Connecticut Non-Wires Solutions Benefit-Cost Analysis Framework

Reference Manual – Version 1.1

-Final-

Prepared for:

Connecticut Public Utilities Regulatory Authority

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EXECUTIVE SUMMARY

Docket No. 17-12-03RE07 – *PURA Investigation into Distribution System Planning of the Electricity Distribution Companies Non-Wires Alternatives* (the "Decision") – established a Non-Wires Solution ("NWS") Process. The NWS Process will be a competitive and transparent mechanism to assess NWSs alongside traditional options to meet distribution system needs.

The ***Connecticut Non-Wires Solution Benefit-Cost Analysis Framework Reference Manual*** ("Reference Manual") provides detail on the NWS Benefit-Cost Analysis ("BCA") framework, outlining the cost-effectiveness test and methodologies that will be used to evaluate bids submitted as part of an annual competitive NWS solicitation.

Cost-Effectiveness Test

The primary cost-effectiveness test used for the Conservation & Load Management ("C&LM") programs is the Connecticut Efficiency Test ("CTET"). To align with the C&LM framework, NWSs will also be assessed using this Modified Utility Cost Test.

Benefit and Cost Components

Table 1 provides an overview of the 17 benefit and cost components for the Connecticut NWS BCA Framework. The components have been categorized as Tier 1 and Tier 2. Tier 1 components (green) have a larger overall impact on the cost-effectiveness results and are the primary focus of the methodology phase. Tier 2 components (blue), while still important, are less impactful and are also more challenging to quantify; however, their value should still be captured as part of the overall BCA framework. Finally, we recommend that some of the Tier 2 societal impacts (light blue) be included but addressed qualitatively (Q).

Table 1: Benefits and cost components for the Connecticut NWS BCA Framework.

Category	Impact		NWS BCA	MUCT	TRC
Bulk System Impacts	Energy	Benefit or Cost	✓	✓	✓
	Capacity	Benefit or Cost	✓	✓	✓
	Market Price Effects	Benefit	✓	✓	✓
	Ancillary Services	Benefit or Cost	✓		
	Transmission Capacity	Benefit or Cost	✓	✓	✓
Distribution System Impacts *(location specific)*	Distribution Capacity	Benefit or Cost	✓	✓	✓
	Distribution O&M[4]	Benefit or Cost	✓	✓	✓
	Reliability	Benefit or Cost	✓/Q[5]	✓	✓
Non-Wire Solution	Utility/Solution Cost[6]	Cost	✓	✓	✓
	Utility Performance Incentive[7]	Cost	✓	✓	✓
Other Resource Impacts	Natural Gas	Benefit or Cost	✓	✓	✓
	Oil and Propane	Benefit	✓	✓	✓
Societal Impacts	Non-Embedded GHGs	Benefit	✓	✓	✓
	Public Health	Benefit	✓/Q[8]		
	Economic and Jobs	Benefit	Q		
	Resilience	Benefit	✓/Q[9]		
	Energy Security	Benefit	Q		

The Reference Manual includes methodologies and direction for assessing each of the components, which are based on the Avoided Energy Supply Cost ("AESC") study, the National Standards Practice Manual ("NSPM"), and the C&LM framework. Regular updates to the methodologies should be considered as the Connecticut NWS process matures and circumstances within the industry evolve.

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Introduction

The Decision in Docket No. 17-12-03RE07 – *PURA Investigation into Distribution System Planning of the Electricity Distribution Companies Non-Wires Alternatives* (the "Decision") – established a Non-Wires Solution ("NWS") Process. The NWS Process will be a competitive and transparent mechanism to assess NWSs alongside traditional options to meet distribution system needs.

The *NWS Process Design Document* ("Design Document") was developed as part of the proceeding, and it outlines the design, structure, governance, and implementation of the NWS process. The Design Document and Decision establish the benefit-cost analysis ("BCA") framework for the NWS Process.

The ***Connecticut Non-Wires Solution Benefit-Cost Analysis Framework Reference Manual*** ("Reference Manual") provides additional detail with respect to the BCA framework, outlining the cost-effectiveness test and methodologies that will be used to evaluate bids submitted as part of an annual competitive NWS solicitation.

A guiding principle in the development and implementation of the NWS BCA Framework for Connecticut is comprehensiveness in order to enable the evaluation of a range of Distributed Energy Resources ("DERs"), and to allow the tool to become more sophisticated as additional data and information becomes available.

Connecticut NWS BCA Framework Reference Manual

Cost-Effectiveness Test: Modified Utility Cost Test similar to the cost-effectiveness test that is used to assess Conservation & Load Management programs but is further modified to assess NWSs.

Benefit and Cost Components: The NWS BCA includes 19 benefit and cost components – a mix of quantifiable and qualitative impacts. The components fall under the five categories: 1) Bulk System Benefits, 2) Distribution System Impacts, 3) Non-Wires Solution Costs, 4) Other Resource Impacts, and 5) Societal Impacts.

Implementation: This Reference Manual will be used by NWS project proponents, the PURA Process Monitor, and PURA staff to calculate and assess the net benefits of NWS proposals submitted as part of the annual competitive solicitation.

The **Reference Manual** is structured as follows:

- An **overview of key elements** of the NWS BCA Framework, including the cost-effectiveness test to be used, the approach to addressing wholesale market impacts, and the BCA benefit and cost components.
- **Detailed methodologies** for each benefit and cost component, including rationale for inclusion, equations and variables, and data sources and assumption.

BCA Framework Overview

Cost-Effectiveness Test

Scope

The Final Decision in Docket No. 17-12-03RE07 established the overarching framework for the NWS BCA. The Final Decision states that the *"creation of a specific benefit-cost analysis model and process, utilizing and building on the framework and inputs form the C&LM Plan, will be a key task for the Process Initiation Phase led by the PURA Process Monitor in collaboration with the EDCs and other stakeholders*." Furthermore, that "*Conn. Gen. Stat. § 16-19e(a) provides ample support for the appropriateness of the broader TRC test as the primary benefit-cost framework and a key decision-making criterion.*"

It is noted that the primary cost-effectiveness test used to assess Conservation and Load Management ("C&LM") programs is a Modified Utility Cost Test ("MUCT").[1] And that the MUCT is closely aligned with a Total Resource Cost ("TRC") test as it considers all resource impacts. **To support consistency with the C&LM framework, as per the Final Decision in Docket No. 17-12-03RE07, the C&LM MUCT is used as the basis of the NWS BCA framework, and further modified to accommodate the unique nature of NWSs (i.e., includes location-specific distribution impacts, ensure incrementality to avoid double-counting).** The Process Monitor believes this is consistent with the Decision in Docket No. 17-12-03RE07 and will support a robust assessment of NWS Process bids.

While the C&LM framework includes the Total Resource Cost ("TRC") and Modified Utility Cost Test ("MUCT") as secondary tests[2], a secondary test is not included in the NWS BCA framework. The EDCs may still choose to perform other benefit-cost analyses for informational purposes; however, this is outside of the formal NWS BCA framework.

Discount Rate

As directed by the Department of Energy and Environmental Protection ("DEEP") the utilities use a nominal discount rate of 3.0 percent (with a 2 percent inflation rate), which was based on 30-year U.S. Treasury Bonds at the time of the decision.[3]

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[1] The primary cost-effectiveness test used for the C&LM programs is the Connecticut Efficiency Test ("CTET"). Adopted in 2022, it is a Modified Utility Cost Test that incorporates avoided GHG benefits, avoided heating oil and propane costs, and additional utility systems benefits associated with reduced arrearages, collection costs, debt-write-offs, and administrative costs. See: Department of Energy and Environmental Protection. April 2022. *Updates to Connecticut Conservation and Load Management Cost Effectiveness Testing*. Available on-line at: https://portal.ct.gov/-/media/DEEP/energy/ConserLoadMgmt/Attachment-B---Cost-Effectiveness-Testing-Update.pdf

[2] The TRC test is used as the primary test for the Home Energy Solutions – Income Eligible ("HES-IE") program and includes the components in the MUCT plus non-energy impacts related to reduced collections and arrearage costs.

[3] Department of Energy and Environmental Protection. Revised December 18, 2018. Rationale for Discount Rate to be Applied in Connecticut's Conservation and Load Management Plans. Available on-line at: https://app.box.com/s/zv7bcoe283tjvppnt853ojmwfa89zahg/file/392409855086

Application

The CT NWS BCA test compares the present value of total benefits and total costs associated with the proposed NWS solution over the useful life of the investment to determine net benefits/cost (in dollars). Benefit values are based on marginal avoided costs, in addition to other quantifiable benefits, and represent energy/cost savings as determined through engineering and evaluation studies.

Cost values reflect costs to the utility or ratepayers from implementing the program (including the shareholder incentive). Customer co-pays are not included; however, it is assumed that any customer co-pay related to energy efficiency, customer-sited storage, or other solutions is equal to, and offset by, a direct customer benefit that is also excluded from cost-effectiveness test.

The approach and methodologies in the Reference Manual should be used by all project proponents for a consistent assessment of the benefit and costs of proposed options. Bids will include detailed inputs and outputs for each quantified benefit and cost stream so that the BCA results are transparent and can be reviewed by stakeholders, including the Process Monitor, who will provide its assessment and recommendations to PURA for consideration.

Reference Manual Updates

The Reference Manual should be reviewed and updated, as needed, on a regular basis to ensure alignment with the Avoided Energy Supply Cost ("AESC") study, the National Standard Practice Manual ("NSPM"), the C&LM framework, and other industry best practices.

BCA Components

Table 1 on the following page provides an overview of the benefit and cost components for the Connecticut NWS BCA Framework.

The components have been categorized as Tier 1 and Tier 2. Tier 1 components (green) have a larger overall impact on the cost-effectiveness results and are the primary focus of the methodology phase. Tier 2 components (blue), while still important, are less impactful and are also more challenging to quantify; however, their value should still be captured as part of the overall BCA framework. Finally, we recommend that some of the Tier 2 societal impacts (light blue) be included but addressed qualitatively (Q).

The table also includes a comparison of the benefit and cost components that are included in the TRC and CTET currently used to assess C&LM programs.

Table 1: Benefits and cost components for the Connecticut NWS BCA Framework.

Category	Impact		NWS BCA	MUCT	TRC
Bulk System Impacts	Energy	Benefit or Cost	✓	✓	✓
	Capacity	Benefit or Cost	✓	✓	✓
	Market Price Effects	Benefit	✓	✓	✓
	Ancillary Services	Benefit or Cost	✓		
	Transmission Capacity	Benefit or Cost	✓	✓	✓
Distribution System Impacts *(location specific)*	Distribution Capacity	Benefit or Cost	✓	✓	✓
	Distribution O&M[4]	Benefit or Cost	✓	✓	✓
	Reliability	Benefit or Cost	✓/Q[5]	✓	✓
Non-Wire Solution	Utility/Solution Cost[6]	Cost	✓	✓	✓
	Utility Performance Incentive[7]	Cost	✓	✓	✓
Other Resource Impacts	Natural Gas	Benefit or Cost	✓	✓	✓
	Oil and Propane	Benefit	✓	✓	✓
Societal Impacts	Non-Embedded GHGs	Benefit	✓	✓	✓
	Public Health	Benefit	✓/Q[8]		
	Economic and Jobs	Benefit	Q		
	Resilience	Benefit	✓/Q[9]		
	Energy Security	Benefit	Q		

[4] Distribution O&M refers to incremental upstream distribution system costs and/or benefits incurred as a result of having the NWS connected to the grid. This is distinct and non-duplicative of operations and maintenance costs directly related to the NWS project.

[5] Reliability is more a more challenging component to quantify and therefore considered a Tier 2 impact for the BCA. However, minimum levels of reliability will be a mandatory requirement for any NWS and therefore a qualitative discussion and/or ranking should be included in the framework.

[6] Utility/Solution Costs include program costs for the NWS test and the CTET; the TRC includes program and customer costs.

[7] Including the Utility Performance Incentive as an impact requires a circular calculation and therefore will be ignored in practice. The PI will only exist if there are net benefits and will be calculated as 25% of the achieved net benefits. However, including it then lowers the net benefits, which in turn lowers the PI. Any NWS with higher net benefits will still produce higher net benefits than another solution after subtracting the societal cost tied to the PI.

[8] NOx avoided societal costs net of compliance costs will be quantified while other public health benefits (e.g., reduced healthcare costs, more broadly) may be addressed qualitatively.

[9] Resilience is a challenging component to quantify and is therefore considered a Tier 2 impact for the BCA. Resilience benefits will by default be assessed qualitatively; however, a quantitative assessment may be requested in cases where an NWS can impact resilience.

Approach to Wholesale Market Impacts

Non-Wires Solutions providers may or may not choose to participate in wholesale or retail markets depending on the nature of the resource and business case. If they are an active participant in the ISO-NE energy market, Forward Capacity Market ("FCM"), and/or ancillary market, these revenue streams must be accounted for in order to avoid double-counting benefits.

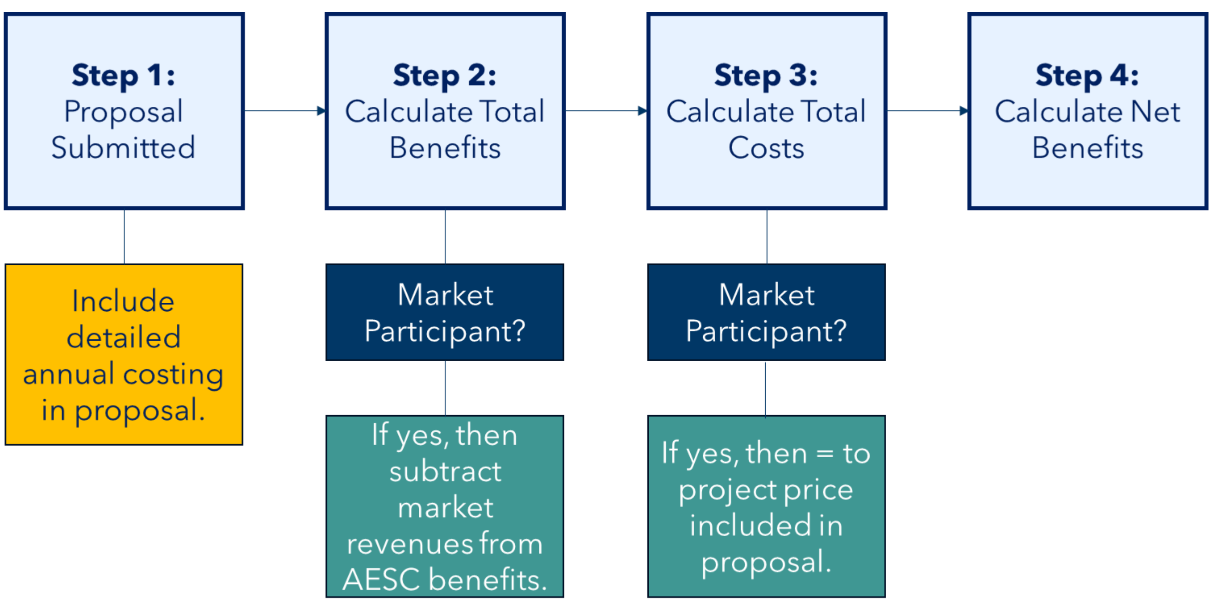
The following outlines an approach for addressing NWSs that participate and earn revenue from wholesale markets.

- **Step 1:** Proponents will be required to submit a detailed costing proposal as part of the bid process. This includes an annual breakdown of expected revenue streams from each anticipated market and will act as a screen for passive resources (i.e., not participating in wholesale markets) and market participants (i.e., those expecting to earn revenue from a market(s).

- **Step 2:** Total benefits are calculated using the methodologies included in this NWS BCA Reference Document, using the AESC study values as proxy for the energy, capacity, DRIPE, and ancillary upstream benefits. If a project intends to participate in the market, then any anticipated market revenue, as outlined in the bid, are subtracted from the corresponding benefit stream (i.e., total project benefits are equal to gross benefits minus market revenues).

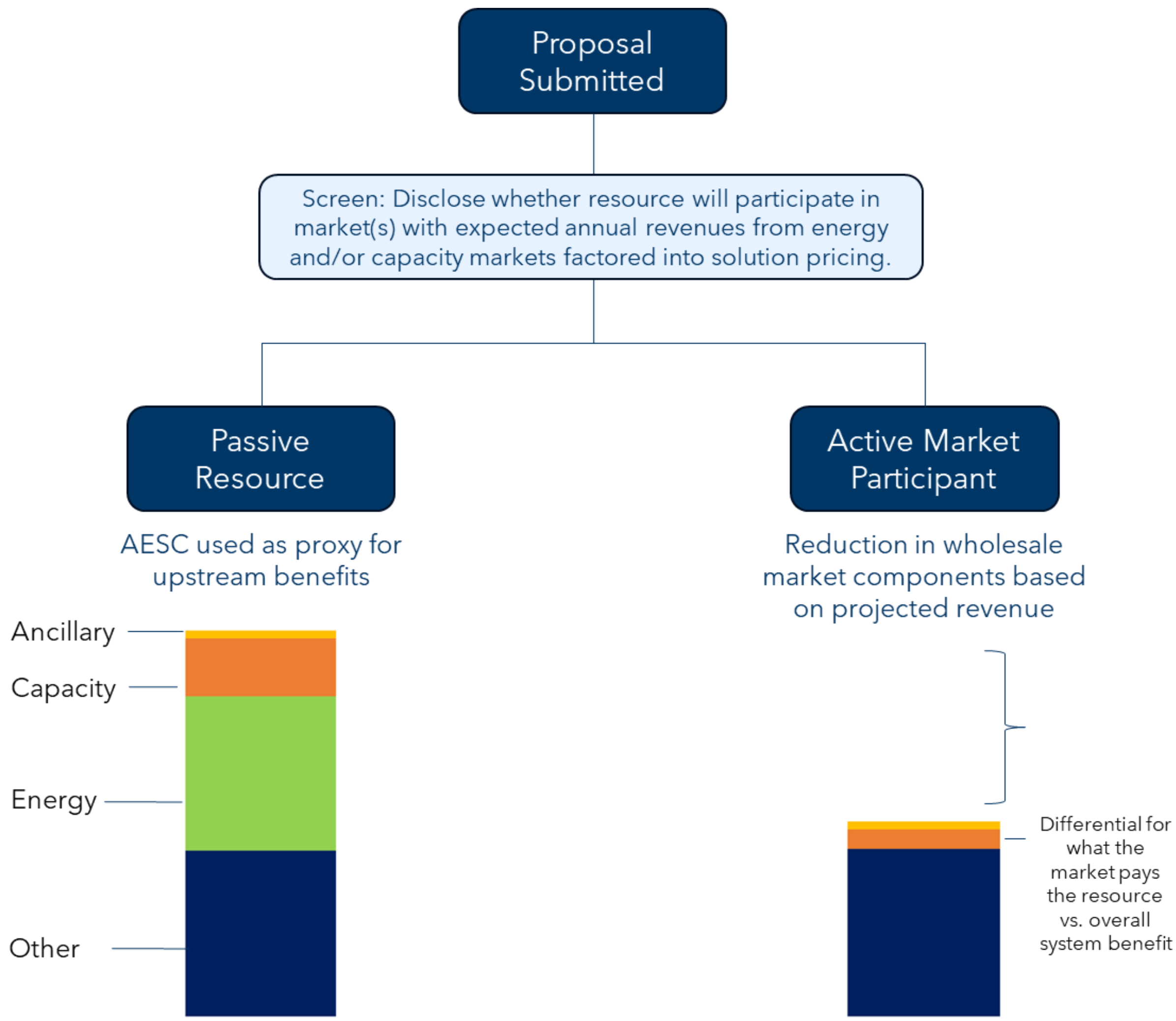
- **Step 3**: Calculate total costs.

- **Step 4:** Net benefits are calculated using **actual** project benefits compared to total project costs.



To note, in cases where projects have the same net benefits, then the net price or the projects' benefit-to-cost ratios (i.e., net of expected market revenues) are to be considered.

The following is an alternative visualization of the benefit streams associated with wholesale market impacts, depending on resource type.



Methodologies

The following methodologies calculate the total impact of each component in real dollars. Total Benefits will be equal to the sum of the net present value (NPV) of each benefit component over the life of the NWS, and total costs will be the sum of the NPV of each cost component.

Total NPV Benefits are then compared to Total NPV Costs to assess net benefits. The MUCT will establish the benefit-to-cost ratio by dividing Total NPV Benefits by Total NPV Costs.

Bulk System Impacts

Energy

Component Type: Quantitative benefit or cost.

Definition & Rationale: Non-wire solutions (NWS) might change the magnitude of energy (i.e., kWh) that a distribution company procures through the ISO-NE wholesale energy market, which could result in a net increase or decrease in energy costs. Hourly Locational Marginal Prices (LMPs) specific to the Connecticut zone are an appropriate proxy for the marginal value of the state's avoided/increased energy use.

Methodology:

Equations & Variables:

The energy impact of an NWS solution is determined by the amount of energy exported to or consumed from the electric grid and can be calculated using the following equation:

$$\boldsymbol{Energy} = \sum_{y=1}^{N} \sum_{h=1}^{8760} (\boldsymbol{PE_{y,h}} + \boldsymbol{RPS_{y}}) * \Delta \boldsymbol{E_{y,h}} * (\mathbf{1} + \boldsymbol{WRP}) * (\mathbf{1} + \boldsymbol{LL_{ME(D \to G)}})$$

Where:

- $\boldsymbol{N}$ is the program's life or the operational life of the NWS.
- $\boldsymbol{y}$ is the operational year.
- $\boldsymbol{h}$ indicates an hourly component determined over an 8760 timeframe.
- $\boldsymbol{PE_{y,h}}$ ($/kWh) is the hourly wholesale energy market price in the Connecticut Load Zone.
- $\boldsymbol{RPS_{y}}$ ($/kWh) is the annual renewable compliance cost or benefit in Connecticut.

- ΔE_h (kWh) is the increase or decrease in energy consumption in a given hour resulting from installing the NWS. If the system exports energy into the grid, ΔE_h will be positive.
- ***WRP*** (%) is the wholesale energy risk premium, reflecting the difference between wholesale and full retail prices (i.e., retail suppliers incorporating risk in contract prices).
- $LL_{ME(D \to G)}$ (%) is the utility's marginal line loss factor, which may include transmission and distribution line losses depending on the NWS's location.

Data Sources & Assumptions:

Inputs	Source
Generation Profile(s)	Annual 8760 forecasted load shape provided by the project proponent, which includes a technology degradation rate
Hourly Marginal Energy Costs	AESC
Wholesale Risk Premium	AESC
Marginal Line Loss Factors	AESC and Distribution Companies
Annual RPS Compliance Costs	AESC

Notes:

- The energy component includes the Regional Greenhouse Gas Initiative ("RGGI") and NOx and SOx regulatory compliance costs, a wholesale risk premium, and line losses.
- The NWS's location, whether in front of the meter (FTM) or behind the meter (BTM), will impact how line losses are applied to the energy impact. The electricity generated by customer-sited DG resources reduces the amount of energy that would otherwise be distributed through the distribution network. Any surplus energy exported back to the grid is assumed to be distributed within the distribution network. Therefore, the avoided distribution line losses apply only to the behind-the-meter or self-consumed portion of the energy produced by the distributed energy resource. If the energy is exported to the distribution or transmission grid, appropriate derates should be applied to the line loss factors.
- Line loss benefits are calculated at the margin. Marginal losses have been estimated to be approximately 1.5 times average losses.[10]
- Renewable Portfolio Standard (RPS) compliance costs are proportional to retail sales. Reductions in retail sales through behind-the-meter consumption reduce RPS compliance costs, while electricity exported back to the grid does not. Therefore,

[10] Regulatory Assistant Project. 2011. Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements.

the NWS's location, whether in front of the meter (FTM) or behind the meter (BTM), will impact the RPS compliance requirements for the distribution utility.

Capacity

Component Type: Quantitative benefit or cost.

Definition & Rationale: The reduction or increase in a distribution company's capacity payment obligation resulting from a decrease or increase in system demand (i.e., kW) that is coincident with the annual ISO-NE system peak. The value of capacity is determined by the ISO-NE Forward Capacity Market (FCM) and adjusted to reflect variation between the Forward Capacity Auction (FCA) clearing price and the actual cost of capacity procured through the market.

Methodology:

Equations & Variables:

The net capacity impact will be calculated annually using the following equations, assumptions, and inputs.

$$\boldsymbol{Capacity} = \sum_{y=1}^{N} \left(\boldsymbol{PC_y} * \boldsymbol{ECR} * (\mathbf{1} + \boldsymbol{R}) * (\mathbf{1} + \boldsymbol{WRP}) * \left(\mathbf{1} + \boldsymbol{LL_{ME(D \to G)}}\right) * \boldsymbol{\Delta C_y}\right)$$

Where:

- ***N*** is the program's life or the operational life of the NWS.
- ***y*** is the year.
- PC_y (\$/kW-year) is the forecasted ISO-NE FCM cleared capacity price forecast.
- ***ECR (%)*** is the Effective Charge Rate that is applied to the future-looking forward capacity prices to account for the difference between the future-looking auction prices and the actual prices at which resources are procured.
- ***R*** (%) is the Reserve Margin.
- ***WRP*** (%) is the wholesale energy risk premium, reflecting the difference between wholesale and full retail prices (i.e., retail suppliers incorporating risk in contract prices).
- $LL_{MC(D \to G)}$ (%) is the utility's marginal line loss factor, which may include transmission and distribution line losses depending on the NWS's interconnection point.
- ΔC_y (kW)is the average change in capacity coincident with the ISO-NE system peak hour in the given operational year.

Data Sources & Assumptions

Inputs	Sources
Forecasted Capacity Prices	AESC
Effective Charge-Rate (by zone)	ISO-NE FCM Net Regional Clearing Price and Effective Charge-Rate Forecast.
Wholesale Risk Premium	AESC
Reserve Margin	AESC
Line Losses	AESC and Distribution Companies

Notes:

- To accurately calculate the average capacity contribution of a Non-Wires Solution the focus is on performance during the peak hours of the ISO New England (ISO-NE) system. This involves using the hourly ISO-NE system load profiles from the Avoided Energy Supply Component (AESC) study. These load profiles are instrumental in pinpointing the peak hours for each year, reflecting the impact of electrification in transportation and heating on the system's peak demand.
- The ISO-NE Forward Capacity Auction (FCA) sets the capacity price three years in advance of the capacity need; therefore, the actual cost at the time of delivery can differ from the auction's clearing price. The "effective charge rate" is a predictive factor for the variance between these future auction prices and the actual prices at which capacity is procured. However, effective charge rate forecasts are typically short-term. To develop long-term forecasts, it is recommended that a trend between the near-term effective charge forecasts and the FCA prices be established and then extrapolated to estimate capacity prices over the lifetime of the solution.

Market Price Effects

Component Type: Quantitative benefit or cost.

Definition & Rationale: The electricity generated or consumed by an NWS changes the energy and capacity procured through the wholesale electricity and natural gas markets. This change in demand results in a shift in market clearing prices, and this price shift, also called Demand Reduction Induced Price Effects (DRIPE)—may be passed on to market participants and their customers.

This component includes the impact of a shift in energy prices (Energy DRIPE), capacity prices (Capacity DRIPE), and the indirect price impacts between gas and electricity prices (Electric-to-Gas-to-Electric or Cross-DRIPE). It includes only the DRIPE impact on Connecticut ratepayers, not the impacts to the entire ISO-NE load.

Methodology:

Equations & Variable:

Energy DRIPE: The following equation determines the Energy DRIPE of an NWS solution:

(1)

$$\boldsymbol{Gross\ DRIPE_{y,h}\ = PE_{y,h} * \frac{CT\ Load}{ISONE\ Load_{y,h}} * Unhedged\ Portion_{y} * Price\ Elasticity_{h}}$$

(2)

$$\boldsymbol{DRIPE\ Decay_{y,y+10} =\ 0.975 * \left(1 - RI_{y,y+10}\right) * (1 + Demand\ Elasticity_{y,y+10})}$$

(3)

$$\boldsymbol{Energy\ DRIPE_{y} = \sum_{y=1}^{N} \frac{(Gross\ DRIPE_{y,h} *\ DRIPE\ Decay_{y})}{(1+r)^{y}}}$$

(4)

$$\boldsymbol{Energy\ DRIPE\ = \sum_{y=1}^{N} \sum_{h=1}^{8760} (Energy\ DRIPE_{y,} * \Delta E_{y,h} * (1 + WRP) * (1 + LL_{ME(D\rightarrow G)})}$$

Where:

- ***N*** is the program's life or the operational life of the NWS.
- ***y*** is the operational year.
- ***h*** indicates an hourly component determined over an 8760 timeframe.
- $\boldsymbol{PE_{y,h}}$ ($/kWh) is the hourly wholesale energy market price in the Connecticut Load Zone.
- ***CT Load*** (MWh) is the hourly system load in the Connecticut Load Zone.
- ***ISONE Load*** (MWh) is the hourly ISO-NE system load.
- **Unhedged Portion** (%) is the portion of the Connecticut system load purchased on the spot market.

- **Price Elasticity** is the ratio of the % change in the price to the % change in demand.
- **RI** is the resource impact that captures the impact of generators/resources on wholesale price changes.
- **Demand Elasticity** captures the rebound effect of demand to lower prices.
- **r** is the discount rate
- ***ΔE_h*** (kWh) is the increase or decrease in energy consumption in a given hour resulting from installing the NWS. If the system exports energy into the grid, ΔE_h will be positive.

Capacity DRIPE

(5)

$$Capacity\ DRIPE_y = [Price\ Shift * Unhedged\ Capacity] * (1 - Decay) * (1 + R)$$

(6)

$$Capacity\ DRIPE = \sum_{y=1}^{N} (Capacity\ DRIPE_y * (1 + WRP) * \left(1 + LL_{ME(D \to G)}\right) * \Delta C_y)$$

Where:

- ***N*** is the program's life or the operational life of the NWS.
- ***y*** is the year.
- ***Price Shift*** of capacity refers to how much the price of capacity (measured in $/kW-year per MW) changes in response to changes in demand.
- ***Unhedged Capacity*** *refers to the portion of the capacity procured from the wholesale market.*
- ***Decay*** *includes the impact of resources and demand on the change in capacity prices.*
- ***R*** (%) is the Reserve Margin.
- ***WRP*** (%) is the wholesale energy risk premium, reflecting the difference between wholesale and full retail prices (i.e., retail suppliers incorporating risk in contract prices).

- $LL_{MC(D \to G)}$ (%) is the utility's marginal line loss factor, which may include transmission and distribution line losses depending on the NWS's interconnection point.
- ΔC_y (kW)is the average change in capacity coincident with the ISO-NE system peak hour in the given operational year.

Data Sources & Assumptions

Inputs	Sources
Gross Energy DRIPE Forecast	AESC
Price and Demand Elasticity	AESC
Uncleared Capacity DRIPE Forecast	AESC
E-G-E DRIPE Coefficients	AESC
Reserve Margin	AESC
Line Losses	AESC and Distribution Companies

Ancillary Services

Component Type: Quantitative benefit or cost.

Definition & Rationale: This component represents an increase or decrease in ancillary services that are procured through the market in order to maintain grid stability. It is assumed that any increase or decrease in wholesale load due to NWS production will increase or decrease the ancillary services and load obligation charges that are assessed to Connecticut load serving entities, resulting in either an increase or decrease in costs.

Ancillary Services impacts include changes in charges levied on wholesale load obligations (i.e., First and Second Contingency, Forward and Real-Time Reserves, Regulation, Inadvertent energy, net Commitments Period Compensation (NCPC), Auction Revenue Rights (ARP) revenues, NEPOOL expenses, etc.).

Methodology:

Ancillary Services impacts include changes in charges levied on wholesale load obligations (i.e., First and Second Contingency, Forward and Real-Time Reserves, Regulation, Inadvertent energy, net Commitments Period Compensation (NCPC), Auction Revenue Rights (ARP) revenues, NEPOOL expenses, etc.).

$$\boldsymbol{Ancillary\ Services} = \sum_{y=1}^{N} \sum_{h=1}^{8760} \boldsymbol{LOC_{y,h}} * \Delta \boldsymbol{E_{y,h}} * (\mathbf{1} + \boldsymbol{LL_{ME(D \to G)}})$$

Where:

- ***N*** is the program's life or the operational life of the NWS.
- ***y*** is the year.
- ***h*** indicates an hourly component determined over an 8760 timeframe.
- ***LOC* or** *Load Obligation Charges* ($/kWh) are wholesale ancillary and load charges.
- ΔE_h (kWh) is the increase or decrease in energy consumption in a given hour resulting from installing the NWS.
- $LL_{ME(D \rightarrow G)}$ (%) is the utility's marginal line loss factor, which may include transmission and distribution line losses depending on the location of the NWS.

Data Sources & Assumptions:

Inputs	Source
Net Change in Energy	Provided by the project proponent, identifying, and incorporating a technology degradation rate.
Load Obligation Charges	ISO-NE Wholesale Load Cost Reports.
Line Loss Factors	AESC and Distribution Companies

Transmission Capacity

Component Type: Quantitative benefit or cost.

Definition & Rationale: Load reductions that are coincident with the annual system peak demand can result in avoided investments in transmission facilities. This component focuses on forward-looking, avoided regional transmission system investments, or pool transmission facilities ("PTF"). To note, an NWS resource also has the potential to increase demand during the peak hour, thus increasing the need for future transmission facilities (i.e., a cost rather than a benefit).

Methodology: Project proponents should follow the methodological approach suggested in the AESC study to estimate avoided costs related to pool transmission facilities ("PTF"), which is based on forward-looking investments, as outlined in Chapter 10, section 10.2. To note, given the Connecticut NWS cost-effectiveness perspective, only a portion of avoided PTF costs should be included. The allocation of RNS charges can be used to guide the portion of the PTF costs that would have otherwise been assessed to Connecticut ratepayers.

Distribution System Impacts

Distribution Capacity

Component Type: Quantitative benefit or cost.

Definition & Rationale: An NWS resource has the potential to avoid or defer capacity-related investments on the distribution system (e.g., substations or circuits), if the project reduces load during hours associated with reliability concerns. These capacity deficiencies are highly locational. Conversely, the NSW resource may introduce additional capacity-related investments on the distribution system.

Methodology: The distribution capacity impact is equivalent to the deferral value of the NWS(s) based on the Real Economic Carrying Charge, which shapes the deferral capacity value over the life of the asset and adjusts that with inflation. This location-specific value will be provided by the utility and will include deferred capital expenditures, deferred O&M, and deferred taxes over the expected contract term. The approach included in Chapter 10, section 10.4 of the AESC study may be used as a starting point.

Distribution Operation & Maintenance

Component Type: Quantitative benefit or cost.

Definition & Rationale: There are costs associated with maintaining safe and reliable operation of distribution facilities (e.g., maintaining substations, poles and wire as well as replacement of portions of the system over time). These variable costs are partially a function of the volume of energy that is transferred through the system. This component may be a benefit if the NWS project decreases costs associated with infrastructure maintenance and/or replacement, or a cost if increased investment in distribution system O&M – beyond the deferred upgrade directly associated with the NWS – is incurred as a result of the NWS.

Methodology: This location(s)-specific value will be provided by the utility.

Distribution Voltage

Component Type: Quantitative benefit or cost.

Definition & Rationale: This component refers to voltage regulation, which is required to ensure reliable electricity flow throughout the distribution system at an acceptable range in order to match real and reactive power production with demand.[11] An NWS resource may provide a benefit if it helps address a voltage issue or a cost if adding the NWS project negatively impacts voltage regulation. This component should not take into account impacts already accounted for under the ancillary services or distribution capacity components.

Methodology: This location(s)-specific value will be provided by the utility.

[11] Adapted from the NESP *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (August 2020)

Reliability

Component Type: Quantitative or qualitative benefit or cost.

Definition & Rationale: In the Final Decision in 24-08-08, Non-Wires Solutions Initiation Phase, the EDCs and Process Monitor were directed to: "file a revised methodology for calculating the reliability and resilience components for the NWS BCA reference manual that is consistent with the RE08 Decision and the calculation of these impacts."

As noted in the Final Decision in 17-12-03RE08, PURA Investigation into Distribution Planning of the Electric Distribution Companies – Resilience and Reliability Standards and Programs: "…reliability can be thought of as 'the ability of the power system to deliver electricity in the quantity and with the quality demanded by users'…In short, reliability means that electric service is available when expected."

Reliability is defined here as the relative value of reducing the probability and duration of system events, and the value will be a function of the availability of capacity and infrastructure conditions. This component should not double-count impacts accounted for under the Resilience component. Furthermore, reliability benefits shall only be assigned when the NWS Solution proposed is capable of impacting system reliability, including, but not limited to, dispatchable NWS technologies and solutions over which the EDCs have operational control.

Methodology:

$$Reliability = \sum_{y=1,i}^{N} VoLL\left(Duration_{pre,i}\right) - VoLL(Duration_{post,i})$$

Where:

- $\boldsymbol{N}$ is the program's life or the operational life of the NWS Asset.
- $\boldsymbol{Duration}_{\text{pre,i}}$ (hours) is the annual average outage duration due to distribution system failure that any given customer would experience, before the project installation
- $\boldsymbol{Duration}_{\text{post,i}}$ (hours) is the annual average outage duration due to distribution system failure that any given customer would experience, after the project installation
- $\boldsymbol{VoLL}$ ($/CMO) is the Value of Lost Load (VoLL), is the output of the Department of Energy's Interruption Cost Estimate (ICE) calculator using pre and post reliability inputs like $\boldsymbol{Duration}_{\text{pre}}$ and $\boldsymbol{Duration}_{\text{post}}$.

Data Sources & Assumptions

Inputs	Sources
Probability of a System Outage	Utility
Average Annual Outage Duration	System Average Interruption Duration Index (SAIDI) prepared by the utilities
Value of Lost Load:	ICE Calculator

Non-Wires Solution

Utility/Solution Cost

Component Type: Quantitative cost.

Definition & Rationale: Adding an NWS resource to the distribution system results in project and program related costs. This cost component includes 1) the capital cost for the NWS project, 2) annual O&M project-related costs, and 3) program administrator and financing incentive costs related to administration, incentives (e.g., for participating in DR events), metering, billing, collections interconnection costs (that are not reimbursed), evaluation, and other program-related costs.

Methodology: User-defined inputs provided by the project proponent. Anticipated revenues from each wholesale and retail market stream will be presented in the bid pricing proposal.

Utility Performance Incentive

Component Type: Quantitative cost.

Definition & Rationale: As outlined in the Decision and Design Document, utilities may earn a shareholder incentive for NWSs in the form of a Shared Savings Incentive. Ratepayers will receive 75 percent of the projected net benefits over the asset(s)' lifetime and the utility may collect the remainder. These earning represent a program delivery cost and will be added to the total cost of the NWS project at the end. In other words, the performance incentive is not treated as an upfront cost, for the purposes of screening to quantify the net benefits but it is included to reflect the net benefits accruing to ratepayers and society.[12]

Methodology: User-defined inputs as per the methodology outlined in the Decision and Design Document.

[12] Note that any solution with higher net benefits than another solution will still produce higher net benefits following subtraction of the ratepayer costs tied to the Utility Performance Incentive.

Other Resource Impacts

Natural Gas

Component Type: Quantitative benefit.

Definition & Rationale: This benefit component represents avoided fuel costs associated with the on-site use of natural gas – i.e., a reduction or displacement in the use of natural gas-fired equipment in homes and buildings. This includes commodity, storage, and distribution costs.

Methodology:

$$\boldsymbol{Avoided\ Natural\ Gas} = \sum_{y=1}^{N} \boldsymbol{NG\ Price_{y,End\ Use}} * \boldsymbol{\Delta NG\ Consumption}$$

Where:

- ***N*** is the program's life or the operational life of the NWS.
- ***y*** is the year.
- ***NG Price*** *($/MMBtu)* is the annual cost of gas to retail customers for Southern new England, by end-use.
- ***ΔNG Consumption*** *(MMBtu)* is the increase or decrease in natural gas used by customers as a result of the NWS.

Data Sources & Assumptions:

Inputs	Sources
Natural gas avoided costs	AESC
Net change in natural gas consumption	Provided by the project proponent

Notes:

- It is assumed that the avoided cost of gas includes some avoidable retail margin. As noted in the AESC, some LDC's may not be able to avoid a portion of the retail margin. It will be up to stakeholders to determine if this is the appropriate value stream or if the non-margin avoided costs for Southern New England should be used.
- Appendix C in the AESC includes annual (2024-2060) avoided cost ($/MMBTu) of gas to retail customers by end use (residential and commercial).
- The change in natural gas consumption provided by the proponent should follow agreed upon methodologies and assumptions used to estimate natural gas savings for CL&M programs.

Oil & Propane

Component Type: Quantitative benefit.

Definition & Rationale: This benefit component represents avoided fuel costs associated with the on-site use of heating oil and propane – i.e., a reduction or displacement in the use of other fossil fuel-fired equipment in homes and buildings. This includes commodity, storage, and transportation/delivery costs.

Methodology:

$$\textit{Avoided Delivered Fuels} = \sum_{y=1}^{N} \textit{DF Price}_y * \Delta \textit{DF Consumption}$$

Where:

- ***N*** is the program's life or the operational life of the NWS.
- ***y*** is the year.
- ***DF Price*** *($/MMBtu)* is the annual unit cost of delivered fuels to retail customers by fuel type and sector.
- ***ΔDF Consumption*** *(MMBtu)* is the increase or decrease in delivered fuels used by customers as a result of the NWS.

Data Sources & Assumptions:

Inputs	Sources
Delivered fuels avoided costs	AESC
Net change in delivered fuels consumption	Provided by the project proponent

Water

Component Type: Qualitative benefit.

Definition & Rationale: This component refers to avoided water consumption and the related cost savings. This will be primarily relevant for energy efficiency measures and are not likely to be significant. A project proponent may speak to the potential water savings benefits associated with the NWS resource.

Societal Impacts

Non-Embedded GHGs

Component Type: Quantitative benefit.

Definition & Rationale: While avoided GHG program compliance costs from the Regional Greenhouse Gas Initiative ("RGGI") are embedded in the avoided energy component (i.e., in the wholesale energy price), there may also be additional, non-embedded GHG benefits (i.e., externality benefits) associated with reduced GHG emissions provided the marginal resource is a fossil fuel-fired generator. This benefit component includes carbon dioxide ("CO_2") emissions but does not include avoided methane emissions given challenges to accurately quantify upstream savings and U.S. federal government efforts to reduce upstream methane emissions through a proposed rule for new and existing facilities.

Methodology:

Equation & Variables:

The non-embedded GHG benefit component is calculated on an annual hourly basis.

$$\boldsymbol{Non\ Embedded\ GHG\ Impact} = \sum_{y=1}^{N} \sum_{h=1}^{8760} (SCC_y - RGGI_y) * GHG\ ER_{y,h} * \Delta E_{y,h} * (1 + LL_{ME(D\rightarrow G)})$$

Where:

- ***N*** is the program's life or the operational life of the NWS.
- ***y*** is the year.
- ***h*** indicates that marginal emissions rates are determined over an 8760 timeframe.
- SCC_y (\$/ton) is the Societal Cost of Carbon.
- ***RGGI*** (\$/ton) is the embedded cost of complying with the Regional Greenhouse Gas Initiative.
- $GHG\ ER_{y,h}$ (tons/kWh) is the hourly long-run marginal emission rate for GHGs.
- ΔE_h (kWh) is the increase or decrease in energy consumption in a given hour resulting from the installation of the NWS.
- $LL_{ME(D\rightarrow G)}$ (%) is the utility's marginal line loss factor, which depending on the location of the NWS, may include transmission and distribution line losses.

Data Sources & Assumptions:

Inputs	Sources
Societal Cost of Carbon (1.5% discount rate scenario)	AESC
RGGI Allowance Price Forecast	AESC
Generation Profile(s)	Average 8760 forecasted load shape over the solution's lifetime, provided by the project proponent, identifying, and incorporating a technology degradation rate
Marginal Emission Rates	AESC
Line Losses	AESC and Distribution Companies

Notes:

- The AESC study includes two approaches for calculating the value of avoided carbon emissions – a marginal abatement cost test and the Social Cost of Carbon (SCC). The SCC method and forecast in the AESC is recommended give challenges related to establishing marginal abatement projections at a regional perspective.

Public Health

Component Type: Quantitative and qualitative benefits.

Definition & Rationale: This component includes both quantitative and qualitative benefits. In terms of quantitative benefits, while avoided nitric oxide/nitrogen dioxide ("NO_x") environmental program compliance costs are embedded in the avoided energy component (i.e., in the wholesale energy price), there are additional non-embedded NO_x benefits (i.e., externality benefits) from avoided fossil fuel generation which support better health outcomes. This component does not include sulfur dioxide ("SO_2") or particulate matter – both of which are excluded from the AESC study, which assumes all coal-fired generation is off-line by 2025.

In terms of qualitative benefits, a project proponent may speak to the reduced healthcare costs, more broadly, from reduced emissions from fossil fuel-fired generation.

Methodology:

The NO_x benefit component is calculated on an annual hourly basis as follows.

$$\boldsymbol{NOx\ Reduction\ Benefit} = \sum_{y=1}^{N} \sum_{h=1}^{8760} \boldsymbol{PNOx * NOx\ ER_{h,y} * \Delta E_{y,h} * (1 + LL_{ME(D\rightarrow G)})}$$

Where:

- ***N*** is the program's life or the operational life of the NWS.
- ***y*** is the year.
- ***h*** indicates that marginal emissions rates are determined over an 8760 timeframe.
- $\boldsymbol{PNOx_y}$ (\$/ton) is the price per short ton of NO_x.
- $\boldsymbol{NOx\ ER_{y,h}}$ (tons/kWh) is the hourly long-run marginal emission rate for NO_x.
- $\boldsymbol{\Delta E_h}$ (kWh) is the increase or decrease in energy consumption in a given hour resulting from the installation of the NWS.
- $\boldsymbol{LL_{ME(D \rightarrow G)}}$ (%) is the utility's marginal line loss factor, which depending on the location of the NWS, may include transmission and distribution line losses.

Data Sources & Assumptions:

Inputs	Sources
Price per short ton NO_x	AESC
Marginal emissions rate for NO_x	AESC
Generation Profile(s)	Average 8760 forecasted load shape over the solution's lifetime, provided by the project proponent, identifying, and incorporating a technology degradation rate
Wholesale Risk Premium	AESC
Line Losses	AESC and Distribution Companies

Notes:

- The most recent AESC study assumes no embedded NOx prices in the wholesale energy cost projections since New England states are exempt from the CSAPR program and state specific regulations (e.g., in Connecticut) are unlikely to be binding. Therefore, unlike the societal GHG benefit, the externality benefit from avoided NOx is equal to the total price per short ton in the AESC study with no adjustment. This should be revisited should program requirements change.

Economic and Jobs

Component Type: Qualitative benefits.

Definition & Rationale: There are macroeconomic benefits associated with investing in new NWS projects in Connecticut. These include direct, indirect, and induced impacts related to GDP and employment as well as fiscal benefits, which occur during the construction/implementation of an NWS and over the lifetime of the resource. These benefits are resource and context specific. A project proponent may speak to the potential economic and jobs benefits associated with the NWS resource.

Resilience

Component Type: Qualitative or Quantitative benefit.

Definition & Rationale: Resilience services are defined here as the ability of an NWS resource to provide back-up power to a customer or area on the distribution grid in the event that utility electricity services are lost and support rapid recovery from the event.

In Docket No. 17-12-03RE08 Electric distribution resilience is defined by the IEEE Power and Energy Society (PES) in technical reports PES-TR65 and PES-TR837 as "[t]he ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event." As noted by relevant publications, "[i]n some respects, this definition of broad resilience would fit with the system of metrics developed to assess the ability of utilities to 'withstand' incidents without incurring a loss of service"; however, with an increasing frequency of Major Storms, assessing a system's resilience requires a myriad of tools beyond the foundation that reliability metrics can provide.

While resilience services may have significant value to a customer and the distribution system, it is highly context-specific and may be reliant on data that EDCs do not currently track. As such, by default, the resilience component will be requested as a qualitative component only. Resilience benefits shall only be assigned to NWS solutions which are capable of impacting system resilience, including, but not limited to, dispatchable NWS Technologies and solutions over which the EDCs have operational control.

If the Benefit-Cost Ratio (BCR) of an NWS is greater than 0.8, but less than 1 (i.e. 0.8<BCR<1), **and** the NWS solution is capable of impacting resilience, a quantitative assessment of resilience **may** be requested to aid the decision-making process. It is anticipated that, if required, the quantitative evaluation would be requested when evaluating the responses provided through the NWS RFI/RFP process.

Energy Security

Component Type: Qualitative benefit.

Definition & Rationale: This benefit component (or benefit/cost in the case of storage), relates to reduced reliance on fuel and/or energy imports from outside of the state, region, or country, which increases energy independence.[13] A project proponent may qualitatively speak to the potential for improved energy security from the NWS project; ensuring that they are not double-counting utility system reliability.

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[13] Adapted from the NESP *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (August 2020)

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