Residential EV Managed Charging

A Benefit-Cost Analysis Case Study Applying the National Standard Practice Manual™

June 2022 – Updated 2025

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1. Introduction and Overview of Case Study

The purpose of this report is to illustrate a benefit-cost analysis (BCA) for a specific distributed energy resource (DER) technology and a use case that is of growing interest in the electric industry: electric vehicle (EV) managed charging.

Managed charging is defined here as incentivizing or otherwise influencing when electric vehicle charging takes place on an electric grid.

The number of EVs in the United States is projected to grow by at least 7 and up to 23 times over the next decade.[1] The associated vehicle charging demand will increase loads on the nation's electric grid. For this reason, the availability of EV charging programs, including TOU rates and incentive programs, is growing. Examples of utility-implemented EV charging programs include Pacific Gas & Electric's BMW iChargeForward program, National Grid's ConnectedSolutions program, San Diego Gas & Electric's Power Your Drive program, and Puget Sound's Up & Go Electric Residential & Off-Peak Charging Program.[2]

As new programs and offerings have emerged, challenges with analyzing their benefits and costs have also surfaced. Common challenges that this case study aims to address include estimating changes to electrified load shapes and making informed assumptions about current and future EV charging methods.

This case study is informed by a real-world BCA and data for a similar use case but has been generalized into an illustrative and hypothetical example for broader applicability. It was developed to demonstrate key factors and challenges with conducting BCA for a managed charging program offered to existing EV owners. In addition, the case study illustrates key BCA considerations for a single DER use case and demonstrates a specific approach to account for impacts when certain data may be unavailable.[3]

The case study applies guidance from the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (NSPM).

2. National Standard Practice Manual

The *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources (2020)* ("NSPM for DERs" or "NSPM") provides a comprehensive framework for the cost-effectiveness assessment of DERs.[4] The manual offers a set of policy-neutral, non-biased, and economically sound principles, concepts, and methodologies to support single and multi-DER benefit-cost analysis. It is intended for use by jurisdictions to help inform which resources

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[1] Brattle. (2020). *Getting to 20 Million EVs by 2030 Opportunities for the Electricity Industry in Preparing for an EV Future*. https://www.brattle.com/wp-content/uploads/2021/05/19421_brattle_-_opportunities_for_the_electricity_industry_in_ev_transition_-_final.pdf

[2] SEPA. (2021). *The State of Managed Charging in 2021*.https://sepapower.org/resource/the-state-of-managed-charging-in-2021/

[3] This report addresses some but not all key factors that may affect impacts of different DER types. More information is available in Chapters 6-10 of the NSPM for DERs on specific DER types and Chapter 11 on multiple on-site DERs.

[4] *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, National Energy Screening Project (NESP), (2022).

to acquire to meet their specific policy goals and objectives using a primary cost-effectiveness test, and it also provides guidance on the use of secondary tests.

The *Methods, Tools, and Resources Handbook for Quantifying DER Impacts for Benefit-Cost Analysis (2022)* ("MTR Handbook") is a companion document to the NSPM. It provides technical information on how benefits and costs of DER investments can be quantified (monetized or otherwise), with links to resources and tools.

This case study aligns with the fundamental NSPM BCA principles summarized in Table 1, which are referenced where applicable throughout this case study.

Table 1: NSPM BCA Principles

Principle 1	**Treat DERs as a Utility System Resource** DERs are one of many energy resources that can be deployed to meet utility/power system needs. DERs should therefore be compared with other energy resources, including other DERs, using consistent methods and assumptions to avoid bias across resource investment decisions.
Principle 2	**Align with Policy Goals** Jurisdictions invest in or support energy resources to meet a variety of goals and objectives. The primary cost-effectiveness test should therefore reflect this intent by accounting for the jurisdiction's applicable policy goals and objectives.
Principle 3	**Ensure Symmetry** Asymmetrical treatment of benefits and costs associated with a resource can lead to a biased assessment of the resource. To avoid such bias, benefits and costs should be treated symmetrically for any given type of impact.
Principle 4	**Account for Relevant, Material Impacts** Cost-effectiveness tests should include all relevant (according to applicable policy goals), material impacts including those that are difficult to quantify or monetize.
Principle 5	**Conduct Forward-Looking, Long-term, Incremental Analyses** Cost-effectiveness analyses should be forward-looking, long-term, and incremental to what would have occurred absent the DER. This helps ensure that the resource in question is properly compared with alternatives.
Principle 6	**Avoid Double Counting Impacts** Cost-effectiveness analyses present a risk of double counting of benefits and/or costs. All impacts should therefore be clearly defined and valued to avoid double counting.
Principle 7	**Ensure Transparency** Transparency helps to ensure engagement and trust in the BCA process and decisions. BCA practices should therefore be transparent, where all relevant assumptions, methodologies, and results are clearly documented and available for stakeholder review and input.
Principle 8	**Conduct BCAs Separately from Rate Impact Analyses** Cost-effectiveness analyses answer fundamentally different questions than rate impact analyses. Cost-effectiveness analyses should therefore be conducted separately from rate impact analyses.

Key NSPM principles applied to this case study include:

- Accounting for all utility system impacts in the BCA to ensure the DER is treated as a utility resource (Principle 1);[5]
- Using a BCA test that aligns with the hypothetical jurisdiction's applicable policy goals (Principle 2);
- Ensuring symmetry between the treatment of benefits and costs for each impact (Principle 3);
- Accounting for all relevant impacts, even if difficult to quantify (Principle 4);
- Conducting a forward-looking, incremental analysis over the life of the DER(s) and ensuring no sunk costs are included (Principle 5); and
- Avoiding any double counting of impacts (Principle 6).

Consistent with NSPM Principle 7 – to provide transparency in BCA practice – this case study describes the basis for the primary cost-effectiveness test used, presents the full range of relevant BCA input assumptions and results, and provides information on methodologies used to monetize the impacts. References are made in some cases to the MTR Handbook where additional information can be found on methods for monetizing impacts, including those that are hard to quantify.

Finally, this case study does not address bill and rate impacts. While it is important for decision-makers to understand how revenue collections will be impacted and how customer rates and energy burdens may change due to DER investments, conducting rate and bill impact analyses should be separate from BCA, consistent with NSPM Principle 8.

BCA Impacts

The key impact categories for BCAs are, generally, electric or gas utility system impacts and non-utility systems (i.e., other fuel impacts, host customer impacts, and societal impacts). The range of impacts within each category, and associated definitions, are provided in the Appendix.

This case study addresses the full range of electric utility system impacts. The extent to which non-utility system impacts apply is dependent on the applicable policy goals of the hypothetical jurisdiction. As such, this case study presents a jurisdiction-specific test (JST). A JST may or may not align with traditional cost-effectiveness tests (e.g., Utility Cost Test/Program Administrator Cost Test, Total Resource Cost Test, or Societal Cost Test).[6]

3. Case Study Context and Assumptions

This case study describes the cost-effectiveness analysis of a hypothetical residential EV managed charging program proposed by an IOU in the Midwest. It evaluates the incremental impact of a customer with an EV switching from a flat rate to a TOU rate. It is assumed that the TOU rate is a special rate offered only to EV customers, and that customers are enrolled in the

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[5] Generally, in some cases, depending on the DER, use case or profile of the jurisdiction (e.g., whether in an organized market or not), some utility system impacts may not be applicable or material.
[6] See NSPM for DERs Chapter 3 for additional discussion of traditional cost-effectiveness tests.

rate as part of a package offered by the utility which includes an incentive discounting an EV charger. The objective of the BCA is to help determine if the quantified benefits of the proposed program outweigh the proposed costs, using a JST described below.

Reference Case	Residential EV owners/operators pay full price for a Level II charger, charge their EV(s) when they desire at home and are charged a flat $/kWh rate.
DER Case	Residential EV owners/operators receive a utility rebate for their Level II charger if they switch to a TOU electric rate.

3.1 Utility & Grid Profile, Policy Context, and Regulatory Perspective

The IOU planning to offer the EV charging program is located in the Midwest, U.S. and is connected to the Midcontinent Independent System Operator (MISO). The hypothetical generation mix for the region includes coal-fired power plants contributing a significant portion to baseload with marginal natural gas peaker plants operating when needed. Relative to other areas of the country, the region is assumed to have low avoided energy and capacity costs.

The jurisdiction in which the IOU is located and regulated has applicable energy policy goals articulated in statute, regulatory decisions, or otherwise that set forth the purpose for utility investments related to DERs, specifically:

- Providing safe, reliable and reasonably priced electricity services; and
- Reducing greenhouse gas (GHG) emissions based on recently passed statute, which requires that regulatory policy include the societal impact of GHG emissions cost-effectiveness testing for DERs.[7]

In this DER case, the JST includes all electric utility system impacts and the societal impact due to changes in GHG emissions. No host customer impacts are included in the JST as policies do not require accounting for these impacts in its primary BCA test.[8] A summary of the impacts accounted for in this case study BCA is provided in Table 2.

Table 2: Summary of Impacts Included in EV Managed Charging Case Study

Category/Type	EV Managed Charging Case Study (JST Impacts)
Electric Utility System Impacts	All impacts included in JST though some impacts are N/A where impact is not relevant to the use case and/or DER
Natural Gas/Other Fuel Impacts	Not applicable given jurisdiction's policies

[7] Examples of jurisdictions with GHG emission reduction statues is provided at https://www.ncsl.org/research/energy/greenhouse-gas-emissions-reduction-targets-and-market-based-policies.aspx

[8] Unlike a traditional Utility Cost Test (UCT), this JST includes a societal impact (GHG emission benefits to society) which is not a utility-perspective impact stream. Likewise, the JST for this scenario does not align with a traditional Total Resource Cost (TRC) test, which takes utility and host customer impacts into account, whereas this jurisdiction's policy does not require inclusion of host customer impacts in its primary test. Thus, the JST in this case study is unique to the jurisdiction and in alignment with its applicable policies.

Host Customer Impacts	Not applicable given jurisdiction’s policies
Societal Impacts	GHG emission impacts (beyond any compliance costs) are included, consistent with jurisdiction’s policy

3.2 Reference Case & Proposed Program Details

This case study assumes the following for its reference case and the DER case (managed charging program), with further detail provided in Table 3:

- Reference case: Current residential EV owners/operators within the IOU’s operating territory charge their EV(s) when they desire and are charged a flat $/kWh rate.
    - Most residential EV owners/users charge their vehicles at home using a level II charger and pay full price for their charger (assumed to be $1,000).
- Under the proposed DER case, an EV owner/operator would switch to a TOU electric rate in order to receive a utility incentive that discounts the cost of a level II EV charger (at about 50% or $500).
- The TOU rate is a two (2) period rate with a 3.5x cost differential between peak and off-peak prices.
- The measure life (charger lifespan) is assumed to be 11 years, while the program offering is assumed to run for 3 years (2022 - 2024).

All assumptions used in this case study are treated symmetrically in terms of ensuring that both benefits and costs are accounted for (NSPM Principle 3). In addition, the BCA considers future, long-term, and incremental costs (consistent with NSPM Principle 5).

Table 3: Summary of Case Study Context and Key Assumptions

Assumption Category	Assumption Description	Value/Assumption
Utility & Grid Profile	Program Administrator	An IOU
	Location	Midwest/MISO
	Regional Generation Mix	Significant presence of coal-fired power plants for baseload and marginal natural gas peaker plants
	Regional Utility Costs	Low avoided energy and capacity costs. System peak is during the day; evening generation is cheaper than daytime
Policy Context	Key Policy/Regulatory Objectives	Regulatory priorities are to ensure safe, reliable and reasonably priced electricity (utility system impacts) and reducing GHG emissions

Assumption Category	Assumption Description	Value/Assumption
Reference Case	Current Assumed Residential EV Charging Behavior	Level II charger where customer pays full price and customer charges EV whenever they desire, and has no preference for when an EV is charged so long as it has a full charge the next morning
	Current EV Charging Rate	A flat $/kWh charge no matter the time-of-use
DER Case (Proposed Program Details)	Program Offering	Level II EV charger is discounted by 50% if the customer enrolls in a TOU rate
	Program Customer Type	Residential
	Program Offering Time Period/Length	3 years
	Average Retention for TOU rate customer	11 years
	Measure Life	11 years for an EV charger
	Number of NEW Participants Each Year	Year 1: 500 Year 2: 700 Year 3: 1,000
	Financial Incentive for Participants	$500/Installed Level II charger
	Program Administrator Cost	Assumed to equal 20% of financial incentives
	Discount Rate	Assumes a discount rate of 3%

3.3 Impacts Analyzed and Data Approach

Based on this jurisdiction's JST, and the description of the reference case and use case for the EV managed charging program, Tables 4 and 5 below indicate:

- Which utility and non-utility system impacts are accounted for in the BCA;
- Where/how the DER operating profiles were estimated; and
- The associated data sources and approach used to quantify the impacts.[9]

Tables 4 and 5 present the BCA input assumptions including data inputs, descriptions, and general methodology used. Note that while all utility system impacts are part of the jurisdiction's primary JST, some impacts have values of zero in the BCA either because the impact is not relevant to the DER and/or use case or is immaterial in impact.

[9] For more information about conducting BCAs for demand response and electrification technologies, please see the NSPM for DERs Chapter 7 and 10, respectively. For more information on methods to quantify impacts see MTR Handbook.

Table 4: Electric Utility System Impacts

Type	Specific Impact	Data Description & Rationale
Generation	Energy Generation	Calculated using hourly (8760) avoided energy data from a Midwest utility. Hourly data is necessary to capture the impact of the load shift on energy generation, which would not be picked up by annual or monthly avoided cost data. This avoided cost data from the utility was generated during their IRP process and reflects the anticipated generation sources over the forecasted 20 years.
	Capacity	Calculated using avoided generation capacity price data from a Midwest utility. The avoided capacity price is an output of the utility IRP process and reflects anticipated short- and long-term capacity needs.
	Environmental Compliance	Environmental compliance costs (e.g., coal plant emissions) were accounted for within avoided energy costs. Ideally, these costs would be distinctly reported for transparency purposes, however since assumptions are based on actual utility data, a separate value was not available. In the case of GHG compliance costs, the value is zero because the utility has not incorporated GHG emission goals into their resource planning. GHG is treated instead as a societal impact.
	RPS/CES Compliance	While the jurisdiction has an RPS, and therefore this impact is part of its JST, the value is N/A in this use case because the load shapes assumed that energy consumption was not increased or decreased, only shifted. Therefore, RPS compliance is not impacted under the assumption that renewables are not being curtailed since the total energy consumed by the customer (and therefore produced by the utility) doesn't change.
	Market Price Effects	Market price impacts are from the Synapse Avoided Energy Supply Components in New England: 2021 Report and were adapted to the MISO market.[10] The $/kWh value of the market price impacts were proportionally scaled to reflect lower avoided costs of MISO in comparison to ISO-NE.
	Ancillary Services	California Avoided Cost Calculator 2020 data was used assuming ancillary services of 0.9% of avoided energy costs, which applied to the hourly avoided energy costs to quantify ancillary services benefits.
Transmission	Capacity	Calculated using avoided transmission capacity prices ($/peak kW) from a Midwest utility. Avoided transmission prices were generated from a standalone study analyzing the impacts of load reductions on T&D planning needs.
	System Losses	Transmission line loss rates were accounted for within avoided energy and capacity impacts. There are no additional impacts for this particular analysis such as changes in line loss rates as a result of DER implementation.
Distribution	Capacity	Calculated using avoided distribution capacity prices ($/peak kW) from a Midwest utility. Avoided distribution prices were generated from a standalone study analyzing the impacts of load reductions on T&D planning needs.
	System Losses	Distribution line loss rates were accounted for within avoided energy and capacity impacts. There are no additional impacts for this particular analysis such as changes in line loss rates as a result of DER implementation.[11]

[10] Source: https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf

[11] This analysis makes the common simplification of not dealing with time differentiated loss rates, other than utilizing a different average marginal loss rate for peak demand versus average energy consumption. Since marginal loss rates increase with higher loading, in reality loss rates are continually changing throughout the day. Therefore,

Type	Specific Impact	Data Description & Rationale
	O&M	The avoided distribution $/kW value utilized is assumed to cover all distribution spending that can be avoided based on generalized peak kW reductions. As this DER use case doesn't consider a specific distribution feeder/circuit such as is done with an NWA, there are no additional incremental O&M or voltage benefits that can be quantified.
	Voltage	The avoided distribution $/kW value utilized is assumed to cover all distribution spending that can be avoided based on generalized peak kW reductions. As this DER use case doesn't consider a specific distribution feeder/circuit such as is done with an NWA, there are no additional incremental O&M or voltage benefits that can be quantified.
General	Financial Incentives	The assumed incentive level was estimated based on EV industry analysis and a literature survey of EV charger incentives.
	Program Administration Costs	The assumed level of program administration costs was estimated based on benchmarking historic costs for EV programs and EV industry analysis.
	Utility Performance Incentives	Not part of the JST for this jurisdiction since there are no utility performance incentives.
	Credit and Collection Costs	While part of JST for this jurisdiction, no value is included in the BCA as this DER program doesn't affect these costs.
	Risk	To quantify the value from risk reduction, a percent adder method was utilized. This was due to the lack of any jurisdiction numbers for the Midwest quantifying risk reductions per kWh or peak kW. A 5% adder for risk was utilized based on a literature review of risk adders for different jurisdictions. The key sources for the 5% adder were Energy Trust of Oregon and DC Sustainable Energy Utility.[12]
	Reliability	While part of JST for this jurisdiction, no value is included in the BCA as this DER program doesn't reduce utility expenditures on reliability.
	Resilience	While part of JST for this jurisdiction, no value is included in the BCA as this DER program doesn't have a material impact on utility system resilience.

shifting consumption to times of lower loading will result in decreased system losses. For the purposes of this use case, the value of those additional losses is assumed to be minor in comparison to the other benefits streams, and so is not calculated.

[12] Sources: Oregon: ETO. Energy Trust Electric and Gas Avoided Cost Update for Oregon for 2018 Measure and Program Planning, and DC: VEIC, DCSEU Multiyear contract, Contract No. DOEE-2016-C-002, section C.40.10.5 at DCSEU_Multiyear Contract_Final (003).pdf - Google Drive

Table 5: Societal Impacts

Specific Impact	Data Description & Rationale
Resilience	Not included in the JST as not reflected in jurisdiction's applicable policies.
GHG Emissions	Calculated using the Midwest region assumptions from the EPA AVERT Tool to generate hourly emissions factors. This data was then combined with the U.S. EPA social cost of carbon (SCC) values (assuming a 3% discount rate) to generate the hourly $/kWh factors for valuing GHG emissions.[13] The DER use case assumes that the utility has not internalized the marginal abatement cost of carbon. It was conservatively assumed that the resource mix of the jurisdiction did not change over the course of the measure lives.[14]
Other Environmental Impacts	Not included in the JST as not reflected in jurisdiction's applicable policies.
Public Health	Not included in the JST as not reflected in jurisdiction's applicable policies.
Economic Development and Jobs	Not included in the JST as not reflected in jurisdiction's applicable policies.
Energy Security	Not included in the JST as not reflected in jurisdiction's applicable policies.

Several impacts from the tables above warrant some additional explanation and context, as described below.

Accounting for GHG Emissions: Determining Utility System or Societal Impact - The treatment of GHG emission impacts requires distinguishing between environmental compliance impacts (within utility system impacts) and societal environmental impacts[15]:

- Environmental compliance impacts are the direct impacts in dollar terms that will be incurred by the utility and passed on to all customers through revenue requirements and customer rates. Environmental compliance impacts are utility system impacts that will be paid by utility customers and therefore should be included in all BCA tests.
- Societal environmental impacts are imposed on society as a whole but do not affect the cost of electricity services. Societal environmental impacts do not reflect direct costs that will be paid by utility customers and therefore should be included only in a BCA test if that would be consistent with the jurisdiction's policy goals.

This hypothetical jurisdiction assumes a Midwestern location which has high-level policy goals of decarbonization, but those goals have not yet been reflected in the utility's resource planning

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[13] Sources: EPA AVERT Tool: https://www.epa.gov/avert; EPA social cost of carbon (SCC) values: https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html#:~:text=Estimating%20the%20Benefits%20of%20Reducing%20Greenhouse%20Gas%20Emissions,%20%20%243%2C700%20%205%20more%20rows%20

[14] The EPA AVERT Tool was utilized for short-run marginal emissions rates due to the assumption that the DER would not impact long-term baseload generation planning. However, if the underlying assumption is that the resource will be significant enough to influence baseload generation planning, then long-run marginal emissions rates should be used. National Renewable Energy Laboratory (NREL)'s Cambium tool is a source of long-run marginal emissions rates. See the GEB case study for additional discussion on utilizing the NREL Cambium tool.

[15] See MTR Handbook - Chapter 3.2.6 and Chapter 7.1.

and therefore are not inherently accounted for in the utility's avoided energy cost. This, in combination with the assumed absence of a cap-and-trade carbon market, results in no incremental utility system avoided environmental compliance costs for carbon. Therefore, the high-level policy goal of decarbonizing is valued using a damage cost method as a societal impact and utilizes a social cost of carbon (SCC) for valuation (see Table 5 for data description).

Line Losses – In this case study, line loss savings are included in avoided T&D costs. Likewise, increased reliability benefits are included in avoided T&D and avoided generation costs. For this reason, line loss savings and reliability benefits are not shown as separate impact streams. This approach adheres to NSPM Principle 6 to avoid double counting impacts (see Table 1). Depending on the data sources and methodologies used, other BCAs may need to account for reliability and/or line loss impacts separately.

Reliability – Reliability metrics (such as SAIDI, SAIFI, or CAIDI[16]) are typically used to inform a utility's annual reliability performance and expenditures. However, in this use case, the managed charging program would not improve these utility metrics. The ability of the managed charging program to help maintain a reliable grid is already captured by avoiding the T&D capacity investments that would have been required if the load shifting had not occurred.

Risk Benefits - Risk benefits are estimated to equal 5% of avoided energy costs and demand reduction induced price effects (DRIPE) benefits. Given that DRIPE has an elasticity function where the price suppression varies with both demand and commodity prices, there is exposure to volatility that this program offering can help mitigate. Likewise, energy costs can be subject to stochastic fuel price volatility.

Program Financial Incentives Costs - Lastly, program financial incentive costs are estimated based on program offerings and the expected number of new program participants each year, and program administration costs are assumed to equal 20% of total program financial incentives.

4. BCA Results

4.1 Summary of Inputs & Calculated Values

As outlined in Tables 4 and 5 above, a range of impact streams were used to calculate the net benefits of the proposed EV managed charging program, with the input variables summarized below in Table 6 and BCA results provided in Table 7.

[16] SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index). For more information on these reliability metrics, see MTR Handbook.

Table 6: Summary of Relevant Value Streams

Summary of Relevant Value Streams for EV Managed Charging Case Study*	
Electric Utility System Impacts	Societal Impacts
• Avoided Energy Costs • Avoided Generation Capacity Costs • Avoided Transmission & Distribution Costs • Wholesale Price Benefits (DRIPE) • Risk Benefits • Avoided Ancillary Service Costs • Financial Incentive Costs • Program Administration Costs	• Greenhouse Gas Emission Impacts

*As noted in Table 3, some utility system impacts that are part of the jurisdiction's primary JST are not included in the BCA for this use case because either the impact is not relevant to the use case or is immaterial in impact.

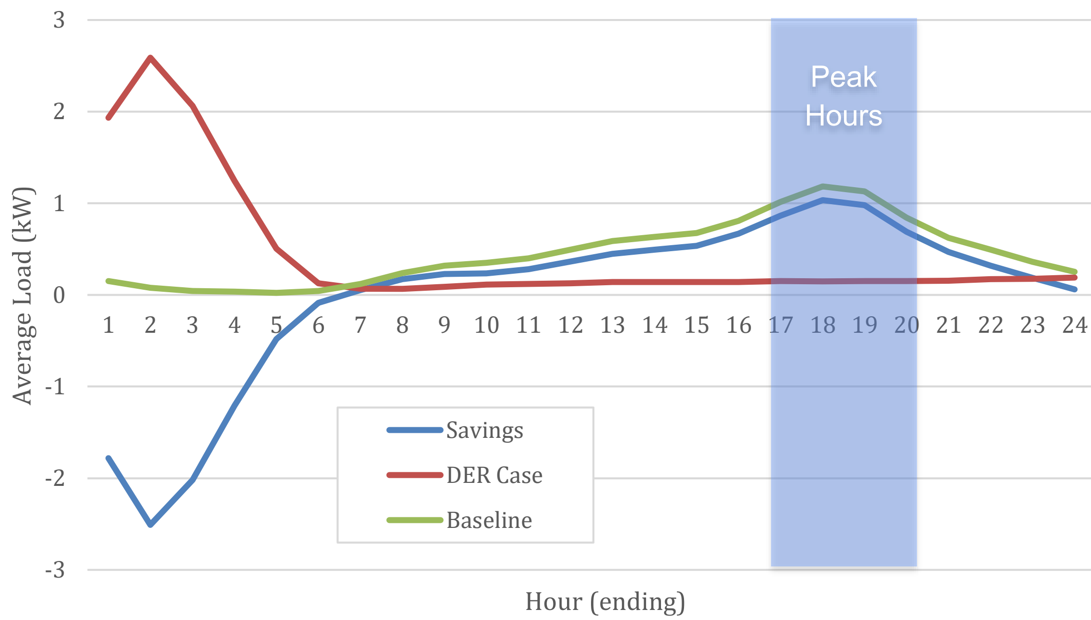
The selection and calculation of these impact streams was carefully reviewed to align with NSPM principles to ensure symmetry and to account for relevant, material impacts.

Load Shape Analysis & Impact Values

Calculating the values for many of these impact streams requires estimating the changes in kWh load per participant per hour of year. This is accomplished by subtracting the expected TOU-influenced charging load shape from the baseline load shape. EV charging load shapes were created using the light-duty vehicle data for Michigan from the medium electrification case of the NREL Electrification Futures Study (EFS) and expert judgement by ICF. The baseline load shape was assumed to be the 2024 light duty EV load shape from the NREL EFS's medium case. This load shape makes assumptions about the proportion of battery electric vehicles (BEV) to plug-in hybrid electric vehicles (PHEV) and vehicle miles driven per year.

The load shape for program participants assumed that EV customers are responsive to the TOU rate, that over 80% of enrolled EV charging load is shifted to off-peak times, and that there is no impact on the total amount of energy consumed (i.e., load is only shifted not decreased or increased). As illustrated in Figure A, this results in approximately 1kW of load shifting per customer. This is expected to be a conservative load shift estimate since the TOU rate is expected to be applied to the whole home, not just the EV charger.

Figure A: EV Managed Charging Load Shape Analysis: Baseline and DER Case



The changes in load shape are then used to calculate various impacts:

1. Avoided energy costs, using hourly generation cost data ($/kWh) from a Midwest utility:

$$Annual\ Avoided\ Energy\ Costs\ (\$) = \sum_{i=1}^{8760} (\Delta Hourly\ Load_{\ i} * Hourly\ Generation\ Costs_{\ i})$$

2. Wholesale price benefits, using hourly DRIPE values from the 2021 New England Avoided Energy Supply Components (AESC) study adjusted for MISO:

$$Annual\ Wholesale\ Price\ Benefits\ (\$) = \sum_{i=1}^{8760} (\Delta Hourly\ Load_{\ i} * Hourly\ DRIPE_{\ i})$$

3. Avoided ancillary services costs (assumed to be 0.9% of avoided energy costs):

$$Avoided\ Ancillary\ Services\ Costs\ (\$) = Avoided\ Energy\ Costs * 0.009$$

4. Changes in GHG emissions, using U.S. EPA's AVERT tool and estimated SCC:

$$GHG\ Impacts\ (\$) = \sum_{i=1}^{8760} (\Delta Hourly\ Load_{\ i} * GHG\ Emissions\ Rate_{\ i} * Social\ Cost\ of\ Carbon)$$

Changes in demand are also averaged across all annual system peak hours to determine an average annual peak reduction value (kW). This value is then used to determine avoided transmission and distribution costs and avoided generation capacity costs using real avoided costs from a Midwest utility. In this case study, the average annual peak reduction value is 1kW from on-peak to off-peak per customer.

Discount Rate

To calculate the net present value (NPV) of the future streams of benefits and costs of the program, a real discount rate of 3% was selected to reflect the "regulatory" time preference. Since a discount rate of 3% is one of the discrete rates for published SCC values, this case study was able to easily align the GHG value stream with the study-wide discount rate.[17]

BCA Result

All calculated values are shown below in Table 7 and are placed into comparable monetary units (NPV in 2021 dollars).

Table 7: EV Managed Charging JST: BCA Values and Results

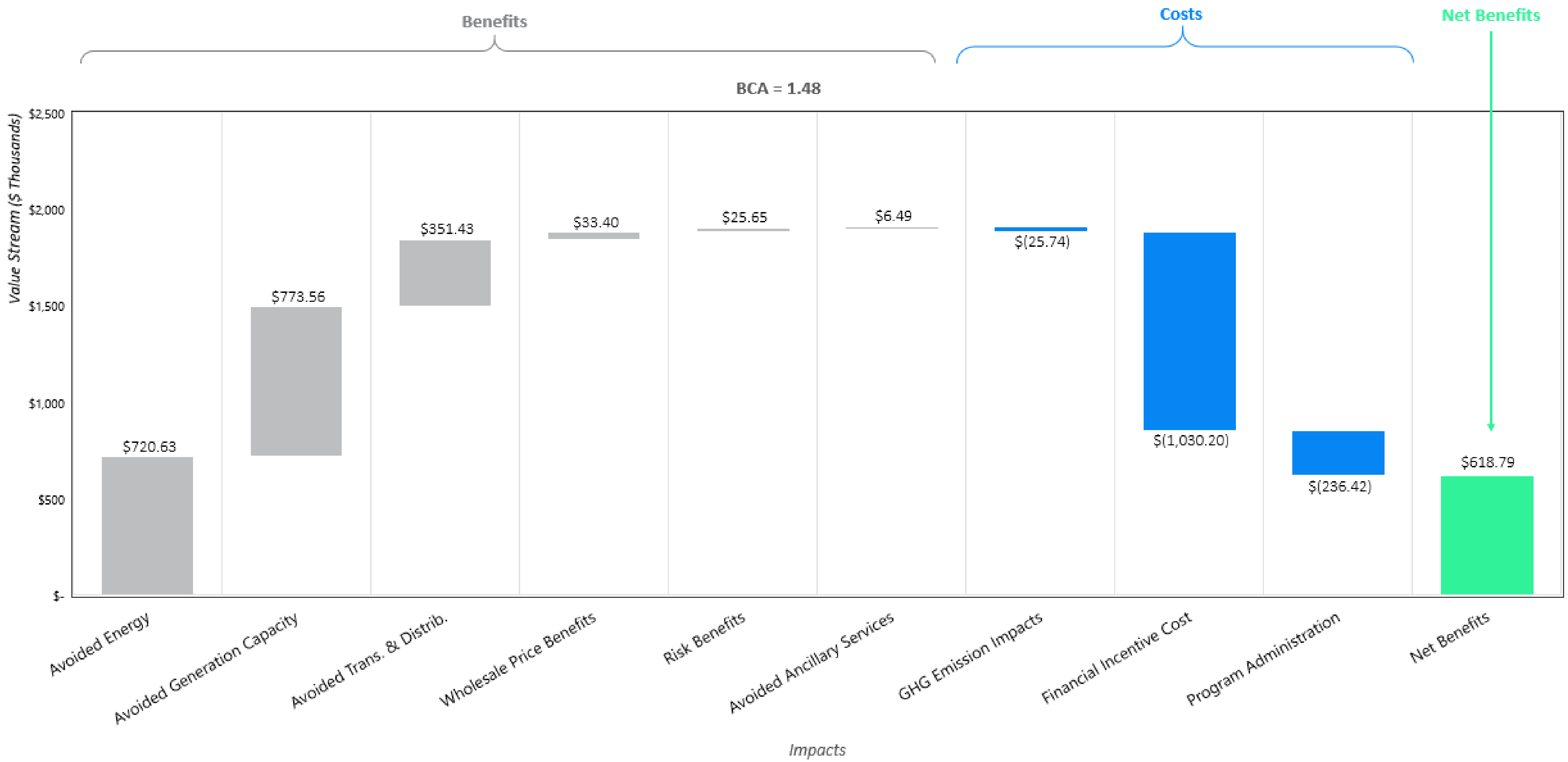
Value Stream	Net Present Value ($ 2021)
UTILITY SYSTEM IMPACTS	
Avoided Energy Costs	$ 720,634
Avoided Generation Capacity Costs	$ 773,558
Avoided Transmission & Distribution Costs	$ 351,426
Wholesale Price Benefits (DRIPE)	$ 33,399
Risk Benefits	$ 25,650
Avoided Ancillary Service Costs	$ 6,485
Financial Incentive Costs	$ (1,030,197)
Program Administration Costs	$ (236,417)
SOCIETAL IMPACT	
Greenhouse Gas Emission Impacts	$ (25,743)
Total Benefits	**$ 1,911,152**
Total Costs	**$ (1,292,357)**
Net Benefit	**$618,795**
Benefit-Cost Ratio	**1.48**

The benefit-cost ratio of this program is 1.48, with net benefits of $618,795. With a benefit-cost ratio greater than 1.0, the proposed program is cost-effective.

Figure B illustrates the BCA results for the EV Managed Charging JST.

[17] When this is not the case, the GHG value stream inputs should be interpolated or extrapolated based on the discreate values published to align this value stream. For more information on using an appropriate discount rate, see Chapters 5-11 and Appendix G of the NSPM for DERs.

Figure B: EV Managed Charging JST: Benefit-Cost Value Streams and Net Benefits



Key: Gray = Estimated Benefits Blue = Estimated Costs Green = Net Benefits

4.2 Summary of Case Study Key Factors and Findings

The key value streams which drove the BCA results are avoided energy costs, avoided generation capacity costs, and program financial incentive costs:

Utility System Impacts

- *Avoided energy costs*: The avoided energy costs are largely driven by a cost differential of 40 - 50% between peak and off-peak kWh generation (average on-peak costs are 6-7¢/kWh while off-peak are 3-4¢/kWh), and the significant average shift of 1kW from on-peak to off-peak per participant.
- *Avoided generation capacity costs*: Avoided generation capacity costs are the result of a $30/kW avoided generation capacity estimate.
- *Program financial incentive costs*: The $500 incentive value assumed in the case study is approximately 50% of the cost of a level II home charger with time flex capabilities, but it was chosen without other supplemental data such as pilot program participation results. Other program administrators may choose to offer larger or smaller incentives for program participation.

Overall, the JST's moderate benefit-cost ratio (1.48) is driven by avoided energy costs, including a significant cost differential between peak and off-peak kWh generation and a significant average shift from on-peak to off-peak per participant. Depending on load shapes and generation mixes, other regions of the country may have larger or smaller peak-to-off-peak cost differentials. Additionally, the JST's benefit-cost ratio is driven by avoided generation capacity costs. Depending on existing customer charging habits and system peak hours, other managed charging programs may predict smaller participant kW shifts. As utilities, regulators, and customers increasingly focus on managed charging for EVs, it is critical to evaluate the key impact streams that reflect the resource being analyzed.

Societal Impacts: GHG Emissions

The BCA shows a slight increase in GHG emissions as a result of the shift from on-peak daytime charging to off-peak nighttime charging. The marginal emissions rates of natural gas peaker plants are lower during the day than more carbon-intensive overnight resources (i.e., coal plants), resulting in the shift from peak charging to off-peak charging increasing GHG emissions slightly.

Additionally, the case study conservatively assumed that the resource mix of the hypothetical jurisdiction would not change over the course of the managed charging program. While a utility could spend the resources to model a shift towards a cleaner generation mix overtime, the GHG value stream is already very minor compared to other value streams and modeling a cleaner grid forecast would have only further diminished its relative scale.[18] Therefore, expending additional cost to calculate the value of GHG emission changes more precisely would not have changed the overall BCA result. However, if policies were in place that prohibited increases in

[18] This is because the level of precision achieved for each value stream should ideally be proportional to the absolute value of the stream and should be reflective of the uncertainty found within a value stream's inputs.

GHG emissions or placed a large price on GHG emissions, then this impact stream could become more influential in the BCA. Likewise, if the jurisdiction chose to use a lower discount rate (a 3% real discount rate was used), then the GHG impact stream would have been larger.

4.3 Conclusions and Areas for Further Research

This case study demonstrates two key concepts that are important to BCA analysis. The first is that the granularity of the savings estimates used should reflect the resource being analyzed. In this case, utilizing hourly avoided cost data allowed for an accurate estimation of the value of load shifting. This resulted in avoided energy benefits that were nearly equal to avoided generation capacity benefits, the value stream that is often considered the focal point of programs that are designed to avoid peak loading.

Secondly, this case study provides a concrete example of a meaningful BCA mantra, that the effort expended in quantifying a value stream should be proportional to the impact and uncertainty of that value stream. This is consistent with NSPM guidance which sets forth that any impact that is deemed to be relevant to a jurisdiction’s policies should be included as part of the definition of its primary JST, however in some cases, a benefit or cost may be relevant but not material.[19] Impacts determined to be immaterial should be documented, but not necessarily included in the BCA so as to avoid expending study costs that have *de minimis* impact on the BCA results and can be highly inaccurate.

One area for further research is the response of different customer types to different load shifting strategies for EVs, and in general the use of more evidence-based approaches in quantifying the hourly impacts of DERs. As more and more different DR and flexible load management approaches emerge, it is vital to be able to have confidence in the estimated load impacts so the value of these programs can be accurately assessed.

[19] *Material* impacts are those that are expected to be of sufficient magnitude to affect the result of a BCA.

5. Additional Considerations

5.1 DER Use Case Impact

As illustrated in this case study, benefit-cost results are heavily dependent on the DERs and use case being examined, as well as the specific policy and utility scenarios that determine the JST. The influence of the "full picture" and comprehensive value streams that the NSPM for DERs sets forth for utility system impacts and other impacts (depending on a jurisdiction's policy situation) can have very significant impacts on cost-effectiveness. In addition, when considering BCA results, care should be taken to ensure that the level of precision achieved for each value stream is proportional to the absolute value of the stream and is reflective of the uncertainty found within a value stream's inputs.

5.2 Accounting for Hard to Quantify Impacts

The NSPM sets forth that if an impact is relevant to a jurisdiction's JST *and the specific use case*, then it should be accounted for as the value is not zero. Exceptions may be where the impact is immaterial, or the cost of obtaining the accurate data for quantifying the value stream is not proportional to the scale of the impact (such as the approach taken in this case study to GHG emissions).

Therefore, when making investment decisions, it is critical that qualitative and non-monetized impacts be considered in addition to quantitative BCA results. A calculated BCA is rarely representative of all critical factors and should not be used as a binary decision-making algorithm. Instead, expert judgment is usually needed to determine the appropriate, relative scale and weighting of qualitative and non-monetized impacts relative to BCA results. Nevertheless, a JST with relevant secondary tests does serve as a strong foundation from which to layer on qualitative and non-monetized impacts. Methods such as applying adders to BCA impact streams and running sensitivity analyses can also help to show how BCAs may change under different scenarios. For further information, see the MTR Handbook.

Appendix – BCA Impact Categories

Electric Utility System Impacts[20]

Type	Utility System Impact	Description
Generation	Energy Generation	Production or procurement of energy (kWh) from generation resources on behalf of customers
	Capacity	Generation capacity (kW) required to meet the forecasted system peak load
	Environmental Compliance	Actions to comply with environmental regulations
	RPS/CES Compliance	Actions to comply with renewable portfolio standards or clean energy standards
	Market Price Effects	The change in wholesale market prices as a result of changes in customer consumption
	Ancillary Services	Services required to maintain electric grid stability and power quality
Transmission	Transmission Capacity	Maintaining the availability of the transmission system to transport electricity safely and reliably
	Transmission System Losses	Electricity or gas lost through the transmission system
Distribution	Distribution Capacity	Maintaining the availability of the distribution system to transport electricity or gas safely and reliably
	Distribution System Losses	Electricity lost through the distribution system
	Distribution O&M	Operating and maintaining the distribution system
	Distribution Voltage	Maintaining voltage levels within an acceptable range to ensure that both real and reactive power production are matched with demand
General	Financial Incentives	Utility financial support provided to DER host customers or other market actors to encourage DER implementation
	Program Administration	Utility outreach to trade allies, technical training, marketing, and administration and management of DERs programs or strategies
	Utility Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of DER programs
	Credit and Collection	Bad debt, disconnections, reconnections
	Risk	Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks
	Reliability	Maintaining generation, transmission, and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions

[20] Tables and descriptions are from the NSPM for DERs.

Gas Utility System Impacts

Type	Gas Utility System Impact	Description
Energy/Supply	Gas Commodity	The gas capacity required to meet forecasted peak load as well as the fuel and Operations & Maintenance (O&M) impacts associated with gas
	Environmental Compliance	Actions required to comply with environmental regulations
	Market Price Effects	The change in wholesale prices as a result of changes in customer consumption
Transportation	Pipeline Capacity	The fixed charges for pipeline transportation services that deliver natural gas to the local distribution company (LDC) city gate
Distribution	Pipeline Losses	The volumetric difference between the gas entering the LDC city gate and the gas measured at customers' meters
	Gas Distribution	Local distribution company costs to deliver gas from the city gate to retail customers
General	Financial Incentives	Utility financial support provided to DER host customers or other market actors to encourage DER implementation
	Program Administration Costs	Costs incurred by the DER program administrator related to the planning, design, implementation, and evaluation of a DER program or initiative
	Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of DER programs
	Credit and Collection Costs	Costs associated with customers who are deficient on energy bill payments, including notices and support provided to customers in arrears, terminations, disconnections, reconnections, carrying costs associated with arrears and writing off bad debt.
	Risk	Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks
	Reliability	Maintaining the gas system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions

Other Fuel Impacts

Type	Other Fuel Impact (oil, propane, wood, gasoline)	Description
Other Fuels	Commodity	The fuel and O&M impacts associated with other fuels
	Environmental Compliance	Actions required to comply with environmental regulations
	Market Price Effects	The change in wholesale prices as a result of changes in customer consumption

Host Customer Impacts

Host Customer Impact	Description
Energy Related Impacts	
Host Portion of DER Costs	Costs incurred to install and operate DERs
Interconnection Fees	Costs paid by host customer to interconnect DERs to the grid
Risk	Uncertainty including price volatility, power quality, outages, and operational risk related to failure of installed DER equipment and user error; this type of risk can depend on the type of DER
Reliability	The ability to prevent or reduce the duration of host customer outages
Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions
Tax Incentives	Federal, state, and local tax incentives provided to host customers to defray the costs of some DERs
Non-Energy Impacts (NEIs)	
Transaction Costs	Costs incurred to adopt DERs, beyond those related to installing or operating the DER itself (e.g., application fees, customer time spent researching DERs, paperwork, etc.)
Asset Value	Changes in the value of a home or business as a result of the DER (e.g., increased building value, improved equipment value, extended equipment life)
Productivity	Changes in a customer's productivity (e.g., in labor costs, operational flexibility, O&M costs, reduced waste streams, reduced spoilage)
Economic Well-being	Economic impacts beyond bill savings (e.g., reduced complaints about bills, reduced terminations and reconnections, reduced foreclosures—especially for low-income customers)
Comfort	Changes in comfort level (e.g., thermal, noise, and lighting impacts)
Health & Safety	Changes in customer health or safety (e.g., fewer sick days from work, reduced medical costs, improved indoor air quality, reduced deaths)
Empowerment & Control	Satisfaction of being able to control one's energy consumption and energy bill
Satisfaction & Pride	Satisfaction of helping to reduce environmental impacts (e.g., key reason why residential customers install rooftop PV)

Societal Impacts

Societal Impact	Description
Resilience	Resilience impacts beyond those experienced by utilities or host customers
GHG Emissions	GHG emissions created by fossil-fueled energy resources
Other Environmental	Other air emissions, solid waste, land, water, and other environmental impacts
Public Health	Health impacts, medical costs, and productivity affected by health
Energy Security	Energy imports and energy independence