATUS OF THE EPC RFP PROCESS

Q. Please summarize the status of Unitil's EPC RFP process.

A. As discussed in our initial testimony, the Company conducted a Preliminary EPC RFP in Stage 1 of the procurement process,[5] the results of which are reflected in Exhibit FDGP-1 (Benefit-Cost Analysis) to the initial filing. After the initial filing, Unitil moved to Stage 2 of the procurement process and, on November 30, 2022, issued the Final EPC RFP (Exhibit SP-2). The Company received responses to the Final EPC RFP on January 20, 2023.

Q. Has the Company completed its evaluation of the Final EPC RFP proposals and did it select an EPC contractor?

A. Yes, Unitil has completed its evaluation and ReVision Energy's ("ReVision") proposal provided the best overall value and scored the highest of all the responses received.[6] Therefore, Unitil has selected ReVision as its EPC contractor for the Kingston Solar Project, subject to negotiating and executing a final contract.

[5] Exhibit JSD-1, at Bates pages 000051-000052.

[6] Each proposal was evaluated and ranked on a quantitative and qualitative basis by criteria that included but was not limited to: Overall company background, history and key characteristics; Experience with similar sized PV projects; Ability to comply/meet the components of the RFP; Ability to execute the work as evidenced by the project execution plan and schedule; Overall pricing proposal; Major equipment warranty periods; Origin of manufacture of major equipment; and Involvement of local businesses and/or local labor.

III. UPDATED BENEFIT-COST ANALYSIS AND BILL IMPACTS

A. Updates to Assumptions and Inputs in the Benefit-Cost Analysis

Q. Please summarize the updates that have been made to the Benefit-Cost Analysis.

A. As summarized in Table 1 below, Unitil has updated and added new assumptions and variables to the Benefit-Cost Analysis (Exhibit SP-7) in five general categories: (1) Capital Costs; (2) Expenses; (3) Performance Characteristics; (4) Avoided Customer Cost Inputs; and (5) Federal Tax Credit.

Table 1: Summary of Updates to Benefit-Cost Analysis

Category	Update
Capital Costs	Initial Capital Costs Inverter Replacement Cost Capital Replacement Costs
Expenses	Operating & Maintenance ("O&M") Expense
	Decommissioning Expense
Performance Characteristics	Project Life (30-Year Project Life to 40-Year Project Life)
	Nameplate Capacity and Degradation Rate
	Annual Production (kWh)
	Capacity at Peak Hour (kW Monthly & Annual)
Avoided Customer Cost Inputs	Energy Rate Futures
	ISO-New England ("NE") Open Access Transmission Tariff ("OATT") Rates Where Applicable
Federal Tax Credit	From Investment Tax Credit to Production Tax Credit

The following sections discuss the updates to each of the five general categories.

<u>Capital Costs</u>

Q. Please summarize the updates that have been made to the capital costs and the purpose for those updated inputs and assumptions.

A. The updates that have been made to capital costs in the Benefit-Cost Analysis are summarized in Table 2, below.

Table 2: Summary of Updates to Capital Costs

Update	Purpose	Tab in Benefit-Cost Analysis Model (Exh. SP-7)
Initial Investment Cost	Reflect updated costs provided in ReVision's RFP response Reflect refinements to System Upgrade and Land Acquisition Costs	"Capital Costs"
Inverter Replacement Cost	Reflect updated costs and timing of replacement provided in ReVision's RFP response	"Capital Costs"
Capital Replacement Cost Funding	Add capital costs for replacement of equipment based on information provided by ReVision	"Maintenance Capital Costs"

Q. How do the capital investment costs received in the Final EPC RFP compare to those received in the Preliminary RFP?

A. As shown in Table 3 (below), the updated capital costs provided in response to the Final EPC RFP are generally consistent with the total costs provided in response to the Preliminary EPC RFP.

Table 3: Comparison of Capital Costs (Preliminary EPC RFP vs. Final EPC RFP)

Initial Capital Cost Element	Estimated Cost (Preliminary EPC RFP)[7]	Estimated Cost (Final EPC RFP)
PV Installation (Includes Inverter 1)	[redacted]	[redacted]
Electric System Upgrades	$600,000	$560,000
Land Improvements	[redacted]	[redacted]
Land Acquisition[8]	$857,938	$820,438
TOTAL	[redacted]	[redacted]

Q. Has the Project's Benefit-Cost ratio decreased as a result of the increased costs summarized in Table 3?

A. No, it has not. Rather (and as discussed below and in Section III.B), the combination of higher costs and increased benefits resulted in an increased Benefit-Cost ratio.

Q. Please provide additional detail regarding the updates to the initial capital costs summarized in Table 3.

A. First, the total PV installation cost increased by less than $700,000, about a 5 percent variance. This relatively modest increase is driven by changes to the design of the Project, which enhance overall reliability, production, and performance, and all of which translate into increased customer benefits. Second, the increase in the Inverter Replacement cost is driven by a higher estimated cost for the equipment, due largely to the change in the design from the initial filing (i.e., using a string inverter design instead of central inverters)[9] and moving the replacement year from Year 15 to Year

7 Exh. FDGP-2 (CONFIDENTIAL), "Capital Costs" tab.

8 Assumes 50 percent of total Land Acquisition Costs are allocated to the Kingston Solar Project.

9 A string inverter design typically requires more inverters because each, individual inverter is converting less power for fewer PV modules. A central inverter design, on the other hand, requires a smaller number of total inverters because each, individual inverter is larger and converting power for a greater number of PV modules. Generally speaking, although the string inverter design being proposed for the Kingston Solar Project is more expensive than the central inverter design utilized in the initial filing, it helps mitigate production risk because if one string fails, the electricity output for the entire array is not lost, only the power being converted from the PV modules associated with that string.

20 based on ReVision's guidance. Third, the Company made a downward adjustment to its estimated cost for system upgrades based on the estimate for the System Impact Study in ReVision's proposal. Lastly, the Company updated the land acquisition costs to reflect the lower agreed upon purchase price [redacted] for the property based on its appraised value.

Q. Please describe the purpose of the Capital Replacement Costs added to the Benefit-Cost Analysis and how the Company developed its estimate.

A. Apart from the inverters, Unitil's initial Benefit-Cost Analysis did not include costs for future capital replacements ("Maintenance Capital Costs"). Upon further analysis, the Company concluded that it is prudent and a more conservative approach to account for the replacement of equipment to avoid lost production outside of the warranty period. Accordingly, the Company updated its Benefit-Cost Analysis to include Maintenance Capital Costs for PV modules and the racking system.

As shown on the tab "Maintenance Capital Costs" in Exhibit SP-7, the Company estimates a Maintenance Capital Cost for PV modules and associated equipment of [redacted] beginning in Year 26, which escalates to an annual amount of [redacted] in Year 40. For racking, the Company estimates a Maintenance Capital Cost of [redacted] beginning in Year 21, which escalates to an annual amount of [redacted] in Year 40.[10]

[10] As shown on the tab "Maintenance Capital Costs" in Exhibit SP-7, the Company applied a 2 percent escalation rate to the estimated maintenance capital costs.

The Company also added Schedule 11, which was not included in the initial Benefit-Cost Analysis, to Exhibit SP-7. Schedule 11 calculates tax depreciation for the Maintenance Capital which was necessary due to the large number of cost vintage years.

The Company developed its estimate for Maintenance Capital Costs based on input from ReVision (*see* Exhibit SP-5, response to Question 3). That data indicates that the failure rate of racking, modules, and inverters (and other components) is extremely low, with a fraction of 1 percent of components requiring service in a given year. Taking that information into account, the Company assumed replacement costs of 0.5 percent of the original cost for modules and racking for the first ten years after the applicable warranty periods (*i.e.*, years 26 through 35 for modules and years 21 through 30 for racking). Thereafter, the Company assumed replacement costs of 1 percent of the original cost for years 36 to 40 for modules and years 31 to 40 for racking after the warranty period. In total, the Company has included Maintenance Capital Costs of approximately $2 million over the life of the project.

Expenses

Q. Please summarize the updates that have been made to expenses and the basis of those updates.

A. The updates that have been made to expenses in the Benefit-Cost Analysis are summarized in Table 4, below.

Table 4: Summary of Updates to Expenses

Update	Purpose	Tab in Benefit-Cost Analysis Model (Exh. SP-7)
Maintenance O&M Expense	Reflect ReVision's RFP Response	"O&M Expense"
Decommissioning Expense	Add decommissioning expense based on estimate provided by ReVision in RFP process	"Decommissioning Expense"

Q. What is driving the update to the estimate for Maintenance Expense?

A. As shown in Exhibit FDGP-2, Schedule 3 of Unitil's initial filing, based on a response to the Preliminary EPC RFP, the Company estimated an O&M cost of [redacted] in Year 1. The Company adjusted that estimate for inflation over the balance of the Project's expected 30-year design life. The Company revised its O&M estimate based on information provided by ReVision in response to the Final EPC RFP. The revised estimate is [redacted] starting in Year 1 for vegetation management with additional maintenance costs of [redacted] beginning in Year 6 to continue the inspection, monitoring, and maintenance contract.[11] As shown on the tab "Capital Costs" in Exhibit SP-7, the first five years of O&M are included in the initial capital costs.

Q. Please now explain the purpose of the Decommissioning Expense and how the Company developed its estimate.

A. The Company did not include an estimate for decommissioning expense in its initial Benefit-Cost Analysis because the guidance it received in the Preliminary EPC RFP

[11] The Company assumed O&M expense will escalate at 2 percent annually based on ReVision's proposal (*see* Exh. SP-4).

was that salvage value would exceed decommissioning costs. However, upon further consideration, the Company determined that it would be prudent and a more conservative approach to include decommissioning expenses in its model. Unitil therefore requested that ReVision provide an estimate of decommissioning costs as part of the Final EPC RFP bid process (*see* Exh. SP-5).

As explained by ReVision, given the low volume of solar arrays that have reached or are approaching the end of their useful life, and the steady advances being made in solar panel recycling, it is not possible to provide a firm estimate of decommissioning costs at this time. Nonetheless, based on its analysis of numerous decommissioning agreements in the public domain for megawatt-scale solar arrays in Massachusetts and Vermont that were approved by municipal Planning Boards, ReVision recommended a conservative estimate of [redacted] for decommissioning the Project. The Company has incorporated ReVision's estimate of [redacted] (current dollars) into the Benefit-Cost Analysis and escalated this value by 2 percent over the life of the Project to estimate the future decommissioning cost of [redacted]. The analysis includes [redacted] as an annual decommissioning expense (spread evenly over the Project's estimated life) as a component of the revenue requirement.

Performance Characteristics

Q. Please summarize the updates that have been made to the Project's performance characteristics and the purpose for those updated inputs and assumptions.

A. The updates to the Project's performance characteristics in the Benefit-Cost Analysis are based on ReVision's response to the Final EPC RFP and are summarized in Table 5 below.

Table 5: Summary of Updates to Performance Characteristics

Update	**Purpose**	**Tab in Benefit-Cost Analysis Model (Exh. SP-7)**
30-Year Project Life to 40-Year Project Life	Reflect ReVision's RFP Response	*All*
Capacity Nameplate and Degradation Rate	Reflect ReVision's RFP Response	"Direct Customer Benefits"
Annual Production (kWh)	Reflect ReVision's RFP Response	"Direct Customer Benefits"
Capacity at Peak Hour (kW Monthly & Annual)	Reflect ReVision's RFP Response	"Direct Customer Benefits"

Q. Please provide additional detail regarding the updates to the inputs for the Project life, system capacity, and degradation rate.

A. The assumptions in both the initial filing (based on the Preliminary EPC RFP) and this update (based on the Final EPC RFP) for Project life, system capacity, and degradation rates are based on the proposal identified as the best overall value in the Preliminary EPC RFP and the Final EPC RFP, respectively. The components, design, and the engineering inputs in the updated Benefit-Cost Analysis (Exh. SP-7) reflect ReVision's proposal.

Table 6: Updates to Design Characteristics

Input	Input (Initial Filing)	Input (Supplemental Filing)
Expected Life of Project	30 years	40 years
System Capacity	6.15 MW (DC) / 4.99 MW (AC)	6.50 MW (DC) / 4.88 MW (AC)
Degradation Rate	0.5% reduction from Year 1 to Year 2 (0.5%) annually	2% reduction from Year 1 to Year 2 (0.5%) annually
Capacity Factor	21.96%	22.78%
Capacity at Peak Hour (kW – Annual)	37.1%	48.8%
Capacity at Peak Hour (kW – Monthly)	12.0%	16.8%

The increase in capacity factor and estimated production at the peak hours is due to several factors. First, the DC capacity of the system is greater than originally proposed for a smaller AC capacity. This increases output during non-peak production hours, allowing the system to produce more AC output throughout the production hours. Second, the proposed tracking system in the ReVision design has a 120 (+/-60) degree range of motion opposed to a 110 degree range of motion. This provides additional output in the early morning and later evening hours.

The Year 1 degradation rate changed because the PV modules (and the attendant performance characteristics and specifications) assumed in the Company's initial filing is different than those provided in ReVision's proposed design.

Q. Please provide additional detail regarding the updates to annual Production (kWh) and capacity at the Peak Hour (kW Monthly and Annual).

A. The estimated capacity factor and the associated production at the peak hours is drawn from ReVision's analysis using the HelioScope tool that considers the characteristics of the specific equipment being proposed (*i.e.*, inverters, solar panels, tracking system, etc.), local historical weather conditions (Concord, New Hampshire), and specific sources of system losses (*i.e.*, inverters, wiring, temperature, soiling, shading, etc.) (*see* Exhs. SP-3; SP-6).

Avoided Customer Cost Inputs

Q. Please summarize the updates to avoided customer cost inputs, and the purpose for those updates.

A. Updates to the avoided customer cost inputs are summarized in Table 7 below.

Table 7: Summary of Updates to Customer Cost Inputs

Update	Purpose	Tab in Benefit-Cost Analysis Model (Exh. SP-7)
ISO NE OATT Rates Where Applicable	Use most up-to-date ISO-NE OATT rates where applicable	"Direct Customer Benefits"
Updated Energy Futures	Using more recent ISO-NE Futures	"Direct Customer Benefits"

Q. What is driving the updates to the avoided customer cost inputs summarized in the table above?

A. The Company updated the analysis to ensure the direct customer benefits are calculated using the most up-to-date ISO-NE OATT rates as shown in Table 8 below.

Table 8: Updates to Regional Transmission Rates

Rate	Initial Benefit-Cost Analysis	Supplemental Benefit-Cost Analysis
ISO-NE Section 4A, Schedule 1 Rate ($ kW-Mo.)	$0.1918	$0.2048
ISO-NE Section 4A, Schedule 5 Rate ($ kW-Mo.)	$0.0074	$0.0070
ISO-NE Section 2, Schedule 1 Rate ($ kW-Mo.)	$0.1459	$0.1459
ISO-NE Section 2, Schedule 9 Rate ($ kW-Mo.)	$11.7453	$11.7453

Similarly, the Company updated its energy rates assumption with a more recent, lower (February 2023) futures forecast.

<u>Federal Tax Credits</u>

Q. Please provide an overview the federal tax credits available pursuant to the Inflation Reduction Act ("IRA").

A. The IRA extended federal tax credits for solar electricity production facilities beginning construction before January 1, 2025. There are two categories of tax credits available under the IRA. The Production Tax Credit ("PTC") provides a corporate tax credit for each kilowatt-hour of electricity produced by a qualifying facility for the first 10 years of operations. There is also an Investment Tax Credit ("ITC"), which provides a corporate tax credit of up to 30 percent of the installed cost of qualified facilities.[12] Stated simply, the PTC is earned over time based on production whereas the ITC is earned when the facility goes into service. Solar projects have a choice between the ITC and the PTC; developers cannot use both.

[12] Projects that satisfy a domestic content requirement are entitled to a 10 percent bonus credit. To qualify for this bonus, the taxpayer must certify that the steel or iron used in the project is produced in the United States and a "required percentage" of the total costs of manufactured products (including components) of the facility are mined, produced, or manufactured in the United States.

Q. What is the rationale for the normalization rules and what are the consequences of violating them?

A. Generally speaking, normalization is a system of accounting used by regulated public utilities to reconcile the tax treatment of ITCs in accordance with the Internal Revenue Code of 1986, as amended. The normalization rules dictate that the benefit of the federal tax credits must be passed back to customers ratably over the life of the investment that produces the credits.

There are two principles underpinning the Internal Revenue Service ("IRS") Normalization Rules. First, Congress wanted to preserve the utility's incentive to invest, and ensure that the ITC was not purely subsidizing the services provided by the utility. IRS Normalization Rules ensure both shareholders and customers benefit from the ITC.

The second principle is to protect the government's tax revenue. If the utility immediately lowered rates for the ITC without normalization, the federal government would experience lower income tax revenue. In such a case, the federal government would be losing tax revenue both for the ITC and lower income due to lower distribution rates.[13]

Violating the normalization rules results in the loss of income tax deductions such as accelerated depreciation or the recapture of tax credits, eliminating tax benefits available including accumulated depreciation.

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[13] *See* 2017-38 I.R.B. (Sept. 18, 2017), *available at* https://www.irs.gov/pub/irs-irbs/irb17-38.pdf.

Q. Please describe the Company's modified approach to the federal tax credits.

A. Upon further analysis, the Company revised its approach to assume the PTC rather than the ITC because, as explained below, the PTC is expected to improve the overall economics of the Project from the perspective of customers.[14]

Q. Why would applying the PTC, as compared to the ITC, potentially enhance the Project's net benefits?

A. Unlike the ITC, the PTC is not subject to IRS Normalization rules. This means the PTC can be used to offset the revenue requirement, including a tax gross up, as it is earned. This has the effect of front-loading the benefits of the tax credits relative to the ITC which, under normalization rules, is flowed back to customers evenly over the Project's life. In short, under the PTC approach customers are able to realize a greater time value of money benefit than compared to the ITC approach.

Q. Will the Company continue to consider options to maximize the value of federal tax credits?

A. Yes. As discussed in our initial testimony,[15] the IRA allows companies to transfer the ITC to other taxpayers in exchange for cash. However, final guidance from the IRS regarding these new ITC provisions has not yet been published. In the meantime, Unitil will continue to investigate options to ensure customers receive the maximum economic value from the federal tax credit.

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[14] In both the initial and supplemental Benefit-Cost Analyses, the federal tax credit is included in the Net Present Value ("NPV") by flowing back the credit and associated benefits through the annual revenue requirement, thereby decreasing the revenue requirement.

[15] Exhibit FDGP-1, at Bates pages 000189-000190.

B. Results of Updated Benefit-Cost Analysis

Q. Does the Company believe the assumptions and inputs used in the Benefit-Cost Analysis are reasonable and conservative?

A. Yes. The base inputs and assumptions in the Benefit-Cost Analysis represent the Company's best estimates and the process the Company employed to develop those estimates is reasonable and conservative. Specific examples of the Company's conservative approach include:

- The inputs and assumptions in the Benefit-Cost analysis are thoroughly documented and based on objective, third-party data and sources:
  - The capital cost, O&M expense, decommissioning cost, Maintenance Capital Costs, performance characteristics, and energy production estimates are based on ReVision's proposal, which was developed and submitted through a competitive solicitation process.
  - Avoided transmission costs are based on ISO-NE Tariff rates.
  - The Company used the "ISO New England MASS HUB 5 MW 5 LMP Futures" to extrapolate electricity prices for the first four years of the Project and escalated these prices beginning in Year 5 by the long-run annual growth rate included in Energy Information Administration's 2022 Annual Energy Outlook for end-use prices.
- The Renewable Energy Certificates ("REC") price assumption is based on the New Hampshire Class II REC for the 2023 term. The [redacted] REC price is a conservative estimate given the current Alternative Compliance Payment rate of

$61.18 for compliance year 2023. Increases in future market demand associated with increasing electrification may result in higher demand for Class II RECs as retail electric sales increase. In addition, the estimated REC pricing is valued in 2023 dollars and not escalated by an inflation factor, such as the Consumer Price Index. To the extent RECs are susceptible to inflation, the potential REC value may be significantly higher in future years.

- There is a 10 percent bonus tax credit if a Project meets the domestic content requirements (*i.e.*, all steel or iron used must be produced in the United States and a "required percentage" of the total costs of manufactured products need to be mined, produced, or manufactured in the United States). Although the Project may be eligible for this bonus tax credit, the Company has not included it in the Benefit-Cost Analysis.
- When calculating estimated peak output, the Company looked to historical peak hours from 2012 to 2021 and did not include years prior to 2012 as this would have inflated the calculation due to the ISO-NE peak shifting later in the day after 2011 (*see* Exh. SP-6).
- The Company has not included indirect benefits in the Benefit-Cost Analysis. When indirect benefits are considered, the Project's already positive net benefits are meaningfully enhanced supporting a finding that the Project is in the public interest.

On balance, the Company believes its Benefit-Cost Analysis is based on reasonable and conservative assumptions.

Q. Please summarize the results of the Company's updated Benefit-Cost Analysis.

A. As shown in Exhibit SP-7, the present value of the Project's benefits is approximately $19.3 million and the present value of the costs is approximately $16.7 million. This produces a net present value benefit of $2.5 million with a Benefit-Cost ratio of 1.15, a meaningful increase relative to the NPV of $1.4 million and Benefit-Cost ratio of 1.09 presented in the Company's initial filing. To be clear, the updated Benefit-Cost ratio (*i.e.*, 1.15) does not include either indirect benefits, or the option value of potential energy storage.

Table 9 below summarizes the respective contributions to the Benefit-Cost ratio and NPV generated by the updates to key assumptions and inputs in the Benefit-Cost Analysis.

Table 9: Respective Contributions to Benefit-Cost Ratio and NPV

	NPV[16]	BCR[17]	Description
	$1.4	**1.09**	
Federal Tax Credit	$1.1	0.08	Switch from ITC to PTC
Peak Output	$1.0	0.06	Higher Peak Output based on RFP response
Longer Facility Life	$0.8	0.05	Expected life of 40 years relative to 30 years in initial filing
Annual Production	$0.7	0.04	Higher capacity factor based on RFP response
Higher Year Two Degradation	($0.3)	-0.02	2% degradation in year 2 relative to 0.5% in initial filing
Higher Capital Costs	($0.9)	-0.06	Higher initial capital costs and included Maintenance Capital Costs
Lower Energy Futures Prices	($1.0)	-0.06	Updated Energy Futures since initial filing
Other	($0.3)	-0.03	Higher O&M, added Decommissioning Expense, and updated regional transmission rates
Updated Benefit-Cost Analysis	**$2.5**	**1.15**	

C. Bill Impacts

Q. Has the Company provided an updated bill impact analysis?

A. Yes, the Company has calculated and provided updated bill impacts by rate class in Exhibit SP-8.

As shown on page 1, line 7, column c of Exhibit SP-8, an average Residential customer would see an increase in their monthly bill of $0.05 per month in Year 1 after accounting for the cost and the direct benefits of the project. In Year 40, an average Residential customer would see a decrease in their monthly bill of $0.53 per

16 Dollars in millions.

17 The Benefit Cost Ratio (BCR) is a function of the NPV. To calculate the incremental effect on the BCR, the NPV of each factor is added to the Benefits or removed from the Costs provided in the initial Benefit Cost Analysis.

month. Overall, the discounted benefit of the project is estimated to accrue to customers in Year 7.

Q. Do the Project's offsetting benefits (transmission, energy, and RECs) flow to all customers or only to default service customers?

A. The offsetting benefits in the bill impact analysis flow to all customers. As explained in our initial testimony, the Kingston Solar Project will be operated as a "load reducer," meaning the energy produced by the facility will offset energy that otherwise would be received by Unitil from the transmission system.[18] In other words, the amount of wholesale power imported from the bulk transmission system (tie points) to meet customer demand will be reduced by the amount of electricity produced by the Kingston Project. This is a reduction in total wholesale system load, and not directly attributable to any specific supplier on the system, such as default service or competitive supply. Further, any production from the Project that is coincident with the monthly peak hour will reduce transmission costs. The cost of transmission is recovered via the External Delivery Charge ("EDC"), which is assessed as a per kWh charge billed to all customers.

The Project will generate RECs that will be retained to either meet Unitil's Default Service Renewable Portfolio Standard ("RPS") obligations or sold into the market and credited back to customers. If the RECs are used the satisfy Unitil's RPS obligations, a transfer price will be established and charged to default service

[18] Exhs. KES-1, at Bates pages 000023-000024; JSD-1, at Bates pages 000058-000059; FDGP-1, at Bates pages 000191-000196.

customers and a credit for the transfer price will be included in the EDC. If the RECs are sold into the market, the REC revenue would be included in the EDC. In both cases, the benefit of the RECs generated by the Project go to all customers.

IV. QUALITATIVE RISK ASSESSMENT

Q. Did the Company identify and discuss potential project risks in its initial filing?

A. Yes. The Company explained in its initial filing that it has not identified any material risks to the Project and described the steps it is taking to manage and mitigate operating and financial risk.[19]

For example, the Company explained that utility-scale solar projects are well established and the market is mature, which lowers technology risk.[20] This risk is further lowered by fact that the Company's affiliate, Fitchburg Gas and Electric Light Company has already developed a utility-scale solar project in Massachusetts.[21] In other words, Unitil has first-hand experience with the development, operation, and maintenance of utility-scale solar technology.

Unitil also explained in its initial testimony that supply chain and cost escalation risks could affect the Benefit-Cost Analysis.[22] The Company further explained that it is mitigating this risk by working through a multi-stage, competitive bidding

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19 Exh. KES-1, at Bates page 000020.

20 *Id*.

21 *Id*. at 000011-000012.

22 *Id*.

process to gather the most up to date pricing and schedule information for the Project.[23] To provide the Commission and intervenors with the best estimate of expected Project costs, the Company has updated its Benefit-Cost Analysis as presented in Section III above.

A further example is the risk mitigation measures built into in the Purchase and Sale ("P&S") agreement that the Company discussed in its initial testimony. Specifically, these provisions make the P&S agreement contingent upon site due diligence, title examination, and the appraised value.[24]

Although the Company identified and assessed Project risks in its initial filing, we appreciate the interest in this subject expressed by the Commission and intervenors at the January 18, 2023 prehearing conference. The following portions of our testimony therefore expands on that discussion by identifying broad categories of risk, discussing the specific risks within each category, and describing the actions the Company is taking to manage and mitigate those risks.

Q. Please identify the categories of potential risks to the Project.

A. Unitil has identified five general categories of potential Project risk: Site Control Risk; Construction and Cost Risk; Permitting Risk; Financing and Financial Risk; and Performance and Operational Risk.

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[23] *Id*.

[24] Exh. JSD-1, at Bates pages 00045-00046.

Site Control Risk

Q. What are the risks associated with site control?

A. A significant risk in the development of any renewable project is securing the rights to use property to construct and operate the facility for its useful life. Private developers typically establish an interest in land for their projects through an easement or a lease (or some combination thereof) and those agreements are commonly pledged as collateral to project lenders. Although leases and easements are a reasonable approach, they can present challenges as developers must negotiate with the landowner (and in some cases multiple landowners) to secure the full scope of rights necessary to develop their projects. An alternative to easements and leases is to buy the property, and acquire fee title, which entitles the purchaser to exclusive possession of the land and an unconditional and unlimited interest of perpetual duration. Unitil has taken this lower-risk approach to site control for the Kingston Solar Project.[25]

Q. What additional steps is the Company taking to mitigate site control risk?

A. As noted above, and discussed in Unitil's initial filing,[26] the P&S agreement has a number a built-in mitigation measures. Specifically, the P&S is contingent upon a title examination and the completion of site due diligence, including the receipt of all necessary construction permits. In addition, to ensure the property is acquired at

[25] Unitil Realty Corporation, an unregulated subsidiary of Unitil Corporation, entered into the P&S agreement on August 25, 2022 for the Kingston Solar Project site. The P&S Agreement was attached to the initial filing as Exhibit JSD-5 (CONFIDENTIAL). Unitil Realty Corporation will transfer the parcel ultimately used for the Kingston Solar Project to UES and retain the remaining parcel for future development.

[26] Exh. JSD-1, at Bates pages 000044-000045.

a fair price, the P&S is contingent upon the property appraising at or above the purchase price. This appraisal clause is the reason the purchase price for the property has been reduced, as noted earlier.

<u>Construction and Cost Risk</u>

Q. What are the potential construction and cost risks for the project?

A. A potential risk for a renewable energy project, or any construction project for that matter, is unforeseen cost escalations that may be driven by estimates that later prove to be inaccurate, inflation, market demand, shipping and freight costs, supply chain disruptions, or other unforeseeable circumstances.

Q. What is the Company doing to mitigate this risk?

A. Certain risks are naturally mitigated by the Project's technology. The upfront costs for PV arrays have declined dramatically over the past several years.[27] Also, over the long term, the Kingston Solar Project will not have any fuel costs, which means that it is insulated from the risk of rising and volatile fossil fuel costs.

Regarding the potential for cost escalation during construction, the Company is managing that risk through several measures. First, the Company has conducted a multi-stage, competitive RFP process to ensure its Project cost estimates are reasonably accurate and robust. As part of that process, the Company has thoroughly

[27] New Hampshire Department of Energy, New Hampshire 10-Year Energy Strategy at 47, 51 (July 2022) (stating the cost of new utility-scale solar has fallen by 90 percent in the last 12 years).

vetted the proposed EPC contractor teams, their technical capabilities, and their prior experience developing similar projects.

ReVision has local project experience, which includes municipal arrays awarded via competitive bid by the Town of Kingston and the surrounding towns of Exeter and Brentwood (where ReVision's office is based). ReVision is currently working with Town of Kingston to develop a 6.2 MW municipal array on the Kingston capped landfill. In addition to the 6.2 MW Kingston landfill project, ReVision is currently working with a local educational institution on a 4.7 MW solar farm and is ready to commence construction (pending utility study) on New Hampshire's largest solar array to date, a 4.3 MW solar farm at the Rockingham County Complex in Brentwood, New Hampshire.

Second, the Company is employing a turnkey, EPC project delivery model, and will remain actively involved throughout the design, engineering, procurement and construction phases of the Project. Notably, ReVision is planning to use Ayer Electric (IBEW), a local firm based in Barrington, New Hampshire, as its primary electrical subcontractor for the Kingston Solar Project.

Third, ReVision places bulk orders for tens of megawatts of solar modules through the Amicus purchasing group approximately two times per year and will include the Kingston Solar Project in a bulk order after contract signing. By aggregating its buying power with other member companies nationwide, ReVision negotiates directly with equipment manufacturers and is able to attain better pricing on equipment.

Fourth, Unitil plans to negotiate and enter into an EPC contract with ReVision that will appropriately allocate construction and cost risk between the parties.

Q. Do project risks generally increase with time?

A. Yes, time is a key concern because pricing estimates are less reliable as time passes. However, the Company does not view time as a significant risk factor because the Commission has approved a six-month procedural schedule for this docket consistent with RSA 374-G:5, V.

<u>Financial and Financing Risk</u>

Q. What are the potential financial risks associated with the Project?

A. One of the risks commonly associated with renewable energy projects is insufficient access to low-cost capital. For this reason, many privately developed renewable energy projects are highly leveraged, which translates into default risk, and the tax benefits often flow, at a discount, to a third-party tax equity investor. In this case, the Company is proposing to finance the Project at its most recently approved cost of capital and to offset the revenue requirement with federal tax credits.

Q. Are there any other financial risks that are absent because the Project is being developed by a public utility instead of a private developer?

A. Yes. In the context of many privately developed projects, project cash flows are derived from a long-term offtake or power purchase agreement ("PPA"), which essentially determine the Project's economics. A PPA introduces the risk of non-payment (and the associated litigation risk), which is absent from the Company's proposed Project. As explained in our initial testimony (and as noted earlier), the Kingston Solar Project is a load reducer and there are no customer contracts to be executed. This is a favorable, lower-risk structure, because the Company and its customers do not need to assume the duties and obligations of a contract in order to receive the benefits produced by the Kingston Solar Project.

Another revenue stream typically associated with solar projects are state incentives, which commonly take the form of net metering credits. This revenue stream is subject to the risk of a future change in state policy, discontinuing these incentive programs. The Kingston Solar Project is not reliant upon any state subsidies and therefore this risk does not apply to this Project.

Permitting Risk

Q. What are the permitting risks associated with the Project?

A. Permitting risk can be viewed along a spectrum. On one end are permitting delays and at the extreme opposite end is the denial of necessary approvals. As discussed in our initial filing, several local, state, and federal permits are required for the Kingston Solar Project.[28]

[28] Exh. JSD-1, at Bates pages 000047-000048.

Q. How is Unitil managing permitting risk for the Kingston Solar Project?

A. As explained in our initial filing, Unitil has hired TF Moran, Inc. ("TFM"), a New-Hampshire based Land Planning firm to perform Site Due Diligence and obtain all the necessary permits to construct the Project. TFM has extensive experience completing site assessment and permit application projects in New Hampshire. In addition, ReVision has local, state, and federal permitting experience and could assist TFM, as necessary.

Lastly, the Company is insulating the Project from permitting risk because it will not authorize the procurement of equipment and materials until we have strong confidence that all necessary local, state, and federal permits will be obtained.

Performance/Operational Risk

Q. What are the potential risks associated with performance and operation of the Project?

A. Energy production is a key driver of Project benefits. Accordingly, once the Project achieves commercial operation, equipment failures and diminished capacity factors are potential risks.

Q. How is the Company mitigating performance and operational risks?

A. The Company plans to manage this risk by several means.

First, the Company plans to enter into an O&M agreement with ReVision to ensure the system generates at its maximum capacity over the projected design life. As part of the final system design, ReVision will develop a detailed, site-specific O&M

plan. The ReVision O&M plan will include daily monitoring of system performance so it can quickly mobilize in-house service personnel either remotely or onsite to address issues that may arise, in accordance with guaranteed response times. The O&M Plan will also include 80-point annual electrical and mechanical inspections and associated preventive maintenance, accompanied by a detailed inspection and production report.

Second, the Project is designed with proven, high-quality components with long-term and robust warranties from manufacturers to ensure the performance and reliability of the equipment. The warranty periods and expected lifespan of major system components provided by ReVision in response to the Final EPC RFP are summarized in Table 10 below.

Table 10: Warranty Periods and Commercial Lifespan

Major Component	Warranty Period (Years)	Commercial Lifespan (Years)
Qcells QPEAK DUO XL 580W Bifacial Solar Modules	25	40
Solectria XGI 1500/125 kW Solar Inverters	20	20
TerraSmart TerraTrack Single-Axis Tracking System	20	40

The 25-year linear performance warranty for the solar modules ensures at least 98 percent of nominal power during the first year and maximum 0.5 percent degradation per year thereafter, resulting in at least 86 percent of nominal power output in Year 25. Qcells is a leading Tier 1 solar panel manufacturer based in the

United States (Georgia) and over the past decade, ReVision has installed large volumes of Qcells modules across northern New England.

Third, the energy production estimates in the Company's Benefit-Cost Analysis are based on data provided by ReVision, which is derived from the industry-standard HelioScope Production software using specific equipment and local weather characteristics. ReVision's production estimates consider the specific pitch, azimuth and other design features of the Project, as well as external factors such as irradiance, soiling conditions, and temperature derived from the nearest TMY2[29] federal weather dataset (Concord Municipal Airport).

Fourth, as discussed above, Unitil has updated its Benefit-Cost Analysis to include Maintenance Capital Costs for PV modules and the racking system. Although the Company expects the capital equipment to operate well beyond the warranty periods, these costs would support the replacement of equipment if necessary to avoid lost production.

Fifth, the Company plans to maintain a limited stock of spare material, including PV modules, a step-up transformer and an inverter that will be utilized when needed to limit downtime.

[29] Typical meteorological year ("TMY") is a collection of selected weather data for a specific location. The first TMY collection was based on 229 locations in the United States and was collected between 1948 and 1980. The second edition of the TMY is called "TMY2".

Sixth, the Project will be a string inverter design as opposed to a central inverter design. Specifically, the Project is designed to utilize approximately 39 125kW inverters instead of a few larger central inverters. This design should reduce replacement costs in the event of an inverter failure, and minimize the reduction in production impacts when inverters and/or PV modules need to be removed for maintenance.

Conclusion

Q. Please summarize the Company's qualitative discussion of potential Project risks.

A. The Company is actively managing the Project to keep the level of spending low in the early development stages when development risk is relatively high. Considering the additional information received in the final EPC RFP process, the Company's view with respect to Project risk remains unchanged from its initial filing. Although Unitil has identified potential risks, it views their effect on the Project's net benefits to be limited, and, as discussed above, is taking prudent steps to measure, manage, and mitigate them.

V. QUANTITATIVE RISK ASSESSMENT

Q. Has the Company performed a quantitative assessment of potential Project risk?

A. Yes. The Company has conducted a stress test and a simulation analysis to quantitatively assess Project risk.

<u>Stress Test Analysis</u>

Q. Please briefly describe the purpose of the stress test analysis.

A. A stress test is useful for understanding the sensitivity of a result to changes in certain variables. In this case, the Company performed a stress test analysis to find the level to which key inputs in the Benefit-Cost Analysis must change such that the Project's net benefits are zero (*i.e.*, the breakeven point).

Q. Please identify the assumptions and inputs upon which the Company performed the stress test analysis.

A. Unitil performed stress tests on the most critical assumptions and inputs summarized in Table 11 below. For each assumption, we found the extent to which it must change (holding the others constant) to create a net benefit of zero.

Table 11: Summary of Stress Test Results

Variable	Base Assumption	Stress Test Value
Annual Capacity Factor	22.78%	19.66%
Initial Depreciable Capital Cost	$13.9 Million	$15.8 Million
REC Price	[redacted]	$16.32
Direct Benefits Escalation Rate	2.00%	-0.09%
ISO-NE Futures (Average Year 1-4)	$0.0784	$0.0571

Q. What conclusions do you draw from the stress test analysis?

A. Simply put, the variables would have to change to levels the Company considers to be low-probability before the Kingston Solar Project no longer produces positive net benefits.

The Company further notes that it has limited the stress test analysis to only direct benefits. When indirect benefits are considered, those benefits serve to further increase the Project's already positive benefits and reinforce a finding that the Project is in the public interest.[30]

Simulation Analysis

Q. Please briefly summarize the benefits associated with simulation analyses.

A. As noted above, stress tests measure the extent to which a given variable must change for the Project to no longer provide positive net benefits. In effect, it changes one variable while holding all others constant. Although that approach is valuable in assessing the sensitivity of analytical results to a given variable, it does not reflect the extent to which variables may, or may not, move together. Simulation analyses (sometimes referred to as "Monte Carlo" analyses) provide the ability to consider such correlations across variables, and to define the statistical properties (for example, the shape and dispersion of potential outcomes) for individual variables. Moreover, by combing those attributes (correlations across variables and the statistical properties of individual variables) we are able to simulate thousands of scenarios, and develop probabilities of outcomes (in this case, the probability that the BCR is greater than 1.00, or the NPV is greater than zero).

[30] In DE 09-137, the Commission held that it is appropriate to include indirect benefits in the Benefit-Cost Analysis after first considering direct and readily quantifiable benefits. In addition, the Commission held that in situations where projects may be marginally uneconomic based on direct benefits alone, it will allow reasonable estimates of indirect benefits to be considered and, if appropriate, to support a public interest finding.

Q. Did the Company perform a simulation analysis?

A. Yes. The Company performed a simulation analysis using @Risk, an add-in tool for Microsoft Excel, to analyze the economic risk of the Project using Monte Carlo simulations. The Company included 9 key assumptions in the simulations, which unlike in the stress test discussed above, can be changed independent of one another. The simulation was conducted with 100,000 unique iterations of the key inputs subject to the established parameters.

Q. Please identify the key inputs included in the simulation analysis.

A. The inputs included in the simulation analysis include: the annual capacity factor, the monthly and annual peak capacity, change in the modeled depreciable capital costs, REC prices, Energy Rates in the initial years which are based on Energy Futures, the escalation rate used for the calculation of Direct Customer Benefits, and the escalation rate used for all other assumptions. Lastly, the Company included the probability that the Project will meet the requirements for the ten percent Domestic Content bonus for the PTC rate.

Q. Please explain how the simulation was arranged.

A. Each of the above variables was assigned a distribution with various parameters. The distributions used were triangular, normal distribution, and binomial distribution. The triangular distributions were provided parameters for the minimum, maximum, and most likely value. The triangular distribution is useful when there is limited data available and there is relatively more subjectivity. For example, for the Depreciable Capital Cost input the Company used its most likely value to be 100% of the modeled cost, the minimum to be 95%, and the maximum to be 115%. However, for better established data sets with less subjectivity, the Company was able to define those data sets as normally distributed and assign a mean and standard deviation. The Company used a binomial distribution for the PTC rate and applied an 80% probability that the Project will qualify for the Domestic Content bonus and a 20% probability that the Project will only qualify for the base PTC rate.

Q. What were the results of the Monte Carlo simulations?

A. The simulation was processed with 100,000 unique iterations and indicates an 84.3% probability that the project will be NPV positive and yield a benefit-cost ratio of 1.0 or greater for customers. The results of the simulation have an average NPV of $4.3 million and a median NPV of $4.1 million. The results of the simulation show an average BCR of 1.26 and a median BCR of 1.24. The skewness of the simulation is positive, between 0.2 and 0.3 indicating fairly symmetrical results with slightly more observations above the mean than below. A negative skew value indicates a higher probability for observations less than the mean while a positive skew value indicates a higher probability for observations greater than the mean. The kurtosis of the simulation, which is a measurement of the “tails” or “flatness” of a distribution, is approximately 3.0 and indicates the dataset is normally distributed. A kurtosis greater than 3.0 is Leptokurtic and less than 3.0 is Platykurtic. Higher kurtosis values indicate that more of the observations are in the “tails” of the curve, while lower kurtosis values indicate observations relatively more concentrated around the mean. Given that the mean and median of the simulations are similar, the results are largely symmetrical as indicated by the skewness, and the kurtosis is approximately 3.0 the Company concludes the results of the simulation are “normally distributed”. The 90th percentile of the results show the possibility of an NPV of $9.9 million and a BCR of 1.59 or better, while the 10th percentile shows the potential for an NPV of ($1.0 million) and a BCR of 0.94 or worse. Figure 1 and Figure 2 below illustrate the distribution of the results of the 100,000 unique iterations included in the scenario.

Figure 1: Simulation Results of Net Present Value

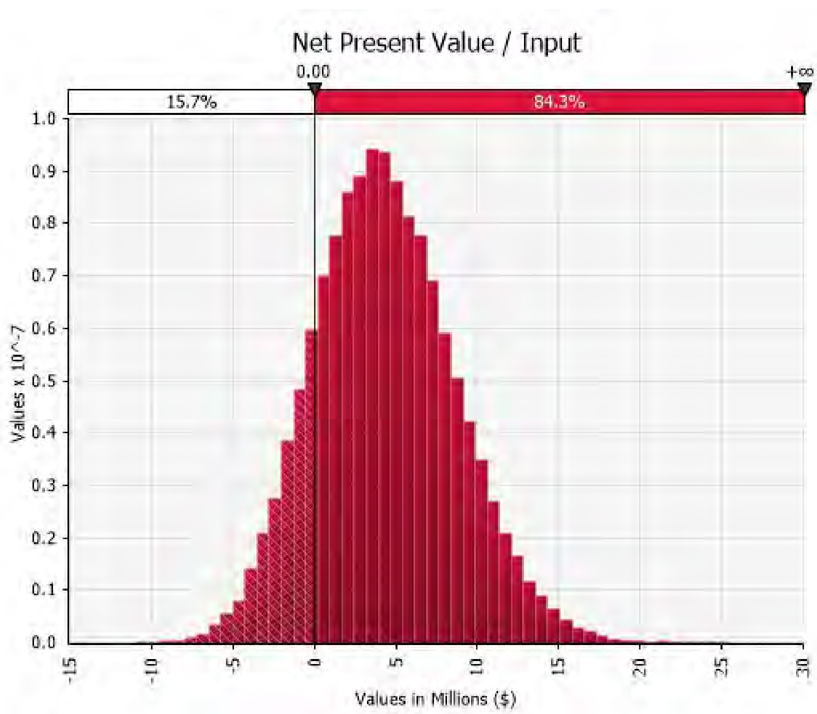
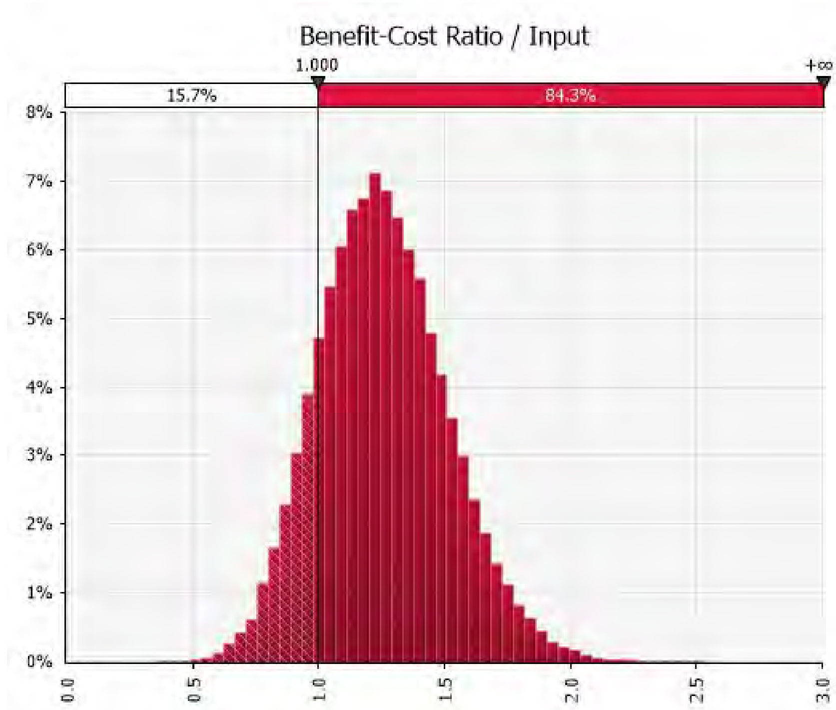


Figure 2: Simulation Results of Benefit-Cost Ratio



Q. Please provide the results of the simulation by ranked percentiles.

A. Table 12, shown below, illustrates the ranked NPV and BCR results by percentile. The 50th percentile represents the median data point of $4.1 million for the NPV and 1.24 for the BCR. The average of the results are slightly higher as a result of the positive skew value. Notably, the results in Exhibit SP-7 are similar to the 35th percentile in Table 12 reflecting the conservative assumptions included in the Benefit-Cost model.

Table 12: Simulation Results Ranked by Percentile

Percentile	Net Present Value	Benefit-Cost Ratio
1.0%	(4,807,353)	0.72
2.5%	(3,526,266)	0.80
5.0%	(2,401,678)	0.86
10.0%	(1,045,952)	0.94
20.0%	641,349	1.04
25.0%	1,316,598	1.08
30.0%	1,934,745	1.11
35.0%	2,503,388	1.15
40.0%	3,070,847	1.18
45.0%	3,607,570	1.21
50.0%	4,132,047	1.24
55.0%	4,671,899	1.27
60.0%	5,232,628	1.31
65.0%	5,838,370	1.34
70.0%	6,457,532	1.38
75.0%	7,124,508	1.42
80.0%	7,879,678	1.47
90.0%	9,933,677	1.59
95.0%	11,645,432	1.69
97.5%	13,149,104	1.79
99.0%	14,850,923	1.90

Q. Which inputs have the greatest impact on the economics of the Project?

A. The REC prices, Energy Rates, and escalation rate used for the direct benefits have the most variability on the results. The capacity at monthly and annual peaks have relatively less variability on the results. Figures 3 and 4 shown below, rank the variability of each input and display the largest impacts each assumption had on the NPV and BCR.

Figure 3: Tornado Graph of Net Present Value

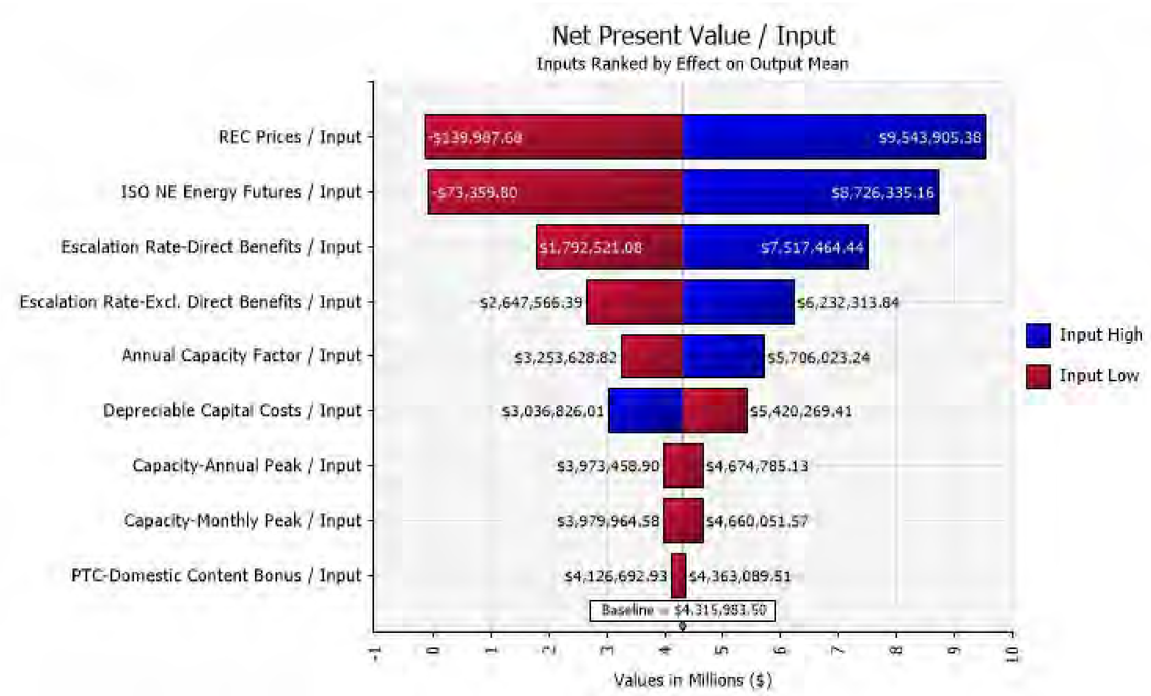
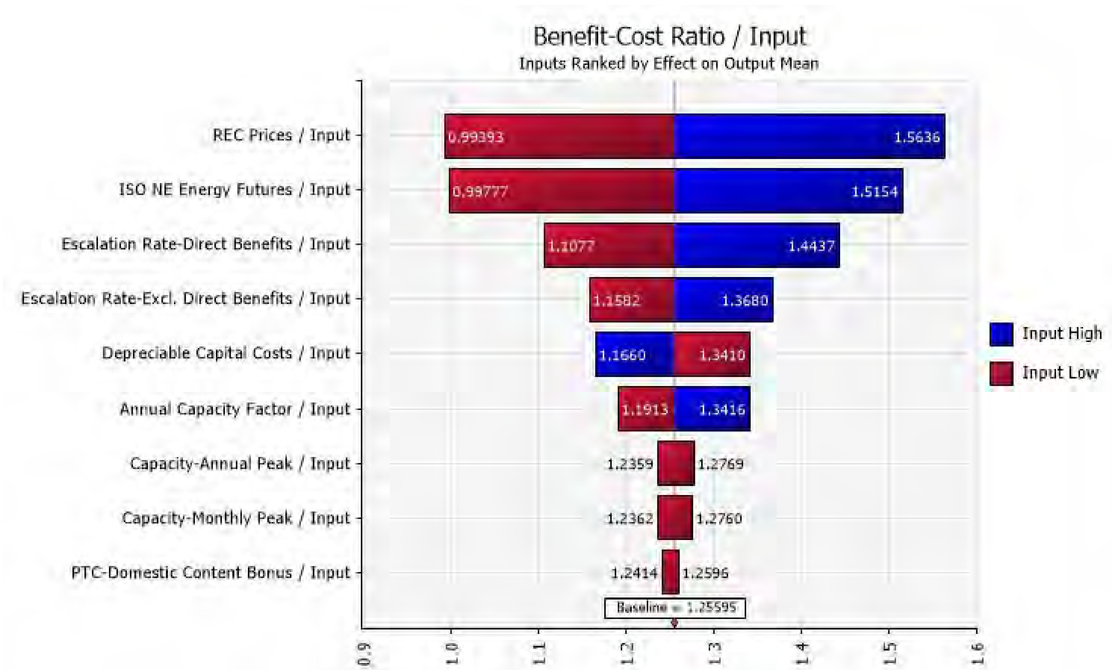


Figure 4: Tornado Graph of Benefit-Cost Ratio



Q. Please provide any other comments on the simulation analysis.

A. The simulation analysis was conducted with reasonable distributions and parameters, which resulted in reasonable results. The simulations included conservative assumptions such as the potential for up to 15% depreciable capital cost overruns as well as a minimum REC price of zero dollars. The results show a strong probability that the Project will yield positive results for customers purely on direct benefits. These favorable results would be further supported if indirect benefits and the value of the future option to add energy storage were included. The Company has a high degree of confidence that the Project will yield positive economic results for customers as supported by the results of the simulation.

VI. CONCLUSION

Q. Please summarize your Supplemental Testimony.

A. The Kingston Solar Project is a meaningful long-term commitment to addressing New Hampshire's climate objectives in a manner that provides tangible benefits to the Company's customers, is cost-effective, and enables economic growth in the state. The updated Benefit-Cost Analysis presented in this Joint Supplemental Testimony continues to demonstrate that the direct benefits of the Project outweigh the costs over the investment horizon. The Kingston Solar Project is good for customers and good for the state of New Hampshire. Accordingly, the Commission should find the Kingston Solar Project is in the public interest.

Q. Does this conclude your Supplemental Testimony?

A. Yes, it does.