Sustainable Energy Advantage, LLC

VT RES/CES BCA Methodology and Data Sources

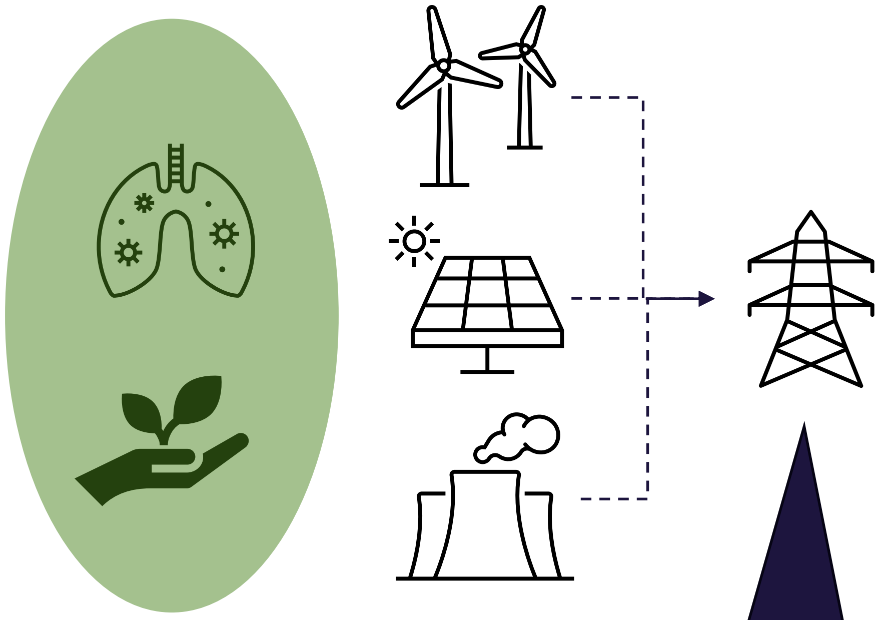
Stakeholder Advisory Group Meetings 3 & 4

Introduction

- Review primary costs and benefits incorporated into benefit cost analysis (BCA)
- In developing inputs and assumptions for the analysis, we prioritize data that are:
  - Publicly-available
  - Based on rigorous analysis from credible sources
  - Not anecdotal
- We call out items that are most open to interpretation/difficult to quantify
- Caveat – research on certain items is ongoing and may be revised

Methodological Overview

- The VT BCA examines the *incremental* costs and benefits of RES/CES
- Value of energy and capacity (after taking into account production profile, capacity accreditation) the same regardless of generation technology
- Analysis compares incremental costs attributable to RES/CES to benefits unique to resources included in the RES/CES (e.g., emissions reductions)
- The impact of different production profiles factors into calculation of incremental costs

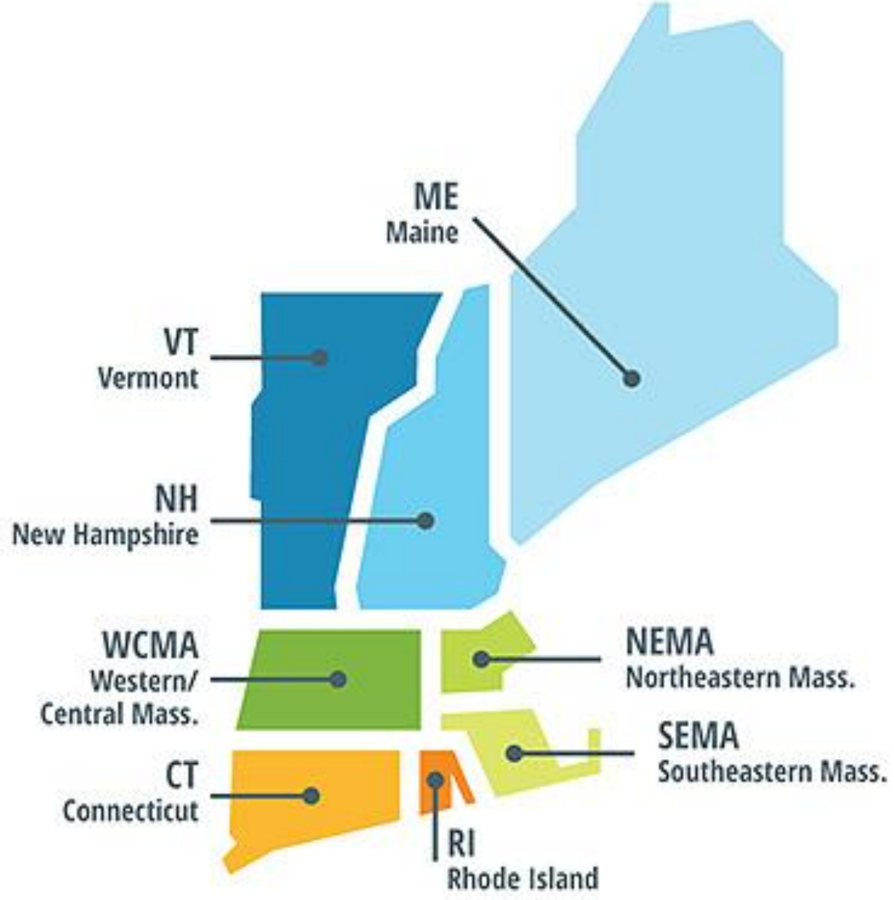


Differences in other characteristics (e.g., emissions) the focus of the analysis

Value of *energy and capacity* (accounting for things like production profile) the same

Other Key Concepts

- Cleared vs. uncleared capacity
  - For some values (e.g., capacity price effects), different projected values apply depending on whether a resource had bid into and cleared the forward capacity market (FCM) or not
  - With the exception of most projects less than 5 MW, we assume projects will be bid into the FCM
- Intrastate vs. regional benefits
  - Certain price effect benefits (see later slides) have financial benefits for all ISO-NE customers
  - Possible to calculate benefits specific to VT (intrastate) vs. regional benefits



Wholesale Load Zones in New England

Primary Benefit/Cost Streams

- Excludes capacity and energy values which are netted from cost

Benefit/Cost Stream	Type	Monetized?	Impacts bills?	Primary Data Source
Incremental cost of RE	Cost of RE	Yes	Yes	Various, SEA analysis
Grid integration costs	Cost of RE	Yes	Yes	NREL studies and/or VELCO Long-Range Plan
Uncleared capacity value	Benefit of RE	Yes	Yes	Avoided Energy Supply Component Study **(AESC)** 2021
Price effects/price suppression	Benefit of RE	Yes	Yes (except electric to gas)	AESC
Reduced transmission costs	Benefit of RE	Yes	Yes	AESC
Reduced distribution costs	Benefit of RE	Yes	Yes	TBD
Improved generation reliability	Benefit of RE	Yes	No	AESC (based on ISO impacts)
Social cost of carbon	Benefit of RE	Yes	No	AESC
NOx emissions	Benefit of RE	Yes	No	AESC
Local pollutants	Benefit of RE	Yes	No	COBRA/AVERT
Land use	TBD	TBD	No	Various
Water use	Benefit of RE	TBD	No	Various

AESC = 2021 Avoided Energy Supply Component Study **(AESC)**

Approach to Establishing Incremental Costs

The approach to calculating incremental cost of RES is customized by tier

Tier I / CES	Tier II	Regional Tier
• Market is illiquid but **compliance costs** (from DUs) and **incremental cost from 'existing' regional tiers** provide starting point • Should some existing portfolio contracts (e.g., HQ/NYPA) be treated as $0 incremental cost? • *'Existing' RPS classes from other New England states offer starting point range of ~$3-~$5/MWh* • RES/CES revisions (toward 100%) region-wide will increase demand tension through 2035, increasing incremental cost over time → *$ impact subject to forthcoming modeling* (but capped at alternative compliance payment – (ACP)) • Assume current ACP method	• Driven by policy and project economics • Assume % of Tier II from net metering (remainder = 1-NM) • Net metering: forecast of net metering rates minus expected value of wholesale energy and capacity • Remainder (Standard Offer or similar/cost-based): missing money analysis → levelized project cost minus levelized market value of energy (accounting for production profile) and capacity • Starting point range: calculated • Assume current ACP method	• Short-term: driven by regional REC supply/demand dynamics • Long-term: projections converge towards missing money (project cost minus levelized market value) • Starting point range ~$35-$38 • ACP: Assume same as Tier II

Because energy and capacity value (including capacity accreditation and consideration of 8760 production profile) are netted out of cost of RES resources, they do not show up as a separate benefit in analysis

Treatment of Interconnection Costs

- Distributed generation pays for grid upgrades needed to interconnect the generation
  - For distribution-connected resources, this can include both distribution and transmission upgrade costs
  - Generally paid for solely by resource (or resources in the case of group studies) that trigger the upgrade;
  - Resources that interconnect when there is available headroom may have minimal interconnection costs, while resource interconnecting on the same circuit that triggers upgrade may bare entire cost
- For the ***distribution*** system, most costs driven by DG are paid for by interconnecting DG customers
  - Other states (e.g., MA) have chosen to socialize some of these costs, sharing the costs across interconnecting generation and ratepayers

These cost are captured in incremental costs described on previous slide (we model interconnection costs when considering revenue requirements)

- For the ***transmission*** system, over the long-term, additional investment will be required to address the variability and location of renewables that may not be paid for directly by interconnecting generation
- While the specific approach to cost recovery for these types of upgrades is an area of evolving policy, we assume that these costs will be socialized across New England

We refer to these costs as “grid or transmission integration costs” and we model them separately (see next slide)

Cost - Transmission Integration Costs – NREL Study

- **Description:** Renewable energy (RE) may drive regional transmission (Tx) network upgrades that are socialized due to their variability and distance from load
  - **Note:** As described on previous slide, grid integration costs considered are separate from *interconnection costs paid for by generators which are already included in estimates of incremental costs*
- **Inputs & Sources**
  - NREL 2022 Standard Scenarios (2022 SS) captures US power system future through 2050 across 70 scenarios and includes detailed data on US transmission investments
  - Gorman et al. 2019 estimates RE-driven Tx costs from various studies (including NREL 2018 Standard Scenarios), actual project costs, and interconnection studies
- **Methodology:**
  - Use NREL 2022 Standard Scenarios to estimate bulk Tx costs (in $/MWh) driven by RE
  - To avoid over-attributing Tx investments to RE that would have occurred anyway, Gorman et al. 2019 netted out Tx investments (in $ NPV) in NREL's 2018 SS *Low Natural Gas Price* scenario from those in the *Low Wind/Solar Cost* scenario
  - Applied same approach as Gorman et al. 2019 using NREL 2022 SS
  - *Result*: $3.14/MWh for solar and wind
- **Limitations**
  - NREL Tx investment data is not available on state or regional level → SEA conducting additional research to adjust figure above to better reflect New England value
  - NREL 2022 SS includes "Low RE Cost" scenarios, such that SEA estimates reflect Tx investment driven by both solar and wind as opposed to attributing costs to a single resource
- **Note –** potential cost/benefits to distribution system addressed later

VT-Specific Grid Cost information

- **Description:** Some relevant VT-specific resources are also available
- **Inputs & Sources**
  - 2021 VELCO Long-Range Transmission Plan examines the transmission upgrades needed under high distributed generation growth scenario
  - Generation Scenarios Planning Tool identified remaining headroom in the distribution system by region
- **Methodology:**
  - Allocate distributed generation across the state with grid-optimal siting pattern
    - If all regions are constrained, implement next most cost-effective upgrade
  - Or allocate distributed generation across the state with current siting patterns by region
    - If grid limitations are encountered, allocate distributed generation to remaining regions
    - If all regions are constrained, implement next most cost-effective upgrade
  - Sum cost of upgrades and back-calculate cost per megawatt-hour
- **Discussion, limitations**
  - Relies on utility estimate of costs
  - Generation Scenarios Planning Tool likely an input to distribution interconnection costs, which will be accounted for in incremental cost analysis
  - VELCO study may include some costs that would be paid by interconnecting generation and some costs that would be borne by ratepayers; further, note that it is a VT-specific study, and for transmission integration costs, a regional perspective is important
  - Further discussion required to ensure VT-specific values used where possible, while avoiding double-counting and appropriately accounting for regional costs

Avoided Energy Supply Component (AESC) Overview

- The AESC study is used by the New England states to estimate the benefits of running various programs
  - Initially, specifically for energy efficiency plans, but use has broadened since
  - Overseen by stakeholders including utilities, state energy offices, and advocates
  - Most recent study completed in 2021
- The AESC includes multiple scenarios with differing assumptions related to EE deployment, renewables deployment, etc.
  - Counterfactuals 1-4 (which assume no/limited new energy efficiency) generally used to calculate benefits from energy efficiency
  - Given that this analysis is focused on generation, we found the "All-in climate policy" case to be most appropriate for most benefits calculations – it can be interpreted "as a projection of expected energy prices, capacity prices, and other price series in a future with ambitious climate policies."
    - Some exceptions – e.g., GHG marginal emissions rates from all-in climate policy case result in low, or zero assumed benefits from RE, as the case assumes that region *has already achieved low emissions*

Benefits of Using AESC	Limitations
• Rigorous analysis, with inputs from users of data (including VT) • Methodology extremely well documented (more transparent than other modeling approaches) • Results publicly available and regularly updated • Regularly used in BCAs	• Not explicitly designed for evaluating RPS • May not capture some interactive effects associated with production cost or capacity expansion models

SEA may make some adjustments to AESC value, such as update near-term projections based on changes in natural gas markets since the 2021 AESC was completed

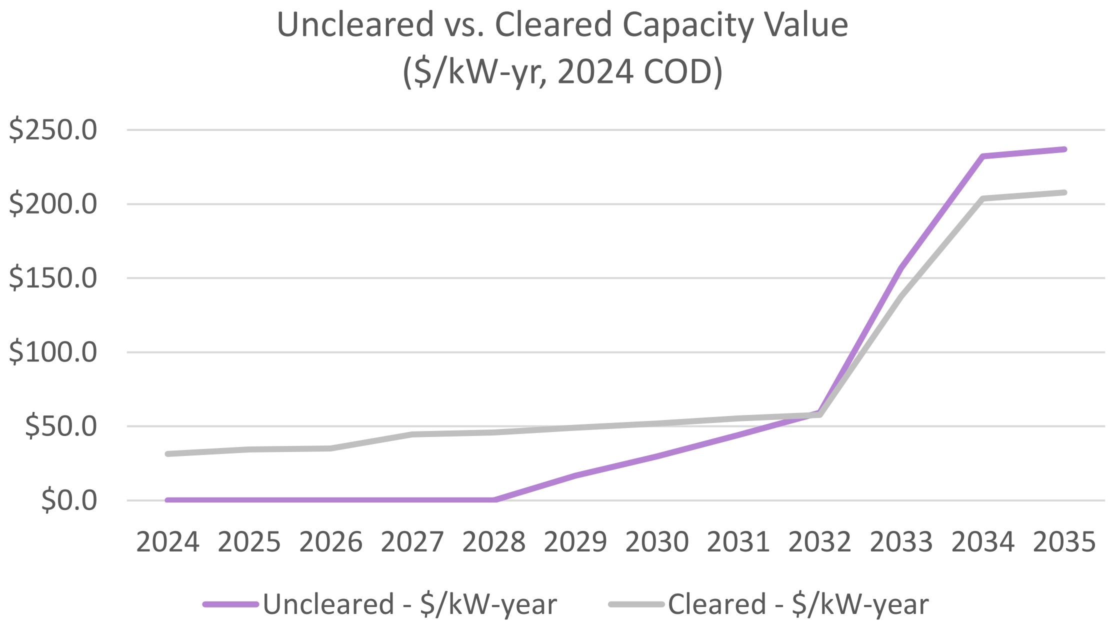
Capacity Accreditation/Coincidence w/ Peaks

- **Description:**
  - Several benefits categories (including uncleared capacity, capacity price effects, transmission benefits, and increased reliability) require an assumption about the probabilistic production of a resource during periods of peak demand
  - The capacity accreditation process, which seeks to adjust a resource's nameplate capacity for the purposes of capacity compensation, helps fill this data need
- **Methodology:**
  - ISO-NE is pursuing a Marginal Reliability Impact (MRI) capacity accreditation approach (similar to NY)
  - Derive technology-specific MRI values as function of installed system capacity
- **Sources and Assumptions:**
  - ISO-NE intended to implement in time for Forward Capacity Auction 19 for the 2028-2029 capacity commitment period (scheduled for Feb. 2025), but software errors necessitated delays
  - So, MRI values derived from NYISO studies
- **Discussion**
  - MRI approach leads to reduced capacity value in the long-run for renewables, storage and gas-only resources
  - We apply default capacity values through 2028 before assuming MRI values implemented starting in 2029 (to account for ISO-NE delay)

Benefit – BTM Uncleared Capacity

- **Description:**
  - For most resources, capacity value accounted for in incremental cost of supply (see slide 6)
  - For behind-the-meter resources that are not bid into the forward capacity market (FCM), we calculate a benefit separately
- **Methodology:** resource capacity multiplied by $/kW capacity value (incorporating reserve margin) and technology-specific coincidence factor (see transmission benefits)
- **Inputs and sources:**
  - Capacity price and reserve margin estimates: 2021 AESC
  - Tech-specific coincidences: SEA estimates benchmarked against other sources (see previous slide)

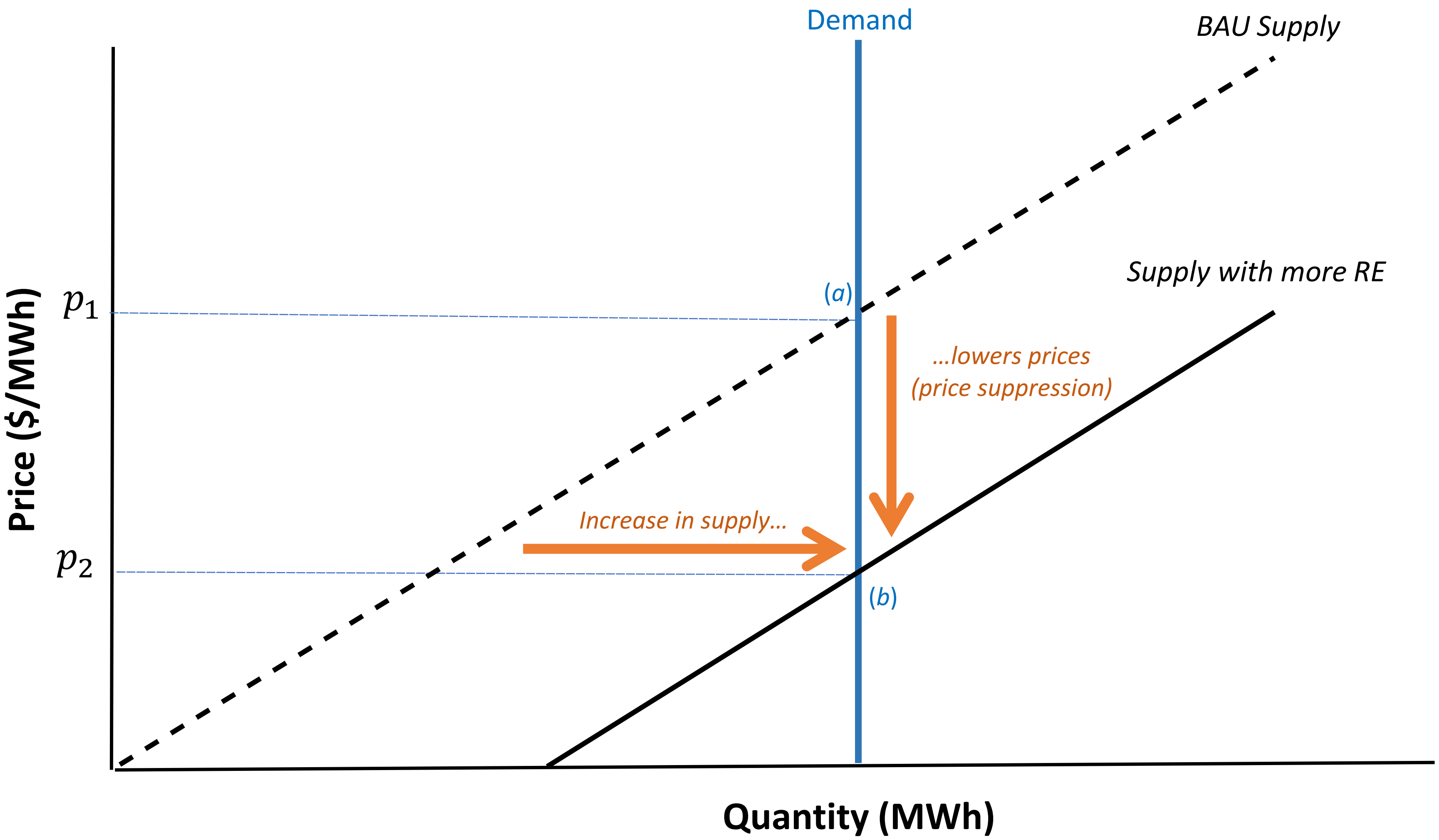
Capacity bid into FCM	Capacity *not* bid into FCM
Shows up as supply	If BTM, shows as *reduction in demand/load*
1 MW of accredited resource = 1 MW of supply in FCM	1 MW of load reduction from resource = 1 MW * (1+reserve margin)



2021 AESC – May Release

Benefit - Price Effects/Price Suppression (1)

- **Description:** For energy and capacity, policy or contract-driven renewables can lead to price suppression
- Low bids from these resources effectively push the supply curve to the right, (more expensive unit on the margin no longer clears) leading to lower clearing prices (reduction in price paid by all consumers)*
- These effects decay over time
- **Source:** AESC 2021



** Similar impact in energy efficiency; demand shifts to the left instead of supply shifting to the right – in that context, called demand reduction induced price effect or DRIPE*

Benefit - Transmission Benefits

- **Description:** resources that are connected to the distribution system (effectively reducing loading on transmission system) may contribute to avoiding or deferring load-driven transmission system investments
- **Methodology overview:** $/kW estimate of pool transmission facilities (PTF) deferral value multiplied by resource kW and technology-specific coincidence factor
- **Potential Inputs and sources:**
  - Amount of load-driven transmission that is avoidable by distributed generation may be zero. 2021 Vermont Long Range Transmission Plan finds none: **$0/kW-year**
    - Vermont System Planning Committee Geotargeting Subcommittee has found none
    - Some components of upgrades may be avoided, likely > $0 but small
  - PTF value: 2021 AESC - **$87.4/kW-yr.** Vermont Public Utility Commission has found:
    - **"The avoided cost of transmission infrastructure investments is likely not zero, and likely not as high as the generic value calculated in the AESC study".** Finding 73. p.28
  - Tech-specific coincidences: SEA estimates benchmarked against other sources; for variable renewables, generally decline over time w/ increasing saturation of variable resources
- **Related benefit:** distribution system connected resources avoidance of charges associated with transmission line losses

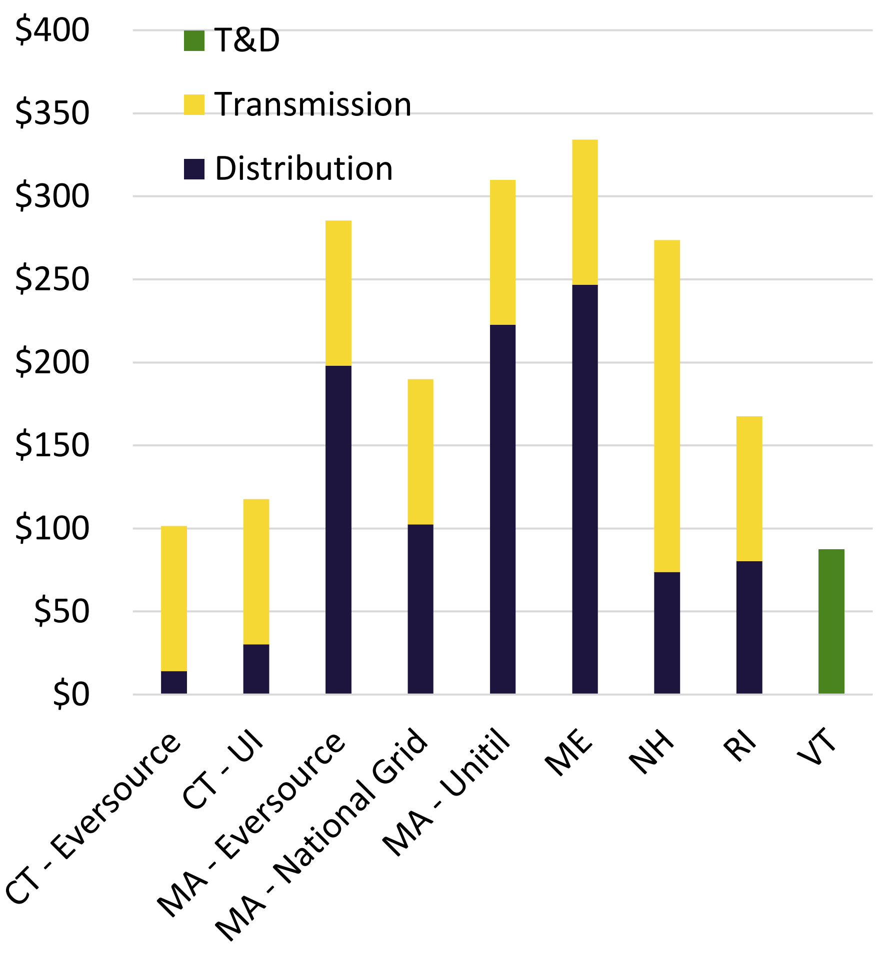
Benefit - Distribution Benefits

- **Description:** similar to transmission benefits, but more challenging to quantify given heterogeneity of distribution system loading
- **Potential sources:**
  - 2021 AESC compiled utility and state-level estimates of avoided distribution system costs used in benefit cost modeling – range from $14-247/kW-yr
  - NH value of distributed energy resources (VDER) study, based on NH's Locational Value of Distributed Generation study - $73.74/kW-yr
  - VT PUC Order referenced in previous slide, finding that $87.4/kW-yr **represents potential benefit to distribution *and* transmission system**

Discussion:

- Most states have adopted separate, additive estimates for transmission and distribution system benefits
- **One option** – assign portion $87.4/kW-yr value supported by VT PUC to distribution and transmission system

T&D System Avoided Costs/Charges
$/kW-yr (some nominal, some 2018$)



NH: Derived from 2023 New Hampshire VDER study
Others: 2021 AESC – May Release

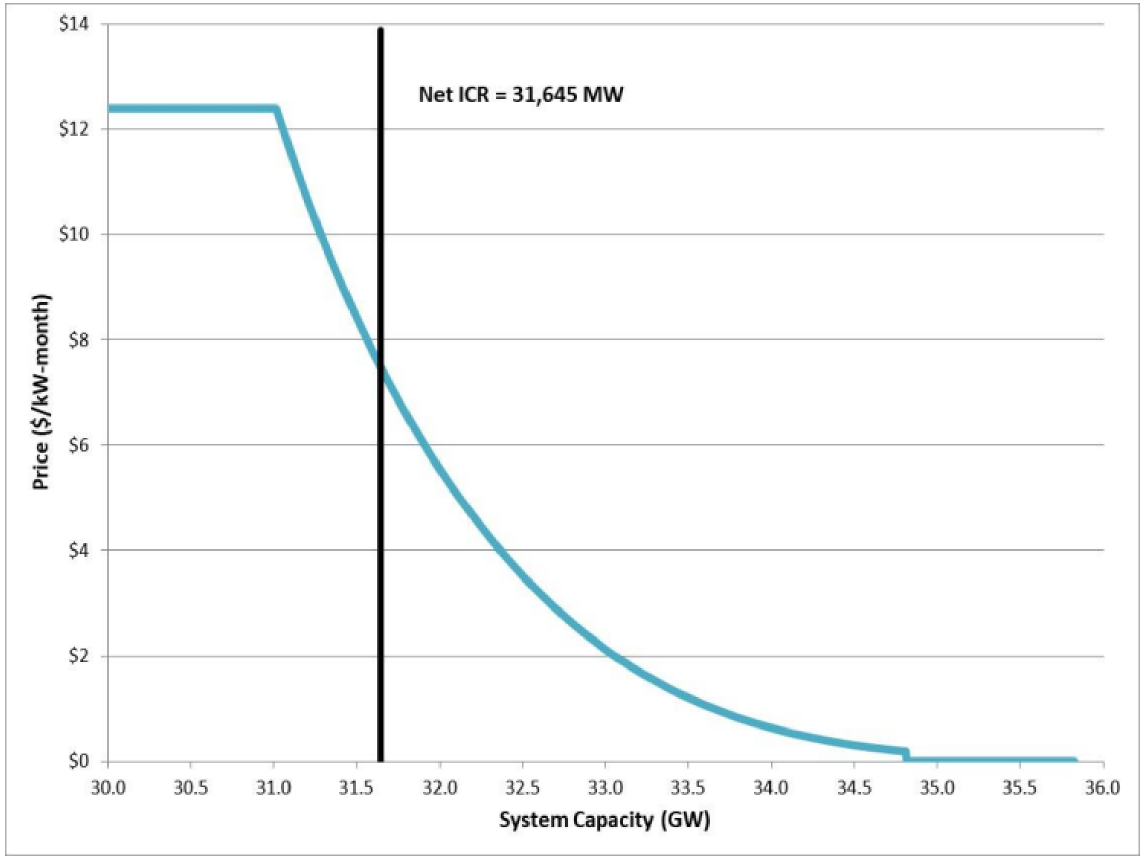
Customer-sited vs. Grid-Connected Generation

- **Description**: benefits unique to generation connected on the customer's side of the meter (and appropriately sized to load) can include avoided distribution-system losses
- **Methodology:** energy and capacity values multiplied by estimated percent distribution (and transmission – which applies to FTM resources as well) losses
- **Inputs and Sources:** energy and capacity value projections and loss estimates from AESC 2021
- **Discussion:**
  - While *participants* (those installing customer-sited resources) may experience lower distribution charges, in most instances, this represents a transfer of costs to non-participants (those w/o customer-sited resources)
  - Literature review (including studies specifically of value of distributed resources, such as 2023 NH VDER study) do not quantify additional benefits specific to customer-sited resources

Benefit - Improved Generation Reliability

- **Description:**
  - Because of downward slope in FCM demand curve, resources bidding $0 or close to $0 for capacity shift supply curve out, reducing auction clearing price and increasing MW of capacity procured
  - Higher volume of capacity results in higher reliability
  - A societal benefit – doesn't reduce VT ratepayer bills
- **Methodology:**
  - Increase in cleared capacity (MW) multiplied by ISO-NE estimates of impact on increased capacity on reliability/probability of outages occurring
  - Estimates of reduced outages (in MWh) resulting from increased cleared capacity multiplied by value of lost load (VOLL – how customer value not losing power)
  - This, in turn, multiplied by technology-specific coincidence factors and capacity of modeled resources
- **Inputs and Sources:**
  - AESC provides estimates for values described above
- **Discussion:**
  - May be some additional resiliency benefits associated with BTM solar + storage, but that is contingent upon storage
  - May be some additional resiliency benefits associated with avoiding overloading, but we are unable to identify a reliable methodology for quantifying (that are not already captured in distribution system benefits discussed above)

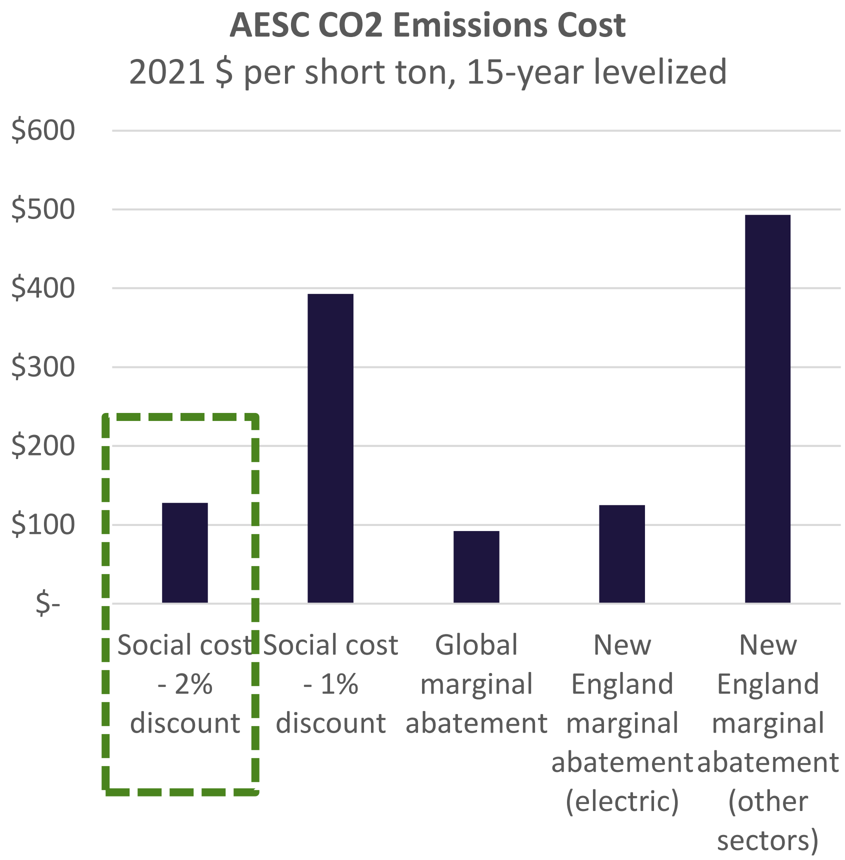
FCA 16 System-wide Demand Curve



[ISO-NE presentation on FCM 16 Installed Capacity Requirements]

Benefit - Non-Embedded GHG and NO_X Reduction

- **Description:**
  - Increased RE generation will displace some generation from resources that emit GHG (social cost of carbon) and NO_X.
  - Some cost for GHG emissions embedded in wholesale energy prices, due to the Regional Greenhouse Gas Initiative (RGGI) – non-embedded GHG costs subtract this value
- **Methodology:** Multiply hourly modeled RPS portfolio production by marginal emissions rate (lbs/MWh) by value for GHG and NO_X
- **Inputs and Sources:**
  - AESC provides marginal emissions rates (use Counterfactual #1, as All-in-Climate Policy sensitivity has low emissions rates that would result from more aggressive RPS already being implemented)
  - AESC calculates GHG cost multiple ways (see table); consistent with other VT analyses, we will use $128/short ton
  - For NOx, use $14,700/ton NO_X (from AESC)



Benefit – Avoided Local Pollutants/Health Impacts

- **Description:** While AESC provides estimates for non-embedded GHG and benefits from avoided NO_X emissions, the U.S. EPA's AVERT and COBRA tools can be leveraged to quantify and monetize SO_2 emissions and particulate matter (PM2.5) down to the county level
- **Inputs & sources**
  - AVERT (Avoided Emissions Generation) tool: translates the energy impacts of EE/RE policies/programs into PM2.5, NOx, SO_2, and CO_2 emission reductions at regional, state, county levels
    - Results can be used as inputs to COBRA
  - COBRA (Co-Benefits Risk Assessment) tool: converts changes in criteria air pollutants (PM2.5, SO_2, NOx, NH_3, Volatile Organic Compounds) into changes in ambient air quality for a given year, then uses the air quality changes to estimate changes in health outcomes and converts those health benefits into monetary value
    - Outputs include tables, maps of health impacts (illnesses/deaths avoided) and related economic impacts

Cost – Land Use – Carbon Sequestration

- **Description:** ecological costs due to reduced carbon sequestration arising from changes in land use (i.e., clearing forested area for renewable energy development)
- **Inputs and sources:**
  - EVALIDator produces estimates of various forest attributes, including sequestered carbon, based on data from the U.S. Forestry Service (USFS) Forest Inventory and Analysis (FIA, also known as the "Nation's Forest Census")
- **Methodology overview:**
  - Carbon sequestration potential (tCO_2/acre) and annual carbon sequestration potential (tCO_2/acre-year) estimated based on 2021 Vermont FIA data

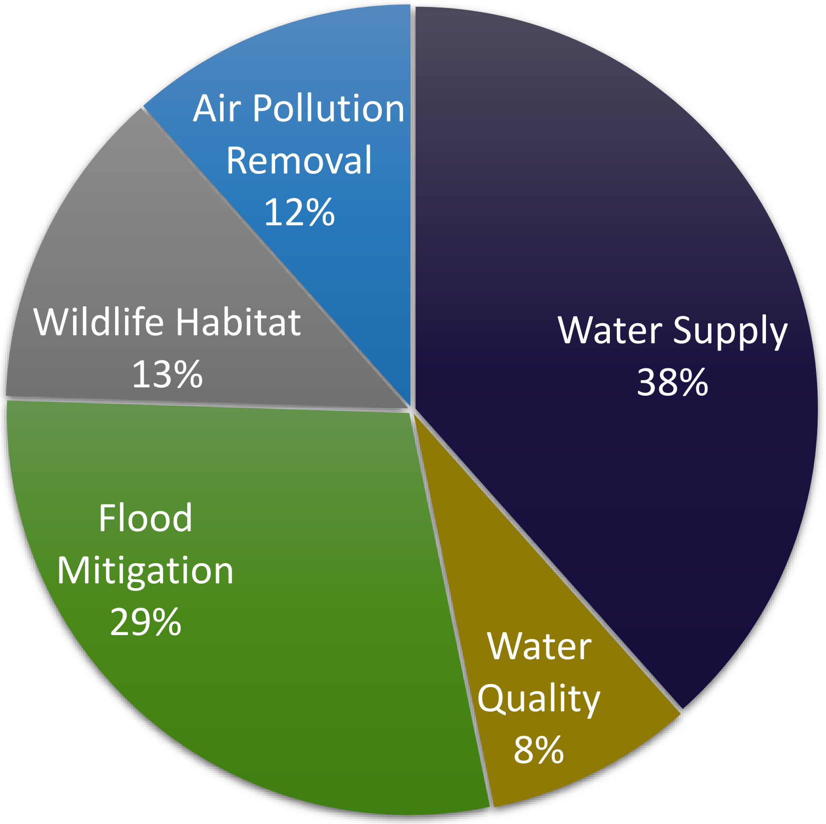
Unit	Carbon Sequestration Potential (carbon emitted with development)	Annual Carbon Sequestration Potential (additional carbon sequestered by undeveloped forests)
tCO_2/Acre	90.73	1.26

  - Carbon sequestration potential translated to dollar ($) terms using the value of carbon ($/ton)
- **Limitations:**
  - Methodology does not differentiate results for varying existing site conditions (pre development) or level/type of development (e.g., traditional ground-mount solar, agrivoltaics, land-based wind, etc.)
  - Methodology cannot easily translate the impact of each potential technology (i.e., this would better fit a program specifically incentivizing development on specific types of land)

Cost – Land Use – Other Ecological Services

- **Description:** non-carbon ecological costs arising from changes in land use (i.e., clearing forested area for renewable energy development)
- **Inputs and sources:**
  - “The Economic Value of Protected Open Space” – a study prepared for the Delaware Valley Regional Planning Commission
- **Methodology overview:** the study quantifies the average non-carbon ecological benefits of protected open space at ~$662/acre-year for four environmental services: water quality, flood mitigation, wildlife habitat, and air pollution removal
- **Limitations:**
  - Methodology does not differentiate results for varying existing site conditions (pre-development) or level/type of development (e.g., traditional ground-mount solar, agrivoltaics, land-based wind, etc.)
  - Methodology cannot easily translate the impact of each potential technology (i.e., this would better fit a program specifically incentivizing development on specific types of land)
  - The referenced study is based on Southeastern Pennsylvania rather than Vermont

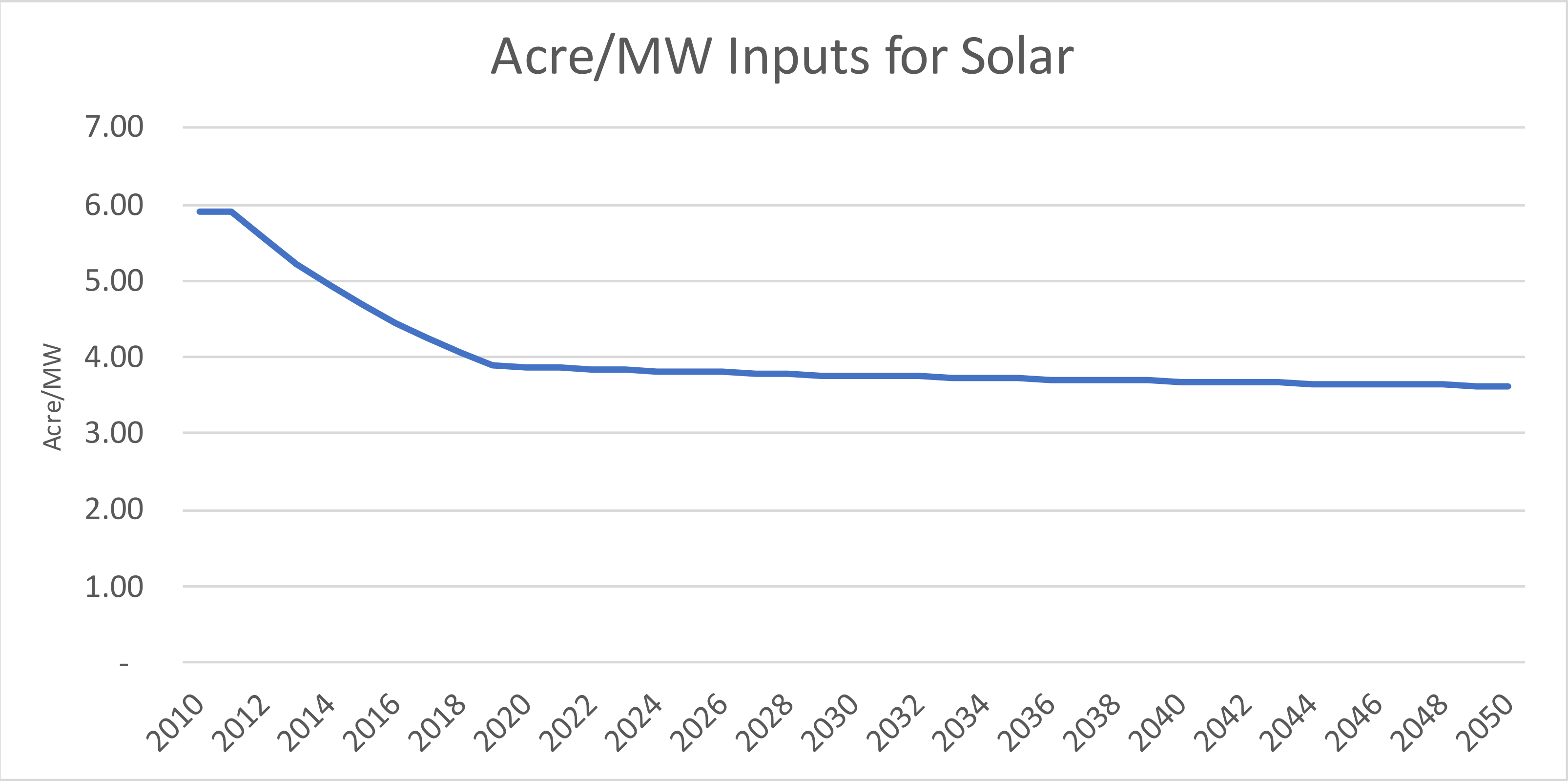
Benefits included in non-carbon ecological valuation



“Economic Value of Protected Open Space”

Cost – Land Use – Acres/MW Estimates

- SEA has forecasted estimates for the land requirement per unit of energy capacity (MW) of various renewable energy technologies, including wind and solar



SEA projections

Cost – Land Use – Literature Review

- The table below provides a sample of the available research literature that addresses land use impacts of renewable energy development

Publication Title (Year)	Description
Resource Potential and Land Use Tradeoffs of Renewable Electricity Development in Vermont, USA (2014) – LINK	Investigates the resource potential and land use tradeoffs of commercial solar PV and wind energy development in Vermont
The potential land requirements and related land use change emissions of solar energy (2021) – LINK	Calculates the land use requirements and resulting greenhouse gas emissions related to land cover changes of renewable energy development
Land Requirements for Utility-Scale PV: An Empirical Update on Power and Energy Density (2022) – LINK	Updates estimates of power (MW/acre) and energy (MWh/acre) density for utility-scale PV solar facilities, differentiates between fixed-tilt and tracking technologies
Site Wind Right: Identifying Low-Impact Wind Development Areas in the Central United States (2022) – LINK	Identifies locations for wind energy deployment in the United States that minimize impacts to wildlife
Land-use intensity of electricity production and tomorrow's energy landscape (2022) – LINK	Calculates the current and potential future land-use intensity of energy (LUIE) to investigate whether land use requirements constrain decarbonization strategies

- Despite the quantity of such research, there is a lack of studies that provide economic valuations of ecosystem services impacted by renewable energy development. We were unable to find any such studies for Vermont.

Cost – Land Use – Discussion

- **Discussion:**
  - Available research sufficient to develop dollar estimate of costs/benefits when the change in land use is well-defined, e.g., forestland fully cleared for development
    - Can be reasonably applied when evaluating policies that consider providing adders for specific types of development (e.g., rooftop or carport) and when it is well-established/documented that, without that incentive, development would occur on forested land
  - Available research insufficient to for the nuances of an RPS analysis
    - Regional nature of RPS makes establishing a credible counterfactual challenging:
      - What type of development is occurring because of changes in VT's RPS?
      - What type of development would have occurred absent VT's change (e.g., are there restrictions on development on certain types of parcels and what is happening in practice)?
    - Certain key development types (primarily, offshore wind) not addressed in literature reviewed
- **Possible approach:**
  - By default, we will quantify acres of development associated with portfolio of resources in given scenario, but *not* calculate a $ value
  - In a single sensitivity, we could apply the values discussed above as a *benefit* to net-metered resources, under the assumption that they are not yielding land use impacts, though we note that this is not a methodologically robust approach

Benefit - Water Use

- **Description:** volumes of water are associated with the operation of fossil fuel power plants. We aim to capture fossil fuel water use as a benefit associated with renewable portions of the generation portfolio
- **Inputs and sources:**
  - EIA, Thermoelectric cooling water data (last release: Feb 2023, contains 2021 data)
    - Dataset broken out by power plant; includes plant type, fuel, capacity, and several other fields including *Average of Water Withdrawal Intensity Rate (Gallons / MWh)* and *Average of Water Consumption Intensity Rate (Gallons / MWh)*
  - Kondash et al, 2019, *Quantification of the water-use reduction associated with the transition from coal to natural gas in the US electricity sector*
    - Research paper; data includes Lifecycle Water Consumption Intensity of Electricity Generation (m^3/MWh) and Lifecycle Water Withdrawal Intensity of Electricity Generation (m^3/MWh), by type of power plant
    - Considers and quantifies full lifecycle, including upstream water consumption (i.e., from mining and fracking)
  - U.S. DOE Office of Scientific and Technical Information (OSTI), "Water and Wastewater Annual Price Escalation Rates for Selected Cities Across the United States: 2023 Edition"
    - Values ($/kGal) for Water and Wastewater Utility Volume Charge by utility in select states in 2021
- **Methodology:** Combining Gal/MWh values from EIA data with $/Gal data from OSTI to produce a monetary cost due to water use/benefit to reduced water use
  - Given that fossil fuel plants are often located strategically near water sources for cooling purposes, the OSTI utility volume charges may not be entirely appropriate to apply; however, values from available neighboring states (i.e., ME or NH) may be applied for some sensitivities to approximate (see Limitations below)
- **Possible approach:**
  - NREL, in its prospective studies, does not monetize water because it claims there is a lack of solid methodology to do so
  - By default, we will quantify gallons of water consumed and withdrawn but not apply $ value; in a single sensitivity, we will apply OSTI $/gal rates to water consumed, though we note that this likely *significantly overvalues the cost of water consumption*

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Appendix

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Distribution Benefit Studies

- Given complexity of benefit, SEA conducted literature review to benchmark AESC-compiled results with other studies (included below) – wide variety of methodologies and results

State or EDC	Source	Finding
New Hampshire VDER	NH DOE VDER study webpage	Distribution capacity is ultimately assigned $73.74/kW-yr
Minnesota Value of Solar Tariff- Xcel community solar	Docket 13-867 for VOS values VOS methodology whitepaper	Avoided Distribution Capital Cost $0.0041 / kWh in 2023
California Sacramento Municipal Utility District Value of Solar + Storage Study	VOS technical report	Total deferrable dist. capacity is $51.49 in 2026, the derated to adjust for solar output to $8.26/kW-yr.
Connecticut Yale study	The Value of Distributed Solar: Evidence from a Field Experiment	Avoided distribution capacity valued at $23.86 per kW-year, solar contribution is 0.24 / kW nameplate, for $5.7 per kW per year.