National Standard Practice Manual

For Benefit-Cost Analysis of Distributed Energy Resources

2026



NASEO

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National Energy Screening Project

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The views and opinions of authors expressed herein do not necessarily state or reflect those of NASEO's members.

An NSPM Summary version and supporting resources and tools are available at: www.naseo.org/topics/nesp



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Glossary

Advanced metering infrastructure (AMI): an integrated system of smart meters and data management systems that enables two-way communication between utilities and customers.

Aggregator: a company that negotiates with producers of a utility service such as electricity on behalf of groups of consumers, or which bundles DERs to engage as a single entity—a virtual power plant (VPP)—in power or service markets.

Alternative thresholds: an approach to address hard-to-monetize impacts that allow DERs to be considered cost-effective at pre-determined benefit-cost ratios. (See Appendix C.)

Analysis period: the time period over which cost-effectiveness analysis should be conducted. (See "Expected useful life" and Appendix H.)

Ancillary services: services required to maintain electric grid stability. They typically include frequency regulation, voltage regulation, spinning reserves, and operating reserves, either traded in wholesale energy markets or self-supplied by utilities.

Avoided costs: the costs of those electricity and gas resources (e.g., generation, transmission, and distribution system infrastructure) that are deferred or avoided by the DERs being evaluated for cost-effectiveness. (See Chapter 6.)

Behind-the-meter (BTM): Also referred to as "customer-facing," BTM includes a range of technologies that customers can install to reduce the host customers' bills and/or improve the operational efficiency of the distribution system, thus also sometimes providing value to the grid. This includes all types of DERs, such as EE, DR, DG, DS, ELEC, and EVs.

Benefit-cost analysis (BCA): a systematic approach for assessing the cost-effectiveness of investments by comparing the benefits and costs of alternative options. BCA is also commonly referred to as cost-effectiveness analysis.

Best available: information that is based on acceptable standards of accuracy, reliability and relevancy, is up-to-date and mindful of limitations, is peer-reviewed when appropriate and required, and delivered at an appropriate time in the decision-making process.

Bill impact analysis: indicates the extent to which customer bills are affected for customers that participate in DER programs and those who do not.

Building electrification: substituting electricity for consumption of other fuels, e.g., space heating, water heating, cooling, cooking, drying, and other end-uses, therefore increasing electric system costs. (See "Electrification" and Chapter 12.)

Cost-effectiveness: when investment in a resource is worthwhile; measured by the benefits of investing in a resource being greater than the costs of investing therein.

Demand flexibility: the capability provided by DERs to reduce, shed, shift, modulate, or generate electricity; energy flexibility and load flexibility are often used interchangeably with demand flexibility.

Demand response (DR): DR programs play a role in the operation of the electric grid by reducing or shifting their electricity usage during peak periods in response to time-based rates or other forms of financial incentives. DR programs are used by some electric system planners and operators as resource options for balancing supply and demand. Methods of engaging customers in DR efforts include offering time-based rates and direct load control programs which provide the ability for power companies to e.g., cycle air conditioners and water heaters on and off during periods of peak demand in exchange for a financial incentive and lower electric bills. (NERC 2011) (See Chapter 9.)

Discount rates: a component of cost-effectiveness analysis which reflects a "time preference"—the relative importance of short- versus long-term impacts. A higher discount rate gives more weight to short-term benefits and costs relative to long-term benefits and costs, while a lower discount rate gives greater weight to long-term impacts. (See Appendix G.)

Dispatchable: the ability to actively control (in this case) DERs located near consumption points to adjust their power output (injection or reduction) in real-time on demand, typically under the control of the utility, either through technical control or by the terms of a contract, or both.

Distributed energy resource (DER): electricity and gas resources sited close to customers that can provide all or some of their immediate power needs and/or can be used by the utility system to either reduce demand or provide supply to satisfy the energy, capacity, or ancillary service needs of the grid (DOE 2019a). These include energy efficiency, demand response, distributed generation, distributed storage, electric vehicles, and building electrification.

DER pricing mechanism: includes initiatives and performance-based compensation to encourage customers to install and utilize DERs as efficiently as possible through price signals. Examples include time-based pricing (time-of-use or TOU rates, peak time rebates, and critical peak pricing) and net metering compensation.

DER programs: include passive and performance-based programs, initiatives, and policies that encourage customers to adopt DERs. Examples include traditional utility EE programs, traditional utility DR or bring-your-own-device (BYOD) programs, EV managed charging programs, distributed storage incentives, and investments in EV infrastructure.

DER procurement: includes initiatives to procure DERs, whether built by a utility or procured from third-party vendors, e.g., competitive and/or technology providers, typically using a competitive procurement process.

Distributed generation (DG): electric generation interconnected to the distribution grid and operating at the distribution level, generally near a load, though sometimes stand-alone. DG includes distributed solar photovoltaic (PV) technology, combined heat and power (CHP), district heating and cooling, small wind, and biomass and biogas facilities associated with landfills and agricultural operations. (See Chapter 9.7.)

Distributed storage (DS): technologies used to locally store energy. This manual primarily focuses on BTM resources, such as lithium-ion batteries, but it can also apply more broadly to all distributed storage types (e.g., thermal, including electric water heaters) and chemistries (e.g., lead-acid) as opposed to those connected at transmission (e.g., pumped hydro and compressed air). (See Chapter 11.)

Double-counting: the inclusion of overlapping impacts in analyses and thus counting one effect more than once.

Effective useful life (EUL): the average time over which a DER measure results in energy savings (or use) including the effects of equipment failure, removal, and cessation of use.

Electric vehicle (EV): a vehicle powered directly by electricity rather than other fuels. These can also in some instances operate as storage devices. (See "Vehicle to Grid" and "Electrification" and Chapter 12.)

Electrification (ELEC): increased electrification of end uses, when beneficial to the utility system as a whole, including the increased integration of electrification including building electrification and EVs. This can be "partial," where some but not all fuel consumption is replaced by electricity (e.g., a plug-in hybrid EV), or "complete" (e.g., a battery electric vehicle). (See Chapter 12.)

Enabling effects: when some DERs make it easier or more cost-effective to adopt other types of DERs. (See Section 11.5.)

Energy efficiency (EE): Resources that include technologies, services, measures, or programs that reduce energy consumption by host customers and that are funded by, promoted, or otherwise supported on behalf of all electricity and gas utility customers. (See Chapter 8.)

Environmental compliance: the process by which utility systems adhere to federal, regional, and state/local laws designed to manage and mitigate the ecological impact of energy production. These regulations typically require a reduction in emissions from energy generation or place limits on allowable levels of emissions from new or existing energy resources.

Forward-looking analysis: captures the difference between benefits and costs that would occur over the lifetime of the DERs and those what would occur absent the DERs.

Free-ridership: DER savings that would have occurred in the absence of the program.

Front-of-the-meter (FTM): also known as utility-facing, FTM DERs are typically operated to reduce system costs (as opposed to BTM DERs, which are typically operated to reduce customer costs). (See Chapter 7.)

Greenhouse gas (GHG) emissions: gases that trap heat in the atmosphere (including carbon dioxide, methane, nitrous oxide, and fluorinated gases) emitted from human activities, primarily burning fossil fuels for electricity generation, transportation, industrial processes, commercial and residential heating, and agriculture.

Grid-interactive efficient building (GEB): an energy-efficient building that uses smart technologies and on-site DERs to provide demand flexibility while co-optimizing for energy cost, grid services, and occupant needs and preferences in a continuous and integrated way (DOE 2019a). (See Chapter 13.)

Grid modernization: investments in updating the grid to accommodate DERs, multi-way power flows, and/or active management of the distribution grid to achieve reliability and greater efficiency (DOE 2017b). These are often categorized as either utility-facing, which may support increased DER implementation, or customer-facing, which often include a range of DERs.

Grid services: suite of capabilities that provide dynamic load control to support the electric grid including shedding, shifting, and modulating loads. Grid services support the generation, transmission, and distribution of electricity by providing value through avoided electricity utility system costs (e.g., generation and/or delivery costs). Modulating loads provides ancillary services (e.g., frequency regulation) and voltage control.

Host customer: The owner/occupant of the site at which BTM DERs are installed and/or operated. In some cases, these are program participants, e.g., participants in a DR or EE program. In other cases, there is no program, e.g., EV owners.

Incremental analysis: consists of changes that will occur as a result of the DER relative to a scenario where the DER is not in place.

Integrated distribution planning (IDP): a long-run utility planning process that expands on traditional distribution planning and allows for evaluation of both traditional distribution resources and DERs for meeting distribution grid needs. (See Table A-3.)

Integrated grid planning (IGP): a long-run planning process for vertically integrated utilities that evaluates all resource types (DERs and utility-scale resources) to enable optimization across all levels of the utility system (generation, transmission, and distribution). (See Table A-3.)

Integrated resource planning (IRP): a long-run planning process for vertically integrated utilities that evaluates DERs and utility-scale generation for meeting peak and energy demands. (See Table A-3.)

Load shape: a numerical profile of electricity consumption (measured in kilowatts, kW, or megawatts, MW) over a specific time period—typically 24 hours, a month, or a year, illustrating when and how much energy is used, highlighting daily, weekly, or seasonal peaks and valleys.

Long-run: the period covering the full life cycle of the resource being analyzed. The long-run approach is necessary to account for the full benefits and costs of the DER being evaluated, particularly since energy resources, including many DERs, can last decades.

Lost revenues: When DERs reduce consumption of electricity or gas, which can result in fixed costs being spread across a smaller volume of sales, putting upward pressure on rates.

Impacts: both the benefits and the costs of a supply-side or demand-side resource. (See Chapter 6.)

Jurisdiction: any region or service territory to be served by the DERs under analysis. This includes a state, a province, a utility service territory, a city or a town, or some other jurisdiction covered by regulators or other entities that oversee DER initiatives.

Jurisdiction-Specific Test (JST): the primary test created by a jurisdiction following use of the NSPM BCA Decision Framework. It embodies all of the key principles of cost-effectiveness analyses and accounts for that jurisdiction's applicable policy goals by including impacts identified as relevant to that jurisdiction's goals and objectives.

Levelized costs: represent the average cost per unit of energy required to install and operate an electricity or gas resource. The costs of electricity and gas resources, including DERs, can be put into levelized costs to allow for a relatively simple, direct comparison across different resources.

Material impacts: impacts that are expected to be of sufficient magnitude to affect the result of a BCA.

Microgrid: coordinated operation of DERs on a portion of the electric grid in a configuration that allows islanding (functioning independently of the rest of the grid) and potentially adds resource value when operating in parallel with the grid. (See Chapter 13).

Multiple On-Site DERs: when more than one DER is installed in the same building (or facility), or at buildings (or facilities) within a contiguous geographic site such as a campus. (See Chapter 13).

Net energy metering (NEM): also known as net metering, tariff design that allows consumers to receive bill credit on a kWh basis for excess generation injected onto the grid for the use of other customers. (See Chapter 9.7.)

Net present value (NPV): calculates the value of all future program or project benefits minus all costs, adjusted for the time value of money by discounting them to the present. A positive NPV indicates that the program or project benefits are greater than the program or project costs.

Non-dispatchable: refers to programs and measures without such controls and includes time-varying rates that send price signals to encourage customers to alter their energy usage during particular hours.

Non-energy impacts (NEI): are impacts of DERs other than direct energy and demand impacts. While these impacts can be non-energy benefits and related costs, most are considered benefits (non-energy benefits, or NEBs). Examples include reduced emissions, comfort and productivity improvements, local economic development, and reduced risk of utility service disruptions or price spikes.

Non-infrastructure DER solutions: DERs typically sited at more than one location are utilized to defer or avoid a utility infrastructure investment (e.g., non-wires or non-pipe solutions), or to improve system performance and/or customer satisfaction while waiting for the completion of an infrastructure solution (See Chapter 13).

Non-pipes solution: alternatives to meeting on-system natural gas demand that delay or avoid the need for investment in traditional resources such as pipelines, storage capacity, winter-peaking services, and distribution system infrastructure.

Non-wires solution (NWS): also known as non-wires alternative (NWA), geotargeting, and market-based alternative or solution. This is a strategy of deploying DERs in a specific geographic area for the purpose of deferring or avoiding new investments in equipment, distribution, or transmission lines. (See Chapter 13.)

Optionality: refers to the flexibility, reliability, and deferral benefits they provide to the grid, allowing utilities to avoid or delay costly infrastructure investments.

Participant Cost Test (PCT): a cost-effectiveness test, as provided in the 2001 *California Standard Practice Manual*, which includes the benefits and costs experienced by host customers.

Participation impacts: indicate impacts participating customers will experience from participating in a DER program, in terms of bill reductions or increases.

Policy neutrality: a core component of the NSPM guidance. The NSPM does not advocate for any policy or cost-effectiveness test but rather sets forth a BCA Decision Framework that a jurisdiction can use to review its existing policies to develop a cost-effectiveness test which reflects local policy objectives.

Primary cost-effectiveness test: the cost-effectiveness test that a jurisdiction uses to determine whether a DER (or set of DERs) has benefits that exceed costs, and therefore merits acquisition or support from utilities or other energy providers.

Proxies: simple, quantitative values that can be used as indirect indicators for values not monetized by conventional means, which can be applied to any type of benefit or cost that is hard to monetize and is expected to be of significant magnitude. (See Appendix C.)

Public health: Impacts include health impacts beyond host customer impacts, and typically health impacts associated with improved or worsened air quality impacts, where impacts are accounted for in terms of e.g., reduced healthcare costs.

Rate, bill, participant analysis: indicates the extent to which customers will be affected by DERs, and the extent to which DER investments might lead to distributional equity or cost allocation concerns. See "Rate Impact Analysis," "Bill Impact Analysis," and "Participation Impact Analysis."

Rate impact analysis: assessment of the extent to which investing in a resource will impact customer rates, sometimes in the form of a Ratepayer Impact Measure (RIM) test. This is a separate type of analysis from cost-effectiveness, which assesses whether the benefits of investing in a resource outweigh the costs. (See Appendix A.)

Regulators and other decision-makers: refers broadly to any entity that oversees and guides DER analyses and associated investment decisions. This includes Public Utility Commissions, State Energy Offices, and boards of public power authorities and municipal or cooperative utilities.

Regulatory perspective: the perspective of regulators or other decision-makers that oversee resource investment choices, including energy generation and T&D infrastructure. This perspective is guided by the jurisdiction's applicable energy policy goals—whether in laws, regulations, organizational policies, or other codified forms—under which it operates.

Reliability: the ability to maintain power delivery to customers in the face of routine uncertainty in operating conditions, as in cases of fluctuating load and generation, fuel availability, and outage of assets under normal operating conditions (NREL 2022). Reliability addresses high-frequency, low-impact events, meaning the anticipated disruptions associated with normal operating conditions (i.e., "blue sky" days) (NARUC 2025).

Renewable Portfolio Standard (RPS): a regulatory mandate to increase production of energy from renewable resources such as wind, solar, biomass, and other alternatives to fossil-fuel-based electric generation.

Resilience: the ability to prepare for threats and hazards, adapt to changing conditions, and withstand and recover rapidly from disruptions (The White House 2025). Resilience addresses low-frequency, high-impact events.

Revenue shifting: occurs when reduced consumption from DERs shifts the collection of revenues from DER customers to others but does not increase rates. This can be caused by downward pressure on rates created by avoided utility system costs exceeding the upward pressure on rates from reduced sales. Not to be conflated with cost-shifting, which occurs when reduced consumption from DERs shifts collection of revenues from DER customers to others but increases rates. (See Appendix A.)

Risk: an adverse outcome that can occur because of uncertainty. In statistical terms, risk is the expected value of a potential loss (Ceres 2012). Meaning, risk is the probability of an adverse outcome occurring multiplied by the consequence of the outcome.

Secondary cost-effectiveness test: a cost-effectiveness test that supports use of the primary test by helping enhance stakeholders' overall understanding of DER impacts by answering additional questions regarding utility DER investments. The impacts included in secondary tests are driven by the purpose of the secondary analyses, including informing decisions on how to prioritize DERs; informing decisions regarding marginally cost-effective DERs; encouraging consistency across DER types; and considering other types of effects on customers. (See Section 5.2.3 and Appendix D.)

Single-DER analysis: when one DER type is assessed in isolation from other DER types and is evaluated relative to a static set of alternative resources. (See Chapters 8–12.)

Smart neighborhoods or communities: a set of homes or buildings that include GEB characteristics that can be connected as a neighborhood-style microgrid (DOE 2019c). (See Chapter 11.)

Societal Cost Test (SCT): a cost-effectiveness test, as provided in the 2001 *California Standard Practice Manual*, which includes the benefits and costs experienced by society.

Spillover: installation of DERs by customers who did not directly participate in a DER program but were nonetheless influenced by the program.

Symmetry: a key principle for the treatment of benefits and costs which is necessary to avoid bias toward any one resource, whereby both benefits and costs are included (or excluded) for each relevant impact. If each type of impact is not treated symmetrically, the result will be a sub-optimal selection of resources. (See Chapter 3.)

Third parties: the broad range of independent provider such as aggregators or implementation, service, or technology providers.

Time-varying rates: Rate designs that provide different price signals to customers at different times of the day, season, or year, based on differences in underlying costs to the system.

Total Resource Cost Test (TRC): a cost-effectiveness test that includes the benefits and costs experienced by the utility system, plus benefits and costs to the program participants.

Transfer payment: a one-way payment of money for which no money, good, or service is received in exchange. This is uncommon in DER BCAs. (See Appendix I.)

Transparency: a key principle whereby cost-effectiveness practices fully document all relevant inputs, assumptions, methodologies, and results. (See Appendix D and Appendix J for recommended templates and reporting formats.)

Utility: any entity that funds, implements, or supports DERs using customer or public funds that are overseen by regulators or other decision-makers. This includes investor-owned utilities; publicly owned utilities; municipal utilities; cooperative utilities; program administrators; community choice aggregators; regional transmission organizations and independent system operators; federal, state, and local governments; and other energy service providers. **Utility expenditures** refer to spending by any of these entities on DERs.

Utility Cost Test (UCT): a cost-effectiveness test includes the benefits and costs experienced by the utility system. This test is also known as a Program Administrator Cost Test (PACT).

Utility system: all elements of the electricity or gas system necessary to deliver services to the utility's customers. For electric utilities, this includes generation, transmission, distribution, and utility operations. For gas utilities, this includes transportation, delivery, fuel, and utility operations. This term refers to any type of utility ownership or management, including investor-owned utilities, publicly owned utilities, municipal utility systems, cooperatives, etc.

Vehicle to grid (V2G): a two-way flow capability in some EVs that allows EVs to function as storage devices that can push electricity back onto the grid, thus potentially reducing net system peak demands and/or net T&D peak demands. (See "Electrification" and Chapter 9.7.)

Virtual power plants (VPP): aggregations of DERs that can balance electricity demand and supply and provide utility-scale and utility-grade grid services that can be dispatched to benefit the grid and/or participate in a wholesale market. (See Chapter 13).

Acronyms

ADMS	advanced distribution management systems
AMI	advanced metering infrastructure
BCA	benefit-cost analysis
BCR	benefit-cost ratio
BTM	behind the meter
BTU	British thermal unit
BYOD	bring your own device
BYOT	bring your own thermostat
C&I	commercial and industrial
CAIDI	customer average interruption duration index
CBO	community-based organization
CEMI	customers experiencing multiple interruptions
CES	clean energy standard
CHP	combined heat and power
COP	coefficient of performance
CPCN	certificate of public convenience and necessity
CPS	clean peak standard
CS	community or shared solar
DCFC	direct-current fast charger
DEA	distributional equity analysis
DER	distributed energy resource
DERMS	distributed energy resource management systems
DG	distributed generation
DOE	Department of Energy
DPV	distributed solar photovoltaic
DR	demand response
DRP	distribution resource plan
DS	distributed storage
DSP	distribution system planning
EDA	economic development analysis
EE	energy efficiency
ELEC	electrification-related DERs
EM&V	evaluation, measurement, and verification
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
FIT	feed-in tariff
FTE	full-time equivalent
FTM	front of the meter
FTR	fixed transmission right
G&T	generation and transmission
GDP	gross domestic product
GEB	grid-interactive efficient building
GHG	greenhouse gas
GT&D	generation, transmission, and distribution
HPWH	heat pump water heater
HVAC	heating, ventilation, and air conditioning
ICE	interruption cost estimate
IDP	integrated distribution planning
IGP	integrated grid planning
IOU	investor-owned utility
IRP	integrated resource plan
ISO	independent system operator
ITC	federal investment tax credit
JST	jurisdiction-specific test
KW	kilowatt
KWH	kilowatt-hour
LAUF	lost and unaccounted for
LBNA	locational net benefit analysis
LCOE	levelized cost of energy or electricity
LCSE	levelized cost of saved energy
LED	light-emitting diode
LOLE	loss-of-load expectation
LOLP	loss-of-load probability
LSE	load-serving entity
MMBTU	million British thermal units
MPE	wholesale market price effects
MW	megawatt
MWh	megawatt-hour
NASEO	National Association of State Energy Officials
NEI	non-energy impact
NEM	net energy metering
NESP	National Energy Screening Project
NPS	non-pipes solution
NPV	net present value
NSPM	National Standard Practice Manual
NWS	non-wires solution
O&M	operations and maintenance
PACT	Program Administrator Cost Test
PBR	performance-based regulation
PCT	Participant Cost Test
PIM	performance incentive mechanism
PUC	Public Utility Commission
PURPA	Public Utility Regulatory Policies Act
PV	solar photovoltaic
PV	present value
RBA	rate and bill impact analysis
REC	renewable energy credit
REC	renewable energy certificates
RGGI	Regional Greenhouse Gas Initiative
RIM	Rate Impact Measure (test)
RPS	renewable portfolio standard
RR	retail rate
RTO	regional transmission organization
SAIDI	system average interruption duration index

SAIFI	system average interruption frequency index
SCT	Societal Cost Test
SIR	savings-to-investment ratio
T&D	transmission and distribution
TOU	time of use
TRC	Total Resource Cost (test)
UCT	Utility Cost Test
V2G	vehicle to grid
VAR	voltage levels and reactive power
VDER	value of distributed energy resources
VNM	virtual net metering
VOLL	value of lost load
VOS	value of solar
VPP	virtual power plant
WACC	weighted average cost of capital
WTP	willingness to pay

1. Introduction

The National Association of State Energy Officials (NASEO) created this 2026 Edition of the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (NSPM) as a part of its National Energy Screening Project (NESP)[2]. The Manual is intended to help State Energy Offices, Public Utility Commissions, boards and leadership of consumer-owned utilities, and others apply a comprehensive and consistent benefit-cost analysis (BCA) framework to analyze optimal levels of distributed energy resources (DER), analyze DER benefits and costs, and avoid uneconomic investment decisions that can lead to unintended increased electric and natural gas utility costs for consumers and businesses.

DERs are resources located on the electric or natural gas distribution system that are generally sited close to or at customers' facilities. The DERs addressed in this Manual include technologies that fall into the following categories:

- Energy efficiency (EE)
- Demand response (DR)
- Distributed generation (DG)[3]
- Distributed storage (DS)
- Electrification-related DERs (ELEC)[4]

The NSPM can help jurisdictions (e.g., states or local municipalities) identify the full range of DERs whose benefits exceed their costs and develop BCA practices that are most appropriate for their jurisdictions given their goals and objectives.

This Manual focuses on assessing DER benefits and costs in the context of regulatory oversight of electric and natural gas DER investments and strategies, with an emphasis on electricity DERs because these are the most common types of DERs. The principles and concepts also apply broadly to resource investments in non-regulatory contexts (e.g., state policy, legislative, planning, program development, municipal authorities), as well as to utility-scale resource investments.

Whether in the form of policies, regulations, programs, procurement, planning, or other contexts, DER investments have multiple purposes. Either independently or in some combination, DERs can meet a range of electric and natural gas utility system needs and jurisdictional policy objectives. These needs and objectives include reducing utility system costs, planning for large load forecasts, deferring capacity, providing demand flexibility, increasing reliability and resilience, reducing energy burdens for low- to moderate-income customers, managing grid power quality, enabling integration of variable-generation renewable energy resources, and/or reducing emissions.

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[2] The NESP was funded and managed by E4TheFuture from 2016-2025. It became a project of NASEO in 2026, including its full range of products and services. See *National Energy Screening Project (NESP).*

[3] DG includes distributed photovoltaics (DPV), combined heat and power (CHP), and other DG resources (distributed wind, hydro and biomass). This Manual largely focuses on DPV applications.

[4] Electrification of energy loads – the conversion of energy use from non-electric fuels to electricity – is not in and of itself a DER but rather can include DER technologies (e.g., heat pumps, electric vehicles) that replace other fuels to meet a jurisdiction's policy goals and objectives.

Applying a comprehensive and consistent BCA framework to analyze investments in DERs can help jurisdictions (e.g., states or local municipalities) implement optimal levels of DERs and avoid uneconomic decisions that can lead to unintended increased costs for customers.

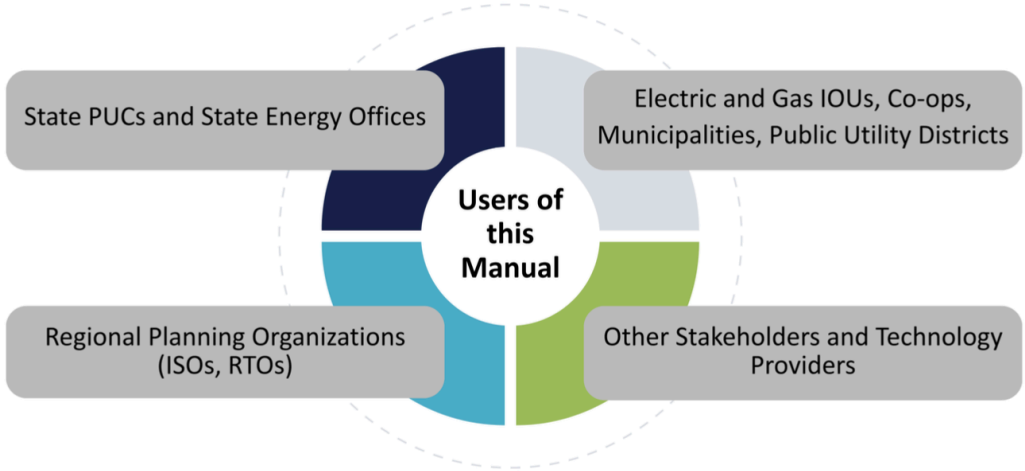
This NSPM sets forth a BCA Decision Framework ("BCA Framework") that focuses on BCA but also incorporates other supporting concepts. The NSPM provides policy-neutral guidance for sound, comprehensive, and balanced assessment of the benefits and costs of DERs. While this Manual does not address every nuance or scenario for DER investments, it can help jurisdictions identify the full range of DERs whose benefits exceed their costs and develop BCA practices that are most appropriate for their jurisdictions given their goals and objectives.

The NSPM provides objective, policy- and technology-neutral, and economically sound guidance for developing jurisdiction-specific approaches to benefit-cost analyses of distributed energy resources.

The BCA Framework also distinguishes between conducting BCAs and other complementary analyses to inform DER investment decisions. Such complementary analyses can include analyzing the rate and bill impacts to customers associated with the DER investment(s) or strategies being considered, relative to alternative options, to address energy affordability concerns and goals.

The NSPM is intended to be relevant to Public Utility Commissions, State Energy Offices, municipal and cooperative utilities (co-ops) and public utility districts and their respective boards, consumer advocates, investor-owned utilities (IOUs), and other stakeholders that have a role guiding or reviewing DER investment decision-making, and independent system operators (ISO) or regional transmission organizations (RTO), as shown in Figure 1-1.

Figure 1-1. Intended NSPM Users



The Manual, and companion tools and resources identified herein, are products of NASEO's NESP. This 2026 edition of the Manual builds upon and replaces the 2020 NSPM version, and its update was guided by an advisory group represented by a range of experts with varying perspectives and backgrounds.

1.1. Scope of Manual and Key Terms

This Manual's scope is summarized as follows:

- This Manual is relevant to all DERs that electric or natural gas utilities (or other energy providers) fund, acquire, or otherwise support on behalf of their customers.
- The NSPM focuses on electricity DERs because these are the most common types of DERs. Nonetheless, the principles, concepts, and guidance also apply to natural gas DERs.
- The guidance applies to all types of electric utilities, including those in regions where utilities are vertically integrated, are distribution-only, or serve as a distribution platform for host customers to access a variety of energy services/ DERs from third-party aggregators.
- While the guidance and concepts provided in this Manual focus on DERs, they are largely applicable to analyzing investments in utility-scale resource investments.
- This Manual focuses on utility DER programs because they are commonly subjected to administrative BCAs. Nonetheless, the principles, concepts, and guidance apply to other DER contexts, as provided in Chapter 5 and Appendix A. This Manual is neutral regarding the use of any mechanisms or approaches to supporting DER investments.
- The NSPM addresses DERs that affect multiple fuel types, including electricity, natural gas, oil, propane, and gasoline (i.e., applications where a DER, or combinations of DERs, affect multiple fuel types).
- The concepts and guidance in the NSPM are applicable to both behind-the-meter (BTM) and front-of-the-meter (FTM) DERs, defined as:
    - *Behind the meter:* These are DERs installed at host customer facilities, where the DER is installed on the host customer side of the utility service connection (i.e., behind the utility retail meter).
    - *Front of the meter:* These are DERs installed on the distribution utility system near customer loads, but not at host customer facilities.
    - The NSPM is neutral regarding whether a DER should be FTM or BTM.
- This Manual expands upon and supersedes the 2020 version of the NSPM for Benefit-Cost Analysis of DERs.

The NSPM has many terms commonly used within the electricity and gas industries. Key terms are defined in the Glossary, the list of acronyms, and relevant sections of this Manual. Some of the terms used are more broadly defined than in other industry applications, as described below.

Key Terms Broadly Used Throughout This Manual

Benefit-cost analysis (also commonly referred to as 'cost-effectiveness analysis') is a systematic approach for assessing the cost-effectiveness of investments by comparing the benefits and costs of alternative options. The Manual uses the term benefit-cost analysis or BCA throughout.

Jurisdiction refers to a state, territory, province, city, town, or some other jurisdiction covered by regulators or other authorities that oversee DER initiatives.

Utility refers broadly to an entity that funds, implements, or supports DERs using customer or public funds that are overseen by regulators or other decision-makers. This typically includes investor-owned utilities (IOUs) and consumer-owned utilities (i.e., publicly owned utilities; municipal or cooperative utilities), and non-IOU DER program administrators (e.g., energy efficiency utilities, community choice aggregators).

Regulator (***and other decision-makers)*** refers broadly to any entity that oversees and guides DER analyses and associated investment decisions. This includes Public Utility Commissions, State Energy Offices, and boards of public power authorities and municipal or cooperative utilities.

Regulatory perspective refers to the perspective of regulators or other decision-makers that oversee resource investment choices, including energy generation and T&D infrastructure. This perspective is guided by the jurisdiction's applicable energy policy goals—whether in laws, regulations, organizational policies, or other codified forms—under which it operates.

Host customer refers to any customer that has a DER installed and/or operated on their site. In some cases, these are program participants (such as in a DR or EE program) while in other cases there is no program (such as with EV owners).

Third party refers to the broad range of independent providers such as aggregators, or implementation, service and technology providers.

1.2. Role of Benefit-cost Analysis

BCAs answer the fundamental question: *Will total costs, across all of a utility's customers, increase (net costs) or decrease (net benefits) as a result of a resource investment?*

BCA is a systematic approach for assessing the cost-effectiveness of investments by comparing the benefits and costs of alternative options. It is widely used by businesses for deciding whether to proceed with projects, investments, programs, initiatives, or other courses of action. The analysis entails identifying all the relevant benefits and costs of a program or project and determining whether the benefits exceed the costs over the lifetime of the expected program or project.

Utilities use BCAs, both for making internal resource investment decisions and to justify resource investment decisions to regulators and other stakeholders. BCA has been used for many years to

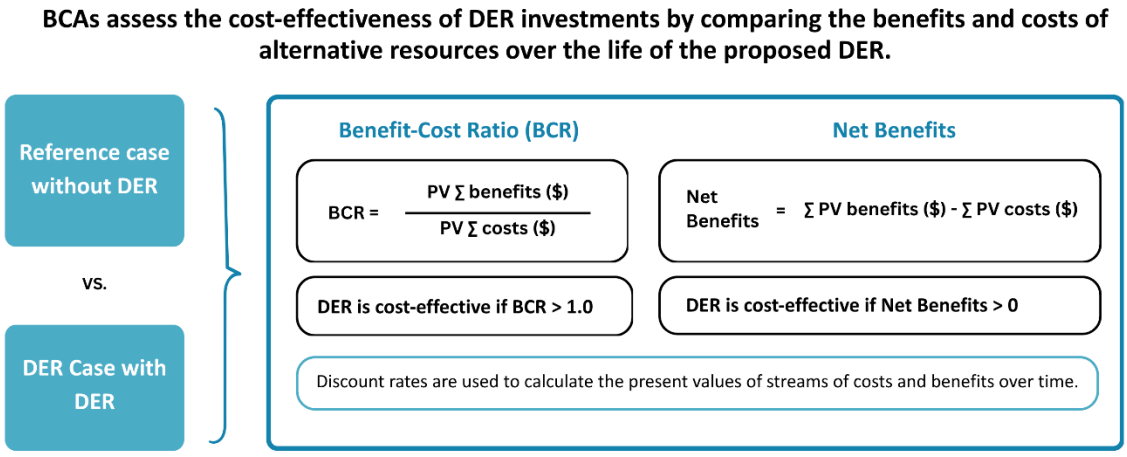
demonstrate the cost-effectiveness of specific DER investments and is central to several utility planning practices used to optimize resource decisions.

BCAs compare DERs consistently and comprehensively with each other and with alternative resources. BCAs covered in the NSPM answer this fundamental question: *Will **total costs**, across all of a utility's customers, increase (net costs) or decrease (net benefits) as a result of an investment?* BCAs can also answer other related and overlapping questions, such as:

- How can DERs be used to reduce utility/power system costs?
- How can DERs help to meet applicable policy goals (e.g., providing benefits to low-income customers, improving resilience of the grid, reducing emissions)?
- How cost-effective is one DER type relative to other types for a specific use case?
- How should investment in different DER types be prioritized?
- Which DERs should be implemented considering budgetary or other constraints?

The basic construct of a BCA is depicted below, showing the calculation for comparing benefits and costs of a reference case to a proposed DER case to determine the net present value (NPV) of the investment. BCA results are ideally presented in NPV terms or as a benefit-cost ratio (BCR).

Figure 1-2. Basics of Benefit-Cost Analysis



BCA for DERs can be applied at three different levels:

- *Single-DER analysis:* One DER type is assessed in isolation from other DER types and is evaluated relative to **a static set** of alternative resources. This approach has been used for many years and is relatively simple compared to multi-DER approaches described below. Chapters 8–12 include guidance for single-DER analysis of each DER type.
- *Multiple-DER analysis:* Multiple DER types are assessed and evaluated together, relative to **a static set** of alternative resources. This approach is more complex than single-DER analysis and serves to capture the interactive effects of DERs on one another. Multiple-DER analysis can be applied when analyzing multiple DER types that are located at one customer site—for example, in the context of grid-interactive

efficient buildings, non-infrastructure DER solutions, virtual power plants (VPP), and microgrids. Chapter 13 provides guidance and considerations for multiple-DER BCA.

- *Dynamic system planning:* Multiple DER types are assessed and evaluated relative to **a dynamic set** of alternative resources. Under this approach, the goal is to optimize both DERs and alternative utility-scale resources as well. Dynamic system planning practices include integrated resource planning and distribution resource planning. While guidance is not provided in the NSPM on dynamic system planning, Appendix A provides an overview of BCA issues related to dynamic system planning.

The NSPM focuses on *how to develop BCA tests*, and key considerations in identifying and accounting for benefits and costs in BCA. Other NSPM 'companion' resources and tools provide detailed guidance on methodologies for *how to calculate benefits and costs* and *develop value streams* using analytical tools. These topics and resources are introduced in Chapter 2 and further described in Chapter 14.

1.3. Manual Contents

The NSPM includes the following parts:

- **Part I** presents the *NSPM BCA Decision Framework* ("BCA Framework"), including foundational principles and guidance on the development of primary BCA tests (and any secondary tests) and key considerations.
- **Part II** describes the full range of potential DER benefits and costs (i.e., impacts) that may be included in a jurisdiction's BCA test(s) and presents a range of cross-cutting factors and DER attributes that can affect the valuation and materiality of impacts.
- **Part III** provides guidance on single-DER analysis for various types of DER technologies and discusses key factors that affect BCAs for each type of DER, identifies BCA challenges, and provides guidance on key issues.
- **Part IV** provides guidance on multiple-DER analysis, focusing on specific scenarios: multiple DERs on a customer site; non-infrastructure solutions; VPPs; and microgrids.
- **Part V** describes approaches to accounting for DER benefits and costs, including developing monetary values and consideration of quantitative and qualitative values.
- **Appendices** provide further guidance on topics that warrant additional explanation on key concepts or to support guidance application.

Table 1-1 presents the organization of this Manual by major parts, chapters, and appendices, with a brief description of topics covered. Users of the NSPM can refer to Table 1-1 to help navigate key sections or topics of interest.

Table 1-1. Overview of the National Standard Practice Manual for DERs

Part or Chapter	Topic	Description
Chapter 1	Introduction	Describes the purpose and scope of this Manual, and an overview of BCA
Part I	**BCA Decision Framework and Application**	
Chapter 2	BCA Decision Framework	Describes phases of decision-making process for DER investments

Part or Chapter	Topic	Description
Chapter 3	BCA Principles	Describes fundamental principles that serve as the foundation for this Manual
Chapter 4	Developing BCA Tests	Provides guidance on how to develop a jurisdiction's primary BCA test and any secondary tests, and addresses various BCA parameters to consider
Chapter 5	Valuing Energy Resources in Different Contexts	Addresses the importance of ensuring consistency in the valuation of DERs and other resources across a broad range of contexts and describes how the NSPM Principles and guidance can be applied across the contexts
Part II	**DER Benefits and Costs, Key Cross-Cutting Issues**	
Chapter 6	DER Benefits and Costs	Presents a catalog of the full range of benefits and costs that may be applicable to specific types of DERs
Chapter 7	Cross-Cutting Benefit and Cost Considerations	Discusses a variety of issues and considerations that span several of the benefits and costs listed in Chapter 6
Part III	**Specific DER Types – BCA Issues and Guidance**	
Chapter 8	Energy Efficiency	Provides guidance on key factors that affect the benefits and costs relevant to specific DER technologies (EE, DR, DG, DS, and electrification-related DERs (ELEC), including EV and building technologies)
Chapter 9	Demand Response	
Chapter 10	Distributed Generation	
Chapter 11	Distributed Storage	
Chapter 12	Electrification-related DERs	
Part IV	**BCA for DER Specific Scenarios**	
Chapter 13	Key Considerations when Analyzing Specific DER Scenarios	Addresses key issues to consider when analyzing: multiple on-site DERs, non-infrastructure DER solutions, VPPs, and microgrids. This chapter builds upon material covered in Chapters 7–12
Part V	**Accounting for DER Impacts**	
Chapter 14	Methods for Calculating DER Impacts	Provides guidance on calculating DER benefits and costs in monetary terms, and accounting for hard-to-quantify impacts, and references tools for conducting BCAs and how to present BCA results
Part VI	**Appendices**	
A	Valuing Energy Resources in Different Contexts	Provides detailed guidance to support Chapter 5 on valuing DERs consistently across various contexts (e.g., DER programs, procurement, planning) and the application of NSPM Principles and guidance
B	Rate and Bill Impact Analysis (RBA)	Describes the difference between BCA and rate impact analyses, the role of rate, bill, and participation analyses, and the importance of conducting BCA and RBA separately to inform decision making
C	Economic Development Analysis (EDA)	Describes the difference between BCA and EDA, and the importance of conducting these analyses separately in cases where economic development is an energy policy goal for the jurisdiction
D	Distributional Equity Analysis (DEA)	Describes the difference between BCA and DEA, and the importance of conducting these analyses separately where addressing the distribution of benefits and costs is an energy policy goal for the jurisdiction

Part or Chapter	Topic	Description
E	Traditional Cost-Effectiveness Tests	Summarizes the commonly used traditional cost-effectiveness tests from the *California Standard Practice Manual*, with comparison to this Manual
F	Geographic Boundaries in BCAs	Describes how policies can inform determination of geographic boundaries (state, regional, global) when analyzing certain impacts
G	Developing Secondary BCA Tests	Provides guidance on the purpose for, and how to develop any secondary BCA tests to inform resource investment decisions
H	Discount Rates	Describes ways to determine discount rates that are consistent with a jurisdiction's applicable policy goals
I	BCA Assessment Level	Describes different aggregation levels (e.g., sector, program, portfolio) for analyzing DERs in a BCA, and provides guidance on approaches
J	Template NSPM Tables	Presents various tables that can be used by jurisdictions to document applicable policies and identify relevant impacts to include in their BCA
K	Presenting BCA Results	Provides guidance on presenting results in a way that is most useful for making cost-effectiveness decisions
L	Accounting for Risk & Uncertainty	Defines and describes options on how to account for risk and uncertainty in BCAs
M	Identifying and Accounting for Transfers in BCAs	Provides guidance on impacts that appear to be both a benefit to one party and a cost to another party, thereby cancelling each other out
References		

PART I

Benefit-Cost Analysis Decision Framework and Application

2. Benefit-Cost Analysis Decision Framework

This chapter presents the NSPM BCA Decision Framework, the three phases that comprise BCA development and implementation, and references the chapters that support the three phases.

The Manual sets forth a BCA Decision Framework ('BCA Framework') which is divided into the following three main phases or areas, and is summarized in Figure 2-1:

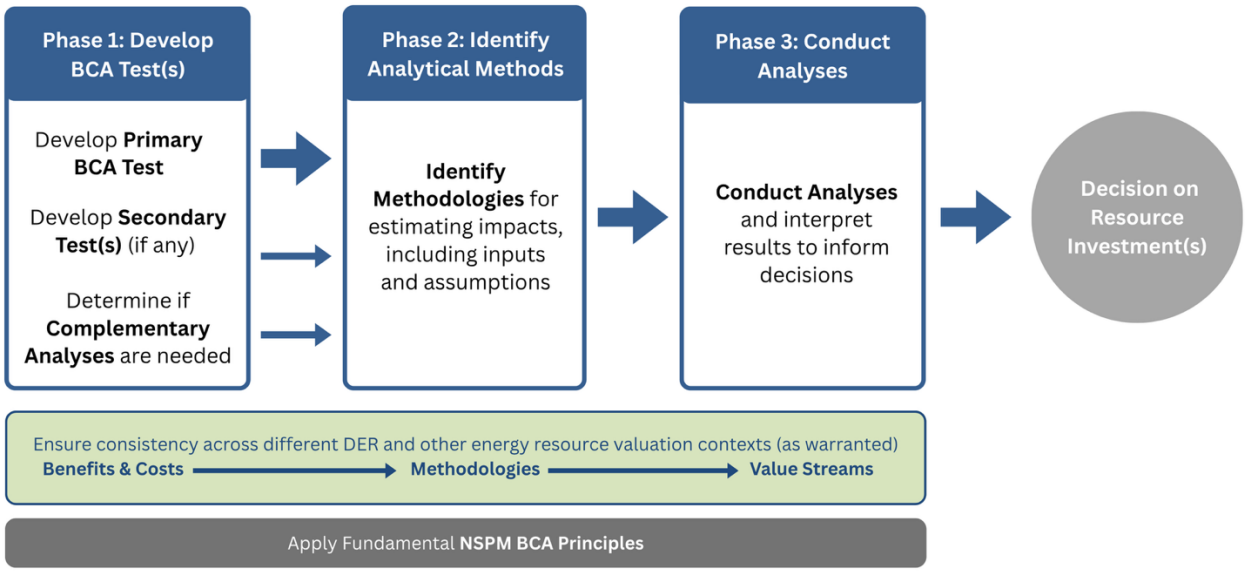
Phase 1: Develop a jurisdiction's primary BCA test (and any secondary tests) and identify whether complementary analyses are needed to inform investment decisions.

Phase 2: Identify the methodologies to use in developing numeric inputs and calculating value streams to include in BCA test(s).

Phase 3: Conduct the BCA (and any complementary analyses) and interpret the results to inform DER investment decisions.

A set of **foundational BCA principles** underpins and informs the approach, assumptions, and work on all three phases of the BCA Framework and supporting process. Chapter 3 describes these foundational principles, referred to as the *NSPM Principles*.

Figure 2-1. BCA Framework



Phase 1 of the BCA Framework

This Manual focuses on Phase 1 of the BCA Framework, encompassing a multi-step process that jurisdictions can use to systematically apply the NSPM Principles to**:**

- Develop a **primary BCA test** that is most applicable to a jurisdiction—a Jurisdiction-Specific Test (JST)—given its energy goals and objectives,
- Develop **any secondary tests** that may merit consideration in addition to the primary test,
- Establish **key analytical parameters** for the BCA test(s), such as geographic boundaries to apply in quantifying different benefits and costs, the discount rate(s) to use, and the aggregation level of impacts that will inform investment decisions, and
- Identify **any complementary analyses** (based on jurisdictional policy goals) that may be useful to undertake in parallel with BCAs, such as assessing rate impacts, economic development impacts, and/or the distribution of impacts to different populations.

This multi-step process, described in Chapter 4, can be used to develop a new primary BCA from the ground up. Jurisdictions can also use a subset of the steps to assess the extent to which existing BCA tests (or specific elements of them) align with the NSPM Principles.

Applying the multi-step process can involve either a formal stakeholder process (led by a Public Utility Commission or State Energy Office), a regulatory requirement for utilities to apply the steps in their proposed DER plans (on which stakeholders provide comment), or some other informal regulatory or jurisdictional stakeholder process.

The BCA Framework and process will likely vary from jurisdiction to jurisdiction, depending on the regulatory context. Chapter 5 provides guidance on valuing DERs (and other energy resources) in different contexts (e.g., programs, procurement, pricing mechanisms, and distribution and resource planning). It describes the role of the NSPM Principles and use of a primary BCA test in helping to support consistency in valuing resources across a range of contexts.

Chapter 6 provides a full inventory of the potential impacts to include in a primary (and any secondary) BCA test, followed by Chapter 7 which describes DER attributes and considerations that cut across multiple DER types and affect the valuation and materiality of the DER impacts. Chapters 8–13 provide extensive guidance on key factors that can affect the benefits and costs of DERs depending on the DER type, use case, or scenario.

Phase 2 of the BCA Framework

This second phase of the BCA Framework involves the process to review and select methodologies for estimating the impacts, including underlying inputs and assumptions, in a jurisdiction's primary BCA test (and any secondary tests) developed in the Phase 1 process above. Chapter 14 provides an overview of methodological approaches to accounting for DER impacts in BCA, with a focus on developing monetary value streams for DER BCA impacts. It refers to the NSPM companion technical document: *Methods, Tools, and Resources for Quantifying DER Impacts (MTR Handbook)* for comprehensive guidance on calculating the full range of BCA impacts covered in this Manual.

Other methodological resources to support conducting any parallel complementary analyses to BCAs (e.g., rate and bill impact analyses, economic development analyses, distributional equity analyses) are identified in Appendices B, C, and D.

Phase 3 of the BCA Framework

This third phase of the BCA Framework involves conducting the BCA itself (i.e., the actual calculations and development of value streams) and presenting BCA results to inform conclusions regarding the cost-effectiveness of DER investments. Utilities (or their consultants) typically undertake BCAs with review and input from Public Utility Commissions, State Energy Offices and other state agencies, and key stakeholders involved in informing decision-making processes.

Evaluation practitioners use a range of internal or external models to conduct BCAs. The NESP *OpenBCA* tool is one such tool designed to analyze BCAs for single- and multi-DER investments. This NSPM-based tool uses an open-source platform that is publicly available to all jurisdictions.

Appendix K of this Manual provides examples of how to present BCA results to help guide DER investments.

3. Benefit-Cost Analysis Principles

This chapter describes fundamental BCA principles that serve as the foundation for developing a jurisdiction's primary BCA test and any secondary tests. These principles also guide decision-making when conducting BCAs.

Principles are commonly adopted in industries to establish foundational standards by which an industry conducts its practice. When a set of foundational principles is understood, accepted, and applied in an industry, the principles support the decision-makers in making decisions in a clear, transparent, and efficient manner. For example, utility regulators have used the Bonbright Principles for utility ratemaking purposes for decades (Bonbright 1961).

The NSPM Principles (Table 3-1) serve as a foundation for conducting DER BCAs. Developed and informed by DER industry stakeholders, they can play a critical role in guiding regulators and others in the assessment of DER cost-effectiveness. The principles:

- Are policy-neutral (in that they do not prescribe specific BCA tests)[5], are technology-neutral, and are in-line with sound economic practices;
- Provide guidance on how to select relevant categories of benefits and costs for a jurisdiction to include in its primary (and any secondary) BCA test, whether in cases where a jurisdiction develops a new primary BCA test or is updating its existing BCA practice;
- Can guide the selection and application of analytical methods used to quantify BCA impacts, as well as any complementary analyses (such as rate and bill impact analyses); and
- If applied broadly, can help to increase consistency in valuing DERs across a broad range of contexts, as described in Chapter 5.

The NSPM principles in and of themselves do not determine the appropriate cost-effectiveness test for a jurisdiction. The principles are intended to be applied in a manner that considers the characteristics and circumstances of each jurisdiction's approach to energy resources and can result in different BCA tests for different jurisdictions.

Table 3-1 summarizes the NSPM Principles. While this Manual recommends adherence to all the principles, it is up to the users of the NSPM to decide if they will apply the principles in all situations or, for example, if it is necessary to make tradeoffs between certain principles in certain situations.

[5] The NSPM is policy neutral in that it can be used by any jurisdiction, regardless of what policies it has adopted. The Manual does not advocate or reject any specific policies but rather sets forth that a jurisdiction's BCA practices should align with the jurisdiction's policy goals and objectives.

Table 3-1. Fundamental NSPM BCA Principles

Principle 1	**Align with Applicable Energy Policy Goals** Jurisdictions invest in DERs to meet a variety of energy goals and objectives. Accounting for the associated benefits and costs in a jurisdiction's primary BCA test helps to ensure that least-cost investments are used to achieve the goals and objectives.
Principle 2	**Treat DERS as a Utility System Resource** DERs are energy resources that can help meet utility system needs. Using consistent BCA tests, valuation methods, and assumptions when comparing DERs to traditional resources, or to other DERs, avoids bias across resource investment decisions.
Principle 3	**Account for All Relevant and Material Impacts** The relevance and materiality of impacts can vary depending on the DER type or use case. Accounting for all relevant and material impacts, even when difficult to quantify or monetize, ensures DERs are appropriately valued and avoids biased investments.
Principle 4	**Ensure Symmetry in the Treatment of Benefits and Costs** DER investments produce benefits to the utility system and to customers. Treating benefits and costs symmetrically in BCA tests, such that benefits and costs are both either included or excluded, avoids biased results and uneconomic investments.
Principle 5	**Conduct Forward-Looking, Long-Term, Incremental Analyses** BCAs address how benefits and costs will differ in the future because of a specific resource investment relative to what would have occurred absent the investment. This ensures that sunk costs do not influence investment decisions.
Principle 6	**Avoid Double-Counting Impacts** Some BCA benefits and costs can potentially be captured in more than one impact category. Clearly documenting the way in which a BCA accounts for each impact helps to avoid double-counting and either over- or under-estimating the value of DERs.
Principle 7	**Conduct BCAs Separately from Other Complementary Analyses** BCAs inform whether total benefits exceed total costs of a resource investment. Depending on a jurisdiction's policy goals, separate analyses may be warranted to inform investment decisions that address different questions than BCAs, such as rate- and bill-impact analyses.
Principle 8	**Ensure Transparency** Clear documentation of the rationale for decisions on BCA tests, complementary analyses, and associated methods, inputs, and results supports transparency. Transparency enables engagement and instills confidence in resource decision-making processes.

The NSPM Principles are described below and are referenced throughout the remaining chapters and appendices in the Manual, where applicable.

PRINCIPLE 1: ALIGN WITH APPLICABLE ENERGY POLICY GOALS

Most jurisdictions have a variety of energy policies, developed through a mix of legislative action and executive orders, which are often informed by State Energy Offices. Utility regulators (or other state agencies) implement policies by overseeing programs and strategies that can help to meet the state's policy goals.

The choice of investments in DERs and other utility resources can materially affect the costs, timeframe, and ability to achieve such goals. Thus, a jurisdiction's primary BCA test should align with its established policies to inform and guide resource choices.

Policy goals show up in many different ways in a jurisdiction, including but not limited to the following:

- Legislation
- Executive orders
- State Energy Plans
- State agency or board guidelines, standards, or orders
- Utility resource plans
- Requirements of other governing agencies within a jurisdiction

Regulators typically have statutory authority to set rates that are fair, just, and reasonable; ensure that utilities provide customers with safe and reliable services; ensure a fair and reasonable return on equity; and generally, guide utility actions that are in the public's interest. Regulators also typically operate in the context of other applicable jurisdictional laws and policies, some of which affect the implementation of DERs. See Chapter 4, Step 1 for guidance on how to identify applicable policies.

Energy policy goals evolve over time in response to changes in the energy industry and society, as well as changing perspectives from policymakers, regulators, consumers, businesses, utilities, and industry stakeholders. Therefore, a jurisdiction's primary BCA test may need periodic updates.

In some cases, a jurisdiction may have different policy goals for different DER types.[6] Guidance for how jurisdictions can analyze DER types as consistently as possible, even if different goals exist, is provided in Chapter 4 Step 1.

PRINCIPLE 2: TREAT DERS AS A UTILITY SYSTEM RESOURCE

Absent consistent BCA assessment, utilities risk over-investing in some resources while under-investing in others, resulting in potential increased costs for utility customers and missed opportunities for achieving applicable policy goals.

DERs are some of the many energy resources available to meet utility system needs. DERs can help defer or avoid spending on traditional utility distribution, transmission, and generation resources. They can also support increased reliability, improved power quality, and the addition of renewables onto the grid.

As such, when a utility considers investing in or supporting DERs through either incentive programs, procurements, net metering tariffs, or as part of distribution system or other planning process, it is appropriate to compare the DERs with other energy resource options (e.g., large scale power generation, or other DERs). An accurate comparison will use consistent BCA

[6] Where jurisdictions currently evaluate different DER types using different BCA tests or assumptions, it is usually because their BCA practices were developed in different contexts (e.g., different regulatory dockets) without a uniform approach—not because there are any inherent reasons for using different tests for different DERs.

principles, methodologies, and assumptions to avoid bias across resource investment decisions. Absent consistent assessment, there is risk of supporting certain resources over others, resulting in potential increased costs for utility customers and missed opportunities for achieving applicable policy goals. This risk exists regardless of whether the utility owns or controls the DERs.

Applying this principle requires that the full range of utility system impacts serve as the foundation of a jurisdiction's primary BCA test, upon which other (non-utility system) impacts may be added depending on applicable policy goals. Note that some utility system impacts may not be applicable or material to specific DER types or use cases.

Refer to Chapter 4 Step 2 for guidance on applying this principle and Chapter 6 for a description of utility system impacts.

PRINCIPLE 3: ACCOUNT FOR ALL RELEVANT AND MATERIAL IMPACTS

BCA tests should account for DER impacts identified as relevant and material. Ideally, estimates of these impacts will be in monetary terms to inform BCA results, whether in the form of net benefits (or net costs), benefit-cost ratios, or other monetized results.

Relevant impacts are those defined by utility system benefits and costs (according to *Principle 2: Treat DERs as a Utility System Resource*) and any non-utility system impacts identified based on applicable policy goals (*Principle 1: Align with Applicable Energy Policy Goals).* Such impacts may depend on the DER type or use case under analysis.

Material impacts are those that are likely to be of sufficient magnitude to affect the result of a BCA. If an impact is deemed immaterial, this should be noted in the BCA documentation.

Chapter 6 provides further guidance on the relevance and materiality of DER impacts, with additional details on specific DERs in Chapter 8 through Chapter 12.

It is critical to differentiate between what impacts are *included in the BCA test*, versus what impacts *may or may not be relevant or material*. This is especially important when a jurisdiction's primary BCA test applies to more than one DER type.

For example, if an impact is relevant but not material, that impact should be included in the definition of the BCA test but does not need to be included in the application of it – or at least not for a particular DER and/or a particular DER use case.

This distinction is especially important when using the same BCA test across multiple DER types and when using the same test over many years because relevance and materiality as the electric grid, markets and/or other factors change.

As with the attributes of many utility system resources, some DER benefits and costs are challenging to quantify and monetize. Data may not be readily available, conducting studies to estimate values may require a considerable amount of time and/or resources, and such studies might still result in significant uncertainty.

BCAs should account for relevant DER benefits and costs that are expected to be material even if those impacts are difficult to quantify and monetize. In general, any benefit or cost value used in a sound BCA test will be based on a logical, documented, justified method and not be arbitrary or contrived.

PRINCIPLE 4: ENSURE SYMMETRY IN THE TREATMENT OF BENEFITS AND COSTS

Symmetrical treatment in the accounting of benefits and costs, whereby analysis includes (or excludes) both benefits and costs for each relevant type of impact, is necessary to avoid bias in resource investment decisions.

If a jurisdiction's policy goals do not explicitly reference or recognize specific host customer benefits from DER investments, decision-makers can determine—ideally with stakeholder input—whether to include host customer impacts or not, as long as the benefits and costs receive symmetrical treatment.

For example, symmetrical accounting for utility system impacts includes both utility system costs and associated benefits in the BCA. Similarly, to the extent that a jurisdiction's applicable policy goals articulate that host customers' impacts are relevant, then the accounting of those impacts includes both host customer benefits and the associated host customer costs, even if certain impacts are difficult to monetize.

If a jurisdiction's policy goals do not explicitly reference or recognize specific host customer benefits from DER investments, regulators or decision-makers can determine—ideally with stakeholder input—whether to include host customer impacts or not, as long as the benefits and costs receive symmetrical treatment (i.e., either both are included, or both are excluded).

If the accounting of impacts lacks symmetry, the result may be a suboptimal selection of resources because of a bias inherent in the BCA test. This can lead to higher-than-necessary costs imposed upon utility customers.

PRINCIPLE 5: CONDUCT FORWARD-LOOKING, LONG-TERM, INCREMENTAL ANALYSES

BCAs address how benefits and costs will differ in the future because of a specific resource investment relative to what would have occurred absent the investment. This principle embodies three inter-related concepts:

- *Forward-looking impacts*: BCAs should include only forward-looking impacts because historical costs, also known as sunk costs, will not change under any future scenario.[7] Therefore, historical costs are not relevant when comparing future DER implementation scenarios.[8]
- *Long-run benefits and costs*: An appropriate BCA study period is long enough to include long-run benefits and costs of DERs. This approach is necessary to account for the full benefits and costs of the DER in question. The study period length is particularly important where, as with many utility investments, DERs have high upfront costs but lower, or even zero, ongoing costs over their operating life. In addition, many DERs and their alternatives can last decades and thus resource decisions made today can affect benefits and costs far into the future.

[7] The way in which sunk costs are recovered from utility customers does not pertain to BCA tests.

[8] Historical costs do have important implications for rate impacts and potential cost-shifting between customers. These costs may merit consideration in a separate rate impact analysis. See additional discussion under *Principle 7: Conduct BCAs Separately from Other Complementary Analyses* below.

- *Incremental impacts:* Sound BCA tests consider only incremental impacts (that is, the changes that will occur because of the DERs) relative to an alternative scenario. This concept applies to both benefits and costs.

This principle is consistent with utilities having a responsibility to meet utility customer needs in a safe, reliable, and least-cost way over the long term, as well as regulators having a responsibility to protect customers over both the short term and the long term. Over-emphasis on short-term costs may lead to an increase in long-term costs for customers.

The term '*long-run*' refers to the period covering the full life-cycle of the resource under analysis (i.e., for a period of time sufficient to capture the full stream of benefits and costs associated with the resource.)

PRINCIPLE 6: AVOID DOUBLE-COUNTING IMPACTS

When defining and estimating the values of different DER impacts, it is important to recognize that impact categories can overlap, with certain costs or benefits potentially included within more than one impact category. Examples of such overlaps include the following:

- Utility system reliability and risk impacts might overlap with other utility system impacts such as avoided (or increased) generation, transmission, and distribution costs.
- Utility system costs for complying with environmental regulations might overlap with societal environmental costs.
- Public health impacts might overlap with either host customer health and safety impacts or societal environmental costs.
- Host customer resilience might overlap with societal resilience.

Chapter 4 Steps 2 and 3 further identify areas of potential overlap across impacts.

Double-counting can be avoided through systematic and careful documentation of which impacts are included in which categories, as well as careful review of the methodologies used to estimate different categories of impacts.

PRINCIPLE 7: CONDUCT BCAS SEPARATELY FROM OTHER COMPLEMENTARY ANALYSES

Depending on a jurisdiction's energy policy goals, separate analyses that address different questions than BCAs may be warranted to provide complementary information to inform resource investment decisions.

A key example of such a policy goal is to 'ensure just and reasonable rates for all customers.' This goal may merit associated analysis to assess the impact of proposed resource investments on customer electricity and/or natural gas rates and bills. Jurisdictions may also have energy policies that specify economic development goals (such as jobs created) or consideration of the distribution of benefits and costs of resource investments to different customer groups (to address equity concerns). Though these example policy goals sometimes appear in the context of BCAs, they raise fundamentally different questions than the question that BCA tests address and therefore warrant separate analyses. Below is a list of BCA tests and complementary tests, along with the questions they seek to answer:

- **Benefit-Cost Analyses**: Will *total costs*, across all customers, increase (net costs) or decrease (net benefits) due to an investment?
- **Rate and Bill Impact Analyses (RBA)**: Will *electricity and/or natural gas rates and bills* go up or down, and for whom (e.g., for all customers, participants, or non-participants)?
- **Economic Development Analyses (EDA)**: Will the *local economy including jobs* become more or less robust due to an investment?
- **Distributional Equity Analyses (DEA)**: How will DER benefits and costs be *distributed to certain customers relative to other* customers?

RBA: DERs, as with all energy resources, can affect customer rates. Some DERs are likely to increase rates, while other DERs are more likely to reduce rates. Some DERs might have little effect on rates at all. The extent to which DERs will impact rates depends upon many factors, including the deployment of the DERs, and the extent to which they: (a) reduce or increase utility system costs, provide utility system benefits and/or (b) reduce or increase utility sales. Understanding rate and bill impacts associated with DER (or any resource) investment is critical to addressing energy affordability concerns and goals.

BCAs and RBAs serve different purposes, and it is important to delineate and understand the differences to ensure that both types of analyses provide meaningful information to inform DER investment decision-making.

BCAs indicate whether *total electricity (or natural gas) costs, across all customers,* will increase (net costs) or decrease (net benefits) due to a resource investment.

RBAs indicate whether *electricity or natural gas rates and bill will go up or down* due to a resource investment. Understanding rate and bill impacts associated with DER (or any resource) investments is critical to addressing energy affordability concerns and goals.

Rate impacts often appear in the context of BCAs. Jurisdictions sometimes use a **rate impact test** to evaluate DERs.[9] However, because this approach accounts for historical, sunk costs and is not based on a forward-looking, incremental analysis (consistent with *Principle 5: Conduct Forward-Looking, Long-Term, Incremental Analyses*), such analyses are not appropriate to assess cost-effectiveness for two key reasons:

1. Rate impact tests do not answer the core question that BCA tests are designed to answer: *Will total costs increase or decrease due to the investment?* Rather, a rate impact test indicates only whether rates will increase or decrease. In many cases, such increases or decreases are largely a function of changes in how and from whom past, sunk costs (or even new fixed costs) will be recovered.
2. Rate impact tests do not provide particularly useful information on the scale of changes in rates or the portion of customers who will experience increased bills due to DER investment.

However, it is important to understand the rate impacts from resource investments, particularly when paired with assessments of the portions of customers who will experience increases or

[9] Referred to as the Rate Impact Measure (RIM) test, one of the traditional cost-effectiveness tests set forth in the 2008 CA Standard Practice (CPUC 2001). See Chapter 4 and Appendix E for further discussion on traditional cost tests.

reductions in total bills.[10] A rate impact test can be used (a) to determine whether rates are likely to increase or decrease due to proposed DER investments, and (b) to determine whether to conduct a complementary rate, bill, and participation analysis. See Appendix B for additional guidance.

EDA: Economic development and job impacts are often driven, in significant part, by the utility system cost reductions that DERs can provide (which will already be included in any BCA). Thus, while there can be value in quantifying net changes in economic development and jobs to inform regulatory decisions on DER investments—when state energy policies suggest such that economic growth and job creation are important objectives—such quantification should be separate from BCAs rather than mathematically added to BCA impacts to avoid double counting. See Appendix C for information on conducting EDAs.

DEA: A BCA is an essential tool to determine whether a DER investment will provide net benefits for all customers on the utility system. BCAs determine the impact ***across customers on average*** (where costs are typically recovered across all customers or all customers within a customer class, and benefits are typically a blend of avoided (or increased) costs experienced by all customers). A BCA does not assess the *distribution of benefits and costs* across customers with different characteristics. To the extent that a jurisdiction's policy goals set forth requirements to address the equitable distribution of benefits of DER investments, a DEA can be conducted to inform how DER investments will affect a priority population (e.g., underserved community), *relative to all other customers in the utility system*. See Appendix D for further guidance.

Chapter 4 Step 7 provides further guidance on conducting complementary analyses, with detailed information in Appendices B, C, and D.

PRINCIPLE 8: ENSURE TRANSPARENCY

BCAs require many detailed assumptions and methodologies, and they typically produce detailed results. Transparent documentation helps ensure that the approach to BCA is consistent with fundamental principles, regulatory objectives, and applicable policy goals. Transparency enables engagement and enhances confidence in energy resource decision-making processes by facilitating and expediting regulatory and stakeholder review and understanding of BCAs. Transparency requires clear documentation of the following:

- The rationale for decisions on what to include (or not) in the primary BCA test and any secondary tests, as well as any complementary analyses
- The methodologies used to estimate different categories of impacts—benefits and costs—and the rationale for their selection
- Key inputs and assumptions derived from such methodologies
- Analytical results, presented in sufficient detail to understand the key factors underpinning them

[10] For example, if the results of the rate impact test are positive or suggest that the rate impacts might be small (e.g., with a benefit-cost ratio of 0.95), then regulators and other stakeholders might decide that there is no need for a rate impact analysis. If the results of the rate impact test are much lower, then regulators and utilities might decide to investigate rate and bill impacts, and underlying participation rates.

- Areas of consensus and non-consensus across interested stakeholders on all the above

Chapter 4 Step 8 provides guidance on applying *Principle 8: Ensure Transparency*.

4. Developing Benefit-Cost Analysis Tests

This chapter provides guidance on how to develop a jurisdiction's primary BCA test, including consideration of secondary tests and any complementary analyses to help inform resource investment decisions.

4.1. Summary of Key Points

- A systematic multi-step process can guide development of a jurisdiction's primary test for assessing DERs—referred to as the Jurisdiction-Specific Test (JST).
- The JST used to evaluate DERs answers the fundamental question: *Will the cost of meeting utility system needs, while achieving applicable policy goals, increase or decrease?*
- The JST is based on the 'regulatory' perspective, which is the perspective of decision-makers who oversee utility (or publicly funded) DER investment decisions, guided by a jurisdiction's applicable energy policy goals. This test differs from traditional cost-effectiveness tests that are not necessarily designed to take a regulatory perspective or consider applicable policy goals.
- Secondary BCA tests can provide additional information, represent different perspectives, and answer different questions.
- Complementary analyses may be needed alongside BCAs to ensure decision-makers have sufficient information to inform decisions on DER investments.
- Chapter 6 provides further detail on BCA benefits and costs addressed in this chapter.

4.2. Cost-Effectiveness Testing Perspectives

4.2.1. Traditional Perspectives

The BCA tests traditionally used to evaluate DERs consider benefits and costs from different perspectives and therefore answer different cost-effectiveness questions. The perspectives of the traditional tests, as provided in the 2001 *California Standard Practice Manual*, are as follows (see Appendix E on Traditional Cost Tests):

- *Utility Cost Test (UCT),* also known as *the Program Administrator Cost Test (PACT),* which includes the benefits and costs experienced by the utility system.
- *Total Resource Cost (TRC) Test*, which includes the benefits and costs experienced by the utility system, plus benefits and costs to host customers.
- *Societal Cost Test (SCT)*, which includes the benefits and costs experienced by society.

- *Participant Cost Test (PCT)*, which includes the benefits and costs experienced by host customers (i.e., program participants). This test supports program design and host-customer investment decisions.
- *Rate Impact Measure (RIM) Test*, which indicates whether rates are likely to increase or decrease due to DER investments.

Over the years, most states have adopted variations of the UCT, SCT, and TRC Test for cost-effectiveness testing, primarily for EE resources but also for other DERs. In most cases, these tests in their adopted forms do not adhere to the theoretical definitions of the traditional tests (for instance, some states use a modified TRC Test) (ACEEE n.d.); further, traditional tests do not necessarily account for the energy policy goals of the jurisdictions. In other words, the traditional tests often do not reflect the perspective of regulators and other decision-makers that are responsible for reviewing DER investment decisions to ensure that they provide net benefits consistent with applicable policy goals.[11]

An objective of the NSPM is to support jurisdictions' review of their traditional BCA test practices by applying the NSPM principles and determining the extent of alignment with the principles. This process can help to identify specific modifications or refinements to current BCA practice or can inform the development of a new primary test.

4.2.2. The 'Regulatory' Perspective

This Manual presents the 'regulatory' perspective, which broadly refers to the perspective of regulators or similar entities that oversee utility (or other publicly funded) DER investment decisions. This perspective factors in the jurisdiction's applicable policy goals and objectives, whether in laws, state energy plans, regulations, organizational policies, or other codified forms in which utilities operate. The regulatory perspective reflects application of *Principle 2: Treat DERs as a Utility System Resource*

The regulatory perspective reflects a jurisdiction's applicable policy goals that can be articulated in different ways, including but not limited to legislation; executive orders; regulations; commission or board guidelines, standards, or orders; utility resource planning principles and policies; and requirements of other jurisdictional governing agencies.

The regulatory perspective of a jurisdiction is likely to fall somewhere along the spectrum of a utility perspective to a societal perspective, depending on its policy goals. A jurisdiction's perspective is often broader than the utility perspective in that it accounts for applicable policy goals beyond the basic utility goals of providing affordable, safe, reliable electricity services (such as achieving certain environmental goals).[12] The jurisdiction's regulatory perspective is often narrower than a theoretical societal perspective in that

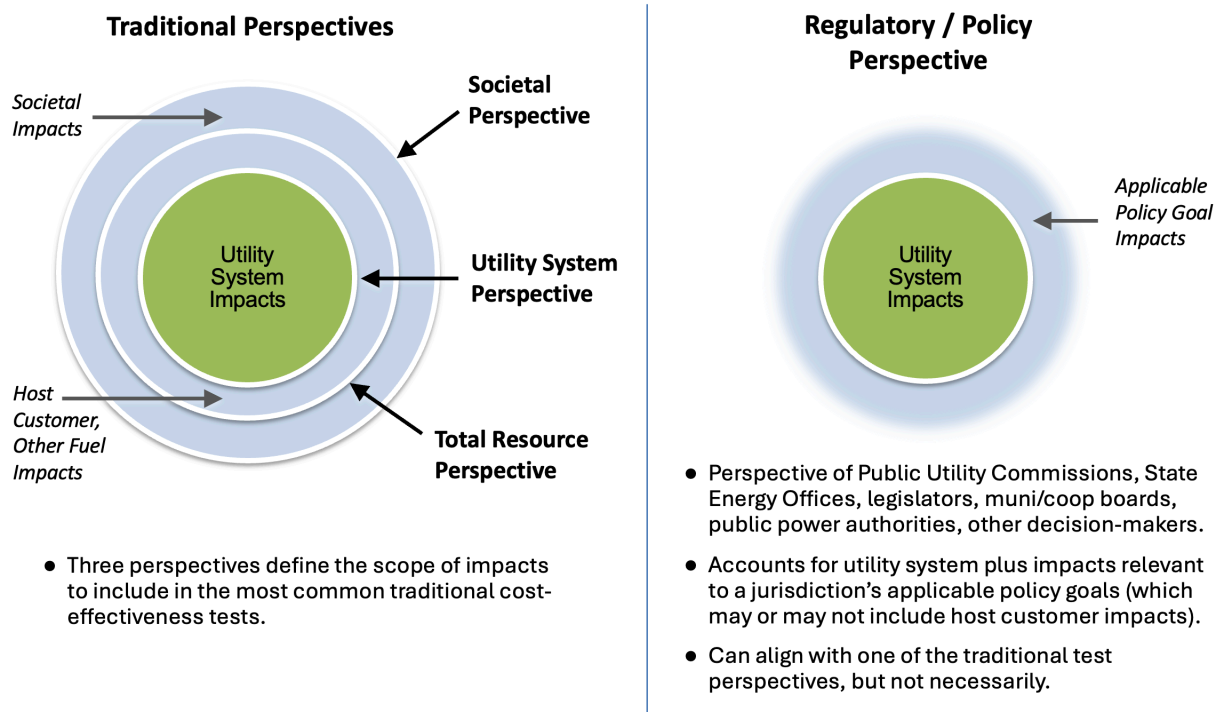
[11] The *California Standard Practice Manual* explicitly notes that policy goals are an 'integral' part of cost-effectiveness analyses, but that it does not address policy goals: "The implementing agencies... have traditionally utilized open public processes to incorporate the diverse views of stakeholders before adopting externality values and policy rules which are an integral part of the cost-effectiveness evaluation. These policy rules are not a part of this Manual" (CPUC 2001, page 6). The NSPM guidance differs in that it sets forth the principle that policy goals should be accounted for in determining the primary test for cost-effectiveness analyses.

[12] See Section 4.3 below for examples of potential jurisdictional policy goals and objectives.

it may not account for all societal impacts according to policy goals articulated in statute, regulatory decisions, or other governing policy documents.

Figure 4-1 illustrates the regulatory perspective (and JST) relative to the perspectives underlying the traditional cost tests. Key to any BCA test perspective is that utility system impacts are foundational and are always included in any test. Section 4.3 below further discusses these perspectives and underlying cost tests, while Chapter 6 fully describes utility system impacts.

Figure 4-1. Cost-Effectiveness Testing (or BCA) Perspectives



To avoid suboptimal resource selections with respect to a jurisdiction's stated policy goals, the regulatory perspective is necessary to ensure a BCA test considers relevant policy goals. Otherwise, the jurisdiction might incur additional costs to meet those policy goals.

4.3. Jurisdiction-Specific Test and Traditional Tests

This Manual refers to the test that aligns with the regulatory perspective as the Jurisdiction-Specific Test, or the JST.

The regulatory perspective could theoretically align with a traditional test perspective, though it is more likely to be unique to that jurisdiction. *As such, this Manual refers to the test that aligns with the regulatory perspective as the Jurisdiction-Specific Test, or the JST.*

Table 4-1 provides a high-level comparison of the use of hypothetical JSTs relative to the traditional tests. The table summarizes the range of perspectives, the key question each test answers, and the categories of impacts. Notably, when a jurisdiction develops and implements its own JST (or refines an existing test) using this Manual's BCA Framework, it is likely to result in a test that differs from one of the traditional tests, though it could result in a test that is consistent with the theoretical definition of a traditional test.

Table 4-1. Jurisdiction-Specific Test Compared with Traditional Tests

Test	Perspective	Key Question Answered	Categories of Benefits and Costs Included
Jurisdiction-Specific Test	Regulators or decision-makers	Will the cost of meeting utility system needs, while achieving applicable policy goals, increase or decrease?	Utility system impacts, plus those impacts associated with achieving applicable policy goals
Utility Cost Test*	The utility system	Will utility system costs increase or decrease?	Utility system impacts
Total Resource Cost Test	The utility system, plus host customers	Will utility system costs and host customers' costs collectively increase or decrease?	Utility system impacts, plus host customer impacts
Societal Cost Test	Society as a whole	Will total costs to society increase or decrease?	Utility system impacts, plus host customer impacts, plus societal impacts

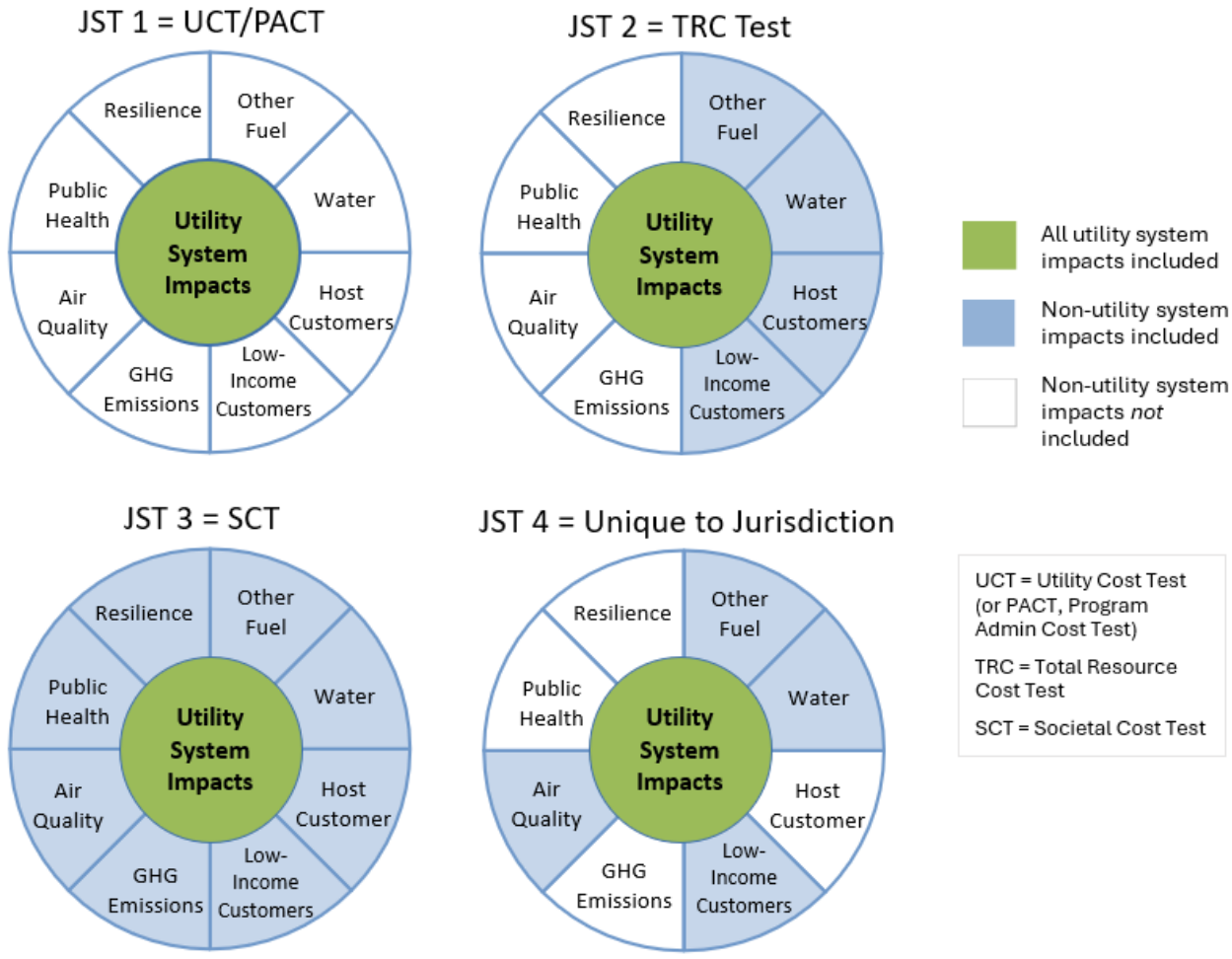
**Also referred to as the Program Administrator Cost (PAC) Test.*

Figure 4-2 further illustrates how a JST can compare to traditional tests:

1. In all cases, the tests account for the full range of utility system impacts, consistent with the principle.
2. JST 1, 2, and 3 provide examples of where a JST aligns with the UCT, the TRC Test, and the SCT, respectively, *assuming* in each case the JST reflects that jurisdiction's specific applicable policy goals.
3. In the JST 4 example, the jurisdiction's specific policies lead to a primary test that differs from any of the traditional tests. This example assumes that the hypothetical jurisdiction has statutes, regulations, orders, or other policy directives that require or suggest that these impacts be accounted for when assessing DER cost-effectiveness.

Importantly, Figure 4-2 illustrates the flexibility provided by the JST to ensure that a test reflects the unique energy policy goals and objectives of the *regulatory perspective*.

Figure 4-2. Example Jurisdiction-Specific Tests Relative to Traditional Tests



**JST 4 (and other examples of JSTs) could include a different set of non-utility system impacts depending on the applicable policies of those jurisdictions. JSTs may or may not include host customer (i.e., participant) impacts, and they may or may not align with traditional tests.*

For additional descriptions on traditional cost-effectiveness tests, see Appendix E.

4.4. NSPM Multi-Step Process to Develop a JST

Developing a jurisdiction's primary BCA test is foundational to a jurisdiction's decision framework for investing in resources, as presented in Chapter 2.

Table 4-2 presents an 8-step process for developing a jurisdiction's JST. The following subsections describe each of these steps in more detail. The process of developing the JST can lead to decisions to also conduct secondary BCA tests and/or to identifying additional complementary analyses that address important policy concerns not addressed by BCA.

Applying the multi-step process can involve either a formal stakeholder process (led by a Public Utility Commission or State Energy Office), a regulatory requirement for utilities to apply the steps

in their proposed DER plans (on which stakeholders provide comment), or some other informal regulatory or jurisdictional stakeholder process.

Note that the multi-step process below supports Phase 1 of the BCA Framework described in Chapter 2. It does not address methodologies for calculating or estimating impacts in BCAs, which is part of Phase 2 of the BCA Framework and addressed in Chapter 14.

Table 4-2. Developing a Primary BCA Test: An 8-Step Process

STEP 1	**Take inventory of applicable energy policy goals and regulatory decisions** Review energy legislation, plans, regulatory decisions, and other related documents and take inventory of the jurisdiction's policy goals and objectives applicable to DER investments.
STEP 2	**Review and account for relevant and material utility system impacts** Review the full range of utility system impacts and identify if any may not be relevant or material for specific DER types, and if any are embedded in other impacts. For impacts affected by geographic scope, determine scope of interest based on applicable policies.
STEP 3	**Decide which non-utility system impacts to include in the primary test** Determine whether to include host customer, other fuel, and/or any societal impacts based on applicable policies, and if so, whether any impacts may not be relevant or material for specific DER types, and if any are embedded in other impact categories. For impacts affected by geographic scope, determine scope of interest based on applicable policies.
STEP 4	**Develop any secondary BCA tests** Decide if one or more secondary test(s) are needed to supplement the results of the primary test in order to explore the sensitivity of the primary BCA results to the inclusion or exclusion of one or more non-utility system impacts and/or to inform answers to different questions than what the primary test helps to answer.
STEP 5	**Select a discount rate(s) for calculating the present value of investments** Select a discount rate to apply to the primary BCA test, as well as the rate(s) to apply to any secondary BCA tests, based on the jurisdiction's applicable energy policies.
STEP 6	**Establish assessment level at which BCA results will inform decisions** Determine the appropriate level of aggregation of DER investments for which BCA results will be used to inform regulatory and other approvals.
STEP 7	**Consider conducting complementary analyses to BCAs** Depending on applicable policies, consider whether other analyses—e.g., rate and bill impact analyses—are warranted alongside BCAs to address questions that BCAs do not answer, but that may be important to achieve policy goals and informing DER investment decisions.
STEP 8	**Document process, comments, and rationale for above steps** Fully document the process and rationale used to establish the primary BCA test, any secondary tests and/or other complementary analyses and BCA parameters.

Note: The 8-step process may not be followed in chronological order and often requires iteration.

STEP 1: TAKE INVENTORY OF APPLICABLE ENERGY POLICY GOALS

This step applies the NSPM *Principle 1: Align with Applicable Policy Goals*. It involves taking inventory of a jurisdiction's applicable policy goals and objectives at the outset of either developing a JST or reviewing existing BCA tests and practices. Such an inventory includes reviewing energy legislation, plans, regulatory decisions, and other related documents that may articulate the jurisdiction's policy goals and objectives applicable to DER investments. This step is necessary to ensure that the BCA test explicitly and properly accounts for such policy direction, and therefore the jurisdiction's regulatory perspective. Table 4-3 provides examples of energy and non-energy-related policy goals that may be applicable in some jurisdictions.[13]

Table 4-3. Examples of Energy Policy Goals

Common Overarching Goals: Provide safe and reliable electricity and natural gas services at just and reasonable rates; support fair and equitable economic returns for utilities; protect/reduce energy burden for low-income and vulnerable customers; reduce greenhouse gas emissions to meet climate goals.
Resource Goals: Reduce electricity and natural gas system costs; support stable energy markets; develop least-cost energy resources; improve system reliability and resilience; reduce system risk; promote resource diversity; increase energy independence; reduce price volatility; provide demand flexibility.
Other Applicable Goals: Reduce environmental impact of energy consumption; increase energy security; promote jobs and local economic development; promote customer equity; improve public health associated with reduced air emissions; improve indoor air quality in homes.

Articulating and documenting applicable energy policy goals is particularly relevant to informing which *non-utility system impacts* to include in a jurisdiction's primary BCA test (such as those associated with the Other Applicable Goals in Table 4-3). In some cases, policy goals may be very general. Decisions on whether to reflect such general policy goals in a jurisdiction's primary BCA test will ultimately be up to interpretation by regulators, ideally informed by meaningful stakeholder input.

STEP 2: REVIEW AND ACCOUNT FOR RELEVANT AND MATERIAL UTILITY SYSTEM IMPACTS

Ensuring a JST includes the full range of utility system impacts adheres to *Principle 2: Treat DERs as a Utility System Resource*. This principle sets forth that DERs be compared consistently with other utility resources. This emphasis on utility system impacts is important because these are the impacts that directly affect the utility customers that are funding utility investments in DERs in one form or another. Including the utility system impacts in a BCA test ensures the test will, at a minimum, indicate the extent to which total utility system costs will be reduced (or increased) by a DER investment or strategy. This step contains three sub-steps:

a) Identify all potential utility system impacts.

b) Determine which utility system impacts are both relevant and material for each DER type in question.

[13] This list is not intended to be exhaustive. Nor is it intended to imply a recommendation of any policies for any jurisdiction. Its purpose is to illustrate the types of policies that jurisdictions often establish.

c) Establish the geographic scope for material impacts where necessary.

A. Identifying All Potential Utility System Impacts

For electric utilities, utility system impacts include the generation, transmission, and distribution of electricity and related services, as well as the costs of DER investments, utility shareholder incentives, impacts on resilience, and other general impacts. For natural gas utilities, utility system impacts include the transportation, storage, and distribution of natural gas and related services, as well as the costs of DER investments, utility shareholder incentives, impacts on resilience, and other general impacts.

Irrespective of the type of utility structure (e.g., investor-owned or publicly owned utilities) or market structure (vertically integrated or distribution-only utilities in jurisdictions with competitive wholesale markets for energy and capacity), utility system impacts are the foundation of all BCA tests. For a jurisdiction with competitive wholesale markets and distribution-only electric utilities, it is important to account for the impacts on generation, transmission, and distribution because DER investments affect all these services, and distribution customers must pay for all those services. Customers ultimately pay for generation and transmission even if the utility funding or supporting the DER provides only distribution services.[14]

Utility system impacts are generally defined as follows:

- *Utility system benefits* typically include all utility system costs that would be avoided or deferred by implementing the DER. These avoided costs are one of the most important, and sometimes challenging, inputs to any BCA of DERs and will significantly affect BCA results. Therefore, it is essential to ensure avoided cost estimates are comprehensive, up to date, informed by stakeholders, and ultimately reviewed and approved by regulators or other decision-makers.

Utility system benefits and costs provide the foundation for all BCA tests.

- The term 'utility system' here is used to represent the entire energy system that provides services to retail customers.
- The most common traditional BCA tests—the UCT, the TRC test, and the SCT—as well as the JST, all include the full range of utility system impacts as shown in Figure 4-1.

- *Utility system costs* typically include (a) the portion of the DER technology (or strategy) paid by the utility, (b) other financial or technical support provided to host customers, and (c) interconnection costs and distribution system upgrades not solely paid by the DER owner, a developer, or some other party. These costs also generally include any other utility system costs associated with DER implementation, interconnection, administration, marketing, evaluation, measurement, and verification. When electrification investments are under consideration, there will also be utility system costs associated with increased demand on electric generation, transmission, and distribution system infrastructure.

[14] It is also important that the avoided cost impact value in the BCA be aligned with utility planning assumptions in order to be consistent with 'actual' avoided costs. For example, if the BCA uses one method to calculate capacity reduction needs, but the utility uses another method and calculates a different value, the BCA will either over- or under-estimate the utility's actual avoided costs (which is dependent on the utility's specific planning and operational practices).

See Chapter 6 for descriptions of DER benefits and costs within each of these categories, and Chapter 7 for discussion of cross-cutting factors that can affect the magnitude of impacts.

B. Determining Which Utility System Impacts Are Relevant and Material

Consistent with NSPM *Principle 3: Account for All Relevant and Material Impacts*, it is important for BCA tests to account for all relevant and material impacts. However, not all utility system impacts will be relevant or material for different types of DERs. For example, in a jurisdiction in which utilities cannot earn performance incentives for delivering EE programs, that type of utility system impact would not be applicable to that DER (unless and until policy on such utility performance incentives changes). Similarly, in a jurisdiction without a renewable portfolio standard (RPS) or other resource standard, that type of utility system impact would not be applicable to any type of DER investment (again, unless and until an RPS policy was adopted).

In addition, even when a DER is likely to have some impact, the value of the impact may not always be large enough, or 'material,' to warrant quantification. In these cases, 'material' refers to when the value of the impact would affect the BCA test result. There will always be some subjectivity to this criterion. Therefore, it is important that decisions related to materiality of impacts are based on stakeholder input and are well documented. Chapter 6 provides examples of how the relevance and materiality of utility system impacts can vary across different DER types.

C. Establishing Geographic Boundaries of Interest for Select Utility System Impacts

Some categories of impacts raise questions regarding the applicable 'geographic boundary' to use for estimating impacts. For utility system impacts, there are two such questions to consider:

- **Market Price Effects**. DER investments that increase or decrease electricity and/or natural gas consumption can have effects on wholesale market clearing prices for electric energy, electric generating capacity, and/or natural gas commodity. Such impacts will be felt across regions served by electric power pools and/or across regions served by natural gas suppliers. Jurisdictions need to decide whether BCA tests should include impacts affecting the entire wholesale market region, only their jurisdiction, only an individual utility service territory, or some other geographic subset.
- **Government Tax Incentives or Rebates**. Decisions must be made regarding whether to treat government tax incentives or rebates as *reductions in costs* (i.e., treating government as 'outside the boundary of interest') or *as transfers* (i.e., treating government as 'inside the boundary of interest'). Those decisions will affect estimates of utility system costs of DER investments in cases in which the utility is directly purchasing the DERs and is therefore the recipient of any financial incentives.[15]

A jurisdiction's policy goals (as articulated in Step 1 above) can appropriately guide decisions on how to establish geographic boundaries of concern or interest for any category of impacts. It is important to note that the geographic boundary of concern can be different for different impacts. For example, regulators may decide that they are only concerned about how market price effects affect customers in their state or province but are concerned about global impacts of greenhouse gas (GHG) emissions. Appendix F provides further discussion of geographic boundaries.

[15] As discussed in Step 3, in cases in which government financial incentives go to host customers, the boundary decision affects treatment of host customer costs (a non-utility system impact, rather than a utility system impact).

STEP 3: DECIDE WHICH NON-UTILITY SYSTEM IMPACTS TO INCLUDE IN THE PRIMARY TEST

This step applies *Principle 1: Align with Applicable Policy Goals*, which sets forth that the primary BCA test—or JST—should reflect applicable energy policy goals and objectives. This step has three sub-steps:

A. Determine which categories of non-utility system impacts to include.

B. Determine which non-utility system impacts included in the JST are both applicable to and material for each type of DER.

C. Establish geographic boundaries of interest for some impacts of interest.

A. Determine Categories of Non-Utility System Impacts to Include in JST

After identifying and accounting for utility system benefits and costs, the next step is to decide which *non-utility* benefits and costs to include in the JST, based on applicable policy goals identified and articulated in Step 1. These non-utility impacts can be categorized as other fuel impacts, host customer impacts, and societal impacts.

Table 4-4 presents a list of potential non-utility impacts that could be included in a primary test to the extent they are applicable to a given jurisdiction. See Chapter 6 for descriptions of DER benefits and costs within each of these categories, and Chapter 7 for discussion of cross-cutting considerations and factors that can affect the magnitude of impacts.

Table 4-4. Example Non-Utility System Impacts

Non-Utility Impact	Description
Other Fuel Impacts	Impacts on fuels not provided by the relevant utility. Examples include electricity impacts (for a natural gas utility), natural gas impacts (for an electric utility), and a range of 'unregulated fuels,' including fuel oil, propane, gasoline, diesel fuel, and wood.
Host Customer Impacts	Host customer portion of DER energy-related benefits and costs (e.g., transaction costs, resilience benefits), and host customer non-energy impacts (NEI), such as impacts on productivity, comfort, health and safety, maintenance costs, and more.
Societal Impacts	• Resilience impacts—Resilience impacts beyond those experienced by utilities or host customers, principally related to the provision of critical services to all customers (e.g., ability of hospitals, policy stations, fire stations, water/wastewater facilities, etc. to provide services during unplanned outages and/or recover quickly from outages). • Greenhouse Gas impacts—Impacts associated with GHG emissions—includes only those impacts not embedded in the utility cost of compliance with GHG regulations. Impacts on compliance costs are treated as a utility system cost. • Other Environmental impacts—Impacts associated with criteria pollutant emissions, land use, water, solid waste, etc.—includes only those impacts not embedded in the utility cost of compliance with environmental regulations. Impacts on compliance costs are treated as a utility system cost. • Public health impacts—Impacts include health impacts beyond host customer impacts, and typically health impacts associated with improved or worsened air quality impacts, where impacts are accounted for in terms of e.g., reduced healthcare costs.

Note: These examples are illustrative and are not meant to be an exhaustive list or applicable in every jurisdiction.

In some cases, the determination of whether to include certain non-utility system impacts is straightforward. For example, legislation establishing a specific DER program might explicitly state that the goals of the program are to improve public health. Or a state might have statutory language requiring consideration of environmental benefits in resource decision-making. In other cases, the determination may be less clear. This is often the case regarding host customer benefits and costs, where policies do not necessarily articulate whether they should or should not be accounted for in a primary cost-effectiveness test.

The decision of which non-utility system impacts to include in a JST is best informed with appropriate input from stakeholders. This can be done through structured discussions in which specific policy language is 'scored' by stakeholders in terms of whether the language is direct or specific enough to justify including a non-utility system impact in a JST, and where the scoring can help narrow differences. The following is one possible set of criteria for scoring policy language:

1. The policy requires an action or specifies a required outcome related to a non-utility system impact.
2. The policy does not require a specific outcome but explicitly states that a non-utility system impact is an objective.
3. The policy makes reference to a non-utility system impact but does not explicitly state that the impact is an objective.

Ultimately, decisions will have to be made not only on how different policies are scored using such standards, but also on which of these three levels of emphasis is necessary to support inclusion of a non-utility system impact in a JST.

Figure 4-3 provides an illustrative example of scoring DER policies in a jurisdiction based on stakeholder input to inform the relevance of non-utility system impacts. As the figure shows, even if there are differences of opinion regarding whether one particular policy suggests a specific non-utility system impact should be included in the JST (noted by the pale green- and teal-colored cells), such differences may become moot if there is consensus that another different policy clearly suggests that impact should be included.[16]

[16] Case study examples of states applying this scoring can be found at: https://naseo.org/nesp/nspm.

Figure 4-3. Example 'Scoring' of Policies and Public Utility Commission Orders

State Policy Articulated Goals/Objectives	Utility System Impacts	Non-Utility System Impacts Relevant to State Goals/Objectives						
			Societal Impacts				Host Customer	
	Generation, Capacity, T&D, General, etc.	Other Fuels	Resilience	GHG Emissions	Other Environ-mental	Public Health	Host Customer (non-LMI)	Host Customer (LMI)
Energy Grid Modernization Act								
State Code, Public Utilities §55–555								
State Climate Mitigation Plan								
Energy Storage Act								
Energy Efficiency Program Plan PUC Order No. 25-123								
Distribution System Planning PUC Order No. 25-456								
Governor's State Enery Plan								
Include in Primary BCA Test (JST)?	*Always include in BCA test*	Yes	Yes	Yes	Yes	No	No, but include in secondary test	

Always account for full range of Utility System Impacts in JST
Concensus that policy goals support inclusion in JST
Policy mentions the impact, may support inclusion in JST
Non-consensus on relevance of impact
Consensus that policy goal does not address impact and should not be in JST

Note that some potential policy goals—such as those related to rate impacts, distributional equity, and/or economic development and jobs—cannot be addressed through BCA tests because the goals are associated with fundamentally different questions than the question that BCA tests answer. As discussed in Step 4 below, additional complementary analyses may be warranted to address such policy goals.

B. Determine Which Non-Utility System Impacts Are Applicable and Material

As with utility system impacts, some non-utility system impacts that are of policy interest in a jurisdiction may not be applicable for each different type of DER in each jurisdiction. For example, interconnection costs paid by a host customer are relevant to distributed generation (e.g., rooftop PV) but are not relevant to EE.

In addition, even when a DER is likely to have some impact, the expected impact may not always be large enough to warrant quantification, or it may not be material given how the electric grid or natural gas distribution system is currently commonly operated. As with utility system impacts, something can be considered immaterial if the expected impact is not large enough to impact the BCA results (within a reasonable assessment of the overall margin of error in BCRs).

Chapter 6 provides examples of the relevance and materiality of how non-utility system impacts can vary across different DER types.

C. Establish Geographic Boundaries of Interest for Select Non-Utility System Impacts

Some categories of non-utility system impacts raise questions regarding the applicable 'geographic boundary' to use for estimating impacts. There are three such questions to consider with regard to non-utility system impacts:

- **Greenhouse Gas Emissions**. Emissions of GHGs affect the global climate with resulting climate changes causing damage across the globe. Jurisdictions need to decide whether BCAs should include global impacts, impacts in their country or region, or some other subset of impacts. As discussed in Appendix F, the default assumption is to use a global boundary for GHGs because it unlikely that a jurisdiction would decide to invest in reducing

GHG emissions solely because of the limited benefits that those local emission reductions would have on the local environment.

- **Criteria Pollutant Emissions and Related Public Health Impacts**. Reductions or increases in electricity and/or natural gas can affect emissions of a range of air pollutants. Depending on locations of fossil-fuel-fired power plants, wind and weather patterns, and other factors, the adverse health and environmental impacts of such emissions can be felt locally, across multiple states or provinces and even across multiple countries. Jurisdictions need to decide whether BCAs should include all or just specific geographic subsets of impacts from changes in such emissions.

- **Government Tax Incentives or Rebates for Host Customers**. Decisions must be made regarding whether to treat government tax incentives or rebates as reductions in costs (i.e., treating government as 'outside the boundary of interest') or as transfers (i.e., treating government as 'inside the boundary of interest'). As discussed in more detail in F, the default decision is to treat tax incentives as reductions in costs. This decision is the default due to the typical perspective of regulators on leveraging non-ratepayer sources of funding. It is also due to the challenges associated with removing the impacts of government incentives when estimating the costs of traditional utility supply resources that would be avoided by DER investments (necessary for symmetry/consistency reasons if government incentives for DERs are to be treated as transfers).

Decisions on how to establish geographic boundaries of concern or interest for any category of impacts should be based on the jurisdiction's policy goals as articulated in Step 1. It is important to note that the geographic boundary of concern can be different for different impacts. For example, regulators may decide that they are only concerned about how federal tax incentives affect customers in their state or province but are concerned about global impacts of GHG emissions. Appendix F provides further discussion of geographic boundaries.

STEP 4: DEVELOP ANY SECONDARY TESTS

While a jurisdiction's primary test will be the principal BCA test used to inform decisions on whether utility ratepayers should fund or otherwise support DERs, it does not have to be used in a vacuum. In some instances, secondary tests can help enhance regulators' and stakeholders' overall understanding of DER impacts. There are two potential reasons to consider the adoption of one or more secondary tests.

- **Sensitive analysis around certain impacts:** There may not be complete clarity about the categories of non-utility system impacts to include in the primary test. In such cases, if a decision is ultimately made to include a category of non-utility system impacts in the primary test, there may be value in requiring a secondary test that excludes that impact (and vice versa). The secondary test can then serve as a sensitivity test. The purpose would be to inform decision-makers of the effect that including or excluding an impact from

Decisions on how to establish geographic boundaries of concern or interest for any category of impacts should be based on the jurisdiction's policy goals as articulated in Step 1. It is important to note that the geographic boundary of concern can be different for different impacts. For example, regulators may decide that they are only concerned about how federal tax incentives affect customers in their state or province but are concerned about global impacts of GHG emissions.

the primary test has on cost-effectiveness, which could potentially inform decisions on DER investments (particularly those that are marginally cost-effective or marginally not-cost-effective under the primary JST).

- **Inform prioritization of DER investments and how much to invest**: The primary JST addresses the question of whether an investment has greater benefits than costs—given a jurisdiction's policy goals—and therefore merits investment. A secondary test may help inform decisions on how to prioritize a range of DER investments that are all cost-effective under a primary JST. Again, this may be particularly valuable if there is some uncertainty over which non-utility system impacts to include in the primary JST. Similarly, secondary tests can also inform decisions on *how much* ratepayer funding to invest (rather than just the '*whether to invest'* question the JST addresses) in a cost-effective DER initiative.

A more extensive discussion of secondary tests can be found in Appendix G of this Manual.

STEP 5: SELECT A DISCOUNT RATE(S) FOR CALCULATING THE PRESENT VALUE OF INVESTMENTS

One of the most important inputs to BCAs is the discount rate. Discount rates assign a time value to money that enables the calculation and comparison of the benefits and costs experienced at different points in time. Higher discount rates value future benefits and costs less than lower discount rates. 'Real' discount rates reflect time preferences even after removal of inflationary impacts (i.e., time preferences even if there was no inflation to consider).

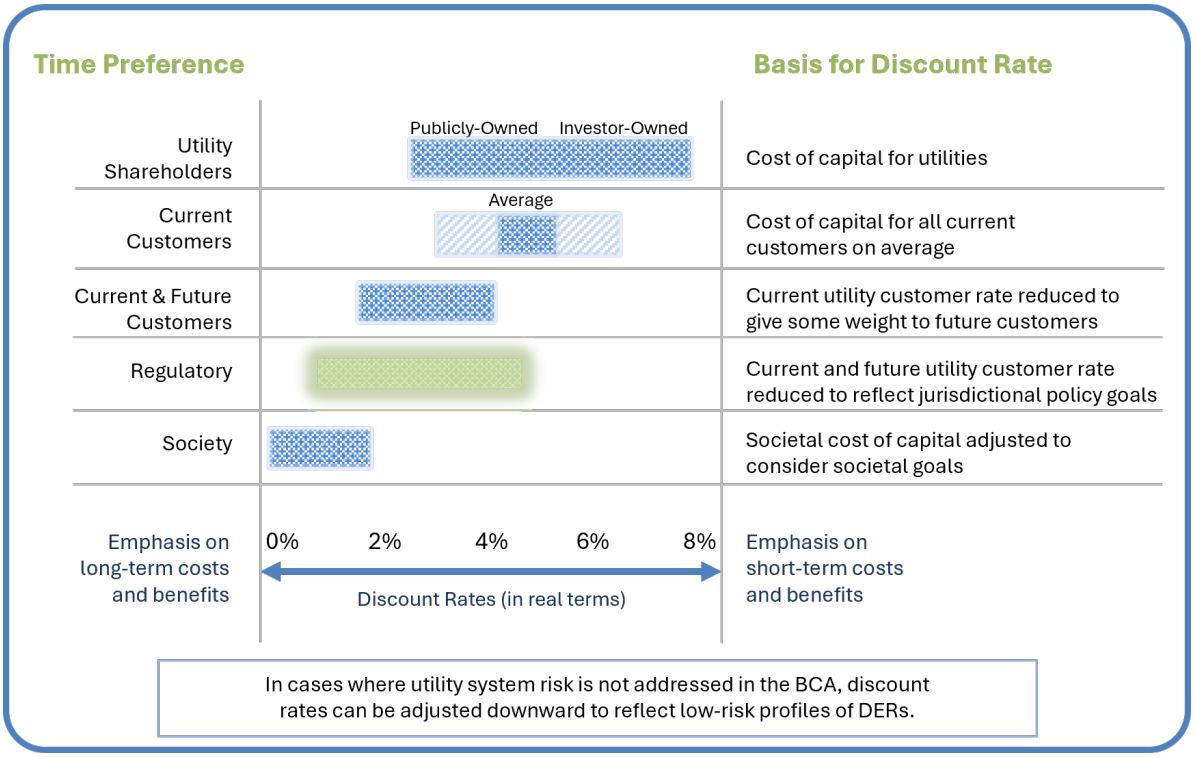
The selection of a real discount rate for use in a BCA test should be a function of a jurisdiction's policies, as articulated in Step 1. The following questions are helpful in selecting a discount rate:

- **Whose perspective is most relevant for the BCA test?** Typically, the perspective of customers is most important.
- **What is the time preference for current utility customers?** Customers' real cost of capital typically ranges from 3 percent to 7 percent.
- **How much weight should be given to future, versus current, customers?** This is a policy choice. Regulators that put greater emphasis on protecting the interests of future customers should choose a lower discount rate.
- **What additional policy goals are relevant?** Policy goals such as addressing climate change, which is a long-term and inter-generational concern, suggest use of a lower discount rate.
- **Has the BCA test adequately accounted for risk in other assumptions?** If risk is not adequately factored into the development of other input assumptions (e.g., avoided energy costs), it can be appropriate to adjust the discount rate to reflect differences in the risk of a DER relative to the alternative resources to which it is being compared.

As shown in Figure 4-4, the more those policies reflect regulatory concerns for inter-generational equity and/or for a broad range of societal concerns, the stronger the argument for using a societal discount rate or something close to a societal discount rate. Conversely, the more the policies focus primarily or exclusively on utility system impacts and on current customers, the stronger the case for a higher discount rate. To the extent that there is uncertainty and/or lack of consensus on

what jurisdictional policy suggests about discount rates, secondary tests that use a different discount rate can function as sensitivities.

Figure 4-4. Factors Informing Choice of Real Discount Rate



See Appendix H for additional guidance on discount rates.

STEP 6: ESTABLISH ASSESSMENT LEVEL AT WHICH BCA RESULTS WILL INFORM DECISIONS

The cost-effectiveness of DERs can be measured at a variety of different levels of aggregation—what is sometimes called 'assessment level.' These levels include the following:

- **Measure level**. This is the application of BCA to the average cost and savings across all utility customers for a particular technology or action that utility programs may promote. Examples could include the cost-effectiveness of utility rebates for residential Energy Star refrigerators, business rooftop PV rebates, and free EV charging devices offered in exchange for commitments to allow managed charging.
- **Customer level**. Also known as 'project-level.' This is the application of BCA to a package of DERs offered to an individual customer. Examples might include the financial incentives for the installation of several different efficiency measures, rebates for the installation of rooftop PV panels with a battery for storage, or incentives a combination of these and/or other DERs.

- **Program level**.[17] This is the application of BCA to an entire program or initiative. This would include not only the cost of an individual measure, but also all non-measure costs such as marketing costs to promote the measure, costs of training trade allies, costs of administering the program or initiative, etc.
- **Sector level**. This is the application of BCA to a combination of programs or initiatives targeted at a particular sector. An example would be a range of EE or DR programs targeting businesses.
- **Portfolio level**. This is the application of BCA to a combination of programs or initiatives targeted at a range of different kinds of customers (e.g., residential and business). Portfolio analyses include not just the sum of all costs of all programs in the portfolio, but also any costs incurred at the portfolio level (e.g., for management of all DER initiatives, development of data tracking systems used for multiple programs, general marketing for multiple DER programs, etc.) that therefore are not allocated to any individual program.

There can be value in conducting BCAs at all these levels, particularly to inform decisions on the design of different programs and/or the make-up of portfolios of programs or initiatives. However, jurisdictions typically also need to decide on the level of aggregation of DER impacts on which regulators should focus when determining if ratepayer investments are cost-effective or not (i.e., the default level of aggregation that should be used to 'screen out' investments, all other things being equal).[18] The higher the level of aggregation used to make decisions, the greater the potential for supporting investments that do not make economic sense. However, there can be important reasons for including some non-cost-effective DER investments in programs or portfolios of programs. For example:

- Some DER measures that are not cost-effective on their own can enable other measures that *are* cost-effective;
- Some non-cost-effective projects may better enable engagement with customers on future projects that are cost-effective (these are sometimes called 'loss leaders');
- There can be value in testing new program ideas that, even if not initially cost-effective, could lead to more cost-effective offerings in the future (e.g., pilot initiatives);
- Some programs or initiatives that are not cost-effective initially can be necessary to spur market development or market transformation that can lead to cost-effective DER deployment in the future; and
- Some non-cost-effective programs or initiatives can be important or even necessary to enable greater equity in the distribution of DER offerings to low-income or other disadvantaged populations.

See Appendix I for additional discussion of BCA assessment levels.

[17] As used here, the term 'program' means an initiative (also a mechanism or an offering) that does not rely in a material way on synergies with other initiatives to effectively engage with the market and/or to drive investment in one or more DERs. While multiple initiatives can be combined and assessed together, there are merits to separately assessing cost-effectiveness of individual initiatives that do not rely on others to drive DER investment.

[18] As discussed above, cost-effectiveness under the state's primary BCA is a critically important criterion for informed regulatory approval of DER investments. However, it need not be the only criterion. Equity concerns, rate impact concerns, and/or other cost-effectiveness perspectives can also be important to consider in regulatory decisions.

STEP 7: CONSIDER CONDUCTING COMPLEMENTARY ANALYSES TO BCAS

BCA tests address the question of whether the total economic benefits of a DER investment are greater than total economic costs—a critically important question for decision-makers to consider. However, as articulated under *Principle 7: Conduct BCAs Separately from Other Complementary Analyses* in Chapter 3, some jurisdictions might have policy goals requiring consideration of other questions when making decisions on whether to support or approve DER investments. Common examples include:

- How will the DER investments affect utility rates?
- How will benefits and costs of the DER investments be distributed, particularly with respect to low-income, rural, historically neglected, or other populations of particular interest?
- How will the investments affect local economic development and jobs?

Table 4-5 summarizes how these concerns are different from cost-effectiveness concerns, both in terms of the questions they address, the impacts they assess, and key metrics or outcomes of potential interest.

Table 4-5. Comparison of BCA to Other Types of Analyses

	Benefit-Cost Analysis	Rate and Bill Impact Analysis	Distributional Equity Analysis	Economic Development / Job Impacts
Question Answered	Will total costs across all customers increase (net costs) or decrease (net benefits) as a result of an investment?	Will electricity and natural gas rates go up or down (e.g., for all customers, participants, or non-participants)?	How will DER benefits and costs be distributed to certain customers relative to other customers?	Will the local economy including jobs become more or less robust as a result of an investment?
Impacts Analyzed	• Utility system costs • Other non-Utility costs of state policy interest	• Reduced or increased utility revenues • Change in utility system costs • Participation in programs	• Specific metrics as identified by jurisdiction's policies (e.g., rate and bill impacts, energy burden)	• Local economic activity • Local employment
Example Metrics	• Present value of change in costs ($) • Present value of change in benefits ($) • Present value of net benefits ($) • Benefit-cost ratio	• Rate Impacts (c/kWh, %) • Bill Impacts ($/month, %) • Participation (#, %)	• Change in electricity rates ($/kWh) • Change in participant bills ($/year) • Change in participation rates (% eligible) • Change in energy burdens (% of income spent on energy bills)	• Changes in gross domestic product ($) • Net change in jobs (FTE) or job-years (direct, indirect, and induced)

In determining whether to conduct additional complementary analyses of these issues—separate from but in parallel with BCAs—jurisdictions will want to consult the applicable policy goals they articulated in Step 1. The approach to making such determinations will mirror the approach used to determine which non-utility system impacts to include in BCAs as articulated in Step 3. Additional information on analyses of rate impacts, distributional equity, and economic development and jobs is available in Appendices B, C, and D.

STEP 8: DOCUMENT PROCESS, COMMENTS, AND RATIONALE FOR ABOVE STEPS

This final step in developing a JST applies *Principle 8: Ensure Transparency* which entails providing documentation on the decisions underpinning a jurisdiction's decision framework. To be truly transparent, the documentation includes all the inputs to and rationale for decisions flowing from the previous seven steps used to develop the primary BCA test (JST), any secondary BCA tests, and any complementary analyses. An example list of important items to document includes:

- A description of the utility system benefit and cost categories;
- An inventory of applicable policy goals used to identify impacts for the primary test with a description of how such goals were interpreted and ultimately used to inform decisions on which non-utility system impacts to include in a JST, as well as any recommended secondary BCA tests;
- Basis for what utility system and non-utility system impacts are determined to be (a) both applicable and material for different DERs, (b) not applicable to one or more types of DERs, and (c) not material for one or more types of DERs;
- Basis for the geographic boundaries to be applied to key utility system and non-utility system impacts;
- Reasoning for the selection of discount rate for use in the primary JST, as well as the discount rate(s) for use in any secondary BCA tests;
- Basis for decisions on the BCA assessment level that will be used to inform decisions on whether to support DER investments; and
- Rationale for any complementary analyses chosen.

Appendix J provides template tables a jurisdiction can use to take inventory of its applicable policies, and to help identify associated benefits and costs of relevant impacts. Appendix K provides guidance on how to present BCA results in ways that are most informative and most useful in making cost-effectiveness decisions. It also provides guidance on how to present results to support efforts to prioritize across different DER types.

Further, *Principle 8: Ensure Transparency* extends to the *process* of developing a jurisdiction's BCA practices. This includes primary and secondary test considerations, where the above information is shared and reviewed with input from interested stakeholders to allow for robust review and input. Such stakeholders include utilities, evaluators, consumer advocates, low-income representatives, State Energy Offices and other state agencies, DER industry representatives, environmental advocates, and others. Stakeholder input is important at the outset of the BCA process for assessing and interpreting applicable policy directives, as it can provide critical viewpoints regarding the value of DERs in the context of the jurisdiction's policy goals.

Applying the multi-step process can involve either a formal stakeholder process (led by a Public Utility Commission or State Energy Office), a regulatory requirement for utilities to apply the steps in their proposed DER plans (on which stakeholders provide comment), or some other informal regulatory or jurisdictional stakeholder process.

Jurisdictions can obtain stakeholder input in several ways, such as through:

- Rulemaking processes,
- Generic jurisdiction-wide dockets,
- Utility commission orders on specific DERs, and/or
- Working groups or technical sessions.

Some jurisdictions may wish to incorporate input from government agencies or representatives that do not typically make decisions regarding DER cost-effectiveness but would nonetheless have insights into the jurisdiction's applicable policy goals. For example, a state's Public Utility Commission may wish to incorporate input from that state's department of environmental protection or department of health and human services.

Finally, it is important to emphasize that transparency is important not only for developing and documenting development of a primary JST and other related decisions (the focus of the multi-step process described in this section), but also for Phases 2 and 3 of the BCA Framework: decisions on common methodologies for quantifying and monetizing impacts to be included in BCA tests and any complementary analyses, and conducting the BCA test using inputs based on methodologies used to analyze specific DER investments, respectively.

5. Valuing Energy Resources in Different Contexts

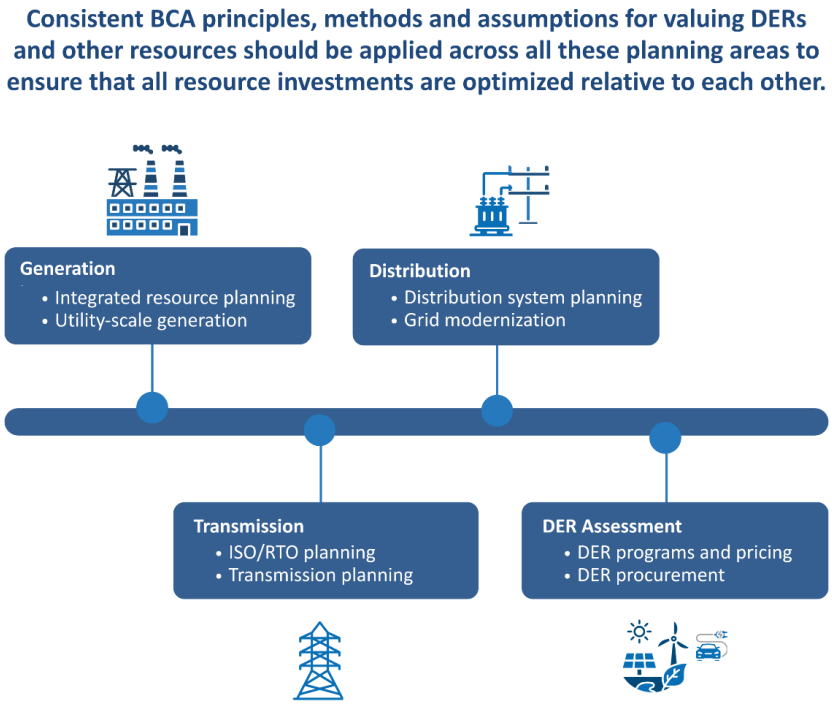
This chapter provides an overview of the importance of consistent valuation of energy resources across a range of different contexts to promote efficient and economic decision-making that can support a jurisdiction's efforts to meet its energy policy goals and objectives. Appendix A provides more detailed guidance on this topic.

5.1. Introduction

This Manual focuses on assessing DER benefits and costs in the context of regulatory oversight of electric and natural gas DER investments and strategies, with an emphasis on electricity DERs because these are the most common types of DERs. The principles and concepts also apply broadly to resource investments in non-regulatory contexts (e.g., state policy, legislative, planning, program development, municipal authorities), as well as to utility-scale resource investments.

There are many situations that entail evaluating the impacts of electricity resource investments to assess the cost-effectiveness, or identify the optimal mix, of resources to serve energy customers in order to promote efficient and economic decision-making in resource investments. Figure 5-1 provides a simple illustration of where assessments of resources, including DERs, can fall along the electricity planning paradigm and be valued in different planning contexts.

Figure 5-1. The Electricity Planning Paradigm



Energy resource planning and investment decision-making practices can involve a range of government agencies, municipal and public authorities, and other entities operating in different contexts, whether related to utility-system or public investments and strategies, regulations, and/or programs. Table 5-1 summarizes the range of entities that may be involved in resource planning and investments, and it describes examples of the general role of different entities.

Table 5-1. Example Roles of Entities in Electricity Planning and Processes

Entity	Electric Generation Planning	Transmission Planning (ISO/RTO)	Distribution System Planning	DER Assessments
Public Utility Commissions	Approve integrated resource plans (IRP); issue/deny CPCNs; oversee resource adequacy and least-cost planning	Limited direct role; may review or approve cost recovery and siting	Provide regulatory oversight; approve utility plans, grid investments, and performance metrics	Approve DER programs, rate design, incentives, procurement frameworks
State Energy Offices	Inform development of legislation and policies; conduct analysis; support state energy goals across all sectors; lead energy emergency planning	Coordinate with states/regions; limited formal authority	Support policy development, pilot programs, and funding; approve siting of DERs in some states	Design/statewide programs; technical assistance; market development for DERs; attract private investment
Municipal Electric Authorities (Munis)	Conduct their own resource planning; may not require CPCNs depending on state	Participate in ISO/RTO processes (if members); may co-own transmission	Responsible for local distribution planning and upgrades	Develop local DER programs; set tariffs; procure DERs for municipal needs
Electric Cooperatives (Co-ops)	Develop resource plans (often via generation and transmission co-ops); often less formal IRP/CPCN	Participate via G&T or jointly in ISO/RTO regions	Plan and operate distribution systems; focus on reliability and costs	Offer DER programs; pilot projects; limited but some procurement
Public Power Authorities	Develop generation portfolios aligned with public mandates; may bypass CPCNs	Own/operate transmission; active in regional planning and grid modernization	May own/operate distribution in some cases; lead large-scale modernization projects	Procure large-scale DERs; run programs aligned with policy (e.g., storage, renewables)

Notes: Certificate of Public Convenience and Necessity (CPCN) refers to a regulatory approval requirement by utilities and energy developers to construct, operate, or expand infrastructure, such as power plants or transmission lines. G&T coops are formed by electric distribution cooperatives to pool their purchasing power for wholesale electricity.

While this Manual focuses on assessing DER benefits and costs in the context of regulatory oversight of DER investments and strategies, the NSPM principles and concepts apply broadly to valuing all energy resources. Table 5-2 below presents more specific examples of where benefits and costs of DERs and other energy resources are evaluated, and the associated questions addressed by each context. In these contexts, state agencies, municipal authorities and cooperatives, utilities and others may assess the relevant impacts of DERs and other resource investment decisions.

Table 5-2. Valuing Energy Resources and Strategies in Different Contexts

Context	Examples	Example Questions to be Answered
DER programs	Review of programs including EE, DR, DG, DS, EVs, multi-DER programs (e.g., GEBs, NWS/NPS, VPPs)—both prospective and retrospective	Should there be an investment in the DER program? Can DER programs be designed to increase net benefits?
Utility scale generation	Review of utility investment in large-scale, front of the meter generation, before the investment has been made	Is the generation resource necessary, and will it meet public needs at lower cost than alternatives?
Resource procurements	Procurements from third parties of energy and capacity, large-scale renewable generation, DERs, NWS/NPS, or VPPs	What is the maximum amount that should be paid (i.e., ceiling price) to procure the resource?
Energy price signals	Rate design in rate cases, DR programs, time-varying rates; paying for grid services through price signals	What price signal will optimize customer demand profiles and the adoption of DER?
Grid modernization	Review of grid modernization investments e.g., grid-enhancing and hardening technologies, AMI, DERMS, ADMS	Should the grid modernization investment be made?
Dynamic system planning	Assessment and evaluation of multiple energy resource types relative to a dynamic set of alternative resources, such as Integrated Distribution System, Resource, Grid and/or Electricity Planning	Which portfolio of large-scale and distributed energy resources will provide the greatest benefits?
Retrospective prudence reviews	Review of utility investments after the investments have been made, often during a rate case	Was the capital investment in question expected to provide net benefits to customers at the time it was made?
Performance incentive mechanisms (PIMs)	Determining PIMs to incentivize utilities in context of EE programs, resource procurements, GHG and other emissions, grid modernization, etc.	How much should a utility be rewarded or penalized, based on the benefits or costs experienced?
State energy policies, planning and programs	Support and implement a variety of state energy policies, legislation, plans, and programs (distinct from regulation or regulated utilities)	Will the state's policies, planning, and program efforts help to meet its specific energy goals and objectives by providing net benefits to the state?

Valuation or BCA assessments typically occur separately from each other in different processes within a state. As a result, the practices, assumptions, and methods used to evaluate benefits and costs of DERs and/or other resources are often inconsistent. This can lead to different conclusions about the value or cost-effectiveness of different resource options—and thus suboptimal investments in resources—that can make it difficult for the jurisdiction to meet its mandated energy policy goals and objectives.

Further, while Table 5-2 largely presents regulatory-focused contexts—led by Public Utility Commissions that often involve State Energy Offices and other state agencies, utilities, and other stakeholders—additional contexts for valuing energy resources also apply. These include common categories of state initiatives related to state policies, planning, and programs that typically involve legislative and executive order authority to support DERs, potentially with state general funds versus utility ratepayer funds. For example, ratepayer-funded EE program valuations typically take place in Public Utility Commission regulatory dockets focused on EE investments, transmission and distribution (T&D) investments are evaluated in regulatory dockets focused on grid modernization, and State Energy Offices often oversee DER rebate programs using state general funds.

In most jurisdictions, these assessments typically occur separately from each other in different processes. As a result, the practices, assumptions, and methods used to evaluate benefits and costs of resources are often inconsistent or not coordinated when applied within a jurisdiction. This can lead to different conclusions about the cost-effectiveness of different resource options—and thus potentially suboptimal investments in resources—that can make it difficult for a jurisdiction to meet its mandated energy policy goals and objectives.

Below is an overview of how BCA, and guidance in this Manual, generally applies to different contexts, with details on each context described in Appendix A.

5.2. Consistent Application of NSPM Guidance Across Valuation Contexts

Applying the NSPM principles and concepts improves the consistency of valuing DERs and other resources across the range of contexts in Table 5-2, offering several advantages:

- **Economic decision-making.** Applying consistent benefits, costs, assumptions, and methods across contexts will promote efficient and economic decision-making. For example, if a utility's DS program BCA evaluations do not include resilience benefits, but its grid modernization project BCA evaluations do include resilience benefits, then the utility will undervalue its DS programs relative to its grid modernization investments.
- **Applicable policies.** Using a BCA test, methods, and assumptions that consistently reflect a jurisdiction's energy policies will help promote those policies across all relevant contexts, such as policies related to ensuring a safe, reliable, and secure energy system; reducing risks of energy supply disruptions to the energy systems; improving efficiency in buildings and manufacturing to lower costs for all customers; improving public health; promoting economic development; and protecting the environment.

- **Stakeholder input.** If robust stakeholder input informs the BCA tests, methods, and assumptions in one context, then that stakeholder input will benefit the other relevant contexts where stakeholder input was not available or practical.
- **Administrative efficiency.** Using consistent BCA tests, methods, and assumptions across relevant contexts will enhance the administrative efficiency of DER investment reviews. This will result in benefits for commission staff, utilities, intervenors, and other stakeholders.

Applying the NSPM principles and concepts consistently across different energy resource investment or strategy contexts promotes efficient and economic decision-making.

Guidance in this Manual can apply to the range of valuation contexts listed above to support consistency in a jurisdiction, specifically in these areas:

- Fundamental BCA principles,
- Use of a primary BCA test,
- Use of any secondary BCA tests,
- Methods and assumptions for calculating resource impacts,
- Planning parameters e.g., study period and discount rate, and
- Conducting complementary analyses.

NSPM guidance in these areas may be applicable to the full range of energy resource valuation contexts in Table 5-2, however in some cases only a portion of the NSPM guidance might be applicable, as described in Appendix A.

Jurisdictions that seek to encourage consistent valuation of DERs across multiple contexts will need to (a) review the context to determine whether and how the NSPM guidance applies to it, and (b) identify ways to apply the NSPM guidance consistently to it.

5.2.1. Fundamental BCA Principles

Applying the BCA principles across all relevant contexts will promote consistency regarding fundamental analytical concepts. The principles are relevant to the evaluation of benefits and costs, regardless of whether the evaluation is for the purpose of reviewing DER investments or valuing other utility investments.

5.2.2. Primary BCA Test

Using the same primary BCA test—specifically the same list of benefits and costs as in the primary BCA test—across all relevant contexts as applicable will promote consistency and economic decisions. If there are multiple primary BCA tests already in use across relevant contexts, the most appropriate BCA test would be the one that reflects the most recent regulatory goals, the most recent direction from legislation, the most recent and robust stakeholder input, and with the most support or approval from regulators.[19]

[19] Ideally, the primary BCA test would have been developed pursuant to the NSPM multi-step process (see Chapter 4); if such a primary test is not in place, the jurisdiction can consider applying the multi-step process to develop one.

5.2.3. Secondary BCA Tests

Secondary BCA tests answer different questions than primary BCA tests (see Chapter 4). Using consistent secondary BCA tests across relevant contexts, to the extent that the same questions are relevant, will help answer those questions consistently. For example, if a jurisdiction uses the UCT as a secondary test in the context of DER programs and portfolios to help prioritize those programs, then it should use the same secondary test in the context of infrastructure investments to prioritize those investments.

5.2.4. Methods and Assumptions

Applying the same methods and assumptions for estimating the values of each benefit and cost across all relevant contexts will promote analytical consistency and economic decisions. For example, the same avoided energy costs used to evaluate DER programs and portfolios should also be used to evaluate resource procurements or utility-scale generation facilities. Utilities in a jurisdiction might be using different values of the same benefit or cost in different contexts because the values were estimated at different times and in different forums. In these cases, the estimates that use the most recent information and are more thoroughly informed by stakeholder input and regulatory review will be most appropriate.

Utilities in a jurisdiction might be using different values of the same benefit or cost in different contexts because the values were estimated at different times and in different forums. In these cases, the estimates that use the most recent information and that are more thoroughly informed by stakeholder input and regulatory review will be most appropriate.

5.2.5. Planning Parameters

Applying the same planning parameters across all relevant contexts, to the extent applicable, will promote consistent and economic planning decisions. The two main planning parameters are discount rates and study periods.

5.2.6. Complementary Analyses to BCA

Applying complementary analyses consistently across all relevant contexts, to the extent appropriate and feasible, will promote consistency in valuing DERs to meet a jurisdiction's policy goals. For example, if a proposed DER portfolio requires an analysis of rate impacts to inform the decision of which DER programs to pursue, then the IRP context should also conduct rate impact analyses to guide the selection of the optimal resource portfolio.

5.2.7. Transparency in Assumptions and Results

Presenting the benefits, costs, and analytical results from each relevant context consistently facilitates comparison and improves administrative efficiency across contexts.

PART II: DER Benefits and Costs and Cross-Cutting BCA Issues

6. DER Benefits and Costs

This chapter presents a catalog of the range of benefits and costs in BCAs for DERs, including a description of each type of benefit or cost, and guidance on whether an impact is relevant and material depending on the DER type.

6.1. Summary of Key Points

- DERs can have a wide range of impacts that affect the electric utility system, the natural gas utility system, other fuel systems, host customers, and society. The relevance and materiality of an impact can depend on the DER type.
- While some impacts are always a benefit or cost for certain DER types, other impacts can be either a benefit or a cost depending on various factors, such as the DER technology characteristics, where the DER is located, and when and how it operates.
- For DERs funded or otherwise supported by electric (or natural gas) utilities, it is appropriate for BCA tests to include all electric/natural gas utility system impacts to the extent the impacts are relevant and material.
- Depending on the applicable policy goals, a jurisdiction's primary BCA test (i.e., JST) might include other fuel system impacts, host customer impacts, and/or societal impacts, to the extent the impacts are relevant and material.
- Information presented in this chapter assumes that each DER type is implemented and operated in isolation from other DER types. When a BCA test encompasses *multiple* DER types, the impacts may be different than those presented in this chapter (e.g., the net impact is not equal to the sum of the individual DER impacts). Chapter 13 provides further discussion on the implications of multiple DER BCAs.

6.2. Introduction

The guidance in this chapter focuses on the range of impacts that might be relevant and material to one or more DER types, and whether the impacts might be a benefit or cost depending on various factors. This guidance does not address methodologies for how to *quantify* these impacts. Refer to Chapter 14 of this Manual for guidance on approaches to accounting for DER impacts. The DER types covered in this chapter are EE, DR, DG, DS, and electrification-related DERs (ELEC), which are introduced and described in Chapter 1. Further detail on BCA for each DER type or category is provided in Chapters 8–12, with guidance on BCA for DERs in specific scenarios in Chapter 13.

6.3. Electric Utility System Impacts

6.3.1. Summary

The full range of electric utility system impacts serve as the foundation of a jurisdiction's primary BCA test (see *Principle 2: Review and Account for Relevant and Material Utility System Impacts*).

Table 6-1 presents a list of potential electric utility system impacts commonly associated with DERs and a description of each impact, organized by five categories: Generation, Transmission, Distribution, Cross-Cutting Generation, Transmission, and Distribution (GT&D), and General. Cross-cutting GT&D impacts are often captured or accounted for within generation, transmission and/or distribution impacts. These impacts on the electric utility system occur when either electric or natural gas utilities support DERs that have impacts on electricity consumption. The impacts are the most common examples of utility system impacts that can either increase or decrease costs to the utility system because of a DER investment, which affects all utility customers. DER-specific Chapters 8–12 provide further details.

Table 6-1. Electric Utility System Impacts

Type	Utility System Impact	Description
Generation	Energy Generation	The production or procurement of energy (kWh) from generation resources on behalf of customers
	Capacity	The generation capacity (kW) required to meet the forecasted system peak load
	Environmental Compliance	Actions needed to comply with environmental regulations
	Renewable Portfolio Standard/Clean Energy Standard Compliance	Actions needed to comply with renewable portfolio standards or clean energy standards
	Market Price Effects	The decrease (or increase) in wholesale market prices due to reduced (or increased) 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 lost through the transmission system
Distribution	Distribution Capacity	Maintaining the availability of the distribution system to transport electricity safely and reliably
	Distribution System Losses	Electricity lost through the distribution system
	Distribution O&M[20]	Operations and maintenance (O&M) of the distribution system
Cross-Cutting GT&D	Risk	An adverse outcome that can occur because of uncertainty
	Reliability	The ability to prevent or avoid routine short-term outages under normal operating conditions due to fluctuating load and generation, fuel availability, and/or outage of assets
	Resilience	The ability to prepare for threats and hazards, adapt to changing conditions, and withstand and recover rapidly from disruptions
General	Financial Incentives	Utility financial support provided to DER host customers or other market actors to encourage DER implementation
	Utility Direct Investment	Direct costs for development and deployment of DERs by the utility, typically on the utility side of the meter
	Program Administration	Utility outreach to trade allies, technical training, marketing, and administration and management of DERs

[20] DER impacts on transmission O&M costs are likely immaterial but can be included in a BCA to the extent they are identified as material.

Type	Utility System Impact	Description
	Utility Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of DER programs
	Credit and Collection	Bad debt, disconnections, reconnections

Table 6-2 illustrates how not all utility system impacts are relevant or material to specific DER types and/or may vary by the unique aspects of individual utility systems (e.g., vertically integrated or not, in wholesale market or not). For instance, DR may not have a material impact on RPS compliance costs because the purpose of DR is to shift load, rather than to reduce energy usage. Further, in some cases, an impact may be embedded in another impact from a methodological standpoint.

Table 6-2. Potential Benefits and Costs: Electric Utility System

Category	Utility System Impact	EE	DR	DG	DS	ELEC
Generation	Energy Generation	●	●	●	●	●
	Capacity	●	●	●	●	●
	Environmental Compliance	●	●	●	●	●
	RPS/CES Compliance	●	NM	NR	●	●
	Market Price Effects	●	●	NR	●	●
	Ancillary Services	NM	NM	NM	●	NM
Transmission	Transmission Capacity	●	●	●	●	●
	Transmission System Losses	●	●	●	●	●
Distribution	Distribution Capacity	●	●	●	●	●
	Distribution System Losses	●	●	●	●	●
	Distribution O&M	●	●	●	●	●
Cross-cutting GT&D	Risk	●	●	●	●	●
	Reliability	●	●	●	●	●
	Resilience	NR	NR	NM	NM	NM
General	Financial Incentives	●	●	●	●	●
	Utility Direct Investments	NR	NR	●	●	NR
	Program Administration Costs	●	●	●	●	●
	Utility Performance Incentives	● / NR	● / NR	● / NR	● / NR	● / NR
	Credit and Collection Costs	●	●	●	●	●

● = typically a benefit for DER type; ● = typically a cost for DER type; ● = either a benefit or cost for DER type, depending upon the application of the DER; NM = typically not material; NR = not relevant for DER type.

Note that the above table, and all tables in this chapter, are illustrative as there may be specific use cases or contexts where the impact may be differently characterized than what is presented in the tables. Further, in some cases where an impact is labelled 'not material' (NM), this may change in the future as the grid evolves.

Demand and Grid Flexibility

Benefits or costs associated with grid or demand flexibility from DERs are not represented as a discrete line-item impact in a BCA test. Rather, flexibility impacts typically affect the magnitude and type of DER impacts, primarily for utility system impacts. For example, DERs provide demand flexibility by:

- Reducing generation capacity, ancillary services, transmission, and distribution costs;
- Reducing system risks and increasing system reliability and resilience; and
- Incurring additional incremental grid costs through system upgrades (e.g., DG and DS involve a shift from a one-way power flow to an upgraded, more dynamic, 'bi-directional' system where resources near the customer can generate, store, and flexibly draw energy from the electric grid).

Benefits or costs associated with grid or demand flexibility from DERs are not represented as a discrete line-item impact in a BCA test. Rather, flexibility impacts typically affect the magnitude of DER impacts, primarily for utility system impacts. This is also the case for temporal and location impacts (see Chapter 7).

Flexibility can have both short- and long-term impacts, such as on generation and T&D capacity and operations, as well as providing 'optionality' to address risk-related impacts over the long term.

The temporal and locational attributes of DERs, and interactive effects between DERs, can also impact the magnitude of some electric utility system impacts (see Chapter 7). Table 6-2 also illustrates that in some situations these impacts might be in the form of costs, while in other situations they may be in the form of benefits (i.e., avoided costs). For example, EE programs will typically create a benefit by reducing electricity generation, while electrification resources will typically create a cost by increasing electricity generation. As another example, DG fueled by renewable resources will typically reduce environmental compliance costs, but DG fueled by fossil fuels will typically increase environmental compliance costs.

6.3.2. Generation Impacts

Energy Generation

Definition: The amount of energy production or procurement (i.e., kWh) from generation resources purchased on behalf of customers. Energy generation costs include the fuel cost and variable operations and O&M costs and can vary by season and time of day.

BCA Considerations: In general, DERs will create energy generation benefits when they reduce the amount of electricity that utilities need to produce or procure to meet load. Conversely, DERs will create costs if they require higher levels of energy generation. An exception to this occurs during

periods of negative pricing whereby consuming grid energy (e.g., storage or EV charging) results in a benefit and curtailing grid energy consumption results in a cost.[21]

Generation Capacity

Definition: The amount of generation (i.e., kW) required to meet the forecasted peak load,[22] which typically includes an additional reserve margin. A utility will either need to build generation capacity or procure it (for instance through bilateral contracts or wholesale market purchases) to ensure it has sufficient generation capacity to meet its planning requirement.

BCA Considerations: The effect of a DER on generation capacity is limited to instances when a DER's operation coincides with the utility system peak load. If a DER's operation results in a net increase in load (such as with electrification) during the system peak, the utility will incur additional generation capacity costs. Alternatively, if a DER's operation results in a net decrease in load (e.g., EE savings; curtailment through DR; PV generation; injections from DR) during the system peak, the utility will derive a benefit in the form of lower generation capacity needs.

Environmental Compliance

Definition: There are several environmental regulations that impact the utility system. These can include federal regulations such as the Clean Air Act, regional mandates such as the Regional Greenhouse Gas Initiative (RGGI), or state and local mandates. These regulations typically require a reduction in emissions from energy generation or place limits on allowable levels of emissions from new or existing resources.

BCA Considerations: While some environmental regulations place a fixed limit on the amount of emissions for new or existing resources, determining a DER's net effect on this impact typically requires an analysis of the marginal emissions rate of the resource being displaced or deferred by the DER (see Section 7.5). For example, if a distributed PV (DPV) resource's output occurs when the marginal supply resource for the utility system is an emitting resource, it will result in a benefit. Alternatively, if a DPV resource's generation occurs when a non-emitting resource (e.g., solar, wind, nuclear) is the marginal resource, then the DPV resource would provide neither a benefit nor a cost.

In cases such as those listed below, it is important to consider and avoid double-counting impacts:

- When criteria pollutants (e.g., nitrogen oxides, sulfur dioxides) are regulated through a cap-and-trade program. The environmental compliance impacts might already be included in the energy generation cost. It is important to ensure that any such embedded environmental compliance impacts are not double-counted by accounting for them as a separate line item in the BCA test.
- When considering the relationship between utility environmental compliance impacts and societal environmental impacts. Utility environmental compliance impacts are the direct costs experienced by the utility and passed on to all customers through revenue requirements. Therefore, these impacts are utility system impacts that should be included

[21] Negative pricing can occur when renewable sources such as wind and solar generate more power than the grid can absorb, causing prices to turn negative. This is most common in states with high renewable penetration such as California, Texas, and Hawaii.

[22] Jurisdictions may have alternative approaches for defining peak (e.g., single peak hour, a certain percentage of top load hours, etc.).

in all BCA tests (see Appendix E on traditional BCA tests).[23] Societal-related environmental impacts, on the other hand, are typically articulated in policies that set forth environmental goals *beyond* compliance requirements. Therefore, for jurisdictions that include societal environmental impacts in their primary BCA test, it is important to distinguish them from utility environmental compliance impacts in order to prevent double-counting.

In estimating utility environmental compliance impacts, it is important for a BCA test to account for all regulations that have already been promulgated and are in effect, and any regulations that are expected to be in effect over the study period (NESP 2022). If there is uncertainty about future environmental regulations, this can be addressed through sensitivity analyses or expected value calculations. (For example, if the likelihood of future promulgation is 70 percent, the environmental compliance cost can be multiplied by 70 percent.) See Appendix L on accounting for uncertainty and risk.

Renewable Portfolio Standard Compliance

Definition: An RPS is a state policy to increase production of energy from renewable sources such as wind, solar, biomass, and other alternatives to fossil-fuel-based electric generation. Similar policies such as clean energy standards (CES) more generally focus on zero-emissions resources (e.g., nuclear, hydropower), or clean peak standards that encourage clean energy resources that can mitigate the utility system peak.

BCA Considerations: In jurisdictions that have adopted an RPS or similar mechanism expressed as a percentage of electric sales, utility or other investments in DERs can reduce RPS compliance costs either by reducing the RPS target by lowering overall electricity demand (e.g., EE) or increasing the level of qualified renewable generation (e.g., DPV).[24] Alternatively, if a DER has the effect of increasing electricity demand (e.g., electrification), it will increase RPS compliance costs. DR and DS do not have material impacts on RPS compliance costs; these DERs are typically used to shift consumption to different hours rather than decreasing or increasing consumption. In addition, DR and DS typically reduce demand in a relatively small number of hours per year.

Wholesale Market Price Effects (MPE)

Definition: In jurisdictions with competitive wholesale electricity markets, wholesale market prices are a function of the demand of buyers and the marginal costs of suppliers at any given instant. When DERs reduce (or increase) the demand for electricity, they reduce (or increase) the wholesale market prices. These price changes create benefits (or costs) for all customers participating in the wholesale market at that time. Wholesale natural gas markets can experience a similar effect from the reduction in natural gas demand from DERs (AESC 2024).

Wholesale MPE are different from energy generation, generation capacity, and ancillary services impacts. The former is the impact on *prices* from a change in demand, which will affect all buyers from the wholesale markets. The latter is the impact on the *costs* associated with consuming a different amount of a commodity.

[23] Except for the Participant Cost Test.

[24] The utility must be able to claim the renewable energy attribute by retaining ownership of renewable energy credits (REC) from renewable DG to realize the benefit of reduced RPS compliance costs. In some cases, the host customer may choose to retain the RECs, and thus renewable DG would not reduce the utility's RPS compliance costs.

BCA Considerations: In general, DERs that reduce the amount of electricity that utilities need to produce or procure to meet load will create MPE benefits. These MPE benefits can occur in both wholesale energy and wholesale capacity markets. Conversely, DERs that require higher levels of energy generation (e.g., electrification related-DERs) will create MPE costs. An exception to this occurs during periods of negative pricing whereby consuming grid energy (e.g., storage or EV charging) results in a benefit and curtailing grid energy consumption results in a cost.[25]

Geographic Boundary and MPEs

MPEs from DERs located in a given utility service territory may extend beyond the borders of that service territory because of the regional nature of most wholesale markets, which tend to encompass multiple utility service territories. Thus, regulators need to decide whether to include the MPEs for (a) only the utility service territory in question, (b) the entire jurisdiction under the regulator's purview, or (c) the entire wholesale market region. The regulatory perspective, which reflects the jurisdiction's applicable policy goals, is the most appropriate perspective to inform the decision on the geographic scope. See Appendix F for further discussion.

Transfer Payments and MPEs

Wholesale MPEs are sometimes referred to as a 'transfer payment' between competitive suppliers and wholesale market buyers because the benefit to one is directly offset by the cost to another. However, this conclusion is misleading. While it is true that the impact on wholesale market buyers' costs is offset by the impact on suppliers' profits, a BCA test should include both impacts because both the buyer's costs and the supplier's profits are a part of the benefits and costs of the electricity resource. See Appendix M for further discussion on treatment of offsetting transfers.

Ancillary Services

Definition: Ancillary services are those services required to maintain electric grid stability. They typically include frequency regulation, voltage regulation, spinning reserves, and operating reserves. These services are either traded in wholesale energy markets or self-supplied by utilities.

BCA Considerations: As with other impacts, a DER's net effect on ancillary services depends on how the DER operates and the real-time system conditions at the time of its operation. Some resources might be actively dispatched to provide ancillary services (for instance, storage providing frequency regulation). Alternatively, even if a DER's operation is not directly in response to a signal to provide ancillary services, it may still create an impact. For example, during times when load is ramping up quickly and/or generation resources are ramping down quickly, DERs can provide additional operating reserves, fast frequency response, or ramping services.

6.3.3. Transmission Impacts

Transmission Capacity

Definition: Transmission capacity refers to the availability of the electric transmission system to transport electricity in a safe and reliable manner. In areas with insufficient transmission capacity

[25] Negative pricing can occur when renewable sources such as wind and solar generate more power than the grid can absorb, causing prices to turn negative. This is most common in states with high renewable penetration such as California, Texas, and Hawaii.

available to support transmission of lowest-cost electricity, there will be transmission congestion costs due to the need to use higher-cost local generation to avoid the transmission constraint.

BCA Considerations: As with generation capacity, a DER's impact on transmission capacity depends on how it operates during times coincident with the transmission peaks. If a DER increases load at the time of the transmission system peak, it will result in added costs. Alternatively, if a DER reduces load at the time of the transmission system peak, it will result in reduced costs.

DERs can reduce transmission capacity costs in two ways:

- DERs might passively defer needed transmission capacity investments if their operation for other purposes (e.g., host customer bill management) results in lower load at the same time the transmission facilities are at their peak. In these instances, a BCA test might attribute the DERs with a systemwide average for the transmission capacity benefit provided.
- DERs can actively defer transmission capacity needs as part of a geographically targeted non-wires solution (NWS). The value of active deferrals is typically based on the actual deferral value of the avoided transmission project (i.e., the costs avoided if the wires investment is deferred for a certain number of years). There is often a minimum cost threshold for consideration of a transmission project for an NWS; therefore, the value of active deferrals is typically higher than that of passive deferrals.

Some DERs that increase electricity consumption, such as EVs and building electrification, could potentially increase transmission capacity costs.

Some ISOs/RTOs allow wholesale market participants to trade fixed transmission rights to help them manage transmission congestion costs. Some DERs may be able to create benefits by reducing transmission congestion and costs of fixed transmission rights. Costs of fixed transmission rights are typically included in wholesale energy market prices and therefore BCA tests might not need to include those costs as a separate impact.

Transmission System Losses

Definition: Transmission lines lose a portion of all electricity produced at electric generation facilities as electricity travels through them. These line losses grow exponentially with higher levels of load, and as such it is important that calculations account for marginal loss rates when determining this impact.

BCA Considerations: To the extent DERs offset utility-scale energy generation (e.g., DG meeting host customer load) they will help avoid electricity transmission and as a result reduce the cost associated with transmission line losses. However, to the extent utility-scale energy generation must meet any incremental load from DERs (e.g., electrification or storage and EV charging) the costs associated with transmission line losses will increase. The magnitude of the impact will depend on the amount of transmission-level load at the time of the DER's operation.

6.3.4. Distribution Impacts

Distribution Capacity

Definition: Distribution capacity refers to substation and distribution line infrastructure necessary to meet customer electric demand. The net impact of DERs will depend on the cost associated with the specific type of distribution infrastructure affected. If customer demand exceeds

distribution capacity, it will require investments to increase distribution capacity to a level that preserves safety and reliability. The net effect of DERs on distribution capacity depends on how they operate during the distribution system peaks.

BCA Considerations: DERs can either actively or passively help defer or eliminate the cost of needed investments by reducing net load during peak hours. With respect to passive benefits, a DER may have the effect of reducing net load despite operating for some other purpose (e.g., host customer bill management). In terms of active deferrals, a utility may incentivize DERs through pricing, programs, or procurements to provide distribution capacity benefits.

Alternatively, DER's might increase distribution capacity costs if the local distribution system does not have sufficient hosting capacity (i.e., if a given feeder cannot accommodate more DERs without impacting system operation under existing control and infrastructure configurations). For example, if a DER consumes electricity from the grid during times of the distribution peak load or injects electricity onto the grid during times of minimum load (and therefore create distribution voltage issues) it would have the effect of creating a cost to invest in the necessary distribution infrastructure to avoid these issues. Distribution voltage regulation is often a component of distribution capacity because it is necessary to ensure reliable and continuous electricity flow across the power grid.

Distribution System Losses

Definition: The distribution system loses a portion of all electricity produced at electric generation facilities as that electricity travels across distribution lines and transformers to the final point of consumption. Line losses expand exponentially as the system experiences higher levels of load, so cost-effectiveness calculations should account for marginal loss rates.

BCA Considerations: The net effect of a DER's operation on distribution line and transformer energy losses depends on the relative balance between load and net DER output. For example, if the net impact of DERs is a reduction of load at the feeder level, then there can be net reductions in line and transformer energy losses, and vice versa.

Distribution Operations and Maintenance

Definition: Utilities incur O&M expenses to maintain the safe and reliable operation of distribution facilities. This includes maintenance of substations, wires and poles, and repairs and replacements. Some portions of distribution O&M expenses are variable, which means the expense incurred by a utility is a function of the volume of energy transfers through the system.

BCA Considerations: When DERs reduce electricity consumption, they will typically reduce the energy transfers through distribution facilities. This creates a benefit by reducing variable distribution O&M expenses. Alternatively, when DERs increase electricity consumption, they might increase distribution O&M expenses. DERs that are intermittent in nature can lead to increased distribution costs due to the need to manage energy flows to maintain voltage and frequency within acceptable limits.

6.3.5. Cross-Cutting GT&D Impacts

Utility System Risk

Definition: Risk is defined as an adverse outcome that can occur because of uncertainty. In statistical terms, risk is the expected value of a potential loss (Ceres 2012b). In other words, risk is the probability of an adverse outcome occurring multiplied by the consequence of the outcome.[26]

BCA Considerations: Risk is not the same as uncertainty, although the two are often linked. It is uncertainty that creates the potential for risk. Uncertainty occurs when the 'correct' or 'exact' value of a parameter is not known or cannot be known (EPRI 2015a). For example, when conducting a BCA test, there might be uncertainty regarding fuel costs, load growth, power plant construction times, or customer adoption of new technologies.

There are several methods that can be used to account for uncertainty, and they fall into two general categories. The first includes sensitivity and scenario analyses that examine risk by running several BCA tests for individual inputs or groups of inputs to produce results for a variety of different futures. The second category includes methods that monetize or otherwise value risk for specific impacts. These include expected value analysis, estimating direct risk, financial hedging, using a risk adder, and using risk-adjusted discount rates.

See Appendix L for a detailed discussion on accounting for risk and uncertainty in a BCA test and Appendix H on discount rates.

Utility System Reliability and Resilience

This section provides definitions of *utility system* reliability and resilience and addresses the key distinction between the two impacts. Sections 6.6 and 6.7 provide guidance on accounting for host customer and societal resilience impacts. Section 6.8 provides a summary comparison of accounting for DER related reliability and resilience impacts and how to ensure that these impacts are not double counted in BCAs across different impact categories.

Utility System Reliability

Definition: Utility system reliability (sometimes referred to as 'grid' reliability) focuses on preventing or avoiding routine short-term outages under normal operating conditions due to fluctuating load and generation, fuel availability, and/or outage of assets (e.g., equipment failure) (NARUC 2025).

BCA Considerations: Utilities make generation, transmission, and distribution investments to maintain reliability standards. Utilities also implement many operational procedures to withstand and respond to reliability events. Some DERs can either help meet those standards or exceed them, in particular with regard to grid reliability at the distribution system level.

The electricity grid operates around reliability standards that require enough reserve capacity to maintain service to customers, even if there is a failure of a large asset/component (e.g., transmission line or power plant) to perform/operate.

[26] 'Probability' can be further broken down as the 'threat' multiplied by the 'vulnerability' of an adverse outcome, as described in the context of energy security risk in the report: Risk Assessment Essentials for State Energy Security Plans, April 2024 (DOE 2024d).

Distribution system reliability is typically measured by standard industry metrics presented in Table 6-3 below.

Table 6-3. Electric Utility – Distribution System Reliability Metrics

Area	Utility-Specific Metrics
Distribution	System Average Interruption Duration Index (SAIDI) System Average Interruption Frequency Index (SAIFI) Customer Average Interruption Duration Index (CAIDI) Customers Experiencing Multiple Interruptions (CEMI) Customers Experiencing Longest Interruption Duration (CELID) Momentary Average Interruption Frequency Index (MAIFI)

EPRI 2025.

The most common reliability metrics are those related to the frequency and duration of interruptions relative to the distribution system:

- *SAIDI (System Average Interruption Duration Index):* Measures the total duration of interruptions (in minutes or hours) for the average customer during a year
- *SAIFI (System Average Interruption Frequency Index):* Measures the average number of times a customer experiences a sustained interruption (typically > 5 minutes) in a year.
- *CAIDI (Customer Average Interruption Duration Index):* Represents the average time required to restore power, calculated by dividing total restoration time by the number of interruptions.

These metrics can be further broken down to provide more granular data to address outage events by geography, customer type, voltage class, chronic outage clusters (e.g., using CEMI metric) and customer outage duration (e.g., CELID).

Utility reliability impacts can be monetized by estimating an appropriate Value of Lost Load (VoLL) to all customers associated with avoiding outages due to normal operating conditions. Using data collected from SAIDI, SAIFI and CAIDI metrics, the VoLL—which reflect the cost to consumers during outages based on the metrics—can be monetized and included in a BCA test. The Customer Interruption Cost (CIC) approach is a common method used to estimate VoLL (NESP 2022). Tools, such as the Interruption Cost Estimate (ICE) Calculator (LBNL 2025a) can be used to estimate VoLL, which applies the CIC approach using customer surveys and their willingness to pay (WTP) for improved reliability to avoid outages.[27]

Utility System 'Grid' Resilience

Definition: There is no commonly used definition of utility system resilience, or definitions for each domain (generation, transmission, and distribution). In this Manual, resilience is generally defined as 'the ability to prepare for threats and hazards, adapt to changing conditions, and withstand and

[27] The ICE Calculator WTP values are updated on a periodic basis. To the extent values may not apply to specific jurisdictions, a 'revealed preferences' approach can be used. This is based on analyzing the actual costs incurred during real-world outages or customer interruptions. These studies, however, can be costly and difficult to undertake.

recover rapidly from disruptions' (White House 2025). Such disruptions are often due to high-impact, unpredictable and infrequent events like natural disasters (hurricanes, wildfires) or physical or cyberattacks on the electric system. Utility system grid resilience investments focus on preventing major outages, and restoring power once the outage occurs, regardless of the outage duration. Grid resilience investments further aim to minimize the outage scale, duration, and time for the recovery of service (response to the outage event).

BCA Considerations: Most utility investments in grid resilience are associated with distribution system maintenance and planning activities such as grid hardening, vegetation management, and undergrounding distribution lines to prevent storm, wildfire and other damage associated with extreme weather events, as well as energy security investments associated with reducing threats of cybersecurity or physical attacks on the distribution system.

Utility distribution system plans typically present a range of strategies to meet resilience goals and objectives set forth by the jurisdiction's policies and/or by their commission. These resilience strategies often focus on grid investments such as grid hardening, vegetation management, and undergrounding distribution lines to prevent storm, wildfire and other damage associated with extreme weather events. In some cases, strategically located microgrids may be alternatives to upgrading or hardening distribution infrastructure.

The role of DERs in providing *utility system grid resilience benefits (or costs*) is limited, because such impacts are likely not material to reducing the overall cost of preventing, or the cost of restoration from, extreme outage events. Most resilience impacts from DER investments (in the form of better withstanding power disruptions), typically flow to host customers who invest in certain DERs, or to society, as discussed further below.

There may be some DER use cases, however, that can provide utility system grid resilience benefits. For example, when customers self-supply or ride-through severe outage events as a result of e.g., storage and islanded microgrids,[28] this can allow the utility to prioritize the deployment of resources to repair the distribution system and reduce the number of emergency calls (which in turn can potentially reduce storm restoration costs as a result of the reduced need for overtime labor support). Such benefits, to the extent considered material, should be included in the BCA.

In cases where jurisdictions choose to evaluate utility system grid resilience impacts from DER investments, they can use metrics similar to those used for reporting on utility system reliability (e.g., SAIDI, SAIFI, CAIDI), but with an added focus on extreme (non-routine) events and outage response-related metrics (e.g., time to restore 50% and/or 90% of customers). Moreover, while standard reliability metrics rely on historical, frequent outage data, resilience metrics require analyzing high-stress, low-probability events (e.g., through scenario-based modeling) that can cause severe, and often long-duration outages. (EPRI 2025.) In this case, determining monetized resilience values to include in a BCA requires comparing a reference case to a DER case (e.g., comparing utility 'baseline' restoration costs to an 'improved' or 'worse' case resulting from a DER

[28] The term 'ride-through' capacity refers to the ability of DERs to operate during a power outage. The term 'islanding' capacity refers to the ability to isolate a set of customers to operate independently from the rest of the grid, e.g., with a microgrid.

investment(s)). The response-related resilience metrics would then be used to indicate the differences in resilience outcomes across the two cases.

Strategically located microgrids that have the capability of islanding (e.g., a community or set of customers providing critical services) might provide cost-effective alternatives to upgrading or hardening distribution infrastructure to improve resilience (PNNL 2020). In such cases, a BCA could be conducted separately for a microgrid case and distribution hardening case, where each BCA would use the same reference case that assumes no investment is made to improve resilience. Each BCA would include those benefits associated with the specific investment: the grid hardening BCA would include resilience benefits, while the microgrid BCA would include resilience benefits plus other impacts (such as reduced energy, capacity, transmission and distribution costs to the system). The net benefits of the distribution hardening case could then be compared to the net benefits of the microgrid case to determine which option offers the most net benefits.

Most resilience impacts from DER investments typically flow to host customers who invest in certain DERs —whether to residential or small business customers, critical facilities (e.g., hospitals, police and fire stations), major industrial production facilities, military and defense sites, and data centers, as well as to society more broadly that benefits from the provision of critical and other key services during major event outages.

BCA practitioners should avoid any double counting of grid resilience impacts with accounting for host customer and societal related resilience impacts, as further addressed in Sections 6.6.2 and 6.7.2 below.

Most resilience impacts from DER investments typically flow to host customers who invest in certain DERs —whether to residential or small business customers, critical facilities (e.g., hospitals, police and fire stations), major industrial production facilities, military and defense sites, and data centers, as well as to society more broadly that benefits from the provision of critical and other key services during major event outages.

6.3.6. General Impacts

Financial Incentives

Definition: Utilities provide support in the form of financial incentives to DER host customers or other market actors (e.g., retailers, contractors, distributors, manufacturers, integrators, and aggregators) to encourage DER implementation.

BCA Considerations: Financial incentives come in various forms, including rebates, buy-downs of interest rates for financing a portion of DER costs, payments to support trade ally reporting on sales of DERs, funding or co-funding of marketing of DER equipment by trade allies, and sales bonuses provided to retail or contractor sales staff for selling DER equipment.

Time-of-use rates and DG tariffs are also examples of financial incentives used to support DER implementation. Time-of-use rates incentivize customers to shift load from high-cost peak periods to low-cost off-peak periods. If customers can shift load to off-peak periods they receive financial incentives in the form of lower monthly bills. DG tariffs provide financial incentives by compensating host customers for the output from DG systems. See Chapter 9.7 for further discussion on DG tariffs.

Utility Direct Investment

Definition: Utilities incur direct investment costs when they purchase or own DERs.

BCA Considerations: Utilities might purchase or own DERs, typically to deploy them on the utility side of the meter. One example would be a utility-owned battery storage device deployed to address distribution system needs (e.g., as part of non-wires solutions).

Program Administration Costs

Definition: Program administration costs are those incurred by the utility related to the design, implementation, and evaluation of a DER program or initiative.

BCA Considerations: These costs may come in a variety of forms, including costs to support utility outreach to trade allies, technical training, other forms of technical support, marketing, administration, and management of DER programs and/or portfolios of programs. Administration costs also often include evaluation, measurement, and verification studies to inform either DER program design or retrospective assessment of DER performance.

Utility Performance Incentives

Definition: In many jurisdictions, utilities can receive shareholder incentives for meeting specific performance metrics related to the success of DER programs. These performance incentives represent a cost associated with the delivery of the DER program.

BCA Considerations: DER performance incentives can take many forms, including shared savings mechanisms, payments for meeting energy savings targets, payments for meeting capacity savings targets, or combinations of the above. Performance incentives can be rewards, or penalties, or both. This impact is not relevant for jurisdictions that do not have utility performance incentives in place.

Credit and Collection Costs

Definition: Credit and collection costs are those associated with customers who are deficient on their energy bill payments. These costs include notices and support provided to customers in arrears, shutting off service and turning it back on, carrying costs associated with arrears, and writing off bad debt.

BCA Considerations: To the extent a DER lowers a host customer's energy bill, it may reduce the probability of the customer falling behind or defaulting on bill payment obligations and therefore result in a utility benefit. This may be a particularly important benefit of DER programs targeted at low-income customers.

6.4. Natural Gas Utility System Impacts

6.4.1. Summary

In the context where a natural gas utility implements or otherwise supports DERs, the full range of natural gas utility system impacts serve as the foundation of a jurisdiction's primary BCA test (see *Principle 2: Review and Account for Relevant and Material Utility System Impacts*). However, not all natural gas utility system impacts are relevant or material to specific DER types, as described in this section.

Table 6-4 presents a list of the potential natural gas utility system impacts most associated with gas DERs and a description of each impact. For example, an EE program offered by a natural gas utility can result in commodity and capacity benefits. Such programs can also result in costs associated with financial incentives, program administration, and utility performance incentives.

Table 6-4. Natural Gas Utility System Impacts

Type	Utility System Impact	Description
Energy/Supply	Gas Commodity	The natural gas capacity required to meet forecasted peak load as well as the fuel and O&M impacts associated with natural gas
	Capacity	The natural gas capacity required to meet forecasted peak load
	Environmental Compliance	Actions required to comply with environmental regulations
	Market Price Effects	The decrease (or increase) in wholesale prices is due to reduced (or increased) customer consumption
Transportation	Pipeline Capacity	The transport of natural gas from delivery points located on interstate and intrastate pipelines to distribution utility city gate
	Pipeline Losses	Natural gas lost during pipeline transport
Distribution	Local Delivery Capacity	Delivery of natural gas from the distribution utility city gate to retail customers
	Local Delivery Losses	Natural gas lost on the distribution system
Cross-cutting Energy, T&D	Risk	An adverse outcome that can occur due to uncertainty
	Reliability	Maintaining the natural 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
General	Financial Incentives	Utility financial support provided to DER host customers or other market actors to encourage DER implementation
	Program Administration Costs	Utility outreach to trade allies, technical training, marketing, and administration and management of DERs
	Utility Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of DER programs
	Credit and Collection Costs	Bad debt, disconnections, reconnections

Table 6-5 presents the list of natural gas utility system impacts and indicates whether the impact of gas DERs is likely to be a cost or a benefit to the natural gas utility system. The columns for natural gas DG and gas DS are marked as not relevant (NR) because natural gas utilities do not typically implement or otherwise support these types of DERs. The table also includes a column illustrating the potential impacts of electrification on the natural gas utility system, in cases where natural gas utilities invest in electrification measures (e.g., heat pumps).

The impacts presented in Table 6-5 indicate the potential benefits and costs of natural gas utility DER investments on the most common natural gas utility system impacts. This table is illustrative as there may be specific use cases or contexts where the impact may be differently characterized than what is presented in the table.

Table 6-5. Potential Benefits and Costs: Natural Gas Utility System

Type	Utility System Impact	Gas EE	Gas DR	Gas DG	Gas DS	ELEC
Energy/Supply	Gas Commodity	●	●	NR	NR	●
	Capacity	●	●	NR	NR	●
	Environmental Compliance	●	NM	NR	NR	●
	Market Price Effects	●	NM	NR	NR	●
Transportation	Pipeline Capacity	●	●	NR	NR	●
	Pipeline Losses	●	●	NR	NR	●
Distribution	Local Delivery Capacity	●	●	NR	NR	●
	Local Delivery Losses	●	●	NR	NR	●
Cross-cutting Energy, T&D	Risk	●	●	NR	NR	●
	Reliability	●	●	NR	NR	●
	Resilience	NR	NR	NR	NR	NR
General	Financial Incentives	●	●	NR	NR	●
	Program Administration Costs	●	●	NR	NR	●
	Utility Performance Incentives	● / NR	● / NR	NR	NR	● / NR
	Credit and Collection Costs	●	●	NR	NR	●

● = typically a benefit for DER type; ● = typically a cost for DER type; ● = either a benefit or cost for DER type, depending upon the application of the DER; NM = typically not material; NR = not relevant for DER type.

Note that certain electric utility DER programs or strategies can impact the natural gas utility system (and non-utility system) impacts. Examples of this include: the reduced consumption of natural gas space heating that results from electric utility EE programs that provide air sealing to reduce air-conditioner loads, the increased consumption of natural gas from DR programs that rely upon back-up generators, and the increased consumption in natural gas resulting from electric utility combined heat and power (CHP) programs.

Additional details on how natural gas utility DER programs impact the natural gas utility system is provided in Chapters 8–12 for each DER type, including how electric utility DER programs can impact the natural gas utility system (specifically addressed in the EE, DR and DG chapters).

6.4.2. Energy/Supply Impacts

Natural Gas Commodity

Definition: Utilities incur expenses from the procurement of natural gas on behalf of customers, including any related variable O&M costs. This can include the costs related to the transport of natural gas from delivery points located on interstate and intrastate pipelines to customers.

BCA Considerations: Some DERs will create natural gas commodity benefits when they reduce the amount of natural gas that utilities need to procure to meet customer demand. Among the most common examples are EE measures such as insulation, air sealing, high efficiency boilers and furnaces, and electrification (e.g., heat pumps). Alternatively, some DERs such as CHP systems or fuel cells may increase consumption of natural gas. Furthermore, electric efficiency resources can reduce the 'waste heat' from inefficient lighting, refrigeration, or air-flow components, thereby increasing the need for natural gas used for building space heating.

Capacity

Definition: Natural gas utilities contract for firm pipeline transport and storage capacity to meet customer demand. This ensures that pipeline capacity is available when needed to distribute natural gas to customers with firm service contracts.

BCA Considerations: The impact of DERs depends on how their operation affects natural gas consumption during peak hours. For example, natural gas EE or DR programs—potentially as part of a non-pipes solution (NPS)—can lower demand for natural gas supply during peak times and create benefits. Alternatively, if DERs increase demand on other fuel capacity during peak times (e.g., CHP or fuel cells), it will create an added cost for the utility.

Environmental Compliance

Definition: There are costs associated with environmental regulations for natural gas utility (e.g., caps on methane emissions). This is comparable to the environmental compliance costs for electricity resources described earlier (see Section 6.3.2.).

BCA Considerations: As with other impacts, the net effect of a DER on environmental compliance depends on how it affects consumption of natural gas: if it lowers consumption, it will produce a benefit, and vice versa (see Section 6.3.2.).

Wholesale Market Price Effects

Definition: Wholesale market prices for natural gas are a function of the magnitude of demand and the marginal costs of suppliers at any given instant. When DERs reduce (or increase) the demand for natural gas, they reduce (or increase) the wholesale natural gas prices, which creates benefits (or costs) for all customers participating in the wholesale natural gas market at that time (AESC 2024). This is similar to the wholesale MPEs for wholesale electricity markets (see Section 6.3.2).

BCA Considerations: In general, DERs that reduce the amount of natural gas that utilities need to produce or procure to meet customer demand create MPE benefits. Conversely, DERs that increase consumption of natural gas can create MPE costs.

6.4.3. Transportation Impacts

Pipeline Capacity

Definition: Natural gas utilities incur costs related to the transport of natural gas from delivery points located on interstate and intrastate pipelines to distribution utility city gate.

BCA Considerations: For most natural gas distribution utilities, the main source of natural gas capacity costs is the fixed charges for pipeline transportation services that deliver natural gas to the utility city gate. Natural gas distribution utilities typically enter long-term contracts for pipeline delivery capacity with the option to terminate or continue service at the end of the initial contract term. These costs may be embedded in natural gas capacity costs, and it is important not to double-count those.

Pipeline Losses

Definition: Pipeline losses occur when a portion of the natural gas that flows through natural gas pipelines does not reach the distribution utility city gate.

BCA Considerations: A portion of the natural gas that flows through natural gas pipelines does not reach the end-use customer, in part due to pipeline gas leaks. Additionally, pipeline operators retain a portion of the natural gas shipped for compressor fuel and to account for measurement errors.

6.4.4. Distribution Impacts

Local Delivery Capacity

Definition: Local delivery capacity refers to the maximum volume of natural gas that a distribution utility can transport through its local network (the distribution utility's city gate) to end-use retail customers.

BCA Considerations: Natural gas distribution utilities operate the gas mains that connect the transmission pipelines and on-system storage and peaking facilities to homes, businesses, and industrial facilities within their service territories. Natural gas distribution utilities often provide both bundled services, where the customer buys gas from the utility, and unbundled services, where the customer buys natural gas from a marketer and the utility transports the gas to the customer meter.

Local Delivery Losses

Definition: Some of the natural gas that flows through the gas distribution system does not reach the end-use customer.

BCA Considerations: At the gas distribution level, the difference between the total quantity of natural gas measured entering the distribution system and the total quantity of natural gas delivered to end-use customers or used for natural gas utility operations is often referred to as lost and unaccounted for (LAUF) gas. LAUF gas may include leakage, venting, theft, and gas used by the distribution company itself.

6.4.5. Cross-cutting Energy, Transportation and Distribution

Risk

Definition: Risk is defined as an adverse outcome that can occur because of uncertainty. In statistical terms, risk is the expected value of a potential loss (Ceres 2012). In other words, risk is the probability of an adverse outcome occurring multiplied by the consequence of the outcome.

BCA Considerations: Risk is not the same as uncertainty, although the two are often linked. Uncertainty creates the potential for risk and occurs in situations where the 'correct' or 'exact' value of a parameter is not known or cannot be known (EPRI 2015b). For example, when conducting a BCA, the analysis of future benefits and costs includes a degree of uncertainty. Uncertainty is not monetized in BCA tests. Rather, BCA practitioners can use sensitivity analysis to consider uncertain impacts. In contrast, BCA tests include risk monetized using several different methods. These methods include expected value analysis, direct risk estimate, financial hedging, and use of risk-adjusted discount rates. See Appendix L for a detailed discussion on accounting for risk and uncertainty in a BCA test and Appendix H on discount rates.

Reliability

Definition: Reliability is the ability to maintain the natural gas utility system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components. Reliability addresses high-frequency, routine, low-impact events (DOE 2017c).

BCA Considerations: DERs that reduce natural gas consumption during peak periods (e.g., EE, DR, electrification) can improve reliability through eliminating or reducing demand spikes and pipeline constraints. This can help to reduce the probability and/or likely duration of natural gas and other fuel delivery interruptions to natural gas customers (see Section 6.3.5).

Resilience

Definition: Resilience is generally defined as 'the ability to prepare for threats and hazards, adapt to changing conditions, and withstand and recover rapidly from disruptions' (White House 2025). Such disruptions are often due to high-impact, unpredictable and infrequent events like natural disasters (e.g., hurricanes, wildfires), extreme weather or physical or cyberattacks on the natural gas infrastructure.

BCA Considerations: Natural gas infrastructure is susceptible to extreme weather conditions that can cause long-duration loss of service and damage to pipelines. However, there is limited research available on the impacts of DERs on natural gas system resilience.

6.4.6. General Impacts

Financial Incentives

Definition: Utility provision of financial incentives to support DER host customers or other market actors (e.g., retailers, contractors, distributors, manufacturers, integrators, and aggregators) to encourage DER implementation.

BCA Considerations: Financial incentives may come in various forms, including rebates for DER technologies, buy-downs of interest rates for financing a portion of DER costs, payments to support trade ally reporting on sales of DERs, funding or co-funding of marketing of DER equipment by trade allies, and sales bonuses provided to retail or contractor sales staff for selling DER equipment.

Program Administration Costs

Definition: Program administration costs are those incurred by the utility related to the design, implementation, and evaluation of a DER program or initiative.

BCA Considerations: These costs may come in a variety of forms, including costs to support utility outreach to trade allies, technical training, other forms of technical support, marketing, administration, and management of DER programs and/or portfolios of programs. Administration costs also often include evaluation, measurement, and verification studies to inform either DER program design or retrospective assessment of DER performance.

Utility Performance Incentives

Definition: In many jurisdictions, utilities can receive shareholder incentives for meeting specific performance metrics related to the success of DER programs. These performance incentives represent a cost associated with the delivery of the DER program.

BCA Considerations: DER performance incentives can take many forms, including shared savings mechanisms, payments for meeting energy savings targets, payments for meeting capacity savings targets, or combinations of the above. Some jurisdictions might include penalties for not meeting performance targets.

Credit and Collection Costs

Definition: Credit and collection costs are those associated with customers who are deficient on energy bill payments, including notices and support provided to customers in arrears, shutting off service and turning it back on, carrying costs associated with arrears, and writing off bad debt.

BCA Considerations: To the extent a DER lowers a host customer's energy bill, it can reduce the probability of the customer falling behind or defaulting on bill payment obligations and therefore result in a utility benefit. This might be a particularly important benefit of DER programs targeted at low-income customers.

6.5. Other Fuel Impacts

6.5.1. Summary

Electric and natural gas utility DERs can affect other types of fuels, such as oil, propane, diesel, biomass (including wood), or gasoline. Common examples of DERs that affect other fuels include:

- an electric utility ratepayer-funded EE program that targets space heating and reduces consumption of oil, propane, or wood;
- a building electrification program that encourages customers to switch space heating systems from those that use oil, propane, or wood; and
- an EV program that results in reduced gasoline consumption.

The impacts in Table 6-6 are the most common examples of other fuel impacts that can either increase or decrease costs due to a DER investment.

There are also cases where electric utility DERs affect natural gas, and natural gas utility DERs affect electricity. For example, a natural gas utility ratepayer funded EE program supporting the weatherization of homes to reduce natural gas used for space heating can also reduce the amount of electricity used for space cooling. In these instances, the BCA test includes the applicable

electric utility system impacts (see Section 6.3) or natural gas utility system impacts (Section 6.4) from the DER.

Chapters 8–12 provide details on the impacts presented below for each DER type.

Table 6-6. Other Fuel System Impacts

Type	Other Fuel System Impact	Description
Other Fuels (oil, propane, wood, gasoline)	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

In some situations these impacts might be costs, while in other situations they may be benefits, as shown in Table 6-7. For example, building electrification will always be a benefit due to removing or reducing the other fuel heating source. However, EE programs can reduce and increase consumption of other fuels. For example, LEDs installed in a building will emit less heat and may result in increased consumption of other fuels if the building uses oil, propane, or wood heating.

Table 6-7. Potential Benefits and Costs: Other Fuel Systems

Type	Other Fuel System Impact	EE	DR	DG	DS	ELEC
Other Fuels (oil, propane, wood, gasoline)	Commodity	●	●	●	NR	●
	Environmental Compliance	●	●	●	NR	●
	Market Price Effects	●	NM	NM	NR	●

● = typically a benefit for DER type; ● = typically a cost for DER type; ● = either a benefit or cost for DER type, depending upon the application of DER; NM = typically not material for DER type; NR = not relevant for DER type.

Commodity

Definition: Energy suppliers incur expenses from the procurement of fuel (e.g., oil, propane) on behalf of customers, including any related variable O&M costs.

BCA Considerations: Some DERs will create other commodity benefits when they reduce the number of commodities that utilities need to procure to meet customer demand. Among the most common examples are EE measures such as insulation, air sealing, high efficiency boilers and furnaces, and electrification (e.g., heat pumps). Alternatively, some DERs such as fossil-fuel-powered CHP systems or fuel cells may increase consumption of natural gas. Furthermore, electric efficiency resources can reduce the 'waste heat' from inefficient lighting, refrigeration, or airflow components, thereby increasing the need for other commodities used for building space heating.

Environmental Compliance

Definition: Environmental compliance refers to actions required by a natural gas utility to comply with environmental regulations. This is comparable to the environmental compliance costs for electricity resources described earlier (see Section 6.3.2).

BCA Considerations: As with other impacts, the net effect of a DER on environmental compliance depends on how it affects consumption of other fuels: if it lowers consumption, it will produce a benefit, and vice versa (see Section 6.3.2).

Market Price Effects

Definition: Wholesale markets for oil, propane, and other fuels are a function of the magnitude of demand and the marginal costs of suppliers at any given instant. When DERs reduce (or increase) the demand for other fuels, they reduce (or increase) any associated wholesale market prices. This price change creates benefits (or costs) for all customers participating in wholesale markets at that time (AESC 2024). This is similar to the wholesale MPEs for wholesale electricity markets (see Section 6.3.2).

BCA Considerations: In general, DERs that reduce the use of other fuels that suppliers need to produce or procure to meet customer demand create MPE benefits. Conversely, DERs that increase consumption of other fuels can create MPE costs.

6.6. Host Customer Impacts

6.6.1. Summary

The term 'host customer' in this Manual refers to a customer that installs a DER in their home or business. The host customer might be a participant in a utility-sponsored DER program, a customer who installs DERs with the assistance of a third party, or a customer who installs DERs in response to price signals.

For jurisdictions that include host customer impacts in their JST based on applicable policy goals, Table 6-8 presents a list of the potential host customer impacts commonly associated with DERs and a description of each impact. Host customer impacts can be categorized as 'energy impacts' and 'non-energy impacts' (NEIs), as further discussed below. For additional information on these impacts specific to different DER types, see Chapters 8–12.

Table 6-8. Host Customer Impacts

Type	Host Customer Impact	Description
Host Customer	Host portion of DER costs	Costs incurred to install and operate DERs
	Transaction costs	Other costs incurred to install and operate DERs e.g., time spent researching information, obtaining vendor quotes, filling out rebate applications
	Interconnection fees	Costs paid by host customer to interconnect DERs to the electric grid
	Tax incentives	Federal, state, and local tax incentives provided to host customers to defray the costs of some DERs
	Resilience	Ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions
	Host Customer NEIs	Benefits and costs of DERs that are separate from energy-related impacts

As shown in Table 6-9, in some situations, host customer impacts can be benefits, while in other situations they can be costs, or this will depend on the specific DER type and/or use case.

Table 6-9. Potential Benefits and Costs: Host Customers

Type	Host Customer Impact	EE	DR	DG	DS	ELEC
Host Customer	Host portion of DER costs	●	●	●	●	●
	Host transaction costs	●	●	●	●	●
	Interconnection fees	NR	NR	●	●	NR
	Tax Incentives	●	NR	●	●	●
	Resilience	●	NR	●	●	NR
	Host Customer NEIs	●	●	●	●	●

● = *typically a benefit for DER type;* ● = *typically a cost for DER type;* ● = *either a benefit or cost for DER type, depending upon the DER type or use case; NM = typically not material for DER type; NR = not relevant for DER type.*

6.6.2. Host Customer Energy Impacts

In most cases, the host portion of DER costs, any transaction costs, and any interconnection fees will represent costs to the host customers, while tax incentives and resilience impacts are likely to provide benefits to the host customer. These are each described below.

Host Customer Portion of DER Costs

Host customer costs include those costs incurred to install and operate DERs. Utility financial incentives (e.g., rebates) are often provided to defray some of the incremental costs of DERs. In those cases, the host customer DER cost includes only the portion of the DER cost not covered by the financial incentive.

Host Customer Transaction Costs

Transaction costs are those associated with the host customer's acquisition and installation of DERs. These costs can include time spent by the customer researching information, obtaining quotes from multiple vendors, and applications for rebates and other financing mechanisms. This impact will always manifest itself as a host customer cost for any DER type.

Host Customer Interconnection Fees

Interconnection fees are costs associated with the utility and/or ISO/RTO interconnection process paid for by the host customer. Utilities typically require some DERs (e.g., DG and DS) to pay costs to interconnect to the utility grid. This usually requires host customers (or their vendors) to provide an application with relevant data on equipment, sizing, energy production, and location to ensure they meet necessary standards. Utilities charge an interconnection fee to cover the cost of the application and inspection process. In some cases, more detailed engineering analyses are required, with the host customer being responsible for the additional costs.

Similarly, if a DER owner seeks to participate in the wholesale market and is subject to an ISO/RTO interconnection process, they may incur interconnection costs from the ISO/RTO. In some cases, host customers might incur both the ISO/RTO and utility interconnection costs. It is important to ensure that this cost is not double-counted with the host customer portion of DER costs (many installers will submit and pay for the interconnection fee on behalf of customers as part of the total cost of the system).

Host Customer Tax Incentives

Federal, state, and local tax incentives are sometimes available to host customers to defray the costs of some DERs. Whether to include host customer tax incentives in a BCA depends upon the BCA test used. If the host customer impacts are outside of the test, then host customer tax incentives are not relevant. If both host customer impacts and taxpayer impacts are within the scope of the test, then host customer tax incentives should not be included because they offset each other. If host customer impacts are within the scope of the test but taxpayer impacts are not, then the test should include host customer tax incentives because there is no offsetting impact. See Appendix M for guidance on accounting for tax incentives.

Host Customer Resilience

Resilience in this case refers to the ability of host customers (who participate in a utility DER program or strategy) to avoid, mitigate, or quickly respond to power outages because of DER investments made in their home or building/facility.

DER systems with ride-through capacity (e.g., storage) or islanding capacity (e.g., microgrid) can provide energy to host customers in the event of a power interruption and create a resilience benefit in the form of continued supply of electricity. In addition, certain DERs such as EE weatherization can offer resilience benefits by allowing customers to remain comfortable in their home/building without air conditioning or heating for longer periods of time during an outage.

Examples of host customer resilience metrics associated with DERs are provided in Table 6-10, which can be used as the basis for monetizing DER impacts in BCAs.

Table 6-10. Host Customer Resilience

Example Metrics
• Fuel costs for back-up generator • Avoided outage cost • Loss of assets and perishables • Business interruption costs/production • Electric bill savings – no power • Avoided meal delivery and hotel costs

NARUC 2025, LBNL 2024b, NREL 2022.

As indicated above in Section 6.3.5, the ICE Calculator is one method to calculate the VoLL based on an assessment of the 'cost' of short-duration service interruptions informed by customer surveys and their willingness to pay (WTP) for improved reliability to avoid interruptions for up to a 24-hour period. Accounting for the VoLL *beyond a 24-hour* outage period (e.g., for periods of 2–7 days) would require additional surveys of customers (residential, commercial, and industrial) to assess their anticipated costs associated with the example metrics in Table 6-10 above, and their WTP to avoid such outages. WTP surveys and studies are expensive to conduct, and are typically jurisdiction-specific, though some transferability across jurisdictions (e.g., within the same region) may be possible (see Chapter 14). Jurisdictions will need to transparently document and consider any potential overlap when monetizing host customer resilience and utility system reliability metrics.

See Section 6.8 for further guidance on distinguishing host customer, utility system, and societal reliability and resilience impacts.

6.6.3. Host Customer Non-Energy Impacts

DERs can create a variety of NEI for host customers that are separate from the energy saved or produced by DERs. Table 6-11 presents a summary of host customer NEIs that DERs might create. These impacts can sometimes be benefits or sometimes be costs. The presence, direction, and magnitude of these impacts will depend upon many factors, including the type of DER (e.g., EE, DR, DG, storage, EVs), the specific DER technology (e.g., EE lighting versus EE building conditioning), the type of host customer (e.g., low-income, residential, commercial, industrial), and more.

Unlike the other impact categories where impacts may not be relevant or material, there is typically always a host customer impact associated with each type of DER.

Definition: Table 6-11 defines various types of host customer NEIs.

Table 6-11. Host Customer Non-Energy Impacts

Host Customer NEI	Summary Description
Asset value	Changes in the value of a home or business due to the DER (e.g., increased building value, improved equipment value, extended equipment life)
Water costs	Costs or cost savings from increased or decreased water consumption resulting from DER installation
Business Productivity	Changes in a customer's productivity (e.g., changes in labor costs, operational flexibility, costs, reduced waste streams, reduced spoilage)
Operations and Maintenance	Longer-lived equipment requiring fewer replacements over time, efficient equipment that may need servicing more frequently
Comfort	Changes in comfort level (e.g., thermal, noise, and lighting impacts)
Health and Safety	Changes in customer health or safety (e.g., fewer sick days from work or school, reduced medical costs, improved indoor air quality, reduced deaths)
Other	• Amenity (e.g., reduction in refrigeration capacity from removal of inefficient second refrigerators, increases in cooking control and speed with induction cooktops) • Empowerment (e.g., better sense of control of energy use) • Pride (satisfaction from contributing to solutions to environmental concerns) • Reduced financial stress (especially for low-income households)

BCA Considerations: Some NEIs can be difficult to quantify and monetize. By their nature, DER non-energy benefits and costs are less well known and harder to research than utility system impacts and host customer direct benefits or costs. In addition, the host customer NEIs might vary considerably depending upon the type of customer, the customer's facility, the type of DER, and the operation of the DER. Further, there has been little empirical research on host customer NEIs for some DERs, such as DPV, storage, and EVs.

Nonetheless, the fact that host customer NEIs can be difficult to quantify and monetize does not mean that BCAs should exclude them for the following reasons:

- First, *Principle 3: Account for All Relevant, Material Impacts* states that the BCA test should account for impacts that are relevant and material (i.e., expected to have a material impact on the results), regardless of whether they are hard to quantify. See Chapter 14 for general

guidance on methods for accounting for impacts.) The NEIs associated with asset value, water costs, productivity, O&M, comfort, and health tend to have the most material impact on BCA results compared to those in the 'other' category. Some jurisdictions prioritize time and effort spent on evaluating the NEIs to those that are the most material.

- Second, *Principle 4: Ensure Symmetry in the Treatment of Benefits and Costs* requires that cost-effectiveness practices be symmetrical, where both benefits and costs are included for each relevant type of impact, even if difficult to quantify. This means that if a BCA test includes host customer costs, then it will also include host customer benefits, including non-energy benefits that are relevant and material. Similarly, if a jurisdiction decides not to include host customer NEIs in a BCA test, then it should not include other host customer impacts either.

The magnitude of some NEI benefits (e.g., economic well-being, comfort, health, safety) is often greater for low-income customers than for non-low-income customers. This is because the condition of the low-income housing stock is often worse and/or because the economic stress under which low-income customers live can result in greater sacrifice of amenity (e.g., comfort) absent efficiency investments. In addition, there are NEIs not included in the table above that are largely unique to low-income host customers; these might include reduced home foreclosures and reduced need to move residence due to unpaid bills.

6.7. Societal Impacts

6.7.1. Summary

Table 6-12 presents a list of societal impacts commonly associated with different DER types. These impacts are relevant for parties *other than* the electric utility, natural gas utility, other fuel provider, or host customer. Whether a BCA test includes these impacts is dependent on a jurisdiction's applicable policy goals. Chapters 8–12 provide details on these impacts for each DER type.

Table 6-12. Societal Impacts

Type	Societal Impact	Description
Societal	GHG Emissions	GHG emissions created by 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
	Resilience	Resilience impacts beyond those experienced by utilities or host customers

Jurisdictions often have **energy security** related policies and goals. These goals focus on ensuring that the energy infrastructure is robust, secure, reliable and resilient, and can restore services rapidly in the event of any disaster, whether related to severe weather events, systems and infrastructures failures, and/or deliberate physical or cyberattacks. These types of impacts are captured within utility system reliability, resilience and risk, as well as resilience impacts that affect host customers and society, as discussed in Sections 6.3.5 and 6.6.2 and Appendix L.

Similarly, jurisdictions may have **job creation and other economic development** policies and goals related to DER investments that require analysis of these impacts. While these may be societal in scope, *this requires a different analysis than a BCA*. BCAs measure the extent to which costs change because of the DER investment, while economic development analyses (EDAs) measure the extent to which economic activity changes. See Appendix C for further guidance on conducting EDAs.

Not all societal impacts will be relevant and material to each DER type, as shown in Table 6-13. For example, while DS affects resilience by enabling access to power during an outage, the impact of EVs on resilience is not currently material (as of 2026) due to the limited vehicle-to-grid applications.

In some situations, these impacts might be costs, while in other situations they may be benefits (i.e., avoided costs). For example, as shown in Table 6-13, EE programs will typically reduce electricity generation and thereby provide the benefit of avoided GHG emissions, while electrification resources will typically increase electricity generation and thereby create a cost of increased GHG emissions. As another example, DG fueled by renewable resources will typically reduce environmental compliance costs, but DG fueled by fossil fuels will typically increase environmental compliance costs.

Table 6-13. Potential Benefits and Costs: Societal

Type	Societal Impact	EE	DR	DG	DS	ELEC
Societal	GHG Emissions	●	●	●	●	●
	Other Environmental	●	●	●	●	●
	Public Health	●	●	●	●	●
	Resilience	●	NR	●	●	NR

● = typically a benefit for this DER type; ● = typically a cost for this DER type; ● = either a benefit or cost for this DER type, depending upon the application of DER; NM = typically not material; NR = not relevant for this DER type.

6.7.2. Types of Societal Impacts

Greenhouse Gas Emissions

Definition: GHG emissions come from a variety of sources, such as production, transmission, and distribution of both electricity and natural gas; industrial processes; heating of commercial and residential buildings; transportation; agriculture; and a wide range of activities. Societal GHG emissions represent the emissions that occur *after* compliance with environmental regulations and requirements. These societal emissions are referred to as 'externalities' because the impacts are external to the monetary prices of the goods that create them.

BCA Considerations: The magnitude of DER GHG impacts will depend upon the marginal GHG emissions rate of the resources affected by the DER, which in turn will depend upon when the DER operates. The marginal GHG emission rates from a utility system can vary considerably across hours, days, and months, and they can also vary considerably across utility systems and utility control areas (see Chapter 7 for more detail).

For DERs that impact multiple fuels (e.g., electrification-related DERs, EVs) it is important to identify the environmental impact of all fuels affected by the resource. Electrification and EVs will typically increase the GHG emissions from the electricity industry but will reduce the GHG emissions from other fuel sources. Both effects are necessary to derive the net impact on GHG emissions.

It is important to distinguish between environmental compliance impacts and societal GHG impacts for the following reasons:

- Environmental compliance impacts are utility system impacts that it is good practice for all BCA tests to include.[29] Societal GHG impacts, on the other hand, are the impacts on the environment that occur after environmental compliance regulations have been met and should be included only in those BCA tests that include societal GHG impacts.
- In the context of rate, bill, and participation analyses, environmental compliance impacts are utility system impacts that will affect rates. Therefore, it is appropriate to include them in rate, bill, and participation analyses. Societal GHG impacts, on the other hand, are not utility system impacts, will not affect rates, and therefore are not appropriate to include in rate, bill, and participation analyses.

Other Environmental

Definition: Energy resources can have a variety of environmental impacts beyond GHG emissions. These include other air emissions (i.e., those not included in public health), land use, water consumption, solid waste disposal, liquid waste disposal, fuel mining and transportation, disposal of technologies at the end of their useful life, and more. Societal environmental impacts represent the impacts that occur *after* compliance with environmental regulations and requirements. These societal impacts are referred to as 'externalities' because the impacts are external to the monetary prices of the goods that create them.

BCA Considerations: As with GHG emissions, some DERs might increase other environmental impacts, and some might both increase and reduce environmental impacts. Similarly, it is important to distinguish between environmental compliance impacts and societal environmental impacts, both for determining which impacts to include in BCA test and for conducting rate, bill, and participation impacts.

There is potential for considerable overlap between other environmental impacts and public health impacts. It is important to define and address both types of impacts carefully to avoid double-counting or under-counting of impacts.

Public Health

Definition: Air emissions from fossil fuel extraction, combustion, and transportation can impact public health. Emissions including NO_X, SO_2, particulate matter (e.g., PM2.5), ozone, carbon monoxide, volatile organic compounds, mercury, and lead can have implications for the health and well-being of the affected populations (e.g., premature death, chronic and acute bronchitis, non-fatal heart attacks, respiratory or cardiovascular hospital admissions, upper and lower respiratory symptoms, asthma and asthma-related hospital visits) (EPA 2018).

BCA Considerations: The primary way DERs create a public health impact is by increasing or decreasing air emissions. For example, EVs reduce NO_X, SO_2, and PM2.5 emissions compared to an internal combustion vehicle. Similarly, DERs that create a reduction in energy generation can often reduce a marginal generation unit's output and its associated air and water pollution.

[29] Except for the Participant Cost Test.

There is potential for considerable overlap between other environmental impacts and public health impacts. It is important to define and address both types of impacts carefully to avoid double-counting or under-counting of impacts.

Societal Resilience

Definition: Societal Resilience refers to the ability of certain facilities—identified as 'critical' by the jurisdiction—to provide services to the jurisdiction's population during the period of an outage caused by extreme events, regardless of the outage duration.[30]

BCA Considerations: Society can realize DER resilience impacts that are above and beyond those that accrue to host customers and to the utility. Some DERs (e.g., DG combined with DS) allow for critical facilities such as hospitals, fire stations, police stations, water treatment facilities, and other services to continue providing services to 'society' during power outages. Other critical assets within a jurisdiction can include key production facilities such as food, medical equipment, military services, and data centers.

Societal resilience metrics, as shown in Table 6-14 can include changes in SAIDI, SAIFI, and CAIDI metrics for major event outages and the time to respond to safety and critical infrastructure needs, the number of critical customers without power, and the duration of the outage (LBNL 2025b). Other key metrics can be used to estimate the cost to society because of outages, and to inform how DER investments can reduce (or increase) those estimated costs.

Table 6-14. DER Societal Resilience Impacts – Example Metrics

Example Metrics for Critical Facilities and Assets
• Average number (or %) critical services without power (e.g. hospitals, fire stations, police stations) • Average number (or %) critical services without power for more than N hours (e.g., N > hours of backup fuel required) • Time to restore critical facilities • Avoided deaths from critical facilities being able to maintain power during outage • Avoided damages to societal goods and infrastructure (e.g., food spoilage, medicine spoilage, drinking water, sewage treatment systems) • Reduced # of customers using diesel generators, and associated reduction in air pollution • Average number (or %) critical assets without power such as key production or manufacturing facilities (e.g., medical related, grocery stores), military facilities, data centers

Source: NARUC 2025.

Dollar values can be developed for some of the metrics above to reflect the avoided costs to society and critical infrastructure when DERs provide power during outages. Such estimates of avoided costs would require primary research based on surveys of critical facilities and asset owners (to assess VoLL), as well as societal economic and health assessments of potential

[30] Additionally, societal resilience impacts extend to the ability of a state or regional economic system to withstand and respond to widespread and long duration interruptions minimizing labor, price, and economic output impacts. Consistent with NSPM guidance in Appendix C, this type of analysis should be conducted separately from BCAs but can serve as complementary analyses to inform DER investment decisions. Tools for estimating societal economic resilience impacts for long-duration power interruptions include LBNL's Power Outage Economic Tool (POET) which uses surveys and regional economic models to calculate GDP loss and price/labor changes. (LBNL 2024c)

damages to infrastructure (e.g., food spoilage, medicine spoilage, drinking water, sewage treatment systems). Because a host customer can also be a critical facility or asset, it is important to avoid potential double counting of societal and host customer resilience impacts.

See Section 6.8 for further guidance on distinguishing between host customer, utility system, and societal reliability and resilience impacts.

6.8. Reliability and Resilience Impacts - Summary

This section summarizes the key guidance and considerations provided on DER reliability and resilience impacts in this chapter and includes a side-by-side comparison of definitions and how to account for each impact in a BCA.

- **Reliability** (sometimes referred to as 'grid' reliability) focuses on preventing or avoiding routine short-term outages under normal operating conditions due to fluctuating load and generation, fuel availability, minor storms and/or normal outage of assets (e.g., equipment failure) (NARUC 2025). DER reliability impacts in BCA apply *only to the utility system*.
- **Resilience** is generally defined as 'the ability to prepare for threats and hazards, adapt to changing conditions, and withstand and recover rapidly from disruptions') (NARUC 2025). Such disruptions are often due to high-impact, unpredictable and infrequent events like natural disasters (hurricanes, wildfires) or physical or cyberattacks on the electric system. Resilience focuses mostly on how to better enable *restoration of power once an outage occurs*, regardless of the duration of the outage, and aims to minimize the outage impact, duration, and scope and measures the speed of recovery of service. Resilience impacts can apply to the utility system, host customers and/or society, though in the case of DERs, the impact largely flows to host customers and society.

In summary, where reliability focuses primarily on the anticipated risks associated with normal operating conditions, resilience expands the scope to consider how the electricity system can respond to the less frequent, but more severe, impacts of extreme events.

Table 6-15. illustrates how reliability and resilience may not be relevant or material impacts for some DERs and may be either a benefit or cost depending on the DER type.

Table 6-15. Reliability and Resilience Impacts by DER

Impact	Category	EE	DR	DG	DS	ELEC
Reliability	Electric Utility System	●	●	●	●	●
	Gas Utility System	●	●	NR	NR	●
	Host Customer	NR	NR	NR	NR	NR
	Societal	NR	NR	NR	NR	NR
Resilience	Electric Utility System	NR	NR	NM	NM	NM
	Gas Utility System	NR	NR	NR	NR	NM
	Host Customer	●	NR	●	●	NR
	Societal	●	NR	●	●	NR

● = typically a benefit for this DER type; ● = typically a cost for this DER type; ● = either a benefit or cost for this DER type, depending upon the application of DER; NM = typically not material; NR = not relevant for this DER type.

Avoid double-counting

As noted earlier, there may be overlap between host customer resilience and societal resilience impacts. For example, host customers that install certain DERs (i.e., solar plus storage, weatherization) can better withstand recovery from power outages. When those host customers provide critical services to society (i.e., hospitals, fire and rescue services, shelters), a societal impact is created. To avoid double counting in such instances, a BCA test should only include resilience for such customers as either a host customer impact or a societal impact.

Table 6-16. below compares reliability and resilience impacts when considering inclusion in BCAs. See also Chapter 14 of this Manual for additional information on methodologies for accounting for BCA impacts.

Table 6-16. Summary – DER Reliability and Resilience Impacts

Impact	Category	Description and Accounting for Impacts in BCAs
Reliability	**Utility System**	Utilities make generation, transmission, and distribution investments to maintain reliability standards. Some DERs can either help meet those standards or exceed them. Reliability standards include a range of metrics commonly used in the industry, including SAIDI, SAIFI, CAIDI. Monetization of reliability impacts for use in a BCA can be captured by using tools such as the ICE Calculator.
Resilience	**Utility System**	The role of DERs in providing utility system grid resilience benefits (or costs) is limited, because such impacts are likely not material to reducing the overall cost of preventing, or the cost of restoration from, extreme outage events. There may be some exceptions where customers can self-supply or ride through severe outage events because of DERs, such as microgrids, allowing the utility to prioritize use of resources to repair the system and reduce restoration costs.
	Host Customer	DERs can provide benefits to host customers who install certain DERs (e.g., solar plus storage, weatherization) allowing them to better withstand and recover from short and long duration power outages. Monetized values can be assigned to costs that are avoided when a DER provides power during an outage, such as loss of medical equipment operation for host customers, spoilage of perishable food, damaged equipment, and diminished worker productivity.
	Societal	DERs can provide important benefits to critical facilities (e.g., hospitals, fire stations, police stations) when they install DERs to better withstand and recover from short and long duration power outages from extreme, non-routine events to provide services to society. Additionally, DERs can reduce the loss of power to large businesses that support essential services (e.g., certain manufacturing facilities, data centers, etc.) Monetized values can be assigned to costs that are avoided for societal goods and infrastructure when a DER provides power during an outage such as, medicine spoilage, drinking water, and sewage treatment systems.

7. Cross-Cutting Benefit and Cost Considerations

This chapter discusses DER attributes and considerations that cut across multiple DER types and affect the valuation and materiality of the DER impacts listed in Chapter 6. Some of these DER attributes that have an impact on a specific DER type are further discussed in the specific DER chapters (Chapters 8–12). Those attributes that are essential to the BCA of DER specific scenarios (on-site, non-infrastructure solutions, VPPs, or microgrids) are further discussed in Chapter 13.

7.1. Summary of Key Points

- *Temporal and locational impacts of DERs*: The benefits and costs of DERs will vary depending on when they operate and where they are located. DER benefits and costs estimations require sufficient temporal and locational detail to adequately represent the DER operating patterns and consequent benefits and costs.
- *Interactive impacts between DER types*: Some DER types can have interactive effects on other DERs in terms of (1) the magnitude of kW or kWh impacts of other DERs, (2) enablement of other DER types, and (3) marginal system costs. It is best for BCA tests to account for these interactive effects when they are likely to have a material impact.
- *Grid and demand flexibility*: The role of DERs in providing grid flexibility is primarily through demand flexibility. Demand flexibility can make the system more reliable, stable, resilient, and efficient by providing the ability to shed, shift, and/or modulate load to support grid needs, particularly during peak periods. Benefits or costs associated with grid or demand flexibility from DERs typically affect the magnitude of DER impacts, primarily for utility system impacts.
- *Resource ownership and control*: The entity that owns and controls the subject DERs determines when and how they are operated, with significant implications for the resource's benefits and costs, particularly for which entities bear those benefits and costs.
- *Behind- versus in-front-of-the meter DERs*: Some DERs are located in front of the meter and primarily serve to reduce utility system costs. Others are located BTM and mainly serve to reduce customer costs. While the impact categories for these types of DERs are similar, there may be significant differences in operation between utility and host customer needs. A BCA test will need to identify and account for these differences.
- *Wholesale market revenues*: Some DERs are eligible to participate in wholesale electricity markets, which provide revenues to host customers or DER aggregators. These revenues should not be included in BCA tests if this would result in double-counting of the energy, generation capacity, and ancillary services benefits to the utility system.
- *Free-riders and spillover impacts*: Including host-customer (program participant) impacts in a jurisdiction's BCA has important implications for how to treat free-ridership and spillover effects. By definition, jurisdictions focusing on net savings will not benefit from free-riders but will benefit from spillover effects.
- *Rebound effect*: The energy rebound effect is the phenomenon in which energy cost-saving improvements are partially offset by increased energy consumption resulting from behavioral or economic responses. Estimates of the magnitude of the rebound effect vary

significantly. How rebound affects the value of impacts included in BCA can also vary depending on which impacts the BCA test includes, whether the BCA scope includes participant and societal impacts, and the perspectives used.

- *Renewable generation impacts*: DERs can enhance renewable generation by providing grid flexibility and ancillary services to support the increasing amounts of intermittent generation from these resources. DERs can also reduce (or increase) the need to curtail renewable resources during times when renewable generation exceeds customer load. It is important for BCA tests to account for these impacts on renewable generation when those impacts are expected to materially affect the benefits of DERs.
- *Transfer payments and offsetting impacts*: Some impacts from DERs represent transfers from one party to another. In the context of BCAs, an offsetting transfer occurs when one party incurs a cost that is equal to a benefit experienced by another party, and both parties are within the scope of the BCA test. If the cost and corresponding benefit are an offsetting transfer, they will net each other out of the BCA. If the cost and corresponding benefit are not an offsetting transfer, the BCA test should include one of them and exclude the other, depending upon which party is within the scope of the test.

In addition to the considerations discussed below, there are other cross-cutting considerations addressed in the appendices to this Manual. These include geographic boundaries of DER impacts (Appendix F); assessment levels for applying BCA tests (Appendix I); and accounting for uncertainty and risk (Appendix L).

7.2. Uncertainty Creates Risk

All analysis of future benefits and costs includes some degree of uncertainty. The goal of BCA is to provide the information needed to make sound decisions regarding resource investments, despite the uncertainty inherent in resource planning. Uncertainty and risk are linked because uncertainty is what creates the potential for a variety of different outcomes, each with its own probability of occurring. Uncertainty also exists in the costs associated with each such outcome.

Defining risk and uncertainty

In the context of planning, *uncertainty* is defined as the situation where the 'correct' or 'exact' value of a parameter is unknown or cannot be known.

In the context of planning, *risk* is defined as an adverse outcome that can result from uncertainty. In statistical terms, risk is the expected value of a potential loss. Risk is defined by the relationship:

*Risk = probability of the adverse outcome occurring * the consequence of the outcome*

There are a variety of methods available for addressing uncertainty and risk in long-term planning. The most practical methods include the following:

- Direct estimate. Directly estimate the risk value using the risk formula described above: *Risk ($) = probability of the outcome occurring (%) * the consequences of the outcome ($)*. Then add the resulting risk cost (in dollars) to the other costs of the resources that create the risk.

- Hedge value. Estimate the cost of avoiding a risk by calculating the cost of an alternative investment or buying an alternative product that reduces or eliminates the risk of the investment in question. The cost of the alternative can serve as a proxy for the risk. Using a hedge value is comparable to buying insurance to protect against risk.
- Sensitivity analyses. Perform sensitivity analyses to look at how different inputs or modeling assumptions impact benefits and costs. The goal is to determine which inputs or modeling assumptions have the largest impact on the benefit-cost values, and what that impact might be. While conducting sensitivity analyses, change one or more input assumptions at a time to see how those input assumptions are likely to affect the benefits and costs.
- Scenario analyses. Analyze scenarios that account for changes across multiple inputs based upon a specific outlook or forecasting perspective. Base each scenario on a coherent and internally consistent set of assumptions about key relationships and driving forces. Alternative scenarios can serve as alternative model formulations, as alternative sets of input data, or as both.
- Expected value analyses. Use expected value analyses to prioritize and refine sensitivity and scenario analyses by applying probabilities to the different sensitivity and scenario assumptions. Those sensitivities or scenarios with higher probabilities will be given greater weight in the BCA results.
- Risk adder. It may not always be practical to analytically assess and monetize all the ways in which a DER is less or riskier than alternatives. To assign economic value to the relative risk of one or more DERs in such cases, use expert judgment—informed to the extent possible with quantitative and/or qualitative information—to establish a risk 'adder.' This adder is a proxy value typically expressed in volumetric terms (e.g., dollars per MWh) or as a percentage of other benefits or costs.
- Risk-adjusted discount rates. Adjust the discount rate for the BCA test down (or up) to reflect the lower (or higher) risk associated with the resource under evaluation. Risk-adjusted discount rates are an entirely different approach to accounting for risk. This method has the advantage of being simpler than the methods described above, but the disadvantage of being relatively blunt. Section L.2.7, Risk-Adjusted Discount Rates, describes this method in more detail.

7.2.1. Implications of Different Methods

The methods described above have different implications regarding the information and assumptions required, the treatment of uncertainty and/or risk (including the value of risk-aversion), the results of the BCA, and the interpretation of those results. Table 7-1 summarizes these implications.

Table 7-1. Implications of Different Methods of Accounting for Uncertainty and/or Risk

Method	Assumptions Required	Implications for BCA
Sensitivity analysis	Alternative estimates of an uncertain BCA input or inputs	Provides information regarding the range of potential outcomes; results can lead to decisions that deviate from the results of the primary BCA test under the reference case
Scenario analysis	Alternative estimates of multiple related uncertain BCA inputs	Provides information regarding the range of potential outcomes; results can lead to decisions that deviate from the results of the primary BCA test under the reference case
Expected value analysis	Alternative estimates and probabilities of uncertain BCA inputs	Provides a probabilistic, and thus likely more accurate, estimate of uncertain BCA impacts by accounting for the expected value of uncertain outcomes
Direct estimate	The probability and cost of an undesirable outcome associated with a BCA input	Provides a single monetary value of risk for an uncertain BCA impact, based on the probability of the uncertain outcome times the cost of that outcome
Hedge value	The value of a market hedge equivalent to the risk benefit of the BCA input	Provides a single monetary value of risk for an uncertain BCA impact, based on market instruments
Risk adder	A proxy value approximating the degree to which risk is increased or decreased by a DER	Provides a single monetary value of risk associated with a range of BCA impacts, based on stakeholder input and expert judgment
Risk-adjusted discount rates	A market proxy for a low-risk (or high-risk) investment	Low-risk discount rates put greater weight on future BCA impacts under the presumption that there is less uncertainty about those impacts occurring as estimated

Sensitivity and scenario analyses are different from the other methods in that they provide information about the range of potential outcomes, but they do not provide specific monetary values of risk that will influence the results of the BCA test.

It is possible to use some of these methods together. For example, for a program promoting distributed PV combined with storage, practitioners could use a hedge value to account for the risk benefit of avoiding fossil fuel price fluctuations and a direct estimate method to account for the resilience benefit. In this example, the analysis of each type of risk uses the most suitable method.

However, for some of these risk methods, using them together could result in double-counting. For example, it would not be appropriate to use the hedge value method to account for the risk benefit of avoiding the volatility of fossil fuel prices and reduce the discount rate to reflect the risk benefit of avoiding fossil fuel price volatility.

7.3. Temporal Impacts

DER impacts can vary depending on the timing of DER operation, due to temporal variations in utility system conditions. Thus, the value that DERs can provide to the grid will depend upon the time of day, the time it takes to ramp up the DER, and the duration of grid needs (NARUC-NASEO 2022). For example, generation costs and air emissions can vary considerably over time depending upon which power plant is operating on the margin. As another example, DERs can provide greater benefits to the system if they relieve transmission and/or distribution capacity constraints during peak loading; alternatively, their operation could result in additional transmission and/or distribution capacity costs if it increases load during peak periods. The timing of DER operation can also affect grid flexibility (see Section 7.5) or renewable generation curtailment (see Section 7.12).

Although the goal of assessing impacts with greater temporal granularity is to derive a more accurate valuation of impacts, such analyses may also entail greater levels of uncertainty. For example, while a utility may be able to readily determine average impacts, determining them at a more granular temporal level is more complex. BCAs tests must also consider that temporal impacts may change over time as system characteristics evolve, such as the growth of DG and electrification capacity.

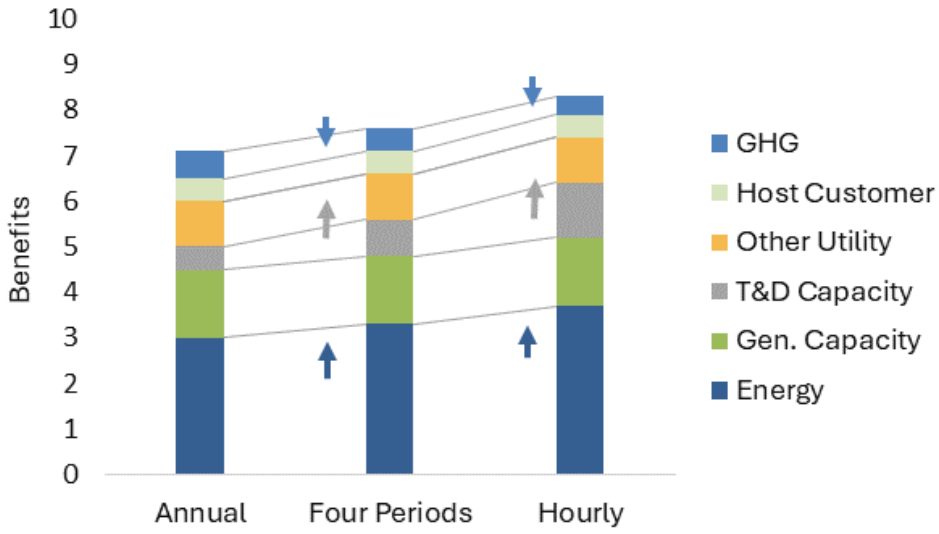
Electric and natural gas utility system impacts typically affected by temporal variation include:

- Energy generation (commodity supply for natural gas),
- System capacity,
- Environmental compliance,
- Market prices, and
- Risk.

Other fuel, societal, and host-customer impacts are also subject to temporal variation. However, for societal and host-customer impacts, temporal variation is commonly due to effects on the utility system (such as for public health and reliability impacts).

Figure 7-1 provides a hypothetical example of the effect that temporal variations can have on the benefits of an EE resource. This example presents six categories of benefits for an EE resource, and how they might vary depending upon whether the benefits are based on annual averages, averages for four periods (winter on- and off-peak and summer on- and off-peak), or hourly data. This example assumes the EE resource provides a larger portion of savings during peak periods than off-peak periods.

Figure 7-1. Example of Temporal Impacts on Energy Efficiency Benefits



This example shows several results:

- The energy GT&D capacity benefits are higher in the four-period case and even higher in the hourly case, as these cases allow for a more accurate breakout of peak versus off-peak hours.
- The GHG benefits are slightly lower in the four-period case and lower still in the hourly case. These lower GHG benefits are because, for this hypothetical electricity system, the higher-emission resources are on the margin during peak periods, and this effect is more accurately captured with more granular data.
- The generation capacity, other utility, and host customer benefits do not change as a result of more granular temporal information.

In practice, the magnitude and direction of the impacts presented here may differ from those shown in this illustrative example, depending on the DER, its operating pattern, location, and other factors. For example, for an EE resource that provides a larger share of savings during off-peak periods than during peak periods, the energy and T&D benefits might be lower because the balance of on-peak versus off-peak savings favors off-peak periods for the grid. Alternatively, the aggregation of multiple DERs can enable the design of complementary temporal interactions among the DERs to maximize benefits to the utility system.

Estimates of DER benefits and costs need sufficient temporal detail to accurately represent the DER's operating patterns and consequent benefits and costs. For some DERs, such as EE and DR, it may be sufficient to use four periods per year to capture temporal impacts adequately. In contrast, some scenarios, such as utilizing DERs as part of an NWS, require more granular analysis, as discussed in Chapter 13.

Although the goal of valuing impacts with greater temporal granularity is to derive a more accurate estimate of actual impacts, it may also entail greater levels of uncertainty. For example, while several industry references provide prototypical DER performance on an hourly basis, there is greater uncertainty in deriving these curves at sub-hourly resolutions. However, increasing amounts of data on load and savings, combined with ever-improving analytical and computational power, may enable more granular analyses of DERs to become standard practice.

7.4. Locational Impacts

The valuation of impacts can also vary depending on the location of the DERs on the distribution system. That DER location will determine which generators (for electricity system impacts) or which circuit on a distribution or transmission system (natural gas or electricity system impacts) the DERs affect. The impact a DER will have on a particular location will depend on local distribution and transmission loading capability, remoteness of the location, the type and frequency of grid needs at the location, and more (NARUC-NASEO 2022).

For example, locating DERs on circuits that have distribution capacity constraints can provide more value because they can help alleviate the constraint. As another example, DERs can be sited at certain customer locations or points on the grid where additional capacity is needed for reliability or resilience.

Alternatively, some DERs can impose costs at certain locations on the grid. For example, a DG resource located in an area of the distribution system with limited hosting capacity might require distribution system upgrades to preserve distribution safety and reliability.

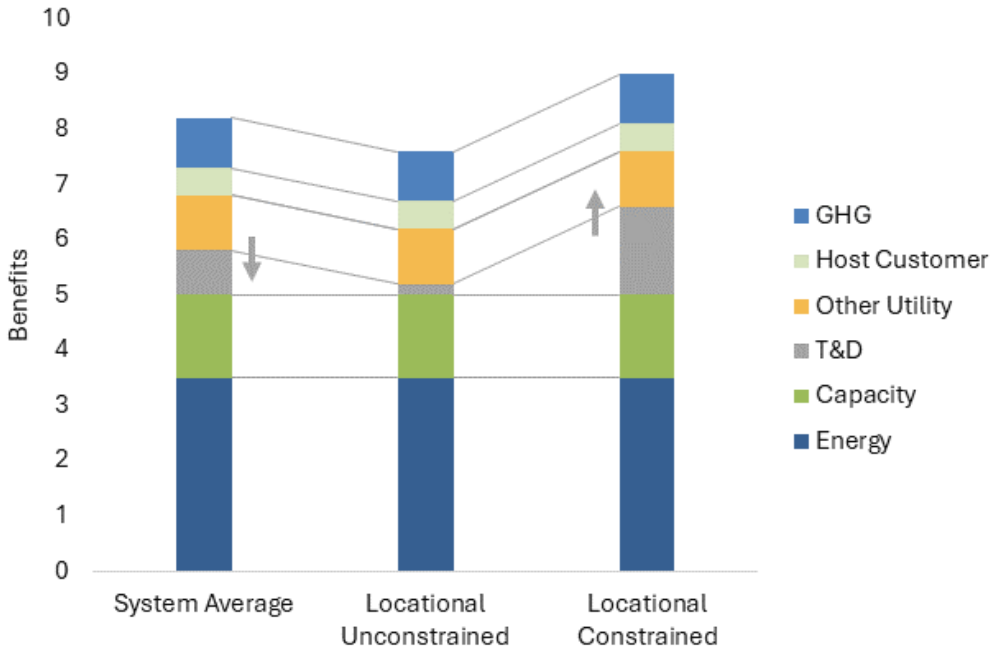
Figure 7-2 provides a hypothetical example of how locational variations can affect a DER's benefits. This example presents six categories of benefits for a DR resource, and how they might vary depending upon whether the benefits are based on the system average, a location with unconstrained distribution capacity, and a location with constrained distribution capacity.

This example shows the following results:

- For the system average, there is a moderate distribution benefit based on the average benefits across the utility system.
- For the unconstrained location, the distribution benefit is zero, leaving only the transmission benefit to be considered.
- For the constrained location, the distribution benefit is higher than the system average and the unconstrained location.

In practice, the magnitude and direction of the impacts presented here may differ from those shown in this illustrative example, depending on the DER, its operating pattern, location, and other factors.

Figure 7-2. Example of Locational Impacts on Demand Response Benefits



Estimates of DER benefits and costs require sufficient detail to accurately represent the DER locational impacts and their consequent benefits and costs:

- For some DERs, where distribution benefits account for only a small share of total benefits, it may be sufficient to use system-average impacts.

- For DERs where more targeted distribution benefits are a significant portion of the benefits (such as non-infrastructure DER solutions, as discussed in Chapter 13), it is more important to capture the locational details.

BCA tests will also need to consider that locational needs—and hence likely impacts—may change over time as system characteristics evolve.

Some impacts might vary by location for some utilities but not others. For example, if energy generation is settled on an ISO/RTO zonal basis and the utility's service territory only spans a single zone, then this impact would not vary for this utility. However, if the utility's service territory spans several zones, then the energy generation impacts might vary across those zones.

Although the goal of valuing impacts with greater locational granularity is to derive a more accurate valuation of impacts, as with more granular temporal analyses, it may also entail greater levels of uncertainty. For example, while a utility may readily determine impacts at the system level, determining them at a more granular locational level (e.g., forecasting load growth, DER adoption, and DER operating profiles at the feeder level) is more complex. Also, as with temporal impact analyses, additional data and better analytical tools are making this complexity easier to address.

7.5. Grid and Demand Flexibility

7.5.1. Flexibility Definitions and Application for DERs

The operational flexibility of the electric grid is critical to meeting the needs of a dynamic grid. Grid and demand flexibility are defined as follows:

- **Grid flexibility** is the overall electricity system's ability to balance and manage fluctuating supply and demand through a mix of generation, distribution, transmission, and demand-side resources.
- **Demand flexibility** (or load flexibility) is a key component of grid flexibility and refers to the ability of consumers to adjust their electricity usage by changing their energy use patterns in response to grid signals or price incentives in order to reduce stress on the grid.

Grid and demand flexibility can be closely interrelated with temporal and locational impacts (NARUC-NASEO 2022). DERs that have the flexibility to provide rapid response to temporal grid requirements (e.g., DS resources) can provide more value to the grid than those that do not. In addition, DER flexibility might provide different values at different locations on the grid depending upon the specific needs of the grid where the DER is sited.

The role of DERs in providing grid flexibility is primarily through demand flexibility. Demand flexibility can make the system more reliable, stable, resilient, and efficient by providing the ability to shed, shift, and/or modulate load to support grid needs, particularly during peak periods.

BTM or building/facility demand flexibility represents the capability of controls, end uses, storage, generation, and EVs to provide benefits to building or facility owners, occupants, and the grid—typically in response to price changes or direct signals (LBNL 2021). Some DERs can operate using two-way communications with grid operators, thereby enhancing their ability to act on price and other signals (DOE 2019a; SEE 2020a; SEE 2020b; RAP 2019b).

DER types or use cases that provide potential grid flexibility benefits include the following:

- **DR programs** can play a crucial role in the operation of the electric grid by reducing or shifting the electricity usage of host customers during peak periods in response to time-based rates or other forms of financial incentives. See Chapter 9 for a discussion of DR.
- **DG and DS** are flexible DERs that can help balance the grid, absorb power fluctuations, and improve overall resilience to disturbances. See Chapters 9.7 and 11 for further discussion of these DERs.
- **VPPs** are aggregations of dispatchable DERs. They might include some combination of rooftop solar with BTM batteries, EVs and chargers, electric water heaters, smart buildings and their controls, and flexible commercial and industrial (C&I) loads. VPPs can balance electricity demand and supply and provide utility-scale and utility-grade grid services similarly to a traditional power plant (DOE 2023a). See Chapter 13 for a discussion of VPPs and grid flexibility.

Benefits or costs associated with grid or demand flexibility from DERs are not represented as a discrete line-item impact in a BCA test. Rather, such flexibility impacts typically affect the magnitude of DER impacts presented in Chapter 6, primarily for utility system impacts.

7.5.2. Accounting for Flexibility in BCA

Benefits or costs associated with grid or demand flexibility from DERs are not represented as a discrete line-item impact in a BCA test. Rather, such flexibility impacts typically affect the magnitude and type of DER impacts presented in Chapter 6, primarily for utility system impacts. For example, demand flexibility provided by DERs can:

- Reduce generation capacity, ancillary services, transmission, and distribution costs;
- Reduce system risks and increase system reliability and resilience; and
- Incur additional incremental grid costs through system upgrades (e.g., generation and storage DERs involve a shift from a one-way power flow to an upgraded, more dynamic, 'bi-directional' system where resources near the customer can generate, store, and flexibly draw energy from the grid).

Flexibility can have both short- and long-term impacts, such as on generation and T&D capacity and operations, as well as providing 'optionality' to address risk-related impacts over the long term.

Accounting for flexibility introduces complexity to the analysis of DER value, because rather than assuming a single, static future (whereby benefits and costs of DER resources are compared to a single, certain future), there is significant uncertainty in any future scenario. Ignoring this uncertainty often leads to overlooking the value (and/or costs) of flexibility that a DER can provide.

Proper quantification of the value of flexibility from DERs requires examining multiple scenarios for the future environment in which the DERs may operate, and accounting for the DER's ability to adapt to that environment. For most value streams, in practice, this will mean creating a unique load shape for the DER for each future scenario, assessing the benefits and costs of each, and assigning a weighted probability to each scenario to estimate the benefit and cost values. These values are then used to modify BCA impacts that already address associated factors such as distribution, transmission, and generation costs, reliability, and resilience.

As mentioned above, Chapter 13 has additional discussion of scenario flexibility analysis in the context of VPPs. It includes commentary on flexibility and BCA for multiple-DER scenarios, DER non-infrastructure solutions, and microgrids.

7.6. Interactive Impacts

While Chapter 6 provides an overview of each individual impact, this section focuses on how multiple DERs might collectively influence their impacts. These interactive effects may manifest themselves in three areas:

- Magnitude of energy use or demand (e.g., kWh or kW) impacts of other DERs
- Enablement of other DER types
- Marginal system costs

It is important to consider the concepts outlined below to understand how the individual DER categories interact to determine the role and value of each DER, and to quantify the net value of all DERs in question.

Interactive effects most commonly occur under multiple-DER on-site scenarios when combinations of DERs impact the same end use. Thus, Chapter 13 discusses interactive impacts in more detail, specifically how interactions between DERs may affect the overall magnitude of impacts or the enablement of other DERs.

7.6.1. Interactive Effects on the Magnitude of kWh/kW Impacts of Other DERs

There are many ways in which one DER might passively or actively affect the magnitude of the kWh or kW impacts of other DERs. For example:

- With EE, there are multitudes of specific measures, many of which can interact with each other when they address the same end uses (such as light fixture retrofits and lighting controls, or insulation additions and air conditioning system retrofits).
- When EE resources reduce a customer's peak demand, they will likely reduce that customer's ability to reduce it through DR or storage.
- When the same customer installs DG and storage resources, the combined benefits of the two operating together are likely to exceed those of each DER operating independently.
- A building or facility with distributed resources (e.g., thermostats, water heaters) may affect the dispatch parameters of a storage resource within the same building or facility.

Chapter 13 includes a discussion of how these passive and active interactions can affect the valuation of DER impacts and mechanisms for accounting for these interactions.

7.6.2. Interactive Effects and Enabling Other DER Types

Some DERs can make it easier or more cost-effective to adopt other types of DERs, beyond the savings in administrative costs and the potential increase in DER uptake that can result from combining the marketing of multiple DERs within a single program. For example, one scenario is combining a DS resource with DG to improve DG's economics. A host can achieve this by storing

excess DG generation during periods of low electricity costs and/or demand and then discharging it from the DS device during periods of high electricity costs or demand.

Another scenario entails an NWS in which the utility requires a portfolio of multiple DER types (e.g., EE, DR, and storage) to meet a system need that could not be met cost-effectively by a single DER type. Chapter 13 covers the enabling benefits of a portfolio of DERs, including multiple on-site DERs scenarios, non-infrastructure DER solutions, VPPs, and Microgrids.

Accounting for this enabling effect is more straightforward when both the enabled and enabling DER types are installed simultaneously. In these cases, it is important for the BCA to account for the collective impacts of all DER types by recognizing the interactive effects. These are the scenarios covered in Chapter 13.

Alternatively, one DER type (the enabling DER) may already be in place when the other (the enabled DER) is installed. In other words, the enabling DER has a 'latent capability.' For example, C&I lighting controls installed as part of an EE program could later serve as DR resources if that provides a greater economic opportunity.

One option to account for this potential latent capability is through probabilistic analysis such as the one below:

- *Estimate the probability of the second DER type being installed.* Probabilities may be based on market research forecasting system-level DER growth expectations and/or more granular analyses on the propensity for individual customers to adopt specific DER types.
- *Forecast the expected impact of interactive effects.* Determine the net impact of these DER types when they interact. This determination should account for the expected timing of the second DER type installation.
- *Calculate a probability-weighted net impact.* Multiply the results of the first two steps to derive a value to include in the cost-effectiveness analysis.

7.6.3. Interactive Effects of Marginal System Costs

Marginal system costs refer to the costs associated with serving the next increment of load (e.g., the next kW or kWh of demand). These costs vary over time due to changes in the system (e.g., a dynamic supply-demand balance, quality of system infrastructure, or a changing resource mix). Marginal system costs are important in DER BCA tests because they determine many of the key DER benefits, such as energy and capacity benefits (see Chapter 14).

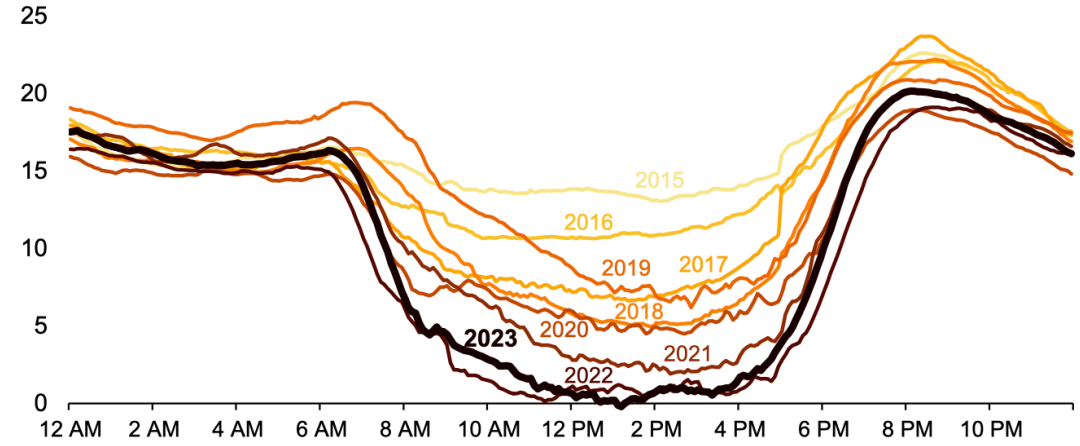
When multiple DERs are installed on a system, they may affect the marginal utility system costs and, thereby, the avoided costs of one another. While this effect on marginal system costs may be small and immaterial for each DER or DER type, the net effect may become increasingly significant as DER deployment increases. Refer to the discussion below in Section 7.10 regarding the importance of program scale and threshold-dependent valuation.

When multiple DERs are installed on a system, they may affect the marginal utility system costs and, thereby, the avoided costs of one another. While this effect on marginal system costs may be small and immaterial for each DER or DER type, the net effect may become increasingly significant as DER deployment increases.

One prominent example of this effect is the 'duck curve,'(CAISO 2016)[31] a daily, temporal demand profile resulting from high deployment of solar resources. As solar resources generate during hours of sunlight, the result will be a lower net load during those hours that might otherwise have been considered peak hours (and, as such, result in lower system marginal costs and lower avoided costs). With sufficient solar deployment, this effect could be large enough to shift the peak period from the afternoon to the early evening, when solar generation dissipates.

Figure 7-3 presents the California duck curve, and how it has changed from 2015 through 2023. It presents daily electricity peak demand, showing the midday dip in peak load due to increased solar generation. As indicated, this mid-day dip has increased significantly over this time period. As a result of this phenomenon, the impact that other DERs (e.g., efficient air conditioning) have on marginal system costs during the afternoon hours will be lower than it would otherwise have been.

Figure 7-3. California's Duck Curve (Gigawatts of Peak Demand)



Data source: California Independent System Operator (CAISO)

Source: (EIA 2023a).

This type of interactive effect is not limited to the duck curve. Another example is when a DR program's size and effectiveness are significant enough to materially change either the timing or magnitude of peak generation, transmission, or distribution demands. If this is the case, it will fundamentally affect the on-peak avoided costs of other DERs. Similarly, greater adoption of EE resources will put downward pressure on the marginal cost of energy, thereby reducing avoided energy costs for other DER types.

In some instances, time-of-use rates can help DERs respond to changes in marginal system costs. For example, time-of-use rate structures could be modified over time to ensure the peak periods for pricing purposes remain consistent with the peak periods that shift due to changes in marginal system costs resulting from substantial DER uptake.

[31] The 'duck curve' is a term for the net electrical load pattern in a grid with high solar penetration and a deep midday dip in net system demand as solar power generation peaks, followed by a steep ramp-up in the evening as solar output declines and people typically return home to use more electricity. This creates a duck-like shape, which challenges grid operators to manage the rapid changes in power required to meet demand.

DER BCA tests should account for these interactive effects on marginal system costs where they are likely to have a significant impact. These interactive effects will be increasingly significant in jurisdictions with growing DER deployment.

Effectively capturing these interactive effects typically requires incorporating DER load impacts into dynamic system planning (i.e., IRP, IDP, or integrated grid planning) to consider both DERs and supply-side resources as potential solutions to meet system needs. Even for jurisdictions and utilities that do not use dynamic system planning, the first step is to determine whether this effect should be considered in the BCA test. In many cases with relatively low DER deployment, the impacts of some DERs on the avoided costs of other DERs might be *de minimis*. This is not an uncommon assumption and thus there are many DER cost-effectiveness analyses that assume avoided cost impacts from DER program implementation are immaterial.

7.7. Resource Ownership and Control

The entity that owns and controls the subject DERs will determine their timing and mode of operation. Those choices will have significant implications for the resource's benefits and costs, particularly with respect to which entities might experience benefits and costs. A variety of entities other than a facility operator or tenant may own and/or operate a DER, including the utility, a landlord, a developer, or a distributed resource aggregator.

Further, there are a variety of ownership and control arrangements whereby one party owns the DER, but another party controls its operation. For instance, a developer might own the DG or DS resource, but the host customer is able to operate the resource for their own purposes; or a customer owns the DR-enabling devices (e.g., a thermostat) but the utility can operate it for its own purposes.

When conducting a BCA test, it is essential to define the party with operational control of the DER, as the decision on when and how to operate the resource will typically factor in valuing benefits and costs. The party controlling the DER will decide when and how to operate it, depending on the financial incentives associated with the DER for the operator and/or owner. Furthermore, who pays the costs associated with the DER and who receives the benefits will determine whether the BCA test includes those benefits and costs, depending on which parties' benefits and costs fall within the BCA test's scope.

Chapter 13 includes use case examples of the competing priorities that can occur depending on who has ownership and control of multiple on-site DERs.

7.8. Behind-the-Meter Versus Front-of-the-Meter Impacts

All the DER types covered in this Manual could be located BTM. However, EE and DR cannot be located FTM because these apply to host customer loads. The principles, concepts, and guidance provided in this Manual are generally applicable to both BTM and FTM DERs, although the primary focus is on BTM DERs. This section discusses how the benefits and costs of DERs might vary depending upon whether the DER is located behind or in front of the meter.

Table 7-2 summarizes key features to consider when conducting a BCA for DERs that might be either BTM or FTM (i.e., DG, DS, EVs). (Table 7-2 does not apply to EE or DR resources because they cannot be FTM.)

Table 7-2. Key Differences Between BTM and FTM DERs

Feature	Behind-the-Meter	Front-of-the-Meter
Primary Owner	Host customer (residential/commercial)	Utility or independent power producer
Primary Goal	Reduce host's bill; backup power	Reduce system-wide costs; grid stability
Who Pays?	Host customer (upfront or via lease)	Utility (costs passed to all ratepayers)
Benefits	Host-specific: reduced bills, reliability, and local backup	System-wide: capacity and grid services
Timing/Dispatch[32]	Aligned with customer peak (e.g., non-coincident demand charges)	Aligned with system peak (e.g., wholesale market prices)
Wholesale Access[33]	Often limited (ancillary services hurdles)	Fully integrated into ISO/RTO markets

Figure 7-4 presents a hypothetical example of how the benefits of a DS resource might be different if it is located behind the meter versus in front of it. This example assumes that the host customer primarily uses the BTM storage to reduce their own energy bills in response to time-of-use (TOU) rates. In contrast, the FTM storage is operated primarily to reduce generation and T&D peak period costs.

This storage example shows the following characteristics:[34]

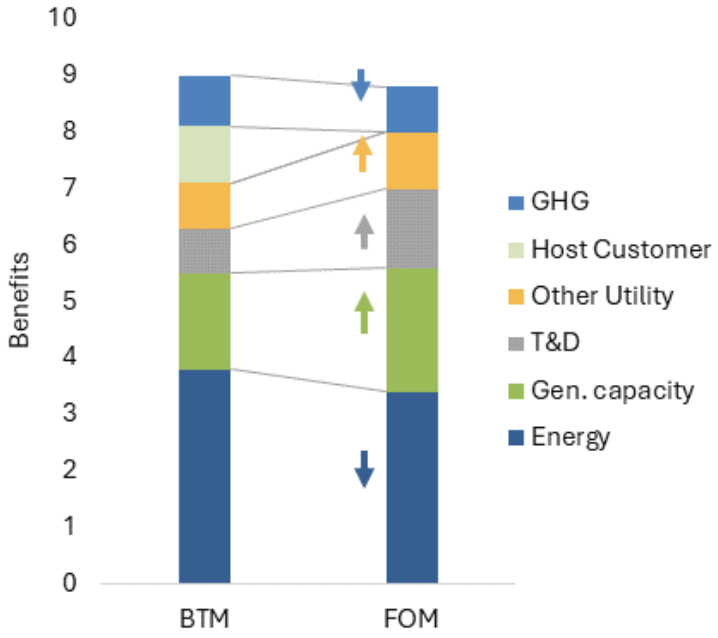
- The energy and GHG benefits of the FTM DER are less than those of the BTM DER because the host customer operated the BTM storage to reduce their overall energy bill in response to TOU rates based on hourly energy costs.
- The generation capacity and T&D benefits of the FTM DER exceed those of the BTM DER because the utility operated the FTM DER to reduce GT&D peak costs.
- The host customer benefits do not exist for the FTM DER.
- The 'Other Utility' benefits of the FTM DER exceed those of the BTM DER because the utility can use the FTM storage to sell ancillary services into the wholesale electricity market.

[32] BTM and FTM DERs may operate at different times due to the various economic incentives available to the host customer versus those of the utility system. For example, host customers with a non-coincident demand charge are likely to operate BTM storage during the customer's peak demand, which may not coincide with the utility's generation, transmission, or distribution peak periods. A more sophisticated rate design that accounts for the time-varying nature of energy, capacity, transmission, and distribution costs should incentivize customers to operate BTM storage in a manner more closely aligned with how a utility would operate a FTM storage.

[33] BTM DERs might be treated differently than FTM DERs with respect to their relationship to wholesale markets. While ISOs/RTOs have expanded opportunities for BTM DERs to participate in wholesale electricity markets, there may still be limitations on BTM DERs' ability to provide and be compensated for certain wholesale market services (such as ancillary services).

[34] In practice, the magnitude and direction of the impacts presented here could vary from this illustrative example, depending upon the DERs, their operating patterns, their location, and other factors.

Figure 7-4. Hypothetical Example of BTM Versus FTM for a Distributed Storage Resource



7.9. Wholesale Market Revenues

Several types of DERs can participate in wholesale electricity markets in some parts of the country. Sometimes, a host customer will participate directly in such markets, while at other times, DER aggregators will combine DERs from multiple host customers to participate in these markets.[35]

When DERs participate in wholesale electricity markets, it is essential to properly characterize the revenues from those markets in the DER BCA test. In regions with wholesale electricity markets, robust BCA tests will include the benefits of energy, capacity, and ancillary services as utility system impacts because those benefits will ultimately reduce utility system costs. These benefits are typically based on the wholesale market prices of those services. Thus, DER wholesale market benefits and costs are relevant for all tests that include impacts on the utility system.

If the BCA test already includes energy, capacity, and ancillary services benefits of DERs in the utility system benefits, there is no *additional* benefit associated with the revenues that host customers receive from wholesale markets. Therefore, if a BCA test includes utility system benefits and costs, then it would not include revenues from host customer participation in wholesale markets.[36] If the BCA test were to include wholesale market revenues to host customers, these

[35] To enhance this practice, FERC has released multiple orders to facilitate DER participation in regional electricity markets through aggregations: FERC Orders 2222 (FERC2020), 2222-A (FERC 2021a), and 2222-B (FERC 2021b).

[36] An exception to the inclusion of host customer wholesale market revenues is a BCA based solely on the host customer's perspective (these are usually known as participant cost tests, PCT). The PCT is explicitly designed to identify the impacts on host customers. The benefits for this test do not include the utility system benefits that are included in the other tests. Instead, the benefits include customer bill savings. Since the host customer revenues from wholesale markets are tangible benefits that are experienced by host customers, in addition to their bill savings, it is appropriate to include wholesale market revenues as one of the benefits in the BCA. See Appendix A.

benefits would be counted twice, which would violate the NSPM *Principle 6: Avoid Double-Counting Impacts*.

7.10. Importance of Program Scale and Threshold Dependent Valuation

The magnitude of a DER program, in terms of energy or capacity impacts, will have significant implications for its overall value, costs, and benefits. Below a certain level of penetration—the *de minimis* threshold—DERs can be viewed as simple, passive loads or generators managed with existing utility infrastructure. That is, below a relevant scale threshold, DERs might have little to no impact on avoided or increased capacity needs, either generation, transmission, or distribution.

The issue of program scale thresholds, and performance thresholds, are particularly important for determining if infrastructure solutions (e.g., NWS), VPPs, and microgrids can achieve their full range of potential benefits (such as deferred capital investments and host customer resilience). Chapter 13 provides further discussion on the topic of program scale and thresholds with respect to assessing multiple on-site DERs.

In practice, BCA tests evaluate most benefit and cost streams using a proportional assumption where there is a price (e.g., a fixed, per-year avoided cost, $/kW) and a quantity (e.g., kW). However, in some DER programs, this proportional simplification might not apply to generation, transmission, or distribution capacity. This occurs when a DER is assumed to avoid or require the addition of specific, infrastructure projects. Here are two examples:

- One of the goals of a DER program is to eliminate the need for a proposed substation. However, a threshold analysis reveals that the proposed DER program would reduce the need for a substation by 70 percent, indicating that the utility would still need to install a new substation. Consequently, the benefits of avoiding the proposed substation are not included in the BCA or are scaled back to the benefits of installing a smaller substation.
- A distributed PV program is assumed to require upgrades to the local distribution system to support the increased generation on the local circuit. However, a threshold analysis reveals that the amount of additional PV generation from the program can easily be carried by the existing infrastructure. Consequently, these distribution upgrade costs are not included in the BCA.

One option for accounting for program scale is to identify and quantify a specific system threshold for the DER being evaluated. This includes identifying the points of inflection where the introduction of additional DER capacity moves from having a passive effect to triggering a response of investment costs or benefits. The BCA test might capture the shift in benefits and costs from zero to a full-value upgrade after crossing the threshold. Here are examples of two types of thresholds.

- *Technical/Operational Utility System Thresholds:* A DER program might realize the benefit from avoided capital expenditure only if the DER program is sized and timed to *defer* a planned substation or feeder upgrade. If the DER program is too small to cross the required capacity threshold, the avoided capital expenditure is assumed to be zero.
- *Market/Program Thresholds:* These relate to aggregation and market participation. One such threshold is the minimum DER capacity required to form a VPP eligible to participate in the wholesale energy or ancillary services market. This threshold would potentially limit

the DER's value to retail bill savings and a minor reduction in distribution demand. Above the threshold, the DERs unlock a high-value market revenue benefit for BCA inclusion.

An alternative approach is to treat incremental DER participation as not having a single, specific threshold, but rather as a step function through distinct stages tied to scale. These could be generic stages, such as low, medium, and high penetration, that would inform the magnitude of benefits and costs to assume at each stage.

7.11. Free-Riders, Spillover Impacts, and Rebound Effects

7.11.1. Free-Riders and Spillover

Impacts of DERs can be accounted for either in terms of net savings or gross savings. Net savings refers to the DER savings that remove the effects of free-riders and spillover. Gross savings refers to the DER savings that do not remove these effects. This section does not address the relative merits of focusing on net savings versus focusing on gross savings in a BCA. This section describes how to account for free-riders and spillover in those jurisdictions that choose to use net savings in their BCA.

Free-riders and spillover are defined as follows:

- **Free-Rider:** A program participant (i.e., host customer) who would have implemented the program's measure(s) or practice(s) in the absence of the program. Free-riders can be (a) total, in which the participant's activity would have completely replicated the program measure; (b) partial, in which the participant's activity would have partially replicated the program measure; or (c) deferred, in which the participant's activity would have partially or completely replicated the program measure, but at a future time beyond the program's timeframe.
- **Spillover (Participant and Non-Participant):** DER implementation without direct support (e.g., financial or technical assistance) from the program. There can be participant and/or non-participant spillover. Participant spillover is the additional impact (e.g., energy savings) that occurs when a program participant independently installs *additional* DERs as an indirect result of participating in the program. Non-participant spillover refers to a program non-participant installing DERs *due to a program's influence* (e.g., a program participant tells a neighbor, the non-participant, about the program).

A jurisdiction's inclusion of host-customer (program participant) impacts in a BCA test has important implications for how to address free-ridership and spillover effects. The treatment of free-riders and spillover is typically seen as particularly applicable to EE since host customer EE projects may often be so beneficial that they are implemented without financial incentives or other program incentives. However, as the economics of other DERs such as electrification, DG, and DS improve, free-ridership and spillover can apply to them as well.

Treatment of Free-Riders in BCA

Utility System Impacts

Benefits: Utility system benefits associated with any savings achieved by free-riders should not be included in DER BCA tests because the DER program did not cause those benefits.

Costs: Any financial incentives paid to free-riders should be treated as a utility system cost, because they are part of the overall cost to the utility of operating the program.

Participant (Host Customer) Impacts

Benefits: Participant benefits associated with any savings achieved by free-riders should not be included in DER program BCA tests because the participants would have achieved the same benefits absent the program.

Costs: Participant costs associated with any savings achieved by free-riders should not be included in the BCA test because the participants would have incurred the same costs absent the program. Financial incentives paid to free-rider participants should be treated as a negative cost (i.e., benefit) to participants because such participants would not have received any such financial support absent the program. However, this reduction in cost to participants cancels out the rebate cost of free-riders to the utility system. Thus, under cost-effectiveness tests that include both utility system and participant impacts, the net cost of free-riders is zero.

Societal Impacts

Benefits: Societal benefits associated with any savings achieved by free-riders should not be included in BCAs because these benefits would have occurred absent the program.

Costs: Societal costs associated with any savings achieved by free-riders should not be included in BCAs because these costs would have occurred absent the program.

Treatment of Spillover Effects in BCA

Utility System Impacts

Benefits: All utility system benefits associated with spillover effects should be included in cost-effective analyses of a DER because they were caused by the program.

Costs: There are no utility system costs directly associated with spillover effects because, by definition, investments made to produce spillover effects are not subsidized by DER programs (i.e., spillover effects are produced when customers install measures without taking rebates or other program services).

Participant Impacts

Benefits: In jurisdictions that include participant impacts in their cost-effectiveness test, all spillover participant benefits associated with spillover effects should be included in cost-effectiveness analyses because such effects were caused by the DERs being analyzed.

Costs: All spillover participant costs associated with spillover effects should be included in cost-effectiveness analyses because such effects were caused by the efficiency programs in question.

Societal Impacts

Benefits: In jurisdictions that include societal impacts in their BCA test any such benefits associated with spillover effects should be included in the test because such effects were caused by the DERs under analysis.

Costs: All other types of costs associated with spillover effects should be included in BCA tests because the DERs under analysis caused those effects.

Table 7-3 summarizes guidance on whether to include free-rider and spillover benefits and costs in cost-effectiveness tests for jurisdictions focused on net impacts.

Table 7-3. Summary of BCA Treatment of Free-Riders and Spillover

Category	Free-Riders		Spillover	
	Costs	Benefits	Costs	Benefits
Utility system impacts	Costs created by free-riders included	Benefits created by free-riders not included	Spillover does not create new utility system costs	Benefits created by spillover included
Participant impacts (if included in BCA test)	Participant rebate benefits offset utility system rebate costs	Benefits created by free-riders not included	Costs created by spillover included	Benefits created by spillover included
Societal impacts (if included in BCA test)	Costs created by free-riders, if any, not included	Benefits created by free-riders, if any, not included	Costs created by spillover, if any, included	Benefits created by spillover, if any, included

7.11.2. Rebound Effect

The rebound effect refers to a phenomenon, typically associated with EE investments, in which energy cost-saving improvements are partially offset by increased energy consumption resulting from behavioral or economic responses. The following are three ways to categorize rebound effect:

- *Direct rebound:* This occurs when a reduction in the price of energy services per unit of use encourages consumers to use more of that service. For example, using more air conditioning in a home when the air conditioner is less expensive to operate.
- *Indirect rebound:* This occurs when the savings from an energy investment are spent on other goods and services that also consume energy. For example: Saving money on home heating with an efficient furnace may lead to spending more on restaurant meals.
- *Economy-wide* (or general equilibrium): These effects can occur as the entire economy adjusts to lower energy costs, not just the household or sector where the efficiency improvement occurs. For example, savings in the manufacturing sector could lower the cost of manufactured goods, leading to increased demand and production, which in turn could result in higher overall energy consumption.

Research has confirmed the existence of the rebound effect and has demonstrated it across various studies, particularly in the context of residential EE programs (Borenstein 2013; Belaïd and Mikayilov 2024; Christou et al. 2025; Greening et al. 2000). However, estimates of the magnitude of the rebound effect vary significantly. How rebound affects the value of impacts in a BCA can vary depending on which impacts are included, and whether the BCA scope includes host customer and/or societal impacts. Beyond energy savings, rebound effects can also reflect the creation of non-energy benefits and society-wide economic value. This potential increase in benefits can be particularly pronounced in low-income communities, where a baseline of suppressed demand for basic energy-consuming services, such as space heating and cooling, is often present.

7.12. Variable Renewable Electricity Generation Impacts

Increasing levels of variable utility-scale renewable generation can create new dynamics for the electricity grid. These increasing levels present both opportunities and challenges for DERs, which

can either provide benefits by supporting the integration of these resources or incur additional costs by exacerbating system needs. To effectively account for material, variable renewable generation impacts, a BCA test may need to account for:

- Operational profile of the DER at a granular level (e.g., hourly);
- Intermittent renewable generation resources when determining utility system benefits;
- Ancillary services benefits related to system ramping from intermittent generation; and
- Periods with negative prices or when renewable resources are otherwise required to curtail operation.

The following are examples of how DERs can create benefits or costs for the electricity grid with respect to variable renewable generation impacts:

- If there are renewable curtailment requirements or periods of negative pricing due to an abundance of solar PV or wind generation relative to demand, then DS programs might be able to provide value (benefits) by shifting net electricity consumption to these periods of negative pricing. Conversely, DERs, such as electrification, that operate during these periods might increase, rather than decrease, some of the utility system costs.
- DR, DS, DG, and EV DR programs can provide fast-reacting, flexible resources that either absorb excess demand (DS and EV) or reduce demand (DR, DG, and EV) to ease ramping needs on the system.
- In locations where substantial solar PV deployment leads to a significant ramp in net load as the sun begins to set (the previously discussed duck curve), there will be a greater need for resources to mitigate the scale of this ramp.
- Electrification measures may provide cost savings to the electric system if they displace or defer any transmission additions that would otherwise be built to enable access to curtailed renewable energy sources. Such avoidance or deferrals would further improve the comparative economics of geo-targeted electrification. Capturing these impacts in cost-effectiveness assessments of electrification measures may require:
    - Identifying planned transmission investments;
    - Estimating the costs and expected timeline for such investments;
    - Estimating the degree to which such investments could be deferred through increased local deployment of electrification measures and resulting reductions in renewables curtailment; and
    - Assigning a value of investment deferral to each kW of added load from electrification (a simple approach would be to divide the value of investment deferral by the amount of electrification needed to produce the deferral).

7.13. Transfer Payments and Offsetting Impacts

Some DER benefits and costs represent transfers from one party to another. In the context of BCAs, an offsetting transfer occurs when one party incurs a cost that is equal to a benefit experienced by another party, and both parties are within the scope of the BCA test.

If the cost and corresponding benefit are offsetting transfers, they will net each other out of the net benefits of the BCA. If the cost and corresponding benefit are not an offsetting transfer, one of them should be included in the BCA while the other should be excluded, depending upon which party is within the scope of the test. Consequently, the treatment of transfers can have significant impacts on BCA results.

In the context of BCAs, an offsetting transfer occurs when one party incurs a cost that is equal to a benefit experienced by another party, and both parties are within the scope of the BCA test.

The key to identifying offsetting transfers is to determine whether both parties experiencing the cost and corresponding benefit are within the scope of the BCA test used. Therefore, offsetting transfers can be identified by the following steps:

- Identify the party experiencing the cost.
- Identify the party experiencing the benefit.
- Verify whether both the party incurring the cost and the party benefiting from it are within the scope of the BCA test. If so, then the set of benefits and costs is an offsetting transfer.

If a set of benefits and costs is determined to be an offsetting transfer, then the BCA test would include both the benefits and costs. One could also exclude both the benefits and costs from the BCA test; however, this approach is less transparent and will result in a slightly incorrect BCR.

If a set of benefits and costs is determined not to be an offsetting transfer, then the BCA test should include either the benefit or the cost, depending on which party is within the scope of the BCA test.

Table 7-4 presents a summary of whether specific impacts, often associated with transfer payments, are typically considered offsets or not in a JST and in three of the historically common tests (per E). In some cases, the impact is not an offsetting transfer under any BCA test. In other cases, whether an impact is an offsetting transfer depends on the BCA test in use.

Table 7-4. Summary of When Impacts Are Offsetting Transfers

Impact	UCT	TRC	SCT	JST
Tax Incentives	Not a transfer; include in BCA	Not a transfer; include in BCA	Offsetting transfer (but incentive should be included in BCA for consistency)	Depends [b]
Utility Performance Incentives	Not a transfer; include in BCA	Not a transfer; include in BCA	Not a transfer; include in BCA	Not a transfer; include in BCA
Host Customer Incentives	Not a transfer; include in BCA	Offsetting transfer (but incentive should be included in the BCA as a cost to the host customer)	Offsetting transfer (but incentive should be included in the BCA as a cost to the host customer)	Depends [c]
Market Price Effects	Not a transfer; include in BCA	Not a transfer; include in BCA	Not a transfer; include in BCA	Not a transfer; include in BCA

[a] *Tax incentives require additional consideration. DER tax incentives must be treated consistently with tax incentives for other types of utility resources, which are embedded in energy costs. Appendix M describes this further.*

[b] *Under a JST, tax incentives are an offsetting transfer only if regulators choose to include taxpayers within the BCA test.*

[c] *Under a JST, host customer incentives are an offsetting transfer only if host customers are within the BCA test.*

PART III

Benefit-Cost Analysis for Specific Distributed Energy Resources

8. Energy Efficiency Resources

This chapter describes the benefits and costs most relevant to EE resources. It identifies key factors that affect EE benefits and costs and provides guidance on addressing common challenges with EE cost-effectiveness analyses.

8.1. Summary of Key Points

- EE resources include technologies, services, measures, or programs that reduce end-use energy consumption by host customers, and that are funded by, promoted by, or otherwise supported on behalf of all electricity and/or natural gas utility customers.
- EE resources provide a wide range of utility system benefits, notably in the form of avoided investments in new electric generating capacity, avoided electric energy generation, avoided gas commodity purchases, and avoided capital investments in electric and/or gas transmission and distribution assets. The costs typically include program administration costs, financial incentives, and utility performance incentives, where relevant.
- The temporal and locational benefits of EE can vary considerably across seasons, days of the week, and times of day, as well as by the physical location on the energy distribution network.
- Some electric EE resources will reduce other fuel consumption, resulting in other fuel benefits. Other electric EE resources will increase consumption of other fuels, resulting in other fuel costs; some natural gas EE measures will also reduce electricity consumption.
- EE resources can create a variety of host customer NEIs, depending upon the efficiency measure and the host customer. EE NEIs can include changes to O&M costs, water impacts, asset value, productivity, economic well-being, comfort, health and safety, and satisfaction and pride.
- EE resources can offer significant reductions in air emissions. As with all DER impact estimates, it is important to use an analysis time period sufficient to capture longer-term impacts. For air emission impacts, that means basing estimates on long-run marginal emissions rates and accounting for changes in new electric generation resources that would otherwise have to be purchased, changes in dispatch of different electric generators (based on season and time of day) and on changes in the emissions from non-electric fuels whose consumption is affected.
- Addressing the impacts of EE resources throughout their full effective useful life requires properly defining counterfactual (baseline) conditions for both savings and costs, particularly with respect to early-replacement projects.
- EE resources will typically create lost revenues. These might lead to increased rates, depending upon the magnitude of lost revenues, the magnitude of EE utility system costs, and the magnitude of utility system benefits. However, as discussed in both Chapter 3 and B, cost-effectiveness and rate impacts are two fundamentally different concerns; it is important to analyze them separately and not conflate them.

8.2. Introduction

For the purpose of this Manual, EE resources include technologies, services, measures, or programs that reduce end-use energy consumption by host customers.[37] EE resources broadly include both (a) investments that provide the same level of (or better) service with lower energy use (total, or per unit of input, or per unit of output); and (b) conservation measures that may result in some reductions in service or amenity (e.g., removal of second refrigerator, adjustment to thermostat setpoints through behavior programs, etc.).

The fundamental BCA principles (Table 3-1) can guide identification of the relevant benefits and costs for EE, as with all DER types. Identifying whether a particular benefit or cost is relevant to EE requires defining the specific EE technology and use case. For example, efficient outdoor night lighting may not avoid any capacity costs for utilities whose peak demand occurs on late summer afternoons.

Some efficiency measures and programs can offer at least the potential to be DR measures in the future. Examples include controllable 'smart thermostats,' variable speed drives on motors, and lighting controls. Such measures can (a) enable utilities to control customers' loads through dispatchable DR in the future, and (b) enhance customers' ability to respond to price signals to lower demand during hours when energy is expensive and/or when there are capacity constraints on the system.

8.3. Benefits and Costs of Energy Efficiency Resources

The tables in this section summarize the potential benefits and costs typically associated with EE resources (see Chapter 6 for definitions of impacts). The tables designate each impact as a benefit, a cost, either a cost or benefit, or not material (i.e., typically not a large enough impact to affect BCA test results) depending on common applications or use cases of this technology. There might be some less common applications where what is most commonly a cost may be a benefit, or vice versa. The tables include notes on applicability that provide further explanation for those impacts that may be either a benefit or cost.

Table 8-1 presents the typical impacts of EE programs implemented by electric utilities on the electric utility system. Table 8-2 presents the typical impacts of EE programs implemented by natural gas utilities on the gas utility system. It is appropriate for BCA tests to include all of utility system impacts presented in these tables, where relevant and material, consistent with NSPM *Principle 2: Treat DERs as a Utility System Resource.*

A jurisdiction's primary BCA test might include other EE impacts—presented in Table 8-3 (Other Fuels), Table 8-4 (Host Customer), and Table 8-5 (Societal)—to the extent they are relevant to the jurisdiction's applicable energy policy goals, consistent with NSPM *Principle 1: Align with Applicable Energy Policy Goals* (see Chapter 4.4).

[37] This definition includes some investments on the utility side of the meter that reduce customers' end-use consumption, such as conservation voltage regulation.

Table 8-1. Typical Impacts of Energy Efficiency: Electric Utility System

Type	Utility System Impact	Benefit or Cost	Notes/Typical Applicability
Generation	Energy Generation	●	A benefit because EE reduces electricity generation
	Generation Capacity	●	Typically, a benefit because most EE measures provide at least some savings at the time of system peak; however, there are some exceptions
	Environmental Compliance	●	A benefit because EE reduces electricity generation
	RPS/CES Compliance	●	A benefit because EE reduces electricity sales
	Market Price Effect	●	A benefit in jurisdictions with wholesale energy and/or capacity markets; not material for those that do not
	Ancillary Services	NM	Can be a benefit, but likely very modest
Transmission	Transmission Capacity	●	Typically, a benefit because EE can reduce transmission peaks; same exceptions as for generation capacity
	Transmission Line Losses	●	A benefit because EE reduces transmission volumes
Distribution	Distribution Capacity	●	Typically, a benefit because EE can reduce distribution peaks; same exceptions as for generation capacity
	Distribution Line Losses	●	A benefit because EE reduces distribution volumes
	Distribution O&M	●	A benefit because EE reduces distribution volumes
Cross-cutting GT&D	Risk	●	A benefit because EE reduces a variety of risks e.g., fuel price volatility
	Reliability	●	A benefit (to the extent not fully captured in avoided generation and/or avoided T&D categories above)
	Resilience	NR	Most resilience impacts typically flow to customers
General	Financial Incentives	●	Financial incentives and program admin costs are almost always incurred; utility performance incentives are costs if in jurisdictions in which they are available
	Program Administration Costs	●	
	Utility Performance Incentives	● / NR	
	Credit and Collection	●	A benefit because customer savings make bill payment easier, especially for low-income programs

● = typically a benefit for this DER type; ● = typically a cost for this DER type; ● = either a benefit or cost for this DER type, depending upon the application of DER; NM = typically not material; NR = not relevant for this DER type.

Table 8-2 presents the typical impacts of EE programs implemented by natural gas utilities on the gas utility system. The table also notes some instances of where and how electric utility EE programs might impact the natural gas utility system. Generally, while natural gas utility ratepayer funded EE programs will always reduce natural gas consumption, electric utility ratepayer funded EE programs can sometimes reduce and sometimes increase natural gas consumption. For example, some electric efficiency measures (e.g., replacing fluorescent T8s with LEDs and/or networked lighting controls in commercial buildings) can reduce waste heat and therefore modestly increase natural gas consumption for space heating (though not always materially).

Table 8-2. Typical Impacts of Energy Efficiency: Natural Gas Utility System

Type	Utility System Impact	Benefit or Cost	Notes/Typical Applicability
Energy/Supply	Natural Gas Commodity	●	Typically, all benefits for natural gas EE, though some limited measures that do not save on peak hours will not provide capacity benefits; electric EE programs that reduce natural gas will create a benefit, those that increase consumption of natural gas will create a cost
	Capacity	●	
	Environmental Compliance	●	
	Market Price Effects	●	
Transportation	Pipeline Capacity	●	Typically a benefit for natural gas EE, though some limited measures that do not save on peak hours will not provide pipeline capacity benefits
	Pipeline Losses	●	Typically a benefit for natural gas EE
Distribution	Local Delivery Capacity	●	Typically a benefit for natural gas EE, though some limited measures that do not save on peak hours will not provide delivery capacity benefits
	Local Delivery Losses	●	Typically a benefit for natural gas EE
Cross-cutting Energy, T&D	Risk	●	A benefit for gas EE (exceptions the same as for those for capacity described above); electric EE programs that reduce other fuels create a benefit and those that increase other fuels create a cost
	Reliability	●	
	Resilience	NR	Most resilience benefits typically impact host customers
General	Financial Incentives	●	A cost for natural gas EE; electric EE programs that affect natural gas will not affect this impact
	Program Administration Costs	●	
	Utility Performance Incentives	● / NR	A cost in jurisdictions that offer them; electric EE programs that reduce natural gas will not affect this impact
	Credit and Collection Costs	●	A benefit for natural gas EE, particularly for low-income programs; electric EE programs that reduce natural gas create a benefit and those that increase natural gas create a cost

● = typically a benefit for this DER type; ● = typically a cost for this DER type; ● = either a benefit or cost for this DER type, depending upon the application of DER; NM = typically not material; NR = not relevant for this DER type.

Table 8-3 presents the potential benefits and costs of EE on other types of fuels, such as oil, propane, diesel, or biomass (including wood). For example, an electric utility ratepayer-funded EE program that targets space heating can reduce consumption of oil or propane. On the other hand, some electric efficiency measures (e.g., replacing fluorescent T8s with LEDs and/or networked lighting controls in commercial buildings) can reduce waste heat and therefore modestly increase fossil fuel consumption for space heating (though not always materially).

Table 8-3. Typical Impacts of Energy Efficiency: Other Fuel Systems

Type	Other Fuel Systems Impact	Benefit or Cost	Notes/Typical Applicability
Other Fuels (oil, propane, wood, gasoline)	Commodity	🟠	Electric EE programs that reduce other fuels will create a benefit, those that increase consumption of other fuels will create a cost
	Environmental Compliance	🟠	
	Market Price Effects	🟠	

🟢 = typically a benefit for this DER type; 🔴 = typically a cost for this DER type; 🟠 = either a benefit or cost for this DER type, depending upon the application of DER; NM = typically not material; NR = not relevant for this DER type.

Table 8-4 presents the typical host customer impacts of EE (see Section 6.6). Treatment of host customer impacts has historically been unbalanced, with the host customer contribution to DER costs included but other NEI benefits excluded. Chapter 3, *Principle 4: Ensure Symmetry in the Treatment of Benefits and Costs* requires either excluding both or including both host customer benefits and costs (depending on a jurisdiction's policy goals).

Table 8-4. Typical Impacts of Energy Efficiency: Host Customer

Type	Host Customer Impact	Benefit or Cost	Notes/Typical Applicability
Customer	Host Customer Portion of DER Costs	🔴	Typically a cost; except when utility program pays the full-measure cost (e.g. LI programs) or there is no measure cost (e.g. behavior programs, disposal of extra appliances)
	Transaction Costs	🔴	Typically a cost: time spent researching information, obtaining vendor quotes, filling out rebate applications, etc.
	Interconnection Fees	NR	Not applicable for EE
	Resilience	🟢	A benefit (e.g. weatherization allows customers to remain warm/cool without heating/cooling for longer periods)
	Tax Incentives	🟢	Typically a benefit where they apply
	Host Customer NEIs	🟢	While some NEIs are benefits and some are costs, the vast majority are benefits (see Section 8.4.4)

🟢 = typically a benefit for this DER type; 🔴 = typically a cost for this DER type; 🟠 = either a benefit or cost for this DER type, depending upon the application of DER; NM = typically not material; NR = not relevant for this DER type.

Table 8-5 presents the typical impact of EE on a range of potential societal impacts (Section 6.7). Inclusion of any of these impacts in a jurisdiction's primary BCA test depends on its policy goals.

Table 8-5. Typical Impacts of Energy Efficiency: Societal

Type	Societal Impact	Benefit or Cost	Notes/Typical Applicability
Societal	GHG Emissions	🟢	Typically, a benefit; magnitude depends on electric generation mix and any other fuel impacts
	Other Environmental	🟢	
	Public Health	🟢	A benefit resulting from reduced environmental emissions; ensure no double-counting of host customer NEIs and societal environmental impacts
	Resilience	🟢	Benefit to e.g., critical services and infrastructure during responses to extreme events

● = typically a benefit for this DER type; ● = typically a cost for this DER type; ● = either a benefit or cost for this DER type, depending upon the application of DER; NM = typically not material; NR = not relevant for this DER type.

8.4. Key Factors that Affect Energy Efficiency Benefits and Costs

8.4.1. Technology Characteristics

EE is an immensely diverse and modular resource: there are hundreds if not thousands of different types of EE measures, addressing numerous energy end uses in a variety of different markets, applications, buildings, and facilities. They can also be promoted through a wide range of programs, implementation options, and market transaction mechanisms. This modularity and diversity of EE means that comprehensive portfolios of EE programs will typically—in aggregate—produce at least some amount of load reduction in every hour of the year. However, the amount of load reduction in peak hours will differ depending on the mix of measures and programs, as well as the season and hours during which the system experiences peak demand.

Some EE measures can enable grid flexibility. For example, smart thermostats or networked lighting controls can enable dispatchable DR or facilitate customers' ability to respond to price signals. BCA tests for EE should ideally consider the potential benefits of enabling other DERs to meet system needs such as grid flexibility or other objectives.

8.4.2. Technology Operating Profile

The temporal and locational value of EE savings can vary considerably across seasons and during different hours of the day, as well as by the physical location on the energy distribution network. Thus, the temporal and locational attributes of EE have important implications for BCA, as these attributes can often dictate the extent to which EE produces generating capacity and/or T&D savings.

The average hourly load shape of when energy savings occur will depend on the mix of efficiency measures in the efficiency program portfolio, the host customers to whom the measures are promoted, the local climate, and a variety of other factors—as shown in the examples below:

- Municipal outdoor lighting savings will typically be higher in the winter than in the summer and occur only at night.
- A larger portion of residential cooling savings than of commercial cooling savings will occur in the evening.
- Industrial motor or process efficiency savings will tend to be more consistent across the hours of industrial operations than residential or commercial energy savings.

8.4.3. Other Fuel Impacts

Table 8-2 presents the potential benefits and costs of EE on natural gas utilities and other fuel systems. As discussed above, natural gas utility EE programs should always reduce natural gas consumption; some electric utility EE programs will reduce consumption of other fuels (such as natural gas, propane, or wood) while in some cases electric EE measures or programs can modestly increase consumption of other fuels (e.g., by reducing waste heat, as discussed in Section 8.3 above).

As shown in Table 8-2, non-electric cost savings resulting from efficiency improvements can extend beyond just commodity (i.e., fuel) savings. For example, when efficiency lowers natural gas

consumption at times of gas system peak demand, it can help defer the potential for future capital investments to upgrade the gas transmission and/or distribution system infrastructure. There may be similar 'capacity' savings associated with reduced infrastructure for distribution of petroleum products.

Though not addressed in Table 8-2, some natural gas efficiency measures can also reduce electricity consumption. Such changes in electricity consumption would be 'other fuel impacts' for a gas utility investment. A jurisdiction's BCA test will likely address these impacts if policy dictates that other fuel impacts be included in its JST.

Some examples of other fuel impacts include the following:

- Gas utility ratepayer-funded weatherization of homes to reduce natural gas used for space heating can also reduce the amount of electricity used for space cooling.
- Either gas utility ratepayer-funded or electric utility ratepayer-funded weatherization of homes could reduce consumption of other fuels associated with secondary heating systems (e.g., propane space heaters or wood burning).
- Gas utility ratepayer-funded rebates for efficient gas furnaces can produce electricity savings when the ore efficiency furnaces have more efficient fan motors.
- Electric utility ratepayer-funded incentives for the installation of demand control ventilation in commercial buildings may reduce both electricity consumption associated with cooling and fans and the amount of gas used for space heating.
- Some electric efficiency measures, such as efficiency commercial lighting controls, can increase heating loads met with natural gas or other fossil fuels by the amount reducing waste heat put into conditioned spaces (but as previously noted, such changes may not be material).

Caution is necessary to ensure all impacts are accounted for and there is no double counting of impacts, for example, that an electricity program and a natural gas program do not both account for the same, overlapping energy savings.

8.4.4. Host Customer Non-Energy Impacts

EE investments can provide a variety of host customer NEIs. Although host customer NEIs can be either benefits or costs, depending on the EE measure, program, or host customer, the impacts in most EE program portfolios are primarily benefits.

Table 8-6 presents a summary of host customer NEIs that EE resources might create. These impacts can sometimes be benefits and sometimes be costs, depending on the most common applications for EE resources. The presence, direction, and magnitude of these impacts will depend upon many factors, including the EE program, the type of host customer (e.g., low-income, residential, commercial, industrial), and more.

Table 8-6. Potential Host Customer Non-Energy Impacts of Energy Efficiency

Category	Benefit or Cost	Examples
Water Costs	●	• Reduced water consumption/cost
Asset value	●	• Installation of newer and/or longer-lived equipment • Improvements to building durability • Related increases in building value
Business Productivity	●	• Improved labor productivity (e.g., from improved air quality or improved lighting) • Reduction in spoilage or product defects • Reductions in volumes of waste • Reductions in occupant turnover and/or increased occupancy rates in leased buildings • Impact of improved aesthetics, comfort, light quality, etc. on product sales
Operation & Maintenance Costs	●	• Longer-lived equipment requiring fewer replacements over time • Efficient equipment that may need servicing more frequently
Comfort	●	• Thermal comfort • Noise reduction • Light quality
Health & safety	●	• Improved well-being due to reduced incidence of illness—chronic (e.g., asthma) or episodic (e.g., hypothermia or hyperthermia) • Reduced medical costs (emergency room visits, drug prescriptions) • Fewer sick days (work and school) • Reduced deaths • Reduced insurance costs (e.g., for reduced fire, other risks)
Other	●	• Amenity (e.g., reduction in refrigeration capacity from removal of inefficient second refrigerators, increases in cooking control and speed with induction cooktops) • Empowerment (e.g., better sense of control of energy use) • Pride (satisfaction from contributing to solutions to environmental concerns) • Reduced financial stress (especially for low-income households)

● = typically a benefit for this DER type; ● = typically a cost for this DER type; ● = either a benefit or cost for this DER type, depending upon the application of DER; NM = typically not material; NR = not relevant for this DER type.

The list below provides specific examples of EE host customer non-energy benefits:

- *Water savings:* Certain EE measures, such as low-flow showerheads, pre-rinse spray valves for commercial dish cleaning, and efficient clothes washers save energy by reducing the amount of hot water (and therefore the amount of water) needed to meet customers' needs.
- *Asset value – building durability improvements:* Sealing and insulating attics can reduce or eliminate ice dams. Ice dams can occur when melting snow on a roof refreezes as ice at the edge of the roof and backs up other melting snow to the point where it can leak and damage the roof, walls, and other structural elements of the home.

- *Business Productivity benefits:* Higher quality LED lighting can enhance aesthetics of retail product displays; ventilation efficiency improvements and/or daylighting or other lighting quality improvements can improve worker productivity; reductions in heating bills can reduce vacancy rates for multi-family building owners; and reductions in industrial waste streams can reduce energy consumption while lowering disposal costs.
- *O&M cost savings:* Efficient LED lighting measures not only save electricity but are longer-lived than the standard/baseline lighting products they replace and, therefore, eliminate some future replacement costs that would otherwise be incurred.
- *Comfort improvements:* Sealing and insulating a home not only saves energy but improves the comfort of the home by reducing drafts and enabling more even distribution of heat. Triple-glazed windows often also reduce the effects of outdoor noise.
- *Health and safety improvements:* Many home-efficiency retrofit programs routinely test for, identify, and address problems such as back-drafting of combustion gases (including carbon monoxide) from fossil-fuel-fired heating or water heating systems and mold problems associated with improper ventilation.

Examples of EE host customer non-energy costs include some losses of amenity (e.g., when second refrigerators are voluntarily relinquished and recycled), increased maintenance costs (e.g., for operating and maintaining CHP equipment or demand control ventilation), and aesthetic concerns.

8.4.5. Emissions Impacts

EE resources can reduce air pollution emissions by reducing the amount of generation that fossil-fuel-fired power plants will need to produce.

EE resources that affect multiple fuels can also have impacts on other fuels. For example, building envelope improvements can produce both electric cooling savings in the summer and natural gas (or other fossil fuel) heating savings in winter—with both forms of savings producing emission reductions.

As discussed in Chapter 6, air emission impacts should account for two important factors: (a) the time period for which the DER operates; and (b) the marginal emission rates of the utility system at the time when the DER operates.

Principle 4: Ensure Symmetry in the Treatment of Benefits and Costs requires accounting for both reduced and increased air emissions from EE resources, to the extent they occur.

8.5. Common Challenges in Determining EE Benefits and Costs

Unique challenges for EE BCA covered in this section are (1) the level of aggregation of EE impacts at which it is appropriate to assess cost-effectiveness; and (2) how to assess the impacts of early replacement measures (i.e., those installed prior to the end of the useful life of the existing equipment.) Appendix I provides more detailed discussion of BCA assessment level options. Chapter 7 provides guidance on other challenges in determining EE impacts associated with the treatment of fixed and variable costs, changing cost and/or benefit baselines, and accounting for free-rider and spillover effects.

8.5.1. Assessment Level for Benefit-Cost Analysis

The cost-effectiveness evaluation of EE resources can take place at several different levels of assessment. Assessments can focus on individual measures, individual customer-specific projects, individual programs combining multiple measures and/or projects, sectors (e.g., all residential or all business programs), and on a portfolio of programs across all sectors.

Evaluation at every level can help inform or improve program design for EE resources. However, for the purpose of making decisions on whether to make an investment (i.e., when used to screen investments as worthwhile or not) the focus will need to be on cost-effectiveness at the program, sector, and/or portfolio levels. Applying cost-effectiveness results at the measure and project levels can have perverse implications (see Appendix I). In some cases, it could reduce the overall net economic benefits of EE investments for the following reasons:

- A customer's interest in a non-cost-effective measure may be key to persuading the customer to install a package of measures that are cost-effective in aggregate.
- A customer's interest in a non-cost-effective measure may be key to the development of a relationship with the customer that can lead to installation of cost-effective measures in the future.
- Installation of a non-cost-effective measure may be necessary to technically or safely enable the installation of other cost-effective measures.

Another disadvantage of assessing cost-effectiveness at the measure or project level is that it can be difficult to account for NEIs, hard-to-monetize impacts, or additional considerations at the measure level. Some NEIs, such as improved health and safety, come in a package of multiple measures, and it is impractical to apply such impacts on each measure.

8.5.2. Early Replacement Measures

Many EE program portfolios include 'early replacement measures.' These measures entail replacing an inefficient existing piece of equipment that is still functioning and would not otherwise have been replaced yet with an efficient new product.

To provide an example, an efficiency program might provide a new LED light fixture with an assumed life of 12 years to replace an existing and functioning T8 commercial light fixture that would normally last for another four years. In this example, the initial savings are a function of the difference in efficiency between the existing T8 and a new LED fixture, and the initial cost is the full cost of the LED fixture. However, the initial savings level would only last for the estimated four years of remaining life for the existing T8. The installation of the LED fixture today would eliminate the cost that otherwise would have incurred four years from now when the T8 would have been replaced absent the efficiency program.

A key to proper assessment of the cost-effectiveness of early replacement EE measures is to develop reasonable estimates of what would have occurred absent the EE program (i.e., the baseline) both for savings and costs.

- *With respect to savings*, program evaluators can develop such an estimate using a dual baseline. In the case of the T8 replacement example, that would mean (1) four years of savings equal to the difference in efficiency between the existing T8 and the new LED and then (2) eight years of savings equal to the (likely smaller) difference in efficiency between

the new fixture that would have been purchased four years from now and the new LED installed today.

- *With respect to cost*, in jurisdictions that include participant impacts, it is good practice for the BCA test to consider not only the upfront cost of the new LED fixture installed, but also the cost savings for the customer of not having to buy whatever new fixture they otherwise would have purchased four years from now. However, to align the baseline timeline with the efficiency investment timeline (i.e., to ensure an 'apples to apples' assessment of the difference in costs) only a portion of the future cost that was eliminated should be treated as a cost savings. In other words, if the baseline product that would have been installed four years from now would have had an expected life of 12 years, it is only appropriate to include eight years' worth of the cost savings (to align the cost comparison with the life of the LED measure installed today).

8.6. Common Interactions with Other DERs

Some EE measures interact with others. For example, building weatherization will yield lower savings when combined with installing a more efficient heating system (and vice versa). There can also be interactions at the EE program level. For example, programs with educational components can help drive participation and increased savings in other programs (what is sometimes called an 'uplift' effect). It is important for BCA tests to address all such interactions, though without double counting the impacts.

In addition, EE measures or programs can have important interactions with other DERs. While such interactions can be with any other type of DER, they are most common with DR and building electrification measures. Key interactions to consider when conducting cost-effectiveness assessments include the following:

- **EE that enables DR**. As noted above, some EE measures—particularly controls such as 'smart thermostats' or networked lighting controls—enable DR. It is appropriate for efficiency program BCA tests to account for that 'enabling' benefit.
- **EE affecting magnitude of DR benefits**. Some efficiency measures will affect the magnitude of the benefits of DR measures, or vice versa. For example, if an EE program has successfully promoted the installation of an efficient central air conditioner, a new DR measure to control that central air conditioner at the time of system peak will yield diminished DR benefits. The obverse is also true: improving the efficiency of a central A/C already enrolled in a DR program will provide less peak demand reduction benefit than improving the efficiency of a central A/C that is not enrolled in a DR program. Either way, it is appropriate for a BCA to account for such interactions where they exist.
- **Building envelope efficiency upgrades allow for downsizing heat pumps installed for electrification**. By lowering the amount of heat that needs to be produced, insulation upgrades, air leakage reduction, and duct sealing can reduce the capacity of the new heat pump needed to electrify space heating in a building. Smaller heat pumps cost less. BCA tests should account for this benefit.
- **Building envelope efficiency upgrades lower winter peak demand from electrified heating**. Insulation upgrades, air leakage reduction, and duct sealing can also reduce the magnitude of electric demand during winter peak hours. For systems that experience or will in the future experience peak demand in the winter, this can be a substantial benefit.

- **It may be possible to begin designing and implementing EE programs to promote the sale of the most efficient EVs.** As with other electricity consuming equipment, there is significant variation in the operating efficiency of EVs. Some jurisdictions have begun to examine the potential to design programs to capture the electric energy savings associated with the purchase of a more efficient EV (relative to standard or average efficiency models). This highlights another way in which electrification and efficiency investments could be delivered together.

For more information on interactions between EE and other DERs, see Chapter 13 on analyzing multiple DERs.

8.7. Changes in Revenues and Rate Impacts

This section discusses how EE resources can influence customer rates, why BCA tests cannot accurately evaluate those impacts, and options for appropriately assessing and addressing rate impacts.

An important factor affecting rates is changes in revenue, which affect how and from whom utilities will recover the system costs they incurred in the past (i.e., sunk costs). When an EE investment leads to a decrease in revenue, that impact is lost revenue and it is one of multiple ways EE resources can affect rates.

As discussed in Chapter 3 and in more detail in Appendix B, jurisdictions need more than BCA tests to thoroughly understand the issue of rate impacts. BCA tests and assessments of rate impacts address fundamentally different questions. BCAs assess the extent to which investments increase or decrease costs; rate impact analyses assess whether rates will go up or down. Though both can be important, concerns about how equitably past costs are recovered are different than concerns about whether total costs will increase or decrease. Thus, lost revenues and any potential related rate impacts are not appropriate to include in BCA tests and require separate evaluation using rate, bill, and participation analyses.

EE resources will typically both add utility system costs (e.g., because of EE program costs) while reducing others (e.g., by avoiding GT&D costs). (See Table 8-1 above). In general, several key factors affect the extent to which DERs might create rate impacts:

- Increases in utility system costs will put upward pressure on rates.
- Reductions in utility system costs will put downward pressure on rates.
- Reductions in sales from DERs will put upward pressure on rates.
- Increases in sales from DERs will put downward pressure on rates.
- Rate design will affect the amount of lost or increased revenues created by the DER.

EE resources will typically create lost revenues because they reduce total system sales over which fixed or sunk costs are recovered.

Regulators and other stakeholders that are concerned about EE rate impacts have several options:

- Conduct a long-term rate, bill, and participation analysis.
- Seek EE program designs likely to mitigate equity concerns.

- Examine ways to expand customer participation, especially among low- and moderate-income customers.
- Periodically review impacts as EE programs are implemented.

9. Demand Response Resources

This chapter describes the benefits and costs most relevant to DR resources, identifies key factors that affect DR benefits and costs, and provides guidance on addressing common challenges for DR cost-effectiveness analyses.

9.1. Summary of Key Points

- DR is a mechanism by which consumers voluntarily manage the timing of their electricity (or natural gas) usage in response to utility system conditions and costs.
- DR is a BTM resource and includes dispatchable (e.g., incentives for participation) and non-dispatchable initiatives (e.g., time-varying rates). While consumers volunteer to participate in DR programs, they may allow other entities such as their utility or third-party aggregators to activate the DR mechanism through which loads are changed.
- DR is a way to manage an electricity grid's (or a natural gas system's) load by encouraging consumers to shed, shift, or modulate their demand, typically during periods of high demand or high energy prices. DR objectives include enabling reliability, economic optimization, or renewables integration at the system and/or localized level.
- The aim of implementing DR resources that result in load-shifting is to create demand-reduction-related benefits during the targeted time periods; the shift may result in demand-increase-related costs during periods to which loads may be shifted.
- The value of benefits and costs (including host customer impacts) depends upon several factors: the DR operating profile, timing and location of the affected load, who controls the activation of DR and for what purpose(s), and the host site characteristics (e.g., residential, commercial, or industrial facility).
- DR investments often occur in combination with EE efforts and increasingly with electrification (both buildings and vehicles) and DS and DG investments. When implemented in combination with other DERs, there can be significant interactive effects that require additional considerations in BCAs, as discussed in Chapter 7 and Chapter 13.
- While DR can enable reductions of fossil fuel generation and related emissions on the grid by enabling increased deployment of renewables, DR resources do not typically result in reduced consumption of other fuels outside of the electric system. Some DR resources might even modestly increase the use of other fuels. For example, the host customer might rely on a fuel-consuming form of backup generation during times when DR is deployed to reduce electricity consumption from the grid.

9.2. Introduction

As defined in this Manual and for this chapter, DR is a broad term that encompasses a variety of BTM approaches for managing the timing and magnitude of consumer energy use. DR encompasses a wide range of technologies and strategies and can be applied to almost any end-use load and across different facility types. DR is one of the most important strategies for creating demand flexibility, along with other resources such as storage and DG. See Section 7.5 for a discussion of grid and demand flexibility and Chapter 13 about assessing combinations of DERs, including DR, for their flexibility benefits and costs.

DR tends to be a voluntary resource, with host-customer options for participation through a dispatchable program or time-varying rates. The grid, however, can host a broad array of DR-enabling technologies, programs, and strategies; the scale, role, and potential purposes of DR programs are expanding.[38] The original DR programs primarily addressed coincident system demand peaks of relatively short duration. However, DR programs can address a range of system needs, such as:

- Reducing distribution system peak demands to avoid or defer substation or other upgrades
- Reducing demand during hours with high energy costs or emissions
- Mitigating demand fluctuations (e.g., those associated with customer-sited EV charging)
- Addressing rapid increases or decreases in availability of non-dispatchable wind and solar generation
- Providing ramping service to mitigate rapid-start requirements on generators

The fundamental BCA principles (Table 3-1) can help identify the relevant benefits and costs for DR, as with all DER types. In most cases, determining the relevancy of a particular benefit or cost to the DR in question requires defining the specific DR and its application. The value of DR benefits and costs (including host customer NEIs such as transaction, comfort, and productivity costs) depends on several factors. These factors include the DR operating profile, when and how the DR is implemented (e.g., in response to a price or dispatch signal), the baseline demand characteristics (counterfactual) of the impacted loads, the technologies utilized, and the host site characteristics (e.g., residential, commercial, or industrial facility). DR programs use a variety of communication technologies, incentive levels, customer engagement strategies, and performance requirements. Also relevant is who owns and who controls the DR resource. For example, the DR could be activated by a landlord, a tenant, an aggregator, or a utility system operator—all of whom can have different objectives and shares of DR benefits.

All of the factors listed above can also have important implications for cost-effectiveness. Section 9.4 discusses some factors that affect DR benefits and costs, and Section 9.5 discusses common challenges in determining the value of these impacts.

[38] According to a 2024 Federal Energy Regulatory Commission (FERC) report: "From 2022 to 2023, demand response participation in the seven U.S. wholesale markets [reached] … a total of 33,055 MW. …. Approximately 6.5% of the wholesale market peak demand for all RTOs/ISOs could be met by demand response resources in 2023… State regulators continue to consider and approve proposals to implement different types of time-varying rates and other opportunities to leverage flexible demand" (FERC 2024).

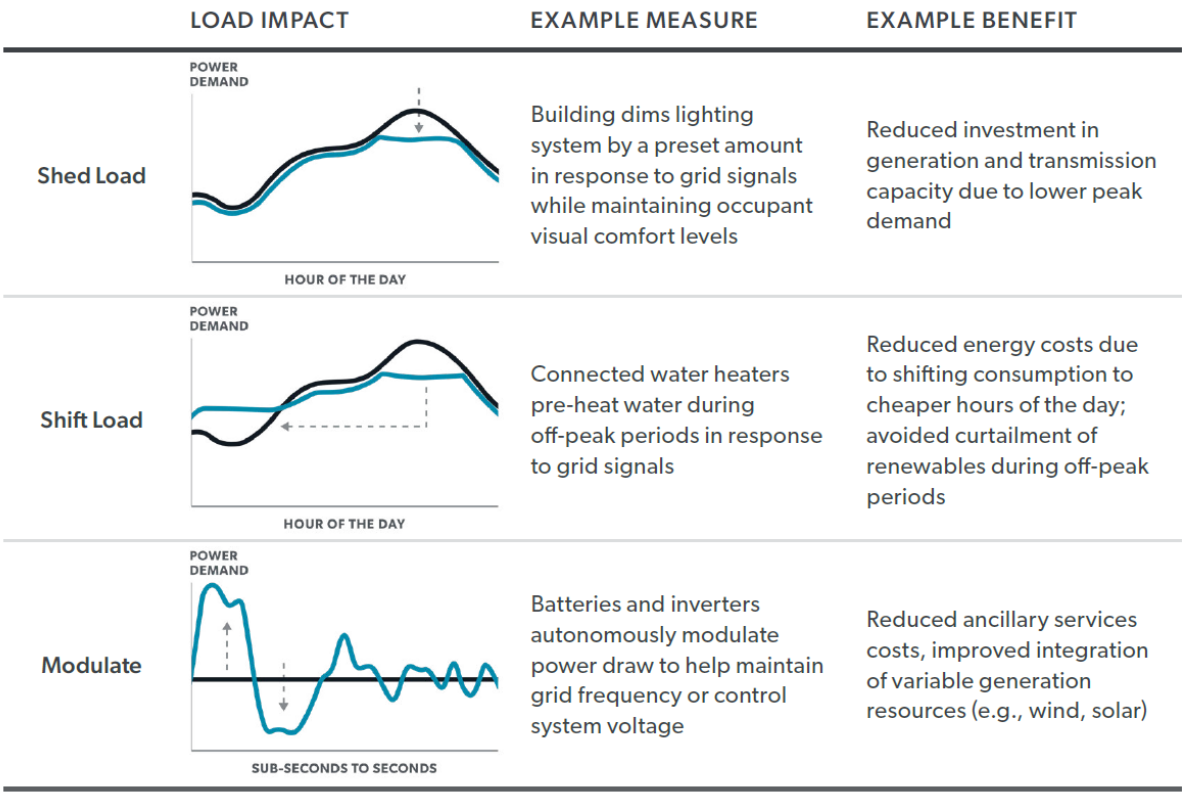
9.2.1. Demand Response Services

DR resources include programs and actions to change energy use during specified time periods. The objective of these programs is to cost-effectively alter customer energy usage in response to local or systemwide grid constraints and/or high market prices, usually by reducing demand during system peak usage periods or, increasingly, during periods of reduced availability of non-dispatchable wind and solar generation (EIA 2023). DR can also result in increased consumption during different time periods, typically when resources are less expensive and/or when there are high levels of renewable generation that cannot otherwise be easily utilized. For example, DR can encourage customers to pre-cool a building in advance of a period of system peak demand when the weather is hot.

From a utility perspective, DR is a change in the power consumption by customers that assists the utility in matching the demand for power with supply. Because utility supply costs can rise dramatically during relatively brief periods, DR can be a cost-effective alternative to generation. Increasingly, DR is seen as a cost-effective solution to infrastructure upgrades and grid constraints as part of an NWS (see Chapter 13).

More broadly, DR services can be characterized as shedding, shifting, or modulating loads, as seen in Figure 9-1.

Figure 9-1. Demand Response Services – Shed, Shift, Modulate

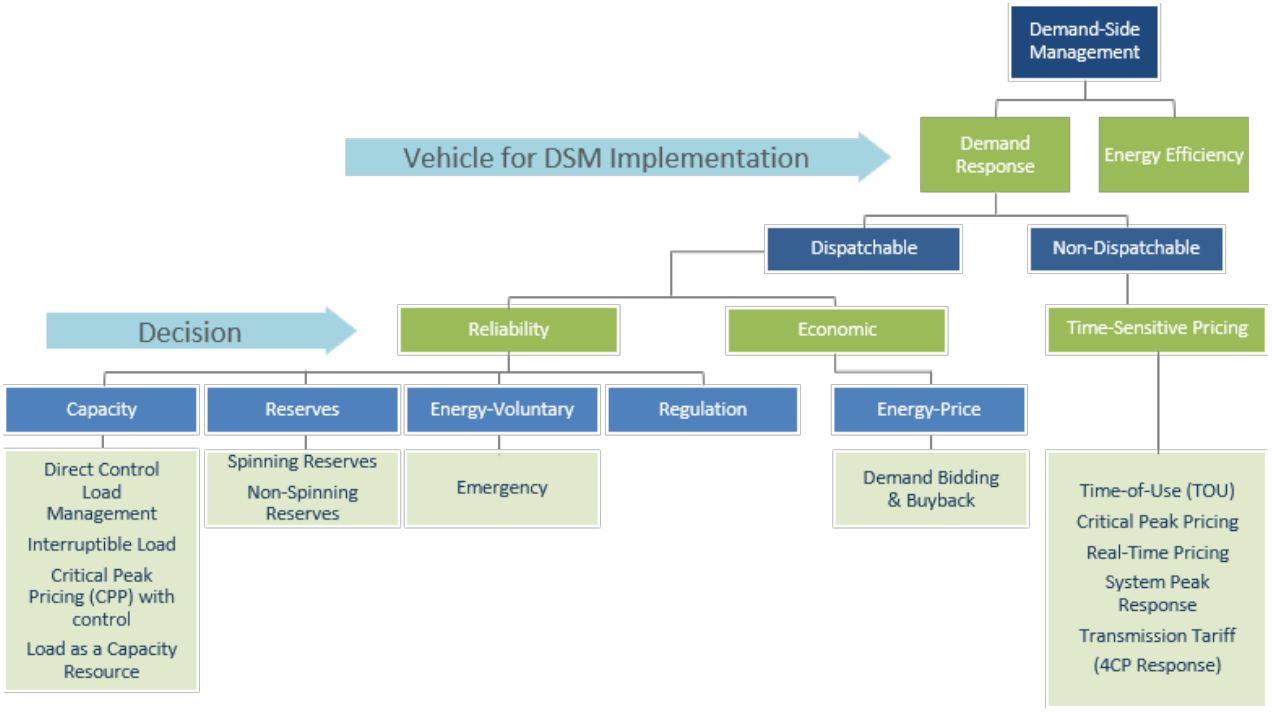


Source: (LBNL 2021).

9.2.2. Demand Response Classifications

Figure 9-2 presents a classification of DR resources, differentiated by dispatchability (e.g., dispatchable versus non-dispatchable), purpose (e.g., economic benefits or reliability), and program type (e.g., TOU rates, critical peak pricing, direct load control). Another type of DR not depicted in the graphic but increasingly being deployed by electric utilities and some natural gas utilities is behavior-based DR, in which educational messaging is used to encourage consumers to reduce their demand at specific times to address capacity constraints and/or high energy prices. Dispatchable and non-dispatchable are the two most common high-level classifications for DR.

Figure 9-2. Demand Response Classifications, Purposes, and Example Programs



Notes: Demand Bidding & Buyback programs are no longer commonly used but remain an option. Source: NERC 2011.

When used with DR resources, the term 'dispatchable' means that the timing and level of response is under the control of the utility (or its representative, such as DR aggregator), either through direct control, by the terms of a contract, or both. Examples of dispatchable forms of DR include air conditioning switches, thermostats, and water heater programs that respond directly to a utility-generated signal. The term 'non-dispatchable' refers to programs and measures without such controls (or mandates) and includes time-varying rates that send price signals to encourage utility customers to alter their energy usage during specific hours, as well as other types of voluntary behavioral programs.

Another standard classification is the DR program purpose or intent. Understanding and characterizing the problems that DR implementors seek to address is the first step in evaluating cost-effectiveness. DR resources may be designed and called upon for several purposes and often provide multiple services simultaneously. Figure 9-2 shows the primary purposes served by various types of DR. One such purpose is to reduce demand during times of high energy prices, which is described as 'economic dispatch' of DR. While high prices often occur at times of system peak

demand when there may also be a reliability concern, that is not always the case. DR programs sometimes also serve to increase loads when renewable generation might otherwise be curtailed. That is another form of economic dispatch: shifting loads from higher-cost hours to hours when the marginal cost of generation is effectively zero. DR programs are perhaps most commonly deployed to address reliability concerns and to reduce related costs associated with ensuring there is sufficient grid capacity to meet customer demands, reserves, and/or ancillary services.

Two other ways of classifying DR, perhaps as subsets of the classification approaches listed above, are by the location of the resource on the system (for location-targeted reductions) and whether there is one-way communication or two-way communication between the controls for the managed load and the entity implementing the program (e.g., aggregator or utility). For example, in more traditional forms of DR (such as one-way water-heating programs) utilities may call on customers only to provide load reductions to meet capacity needs. In contrast, more advanced technologies with two-way communications (such as grid-interactive heat-pump water heaters) can be called upon to provide a broader range of services, including precise frequency regulation,[39] while also providing greater visibility to the DR program manager.

9.3. Benefits and Costs of Demand Response Resources

The tables in this section provide illustrative lists of benefits and costs that are commonly associated with DR resources (see Chapter 6 for definitions of impacts). Each impact is described as a benefit, a cost, or either, depending on the most common, current applications of DR. The tables include notes on applicability that provide further explanation for those impacts that may be either a cost or a benefit. In less common applications, there may be cases where what is typically a cost can be a benefit, or vice versa.

Table 9-1 presents the typical benefits and costs of DR programs implemented by electric utilities on the electric utility system. Table 9-2 presents the typical impacts of DR programs implemented by natural gas utilities on the gas utility system. It is appropriate for BCA tests to include all of utility system impacts presented in these tables, where relevant and material, consistent with NSPM *Principle 2: Treat DERs as a Utility System Resource.*

A jurisdiction's primary BCA test might include other DR impacts—presented in Table 9-3 (Other Fuels), Table 9-4 (Host Customers) and Table 9-5 (Societal)—to the extent they are relevant to the jurisdiction's applicable energy policy goals, consistent with NSPM *Principle 1: Align with Applicable Energy Policy Goals* (see Section 4.4).

[39] Frequency regulation is a type of Modulation, as shown in Figure 9-1.

Table 9-1. Typical Impacts of Demand Response: Electric Utility System

Type	Utility System Impact	Benefit or Cost	Notes/Typical Applicability
Generation	Energy Generation	●	DR typically reduces consumption during high-cost hours and/or shifts consumption to lower-cost hours. If load is shed instead of shifted, energy savings are even greater
	Generation Capacity	●	A benefit because reduced system peak demand is frequently the primary objective of DR
	Environmental Compliance	●	A benefit for DR that reduces electricity generation; but load-shifting could result in costs depending on emission profiles of the impacted hours
	RPS/CES Compliance	NM	When DR is deployed to reduce demand in a relatively small number of hours per year, it will have a very limited direct impact on RPS. However, if used to shift demand to match availability of renewable generation and/or to avoid renewable curtailment (i.e., when increasing demand at times of excess supply), there may be a material benefit
	Market Price Response	●	DR tends to target higher-priced supply hours when price can be very sensitive to demand; it only applies in regions with competitive wholesale markets
	Ancillary Services	● /NM	Not a material impact on typical applications for reducing peak demands but can be a benefit when used to provide modulation services
Transmission	Transmission Capacity	●	A benefit due to load reductions during peak periods
	Transmission System Losses	●	A benefit due to load reductions during peak periods
Distribution	Distribution Capacity	●	Typically, a benefit due to load reductions during peak periods at local or systemwide peaks. However, circuit-level peaks are not always aligned with system peaks, and thus load-shifting to address system peaks could result in increased peak demand at the local circuit or substation level, and *vice versa*
	Distribution System Losses	●	
	Distribution O&M	●	
Cross-cutting GT&D	Risk	●	DR can help insulate the utility system from the risk of very high energy and/or capacity prices
	Reliability	●	A benefit due to better asset utilization of generation resources and enhanced grid flexibility
	Resilience	NR	Most resilience benefits typically flow to customers
General	Financial Incentives	●	Always a cost, where relevant
	Program Administration Costs	●	Always a cost, where relevant
	Utility Performance Incentives	● / NR	A cost (where jurisdictions have performance incentives)
	Credit and Collection	●	A benefit because customer savings make bill payment easier, especially for low-income customers

● = typically a benefit for DER type; ● = typically a cost for DER type; ● = either a benefit or cost for DER type, depending upon the application of DER; NM = typically not material for DER type; NR = not relevant for DER type.

Table 9-2 presents the typical impacts of DR programs implemented by natural gas utilities on the gas utility system. The table also notes some instances of where and how electric utility funded DR programs might impact the natural gas utility system. Generally, while gas utility ratepayer-funded

DR programs will always reduce natural gas consumption, electric utility ratepayer-funded EE programs can sometimes reduce and sometimes increase natural gas consumption, and associated benefits and/or costs.

Table 9-2. Typical Impacts of Demand Response: Natural Gas Utility System

Type	Utility System Impact	Benefit or Cost	Notes/Typical Applicability
Energy/Supply	Natural Gas Commodity	●	Typically, all benefits for natural gas EE, though some limited measures that do not save on peak hours will not provide capacity benefits; electric EE programs that reduce natural gas will create a benefit, those that increase consumption of natural gas will create a cost
	Capacity	●	
	Environmental Compliance	NM	
	Market Price Effects	NM	
Transportation	Pipeline Capacity	●	Typically a benefit for natural gas DR
	Pipeline Losses	●	Typically a benefit for natural gas DR
Distribution	Local Delivery Capacity	●	Typically a benefit for natural gas DR
	Local Delivery Losses	●	Typically a benefit for natural gas DR
Cross-cutting Energy, T&D	Risk	●	DR can help insulate the utility system from the risk of very high energy prices
	Reliability	●	Natural gas DR should improve natural gas reliability; electric DR will not typically affect natural gas peak demand. Natural gas system resilience is not likely to be materially impacted by DR
	Resilience	NR	
General	Financial Incentives	●	A cost for natural gas utility DR programs; not relevant otherwise
	Program Administration Costs	●	
	Utility Performance Incentives	● / NR	
	Credit and Collection Costs	●	Impacts are likely small

● = typically a benefit for DER type; ● = typically a cost for DER type; ● = either a benefit or cost for DER type, depending upon the application of DER; NM = typically not material for DER type; NR = not relevant for DER type.

Table 9-3. Typical Impacts of Demand Response: Other Fuel Systems

Type	Other Fuel Systems Impact	Benefit or Cost	Notes/Typical Applicability
Other Fuels (oil, propane, wood, gasoline)	Commodity	●	Backup generation (e.g., diesel generators) used when DR is deployed can increase fuel and environmental compliance costs
	Environmental Compliance	●	
	Market Price Effects	NM	

● = typically a benefit for DER type; ● = typically a cost for DER type; ● = either a benefit or cost for DER type, depending upon the application of DER; NM = typically not material for DER type; NR = not relevant for DER type.

Table 9-4. Typical Impacts of Demand Response: Host Customer

Type	Host Customer Impact	Benefit or Cost	Notes/Typical Applicability
Host Customer	Host portion of DER costs	●	A cost when they exist (e.g., industrial facility manager's time to manage response to a call for load reduction)
	Transaction Costs	●	Always a cost, to the extent material
	Interconnection Fees	NR	Not relevant for DR
	Resilience	NR	Not relevant for DR
	Tax Incentives	NR	Tax incentives are typically not available for DR
	Host Customer NEIs	●	Can be both costs and benefits. See Section 9.4.5.

● = typically a benefit for this resource type; ● = typically a cost for this resource type; ● = either a benefit or cost for this resource type, depending upon the application of the resource; NR = not relevant for this resource type.

Table 9-5. Typical Impacts of Demand Response: Societal

Type	Societal Impact	Benefit or Cost	Notes/Typical Applicability
Societal	GHG Emissions	●	Reduced emissions during peak hours when DR reduces demand may or may not be offset by increased emissions in other hours (and/or from backup diesel generators used by DR participants during load-reducing hours).
	Other Environmental	●	
	Public Health	●	
	Resilience	NR	

● = typically a benefit for this resource type; ● = typically a cost for this resource type; ● = either a benefit or cost for this resource type, depending upon the application of the resource; NM = typically not material; NR = not relevant.

9.4. Key Factors that Affect Demand Response Benefits and Costs

This section describes a few of the common factors that affect the value of a DR program's benefits and costs.

9.4.1. Technology Characteristics

DR involves more than just installing a technology. Defining the way the DR technology (typically controls, such as grid-enabled thermostats or radio-controlled on/off switches) interacts with the

managed loads and the managed loads' function(s) is essential for determining benefits and costs. One important consideration is whether use of the technology is automated or manual. Automated control of end uses can lead to greater certainty over the level of demand reduction.

9.4.2. Load Profiles

The cost-effectiveness of DR programs is a function of the load changes during the targeted time period, as well as of any load changes in other hours. For example, while participating DR customers during a summer peak event may have their air conditioners' set points raised by a few degrees, there may be a post-event spike in load induced by the air conditioners' recovery to their original temperature set points. Similarly, customers who receive notice of impending super-peak pricing periods may pre-cool their buildings to ride through such events. Thus, both the extent to which customers respond and the way they shift loads (if they shift instead of shed) also affect the cost-effectiveness of the DR program.

The impact of shedding, shifting, or modulating a load also varies depending on the value of the end use served by the load. For example, a hot water tank DR program for single-family homes has less potential impact than a whole-home DR program.

9.4.3. Program Design

Another important aspect of DR programs is the predictability of achieving the expected load management. In other words, to what extent can the utility system count on the DR to deliver the planned demand impacts? DR predictability depends on several factors, such as the speed, precision, and duration capabilities of the DR systems and/or contracts, the duration and frequency of DR activation, and the level of control the utility has over the DR resource. Several of these factors will be affected by the design of DR initiatives. For example, a DR request to reduce usage during on-peak hours may be just an ask for uncompensated, voluntary action (a purely behavioral program) with somewhat less predictable impacts across a season of requests and thus of lower value than a rigorously enforced dispatchable program. Contract- and tariff-based DR programs may offer greater precision in benefit and cost estimation but may also increase program costs through higher incentives.[40]

A residential thermostat control program provides a useful example. For these thermostat programs, the level of peak demand reduction—and the predictability of that reduction—depends on whether the program implementation happens through dispatchable control with limited host-customer override or through voluntary, non-dispatchable designs. However, even dispatchable programs may incorporate host-customer override or opt-out provisions—with customer opt-outs expected to occur more frequently if the dispatch signal is sent, for example, every day for five days in a row during a heat wave. Thus, it is good practice for BCA tests to account for host-customer opt-out behavior that can reduce program benefits, as well as any proactive measures designed to minimize opt-outs. Such measures may incur program costs but will increase benefits.

In general, the level of customer awareness and engagement will substantially impact the effectiveness of DR programs. Building customer awareness often involves multiple and iterative

[40] The predictability of DR programs, including voluntary programs, can be significantly improved through evaluations of DR programs which provide evidence of participation in various program designs and utility customer categories. Several DR program suppliers, Lawrence Berkeley National Laboratory, and utilities have conducted studies of DR implementation to determine net impacts under different conditions and program designs.

education campaigns across various channels. Participation rates are a function of customer type, awareness, program choices, incentive rates, program complexity, hardware and software interactions and costs, and other factors—all of which could impact program costs and cost-effectiveness.

9.4.4. Other Fuel Impacts

In some scenarios, the host customer's response to a DR measure may involve using alternatives or substitute energy resources, such as self-generation (DG or DS). For example, Customer Non-Energy Impacts, an industrial host customer may rely on a generator, such as a fossil-fueled reciprocating engine, to maintain sufficient power during a DR event. Impacts associated with the use of these resources, even if not under utility control, can affect the DR program's cost-effectiveness from a societal perspective (e.g., in terms of pollutants) and the host customer's perspective (e.g., in terms of costs). If DG, DS, or electrification are included with a DR strategy, there will be other fuel interactive effects.

9.4.5. Host Customer Non-Energy Impacts

Table 9-6 presents an illustrative summary of host customer NEIs that DR resources might create. These impacts can sometimes be benefits and sometimes costs. The presence, direction, and magnitude of these impacts will depend on many factors, including the DR program classification (e.g., structure), the type of host customer (e.g., low-income, residential, commercial, industrial), and the affected end uses. The table shows whether impacts are typically a cost or a benefit for the most common DR applications. The actual 'direction' of the impact may vary and should be determined on a case-by-case basis.

Table 9-6. Potential Host Customer Non-Energy Impacts of Demand Response

Category	Benefit or Cost	Examples
Transaction costs	●	Incurred costs for host customers (at least in terms of time) to enroll in DR initiatives
Operations and maintenance	●	Costs associated with maintaining and operating DR systems, equipment, and controls, as well as to adjust business operations during DR events
Asset value	NR	No material impact in most cases
Productivity	NR	No material impact in most cases
Economic well-being	NM	Very modest improvement from DR incentives
Comfort	●	Possible reductions in thermal comfort from the control of A/C and/or related to the availability of hot water during DR events
Satisfaction/Pride	●	Contribution to addressing grid and/or environmental concerns

● = typically a benefit for this resource type; ● = typically a cost for this resource type; ● = either a benefit or cost for this resource type, depending upon the application of the resource; NM = typically not material; NR = not relevant.

9.5. Common Challenges in Determining DR Benefits and Costs

9.5.1. Determining the Counterfactual Host Customer Baseline

Counterfactual host-customer baselines represent what the host customer load patterns would have been in the absence of the DR resource. Comparison of counterfactual baselines to the host customer load patterns with DR determines the DR resource savings.

While historical customer load patterns may be helpful to consider, there can also be significant challenges with assuming historical patterns are an appropriate baseline. For example, host customers might (1) make significant changes to their buildings or facilities that affect load patterns, (2) change usage patterns or occupancy, and/or (3) install other DER types that will affect load patterns (i.e., interactive effects). In addition, there might be structural shifts in the economy (e.g., a recession) that would affect customer load patterns.

Approaches and considerations to determining baseline usage include using control groups,[41] or using a control day and hour(s) for DR participants. The latter is a common approach that includes the two standard methods for residential programs below (CAISO 2022):

- Day Matching – Estimates what electricity use would have been in the absence of DR dispatch, using electricity use data on non-event but similar, recent days.
- Weather Matching – Estimates what electricity use would have been in the absence of dispatch during non-event days with the most similar weather.

Evaluation of historical data and evaluation results from similar programs and target populations can also help establish *a priori* estimates of DR savings to improve DR predictability. In some cases, measuring cost-effectiveness at the portfolio level may be more reliable—even if more general—than results obtained from program-by-program analysis.

9.5.2. Accounting for Multiple Utility System Impacts

DR programs can provide value for multiple grid services. For example, operation of a DR program could be designed to provide either (a) wholesale generation capacity value in an organized market, (b) relief to heavily loaded distribution circuits, or (c) both. Regardless of the DR program design, there will likely be impacts on both generation capacity and distribution system capacity.

In many cases, the season and time of day of peak demand on substations and other elements of the distribution system will be similar to those of generation peak demand. In such cases, deploying DR to address generation peak demands will provide distribution system cost savings, even if it is not specifically designed or deployed to address distribution system peaks. However, some elements of the distribution system will peak at different times or even different seasons than when system generation peaks occur. For those elements of the distribution system, there

[41] A control group is a set of participants who are eligible for the program but do not participate. Their energy usage is measured and compared against the usage of the treatment group (the participants who are enrolled in the DR program) to determine the net impact of the program. This helps isolate the effect of the program from factors such as weather, time of day, or other economic conditions, that can influence energy consumption. RCT refers to participants and treatment group members are randomly selected. A quasi-experimental method is a research design that analyzes the effect of a DR program by using a non-randomized control group. In the context of DR programs, this means that participants are not randomly assigned to the treatment or control group. Instead, researchers use statistical methods to create a synthetic control group or to adjust for pre-existing differences between the groups to ensure a fair comparison.

will be no benefit from deployment of DR to address system peaks. It is even possible that DR deployed to address system peaks will exacerbate *some* local distribution peak demands. For example, a DR program that cycles residential air conditioners and is dispatched on hot summer weekdays between 3 and 5 p.m. to address late-afternoon system peak demand, could increase demand on distribution substations that peak at 6 or 7 p.m. This scenario may occur if the local substation serves a higher percentage of residential load than the system as a whole.

The extent to which a DR program designed to address system generation peaks could provide additional benefits and/or impose extra costs on the distribution system will vary by utility (based on its mix of distribution system peaks). It will also be affected by the design of the DR programs (for instance, whether they control loads for more extended periods than required to address only the system peak). While DR can also be deployed to address both systemwide and local distribution peaks, such approaches may increase the cost of the DR program. In all cases, it is important for BCA tests to account for the combined effects across all aspects of the utility system.

Note that the need to address the interplay between impacts on generation and on distribution system capacity applies equally to DR explicitly designed to address a local distribution peak. In such cases, it is important to understand and account for impacts on generation peaks. For example, if a distribution substation peaks at the same time as the utility system as a whole, DR deployed as part of an NWS to defer a substation upgrade will provide generation capacity benefits that should also be accounted for in a BCA test. If the substation peaks at a different time than the system peak, there may be no such additional generation capacity benefits; there may even be generation capacity costs (if load is shifted in ways that exacerbate a system peak) unless the DR control periods are specifically designed to avoid that situation.

9.5.3. Air Emissions Impacts

The primary mechanism by which DR resources can reduce air emissions (from electricity generation) is by shifting loads from hours associated with high-emission resources to hours with low-emission resources. Conversely, DR resources can sometimes increase air emissions, for example, when host customers rely on fossil-fueled backup power or when electric loads shift from hours with low-emission resources to hours with high-emission resources.

As discussed in Section 7.6, estimates of air emission impacts should account for two crucial factors: (a) the time period over which the DER affects loads (down and/or up); and (b) the marginal emission rates of the utility system during the hours that the DER affects loads.

9.6. Common Interactions with Other DERs

While DR programs can have substantive interactions with any other type of DER, such interactions are most common with EE and electrification-related DERs, where it is common for the design and delivery of these DER programs to be integrated. Examples of key interactions to consider when conducting cost-effectiveness assessments include the following:

- **DR that produces efficiency benefits**. Some DR programs deploy technology, particularly controls such as ‘smart thermostats’ or networked lighting controls, that also typically result in customers lowering their total annual energy consumption. It is appropriate to account for those additional efficiency benefits in the DR BCA test, to the extent that they would not have otherwise occurred. Of course, in such cases, the cost of the technology that enables both DR and EE benefits would be included in the BCA test. Conversely, if a

'smart thermostat' has already been installed in a home for efficiency or other reasons, the DR program simply leverages the thermostat's ability to control loads during peak hours. In such a scenario, the DR BCA test would include neither the EE benefits nor the cost of the thermostat itself.

- **DR affecting the magnitude of EE benefits**. Some DR programs will affect the magnitude of the benefits of current or future EE programs, or vice versa. For example, if a utility is currently running a DR program that is cycling or otherwise controlling a substantial number of residential central air conditioners, the peak demand savings from an EE program designed to promote the installation of efficient new central air conditioners will be diminished. The obverse is also true: controlling central air conditioners through DR will yield lower peak demand reductions if the air conditioners are more efficient due to an EE program. Either way, it is important for BCA tests to account for such interactions where they exist.
- **Simultaneous promotion of EVs and managed charging**. Some utilities are providing both EV incentives and related incentives for the installation of level 2 chargers in homes. The charger incentives are conditioned on contracts that allow the utility to control whether charging occurs during system peak hours. In such cases, under the BCA Framework the BCA test would assess the combined effects of electrification and managed charging, with the managed charging element reducing the added cost to the grid of the electrification measure.

9.7. Changes in Revenues and Rate Impacts

This section discusses how DR resources can influence customer rates, why BCA tests cannot accurately evaluate those impacts, and options for appropriately assessing and addressing rate impacts.

An important factor affecting rates is changes in revenue, which affect how and from whom utilities will recover the system costs they incurred in the past (i.e., sunk costs). If a DR investment leads to a decrease in revenue, that impact is lost revenue and it is one of multiple ways DR resources can affect rates.

As discussed in Chapter 3 and in more detail in Appendix B, jurisdictions need more than BCA tests to thoroughly understand the issue of rate impacts. BCA tests and assessments of rate impacts address fundamentally different questions. BCAs assess the extent to which investments increase or decrease costs; rate impact analyses assess whether rates will go up or down. Though both can be important, concerns about how equitably past costs are recovered are different than concerns about whether total costs will increase or decrease. Thus, lost revenues and any potential related rate impacts are not appropriate to include in BCA tests and require separate evaluation using rate, bill, and participation analyses.

DR resources will typically both add utility system costs (e.g., because of EE program costs) while reducing others (e.g., by avoiding GT&D costs). (See Table 9-1 above). In general, several key factors affect the extent to which DERs might create rate impacts:

- Increases in utility system costs will put upward pressure on rates.
- Reductions in utility system costs will put downward pressure on rates.
- Reductions in sales from DER resources will put upward pressure on rates.
- Increases in sales from DER resources will put downward pressure on rates.
- Rate design will affect the amount of lost or increased revenues created by the DER.

DR resources might create a small amount lost revenues to the extent that they reduce total system sales over which fixed or sunk costs are recovered.

Regulators and other stakeholders that are concerned about DR rate impacts have several options:

- Conduct a long-term rate, bill, and participation analysis.
- Seek DR program designs likely to mitigate equity concerns.
- Examine ways to expand customer participation, especially among low- and moderate-income customers.
- Periodically review impacts as DR programs are implemented.

10. Distributed Generation Resources

This chapter describes the benefits and costs most relevant to distributed generation resources. It identifies key factors that affect DG benefits and costs and provides guidance on addressing common challenges with DG cost-effectiveness analyses.

10.1. Summary of Key Points

- DG includes a range of technology types that vary by the energy source or fuel. The most common DG technology types are DPV, CHP, distributed wind, distributed hydropower, distributed wave and tidal energy, and distributed biomass. Generation is 'distributed' when it is interconnected and operated at the distribution level of the electric grid. The vast majority of DG installations, in terms of the number of systems, installed MW of generation, and host customers, are rooftop solar PV systems.
- DG includes a range of operating configurations that in turn affect cost-effectiveness. These configurations include on-site, BTM generation that never exports energy to the grid; BTM generation that sometimes exports; 'virtual' or aggregated BTM and multi-site generation; community or shared solar (CS) on-site with at least one on-site subscriber; CS with no on-site customers; customer choice aggregation served by DG; and utility-owned and/or operated DG.
- DG benefits and costs are impacted by whether the DG technology has variable output, is dispatchable, or operates on a continuous basis.
- Several other factors that affect DG benefits and costs include whether the DG output is expected to only serve on-site load, only export from the facility to the grid, or both; the compensation mechanism and rates that apply to generation that offsets on-site load and generation that is exported to the grid; interconnection costs and local grid conditions; and baseline and marginal emissions rates for the system in which the DG operates.
- The utility system costs that DG resources allow the utility to avoid determine DG benefits and costs, whether the DG operates purely as a load reducer by offsetting energy required by the host from the utility, or by displacing system generation when exports serve other customers at the distribution level of the grid, or both.
- DG resources generally reduce generation and transmission costs. DG resources can either reduce or increase distribution costs, depending upon (a) the condition of the local distribution grid, (b) the extent to which local generation can enable the utility to avoid distribution costs over the life of the DG system, and (c) the grid's ability to continue to operate safely and reliably with interconnected DG on the system.
- Some DG resources, such as distributed renewable energy generators, do not typically affect consumption of other on-site fuels unless paired with electrification of energy loads. Other DG resources, such as CHP and distributed biomass, can increase consumption of other fuels.
- Similarly, some DG resources, such as distributed renewable generation, can reduce air emissions by reducing reliance on more polluting generation sources. Other DG resources, such as CHP and distributed biomass, might reduce or increase air emissions, depending upon the fuel used, the fuel avoided, and marginal emissions from the electricity grid.

- DG can create lost revenues for the utility by reducing host customer demand. It is important to distinguish utility system costs and lost revenues because under the BCA Framework, lost revenues are not included in a BCA but are included in a rate and bill impact analysis.
- The extent to which DG will create lost revenues depends upon the compensation mechanism used by the host customer. Under the BCA Framework, determination of lost revenues for different compensation mechanisms is as follows:
    - Under net-metering programs, lost revenues are based on the DG generation times the portion of the electricity rate covered by the program.
    - Under net-billing programs, the bill credits are treated as a utility system cost, and the lost revenues are based on the DG generation used to offset on-site consumption times the portion of the electricity rate covered by the program.
    - Under buy-all/sell-all programs, there are no lost revenues. However, there might be increased rates if the cost of the DG exceeds the utility system avoided costs.
    - Under CS programs, there are no lost revenues, and the bill credits would be treated as utility system costs. However, there might be increased rates if the cost of the program exceeds the utility system avoided costs.

It is important to distinguish utility system costs and lost revenues because under the BCA Framework, lost revenues are not included in a BCA but are included in a rate and bill impact analysis.

10.2. Introduction

DG resources include electric generation technologies interconnected to the distribution grid and operating at the distribution level. This generally means DG operates near a load, though some, such as landfill biogas generators, may operate as stand-alone resources not sited close to a particular host customer's load. DG technologies include PV, CHP, district heating and cooling, distributed wind, distributed hydropower, biomass and biogas facilities associated with landfills and agricultural operations, and others. The vast majority of DG installations, in terms of the number of systems, installed MW of generation, and host customers, are rooftop solar PV systems.

The fundamental BCA principles (Table 3-1) aid identification of the relevant benefits and costs for DG, as with all DER types. Those benefits and costs ultimately determine cost-effectiveness. Identifying whether a particular benefit or cost is relevant to DG requires defining the specific DG technology and use case. Generally speaking, because DG substitutes for utility generation, a BCA test can assess DG impacts by evaluating the utility costs avoided or benefits lost by the DG operation—in other words, what the utility would have experienced to serve its customers *but for* the existence and operation of the DG. For example, DG resources that never export energy to the grid, but instead consume all generation on site, have different impacts from those that do export energy back onto the grid. In another

Identifying whether a particular benefit or cost is relevant to DG requires defining the specific DG technology and use case.

example, DG resources that can be dispatched to export energy into the grid during high-cost peak hours will have different impacts on avoided utility system costs than those that cannot.

U.S. Policy Applying to Distributed Generation

The U.S. Federal Public Utility Regulatory Policy Act (PURPA) establishes that DG facilities that meet certain criteria for being a Qualifying Facility (QF) have the rights to sell their excess generation to the utility and to take supplementary, back-up, and other services, as requested, from the utility.[cite] Specific rules apply to QFs that are small power production facilities.[cite] U.S. states have the obligation under PURPA to implement and apply the federal law in state law and regulation, [cite] so QF rights are both federal and state policy in the United States.

In addition, the U.S. Energy Policy Act of 2005 established net metering, explained below, as a federal ratemaking standard and required states to consider net metering (U.S. Public Law 109-58). It is each state's role to establish tariffs that govern the terms of QF sales to the utility and whether to specifically adopt net metering or some other tariff structure applicable to non-utility DG is a state function.

Sources: U.S. Public Law 109-58, codified as 16 USC § 2621(d).

10.3. Benefits and Costs of Distributed Generation Resources

The tables in this section summarize typical benefits and costs of DG resources (see Chapter 6 for definitions of impacts). The tables describe each impact as a benefit, a cost, or potentially either, depending on the most common applications of this technology. In addition to those impacts labeled as 'either' there might be some less-common applications where an impact labeled a cost could be a benefit, or vice versa. The tables include notes on applicability that provide further explanation for those impacts that more commonly may be either a cost or benefit.

Table 10-1 presents the potential benefits and costs of DG investments funded by electric utilities on the electric utility system. It is appropriate for BCA tests to include all of utility system impacts presented in Tables 10-1 and 10-2, where relevant and material, consistent with NSPM *Principle 2: Treat DERs as a Utility System Resource.*

A jurisdiction's primary BCA test will include other DG impacts—presented in Table 10-3 (Other Fuels), Table 10-4 (Host Customers) and Table 10-5 (Societal)—to the extent they are relevant to the jurisdiction's applicable energy policy goals, consistent with NSPM *Principle 1: Align with Applicable Energy Policy Goals* (see Section 4.4).

Table 10-1. Typical Impacts of Distributed Generation: Electric Utility System

Type	Utility System Impact	Benefit or Cost	Notes/Typical Applicability
Generation	Energy Generation	●	Benefit: DG reduces electricity generation and capacity requirements
	Generation Capacity	●	
	Environmental Compliance	●	
	RPS/CES Compliance	NR	
	Market Price Effects	NR	
	Ancillary Services	NM	Benefit or Cost: Depends on DG performance and system conditions; magnitude of benefits and costs may change with deployment rate of DG in specific locations
Transmission	Transmission Capacity	●	Benefit or Cost: Depends on whether DG increases or decreases net transmission peak demand
	Transmission System Losses	●	Benefit: DG reduces transmission system loads
Distribution	Distribution Capacity	●	Benefit or Cost: Depends on increase or decrease in distribution peak demand
	Distribution System Losses	●	Benefit: DG reduces distribution system loads
	Distribution O&M	●	Benefit or Cost: Depends on whether the DG adds to or relieves congestion and grid management costs
Cross-Cutting GT&D	Risk	●	Benefit or Cost: Depends on extent that DG reduces system risks and adds grid operational complexity
	Reliability	●	Benefit or Cost: Depends on whether DG can support reliability or impose reliability costs, particularly at high deployment levels
	Resilience	NM	Most resilience benefits typically affect host customers
General	Financial Incentives	●	Cost (to the extent relevant)
	Direct Utility Investment	●	
	Program Administration Costs	●	
	Utility Performance Incentives	● / NR	
	Credit and Collection Costs	●	Benefit: Customer savings make bill payment easier and more reliable, especially for low-income customers

● = typically a benefit for DER type; ● = typically a cost for DER type; ● = either a benefit or cost for DER type, depending upon the application of DER; NR = not relevant for DER type. NM = typically not material

Natural gas utilities do not typically implement or otherwise support DG programs, and as such there is no relevance to natural gas utility system impacts (as shown in Chapter 6, Table 6-5). However, electric utilities sometimes implement or otherwise support DG programs that have impacts on the natural gas utility system. The primary example of this is electric utility programs that support natural gas-fired CHP. Table 10-2 presents the potential benefits and costs of electric utility CHP programs on the natural gas utility system.

Table 10-2. Typical Impacts of Electric Utility CHP on the Natural Gas Utility System

Type	Utility System Impact	Benefit or Cost	Notes/Typical Applicability
Energy/Supply	Natural Gas Commodity	●	DG that uses natural gas to generate electricity i.e., CHP, increases fuel use and costs for associated impacts
	Capacity	●	
	Environmental Compliance	●	
	Market Price Effects	NM	
Transportation	Pipeline Capacity	●	Typically a cost for DG that consumes natural gas
	Pipeline Losses	●	Typically a cost for DG that consumes natural gas
Distribution	Local Delivery Capacity	●	Typically a cost for DG that consumes natural gas
	Local Delivery Losses	●	Typically a cost for DG that consumes natural gas
Cross-cutting Energy, T&D	Risk	●	Increased gas consumption for CHP might increase risks and reduce reliability of the gas utility
	Reliability	●	
	Resilience	NR	Most resilience benefits typically impact host customers
General	Financial Incentives	NR	For CHP programs, these costs are typically applied to the electric utility because the primary benefit is electricity production
	Program Administration Costs	NR	
	Utility Performance Incentives	NR	
	Credit and Collection Costs	NR	

● = typically a benefit for this DER type; ● = typically a cost for this DER type; ● = either a benefit or cost for this DER type, depending upon the application of the DER; NR = not relevant for this DER type.

Table 10-3 presents the potential benefits and costs of electric utility DG resources on other fuel systems. The primary example of such an electric DG resource is when a utility or a host customer installs a backup electric generator that is fueled by other fuels.

Table 10-3. Typical Impacts of Distributed Generation: Other Fuel Systems

Type	Other Fuel Systems Impact	Benefit or Cost	Notes/Typical Applicability
Other Fuels (oil, propane, wood, gasoline)	Commodity	●	Backup generation (e.g., diesel generators) used when DR is deployed can increase fuel and environmental compliance costs
	Environmental Compliance	●	
	Market Price Effects	NM	

● = typically a benefit for DER type; ● = typically a cost for DER type; ● = either a benefit or cost for DER type, depending upon the application of DER; NM = typically not material for DER type; NR = not relevant for DER type.

Table 10-4 presents the potential benefits and costs of electric utility DG resources on host customers.

Table 10-4. Typical Impacts of Distributed Generation: Host Customer

Type	Host Customer Impact	Benefit or Cost	Notes/Typical Applicability
Host Customer	Host portion of DER costs	●	Cost to customer
	Transaction Costs	●	Cost to customer
	Interconnection Fees	●	Cost to customer
	Resilience	●	Benefit: Typically not relevant for renewable DG; potentially a benefit for CHP
	Tax Incentives	●	Benefit (where applicable)
	Host Customer NEIs	●	Benefit or Cost: Depending on the NEI (see Section 10.4.5)

● = typically a benefit for this DER type; ● = typically a cost for this DER type; ● = either a benefit or cost for this DER type, depending upon the application of the DER; NR = not relevant for this DER type.

Table 10-5 presents the potential societal benefits and costs of electric utility DG resources.

Table 10-5. Typical Impacts of Distributed Generation: Societal

Type	Societal Impact	Benefit or Cost	Notes/Typical Applicability
Societal	Resilience	●	Benefit: Not relevant for renewable DG; potentially a benefit for CHP
	GHG Emissions	●	Benefit: Renewable DG reduces system emissions; CHP can also reduce system emissions depending upon fuel source and generation displaced
	Other Environmental	●	
	Public Health	●	Benefit: Emissions reductions from renewable DG; CHP can also offer benefits depending upon fuel source and generation displaced

● = typically a benefit for this resource type; ● = typically a cost for this resource type; ● = either a benefit or cost for this resource type, depending upon the application of the resource; NR = not relevant for this resource type.

10.4. Key Factors that Affect Distributed Generation Benefits and Costs

10.4.1. DG Technology and Operating Characteristics

DG benefits and costs are impacted by system configuration and operating conditions, as well as by whether the DG technology has variable output, is dispatchable, or operates on a continuous basis. Variable DG resources operate in conformance with the available energy source or 'fuel.' For instance, DPV operates when the sun is shining. Dispatchable resources can be called upon to operate, or stop operating, by the grid operator. A distributed biogas generation facility with gas storage can be dispatched to some degree. Distributed run-of-the-river hydropower and distributed wave generation operate more or less continuously, though with some seasonality.

Characterizing DG benefits and costs starts with an assessment of whether the DG output is expected to serve only on-site load, is only exported from the facility to the grid, or both.

Characterizing DG benefits and costs starts with an assessment of whether the DG output is expected to serve only on-site load, is only exported from the facility to the grid, or both.

Serve on-site load only: Some DG systems by design serve only on-site load and never export energy onto the grid. The cost-effectiveness analysis for such systems will be generally the same as that for any load-modifying resource, such as EE.

Export to the grid only: Some DG systems might be installed by commercial developers solely for the purpose of exporting onto the grid. These DG system operators sell their output to the local utility, to a direct access customer, or to an ultimate customer through the utility and/or the wholesale power system. From the utility system perspective, the cost-effectiveness analysis for these systems will be generally the same as that for a generator located on the distribution system.

Serve on-site load and export to the grid: Many DG systems both serve on-site load and export energy onto the grid. These systems can alternate between these modes instantaneously, based on changes in load and variable generation output. This flexibility makes it difficult to distinguish between costs, benefits, and lost revenues. Different DG compensation mechanisms treat load reduction versus electricity generation differently; therefore, it is important to account for these mechanisms when identifying benefits, costs, and lost revenues of DPV resources (see Section 10.5.1. for more detail).

Excess generation: Over a typical day, month, or year, some DG technologies might alternate frequently between generating for load reduction, exporting to the grid, or both. The term 'excess generation' is sometimes used to refer to generation that is not used to offset host customer consumption from the grid over the course of that customer's billing period.[42] Exported energy from a DG host's facility will serve the nearest load in the grid, and it will displace energy otherwise generated, transmitted, and distributed to serve that nearby load.

[42] In this Manual the term 'billing period' refers to the period used for reading customer meters and billing customers for their consumption. This is typically one month, but other options are possible.

Power outages: For safety reasons, the DG inverter equipment will typically automatically curtail DG output that occurs during a time when the grid is down to prevent unwanted energizing of the grid.

10.4.2. DG Compensation Mechanisms

For the purposes of this Manual, the term 'DG compensation mechanism' refers to the set of financial incentives that a utility offers to encourage or otherwise influence customers' decisions regarding the installation and operation of DG resources. These compensation mechanisms are typically defined in tariffs associated with DG programs. They are sometimes referred to as the rate designs applied to DG customers.

Almost all jurisdictions have DG compensation mechanisms that determine or inform how a host customer will be compensated for DG output and the rates that customers pay for utility service that supplements, backs up, or otherwise ensures DG customer service. These DG compensation mechanisms take several different forms, depending on policy, regulatory decision-making, and the technological capabilities of the distribution grid.

For BCA purposes it is useful to describe DG compensation mechanisms as falling into three categories, which can apply, with or without modification, to all DG customers or facility types:

- *Net metering,* which was defined in the U.S. Energy Policy Act of 2005[43] as "a service to an electric consumer under which the electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period."[44] Net metering can be supported by a simple meter that records net consumption or exports over the course of the monthly (or other) billing period. The rate for both consumption and generation is set equal to the retail rate otherwise applicable to the customer, with some variation among jurisdictions in treatment of certain fixed charges and rate riders.
- *Net billing* approaches, where a portion of the DG output offsets the host customer electricity consumption, while the remaining output (i.e., the excess generation) is compensated at a specific compensation rate that may differ from the retail consumption rate applicable to the DG customer. This approach requires meters that can record consumption and exports separately. The compensation may also vary based on the interval over which consumption and exports are measured. For example, instantaneous net billing records all additions to the consumption and export registers whenever they occur. In other cases, the registers can be netted at specific time intervals, for example, every 30 minutes. In that case, each time increment is recorded as a consumption or export increment by the net difference between readings on the consumption and export registers, and increment values are summed on the bill at the end of the month.
- *Buy-all/sell-all* approaches, where gross DG output is compensated at a certain rate such as a 'value of solar' rate (NREL 2014), and all usage, whether electrically offset or not, is charged at a possibly different rate such as the retail consumption rate that otherwise applies to the DG customer's rate class (PNNL 2018). This approach requires meters that

[43] U.S. Public Law 109-58, codified as 16 USC § 2621(d)(11).

[44] *Id.*

measure the output of the DG system as well as the gross consumption of electricity by the customer.

DG compensation mechanisms can vary in the netting or billing period and the compensation rate for exports. DG customers typically earn bill credits as compensation for the DG output. Jurisdictions vary in their treatment of bill credits that exceed consumption charges or other charges during the billing period, though cash payments for excess credits are not common. Utilities typically carry bill credits over from month to month, denominated either in kWh or dollars, and cleared to dollars on an annual basis or when the customer terminates service. In some jurisdictions, accrued bill credits at the end of the year may be transferred to the benefit of low-income customers or simply be lost.

DG compensation mechanisms can vary in the netting or billing period and the compensation rate for exports.

DG compensation mechanisms may also vary in the treatment of renewable energy certificates (RECs) created when renewable energy is generated. RECs have market value that accrues as a benefit to the holder, either through sale or, for utilities, as an offset to a renewable energy obligation under an RPS. In some cases, DG hosts are required to transfer RECs to the utility in return for the receipt of export compensation. Those RECs may be retired by the utility or sold to generate additional revenue. In other cases, the customer is allowed to keep the associated RECs and can retire or sell them for additional revenue.

10.4.3. Community Solar Projects

Community solar, also referred to as shared solar, is typically implemented through statute or regulation. Its purpose is to provide customers who cannot or choose not to install on-site DG the opportunity to obtain some of the benefits of participating in dedicated self-generation.

CS projects and programs present a special set of circumstances to address in determining cost-effectiveness, starting with full and fair evaluation of the value of the energy generated by the CS facility.

CS programs can take several different forms.

- They can be built, owned, and operated by utility or non-utility entities. This impacts the level of utility costs that may be associated with the program.
- The CS subscription service can be provided by the owner or operator or a third party. This impacts administrative, billing, and customer service costs.
- The CS facility can sell all its energy to the utility, or it can use a portion of the generation to serve the energy needs of the facility host acting as an anchor subscriber. There may be host customer impacts in the form of offset load.
- The CS facility can be relatively large in size (typically 5–10 MW) and located inside or outside the subscriber customer's utility's service territory. This can impact the evaluation of T&D benefits and costs as well as administrative and billing costs.
- Subscription opportunities can be open to any customers in any amounts or can be limited to a maximum share of output, and/or a minimum number of subscribers. Customer management costs are a key factor in cost-effectiveness.
- CS can be especially useful in supporting low-income customer participation in DPV, as many such programs are designed to leverage the benefits of DG for low-income customer

bill reductions. This often requires set-asides or minimum participation levels for low-income customers, which might result in higher customer solicitation and management costs.

- Net metering customers are typically not allowed to also be CS subscribers, but they can be.

All this variety is pertinent to the BCA test.

CS is best understood from a BCA perspective as a set of interacting transactions.

- A CS developer builds and interconnects a DG facility, typically without on-site load, to generate electricity for sale to the local utility. In some cases, utilities build and operate the generation facility and operate the CS subscription service and bill crediting system.
- Customers or investors, typically called subscribers, pay for the CS facility with monthly subscription payments.
- The electricity generated by the CS facility is delivered to the utility for use in serving customers who may or may not be the same as the CS subscribers.
- The utility pays for the delivered CS energy by providing bill credits to CS subscribers, according to the level of their subscription and the output of the DG system. In some cases, the utility may pay the CS facility manager or program subscription manager directly for the delivered energy, and the CS administrator distributes proceeds on a pro-rata basis to subscribers.
- The bill credits are generally structured to exceed the CS customer subscription cost.

CS facilities do not electrically serve CS customers. CS customers earn credits for their subscription share, and their utilities charge them in full for the electricity they consume at their home or business at the rates that apply in the absence of the CS subscription.

Community solar projects differ from other types of DPV because there is typically no host customer whose load would be reduced by the community solar projects. Instead, CS projects typically create bill credits that subscribers in the program receive, either from the utility or through direct billing from the subscriber organization or CS operator. These credits then reduce or offset the subscribers' electricity bills.

Community solar projects differ from other types of DPV because there is typically no host customer whose load would be reduced by the community solar projects.

The magnitude of the CS bill credits is critical to determining the benefits and costs of a CS program. It is also important to consider the extent to which the CS program creates lost revenues, as discussed in Section 10.5.1 below.

10.4.4. Other Fuel Impacts

DG resources can impact the use of other fuels, depending on the resource type and whether the fuel used by the DG resource could alternatively be used to provide another energy service:

- DPV, distributed wind, and distributed hydropower systems typically do not have any impacts on non-electric fuels.
- CHP and district energy systems often rely on fossil methane, biogas, or biomass for primary fuel. These generators can impact fuel use in pipeline systems for fossil and biogas methane.

10.4.5. Host Customer Non-Energy Impacts

Table 10-6 presents a summary of host customer NEIs that DG resources might create. These impacts can sometimes be benefits and sometimes be costs. The presence, direction, and magnitude of DG NEIs will depend upon many factors, including the type of host customer (e.g., low-income, residential, commercial, industrial), and more.

Table 10-6 indicates whether each category of NEIs is typically a benefit, a cost, or either in most common applications for DG resources and provides examples of impacts. The actual direction of the impact, however, may vary and is determined on a case-by-case basis.

Table 10-6. Potential Host Customer Non-Energy Impacts of Distributed Generation

Category	Benefit or Cost	Examples
Asset value	●	Benefit: Increased building value
Economic well-being	●	Benefits: Fewer bill-related calls to utility, fewer utility shut-offs, reconnection charges
Customer Empowerment & Control	●	Benefits: Psychological benefits in the form of personal empowerment, energy independence
Satisfaction/Pride	●	Benefits: Contribution to addressing environmental concerns and increased energy independence

● = typically a benefit for this resource type; ● = typically a cost for this resource type; ● = either a benefit or cost for this resource type, depending upon the application of the resource; NR = not relevant for this resource type.

10.4.6. Air Emissions Impacts

Most DG systems installed in the United States are DPV systems powered by emissions-free solar energy. For these systems, reductions in environmental compliance costs can create benefits to the utility system and reductions in emissions can create benefits to society. These benefits can be quite large and have a substantial impact on cost-effectiveness, depending on systemwide emissions factors.

For other kinds of DG, such as fossil-fired generators, there may be either increased or reduced air emissions depending upon several factors:

- The DG fuel
- The displaced fuel of the baseline electricity generator (and thermal energy generator that the DG may also displace as in the case of CHP)
- The DG operating patterns
- Leakage impacts
- Other factors

The location and effects of air emissions may vary among DG technologies and according to operating profiles. Biomass-fueled DG, such as a wood-burning generation facility, may avoid upstream utility emissions and, for example, methane emissions from anaerobic digestion of wastes. However, these systems typically generate electricity through combustion of the biomass fuel, producing local emissions that have local incremental impacts.

CHP systems that operate efficiently on methane gas may also avoid air emissions by displacing large-scale generation fueled by coal and/or that operate without the efficiency benefit of heat recovery. While CHP systems produce local emissions, the net systemwide efficiency and emissions reductions benefits may yield a net benefit for this type of DG.

Principle 4: Ensure Symmetry in the Treatment of Benefits and Costs requires accounting for both avoided and incremental emissions to accurately account for the emissions impacts of DG systems that produce emissions.

10.4.7. Cumulative Effects: The Duck Curve Example

Unless coupled with energy storage systems, all PV systems in a particular area will start and stop generating in correlation with available sunlight. Large quantities of PV, including both utility-scale and DPV, can therefore have large cumulative impacts on the grid associated with the decline of solar generation as the sun sets. This often occurs at the time when residential system demand is in or approaching the period of peak demand and can create a rapid rise in systemwide energy demand and an acute need for load-following resources.

It is appropriate to include utility system benefits and costs in a BCA, but to not include lost revenues. Lost revenues are appropriately addressed in a Rate and Bill Impact analysis (RBA).

These insolation-related impacts on large fleets of solar generation may be a source of rapidly increased demand for generation, capacity, and ancillary services in the early evening. Even if the effect is small across an entire grid system, clustering of DPV systems could create a problem at smaller scales, down to the feeder level.

The duck curve effect, named for the shape of changing demand net of solar generation over the course of a day, necessitates accounting for the temporal avoided costs in each hour of the day as they change due to the addition of large amounts of PV. Any such estimates of these costs should account for other resources that are likely to be available to mitigate the costs, including DR, storage, and resources providing ancillary services.

10.5. Common Challenges in Determining DG Benefits and Costs

10.5.1. Determining Lost Revenues for Estimating Rate Impacts

Many DG resources will reduce the host customer's load. This is especially true for DPV resources where the solar generator might reduce a large portion of the customer's load. In some periods, the DPV might generate more energy than the customer's load, in which case the excess energy is exported to the grid. As described in Section 10.4.2, many DPV compensation mechanisms allow customers to roll over excess generation from one month to be used against their bills in later months in the form of bill credits.

In conducting a BCA or an RBA, it is critical to distinguish benefits and costs from lost revenues. It is appropriate to include utility system benefits and costs in a BCA but not lost revenues. Lost revenue should instead be included in an RBA.

Appendix B discusses lost revenues, rate impacts, and how to conduct RBAs. However, there are some unique features about DPV compensation mechanisms not discussed in Appendix B that

warrant consideration when conducting RBAs of DPV. In particular, some DPV practices make it more challenging to distinguish cost and benefits from lost revenues.

Treatment of Bill Credits

Many DPV compensation mechanisms use bill credits to provide compensation for DPV generation. Bill credits raise the following key question: *Are bill credits lost revenues, or are they a utility system cost?*

It is reasonable to argue that bill credits are a lost revenue because a bill credit translates into the utility collecting less revenue from bills than it would collect without the DPV. However, to understand how to treat bill credits in a BCA and an RBA, it is best to ask two different questions:

Lost revenues should be measured relative to the total electricity bill that the host customer would have experienced if not for the DG output.

- *Will the bill credits increase the revenue requirements of the utility*? If so, this implies that they are a utility system cost. Increases and decreases in revenue requirements are what cause utility system costs to increase or decrease. These are the utility system costs that it is appropriate to include in all BCA tests, consistent with *Principle 2: Treat DERs as a Utility System Resource*. Bill credits will increase utility revenue requirements, which suggests they should be treated as a utility system cost.
- *Do the bill credits represent a new cost to the system*? If so, this implies they are not a historical, sunk cost. As described in Appendix B, it is not appropriate to include sunk costs in a BCA test because the purpose of BCA tests is to analyze future, incremental, long-term impacts. On the other hand, an RBA should include sunk costs because those costs will affect the extent to which rates change as a result of changes in sales. Bill credits are a new cost to the system, which suggests they are a utility system cost and not lost revenue.

To summarize, DPV program bill credits should be treated as a utility system cost. This means BCA tests would include those bill credits. An accompanying RBA would also include them, along with all the other utility system costs included.

Net Metering

Some net metering programs allow customers to use load-reducing DPV generation to offset the entire retail rate. Other net metering programs allow customers to use this generation to offset a portion of the retail rate, under the logic that some portions of the retail rate should be non-bypassable or that the full retail rate would be too generous. When estimating the lost revenues from net metering programs, it is important to account for the level of retail rate that the DPV is allowed to offset.

If the cost of the DPV system plus the bill credits to subscribers exceed the utility system costs avoided by the DPV system, then that incremental cost is typically shared across all customers through an increase in rates, which would lead to a shift of costs.

Lost revenues should be measured relative to the total electricity bill that the host customer would have experienced if not for the DG output (i.e., the counterfactual host customer bill). It is best to determine the counterfactual bill over the full netting period (typically a year and reflecting 12 monthly billing periods) because this will capture the effects of rolling credits across billing periods. Further, lost revenues can never exceed the host customer's counterfactual bill over the full netting period. In

other words, revenues can only be considered lost if they would have existed in the counterfactual case.

There might be situations where the total compensation paid for the DG output exceeds the host customer counterfactual bill, for example, when the DG compensation is set at a level higher than retail rates to provide an incentive to host customers and to meet DG development goals. In these cases, the additional compensation, above the counterfactual bill, represents a utility system cost passed on to other customers through increased rates.

Net Billing

Net billing compensation mechanisms typically pay for excess generation at a different rate than the retail rate (or portion thereof) used to compensate for the reduced customer load from DPV. One common approach is to set the payments for excess generation to equal the utility system costs avoided by the DPV. Under the BCA Framework, the calculation for the cost of the bill credits uses the compensation rate used for the excess generation. In conducting an RBA, the lost revenues calculation uses the level of retail rate that the DPV is allowed to offset.

Buy-all/sell-all compensation mechanisms do not create lost revenues.

Buy-All/Sell-All Compensation Mechanisms

Buy-all/sell-all compensation mechanisms do not create lost revenues. The host customer continues to purchase all the electricity to meet their internal loads (buy-all), which means that the utility continues to recover the same amount of revenue from the customer that it would have recovered in the absence of the DPV. The host customer sells all the output from the DPV to the utility (sell-all), thus all the payments to the host customer represent the cost of the DPV.

While buy-all/sell-all compensation mechanisms do not create lost revenues, they might nonetheless create a cost shift from host customers to other customers. If the utility payments for the DPV generation exceeded the utility system avoided costs, there would an increase in costs that would lead to increased rates for all customers. On the other hand, DPV buy-all/sell-all mechanisms that pay less than the utility system avoided costs for the DPV generation will not lead to rate increases or cost-shifting because net costs would decrease. Thus, there would be no lost revenues.

DPV program bill credits should be treated as a utility system cost.

Community Solar Programs

CS programs also do not create lost revenues. The subscribers continue to purchase all the electricity to meet their internal loads, which means the utility continues to recover the same amount of revenue it would have recovered in the absence of the DPV. As described above, the CS bill credits to customers do not create lost revenues. They represent a new, incremental cost to be recovered through a utility's revenue requirements and are analogous to the costs of customer incentives or program administration.

While CS programs do not create lost revenues, they might nonetheless create a cost shift from subscribers to non-subscribers. If the cost of the DPV system plus the bill credits to subscribers exceed the utility system costs avoided by the DPV system, then that incremental cost is typically shared across all customers through an increase in rates, which would lead to a shift of costs. A BCA test would not reflect this cost shift because BCAs do not distinguish between who bears the

cost. The RBA would reflect the cost shift because CS participants will experience increased rates plus bill reductions from the bill credits, while non-participants will experience only the increased rates. On the other hand, CS programs that cost less than the utility system avoided costs from the DPV generation will not lead to rate increases or cost-shifting.

10.5.2. Accounting for Interactive Effects

DG installed behind the meter is frequently and increasingly operated along with other DERs such as DS, DR, and Building Electrification. Where the analyzed use case includes the operation of additional, different DERs, interactive effects are a key consideration. Chapter 13 identifies key issues that arise in BCA of multiple on-site DERs, including interactive load impacts and altering the level at which to evaluate DERs. It is also important to account for whether the DG system use case is based on the DG's participation in a non-infrastructure solution, like an NWS program, a virtual power plant, or a microgrid.

10.5.3. Accounting for Transmission and Distribution Impacts

DG resources, as with other DERs such as EE, DS, and DR, have the potential to reduce T&D costs because they are sited close to customer load and result in less electricity being transmitted from centralized generation sources to the host customer. Some DG resources have the potential to increase distribution costs when the level of interconnected DG exceeds the hosting capacity of the system.

It is important for BCA tests to account for all relevant and material T&D impacts created by DG resources, as with any DER type (see Chapter 3 and Section 4.4). The magnitude and direction of these impacts can vary across utility systems, depending upon the hosting capacity on the system and any changes to hosting capacity over time. Therefore, the utility hosting capacity warrants consideration when determining whether new DG resources will likely reduce or increase distribution system costs. The likelihood of such impacts will be greater on circuits identified as approaching maximum capacity or that are experiencing unusually high load growth. Marginal cost of service studies can also serve as a preliminary tool for assessing impacts. In addition, tracking patterns of DG development may help prioritize hosting capacity analyses.

Any single DG facility is unlikely to have much impact on T&D costs on its own, particularly small DG facilities, and particularly when DG facilities are on systems with excess T&D capacity. This raises the issue of whether some impacts are immaterial to the DG BCA test—that is, they are too insignificant to impact the determination of cost-effectiveness. However, when multiple DG facilities are installed or aggregated, they might have significant positive or negative effects on T&D costs. In some utility systems, new DG resources might have very little impact on distribution costs for several years, but then the system might reach a tipping point at which system upgrade costs become necessary.

Ideally, the BCA test inputs should account for the need for interconnection and system upgrade costs for the DG under evaluation.

- If the utility must incur incremental costs to enable a customer to inject DG generation into the grid, then a BCA test should account for those costs in the interconnection or distribution system upgrade costs. If the host customer is required to pay these costs, the BCA test should account for those costs as host customer impacts. In some cases, these costs may have additional benefits to the utility grid as well. The functionality of inverters

also impacts this accounting. For example, smart inverters can provide ancillary services benefits to the local grid.

- If the DG injections do not require any such incremental costs, then there are no incremental costs associated with back-up services or supplemental services.

10.5.4. Accounting for Grid Services to the Host Customer

Utilities are obligated under Public Utility Regulatory Policies Act (PURPA) (see text box on p.10-4) to provide back-up and supplementary power services and rates to certain qualified facilities. This includes qualified DG facilities. This raises the question of whether the back-up or supplementary power services provided to DG host customers represents an impact to include in a BCA test.

Similarly, a common question about the export of electricity from DG resources onto the grid relates to whether host customers benefit from using the grid essentially as a battery during times when the DG resource is not generating. The question is whether this host customer "benefit" represents an impact that should be included in a BCA test.

Under the BCA Framework, BCA tests should account for all *incremental*, relevant, and material distribution upgrade costs created by DG resources and other DERs (see Chapters 3 and 4). Regarding the question raised above:

- If the utility must incur *incremental* costs to enable a customer to export DG generation onto the grid, then the BCA test should account for those costs in the interconnection or distribution system upgrade costs.
- If the DG exports do not require any such *incremental* costs, then there are no costs associated with back-up services, supplemental services, or the host customer using the grid as if it were a battery.

10.6. Common Interactions with Other DERs

While DG measures can interact with other DER types, the most common interactions are with DS measures. Key interactions to consider when conducting cost-effectiveness assessments include the following:

- **Distributed solar paired with batteries**. DPV technologies are increasingly paired with distributed batteries. Such pairing is unlikely to affect the operation of the DPV resource, because solar operation is dictated by solar insolation. On the other hand, pairing a battery with DPV technology allows the battery to charge and discharge at times that are most economical to the host customer (for instance, charging during solar generation periods). Pairing a battery with DPV technologies can also allow the host customer to operate independently of the rest of the grid during short outages. BCA of batteries requires a definition of the use case to establish how the batteries will operate and which benefits and costs will apply (see Section 11.5.1). Thus, when conducting a BCA of distributed solar paired with batteries, it is important to determine just how the battery will be deployed in conjunction with the solar.

10.7. Changes in Revenues and Rate Impacts

This section discusses how DG resources can influence customer rates, why BCA tests cannot accurately evaluate those impacts, and options for appropriately assessing and addressing rate impacts.

Lost or increased revenues and potential rate impacts are not appropriate to include in cost-effectiveness analyses for DG or any DER. Instead, DG lost revenues and rate impacts require separate rate, bill, and participation analyses (see Chapter 3 and Appendix B). In conducting BCAs, therefore, it is important to identify lost revenues to properly exclude them from BCA tests and include them in rate, bill, and participation analyses.

In general, several key factors affect the extent to which DGs might create rate impacts:

- *Increases in utility system costs* will put upward pressure on rates. If the DG creates incremental utility costs and increases revenue requirements, such pressure exists.
- *Reductions in utility system costs* will put downward pressure on rates. If the DG saves on specific utility costs, such as distribution system upgrades, this could lower rates for all customers on the distribution grid.
- *Reductions in sales* resulting from host customers with DG resources will put upward pressure on rates.[45] The ultimate outcome will depend on the relative value of the DG energy produced and the cost of the energy it replaces.
- *Rate design* will affect the amount of lost or increased revenues created by the DG.

DG resources will typically create lost revenues by allowing host customers to reduce their energy bill by reducing their energy consumption. The lost revenues from DG resources will depend upon the DG compensation mechanism in effect, among other factors (see Section 10.5.1).

Regulators and other stakeholders concerned about DG rate impacts could consider the following approaches: (a) conduct a long-term rate, bill, and participation impact analysis; (b) seek and implement DG compensation mechanisms likely to mitigate equity concerns (e.g., by keeping compensation rates relatively low); (c) seek ways to expand customer participation through programs such as CS projects, especially among low- and moderate-income customers; and (d) periodically review impacts as DG deployment rates increase (Consumers Union 2016).

[45] Some DG compensation mechanisms create a different dynamic regarding rate impacts. Some DG compensation mechanisms provide customers with bill credits for the DG output, which can be rolled over across billing periods or be used to support virtual or CS programs. These bill credits are sometimes a better indication of DG lost revenues than reduced sales from the DG resource.

11. DISTRIBUTED STORAGE RESOURCES

This chapter describes the benefits and costs most relevant to distributed storage. It identifies key factors that affect DS benefits and costs and provides guidance on addressing common challenges with DS cost-effectiveness analyses.

11.1. Summary of Key Points

- DS resources are systems and devices located close to customer load that directly store energy (e.g., batteries, capacitors), convert energy into other mediums for storage (e.g., electric hot water heaters), or function as energy carriers (e.g., hydrogen gas).
- DS resources can be located BTM or FTM.
- DS resources typically have limited operation parameters for charging and discharging, which will significantly affect the type and magnitude of the benefits they offer.
- The benefits and costs of DS resources will depend greatly on where and how the resource is operated—the 'use case.' Use case factors include:
    - Who owns and operates the resource? The utility, the host customer, or a third party?
    - What is the primary purpose of the DS? To sell output into wholesale electricity markets, to meet utility system needs, or to meet host customer site needs?
    - What are the financial incentives for operation of the resource? Market prices, meeting utility system needs, or meeting host customer site needs?
    - What potential benefits are sought: optimizing market revenues, reducing utility system costs, reducing host customer energy costs, increasing host customer resilience and associated societal resilience benefits (e.g., by improving resilience in critical facilities)?
    - Where is the DS located? Will it be able to avoid local distribution and transmission costs, and at what value?
    - What are the technical limits of the DS technology, especially regarding time to charge and time to discharge?
- DS resources can offer a variety of benefits, though not necessarily simultaneously, depending on the owner/operator and the primary purpose of the resource. The BCA test will need to identify or make assumptions about which benefits, as listed below, the DS will provide, depending on its use case:
    - Market revenues: potentially for generation capacity, energy arbitrage, reliability, or ancillary services.
    - Meeting utility system needs: potentially for generation capacity, transmission capacity, distribution capacity, mitigating renewable generation curtailment, system reliability, or system resilience.

    - Meeting host customer and societal needs: depending on the price signals sent to the host customers, this could potentially include generation capacity, transmission capacity, distribution capacity, system reliability, system resilience, host customer site resilience, and societal resilience (e.g., for critical facilities).
- DS resources can either reduce or increase air emissions, depending upon the use case for the DS device, the marginal emission rates during charging times, the marginal emission rates during the discharging time, and the round-trip efficiency of the storage resource.

11.2. Introduction

DS resources are systems and devices located close to customer load that directly store energy (e.g., batteries, capacitors), convert energy into other mediums for storage (e.g., electric hot water heaters), or function as energy carriers (e.g., hydrogen gas).[46] DS devices are designed to store energy when costs are low and produce energy at a later time when costs are high or reliability is a priority. DS resources can be located behind the meter or in front of the meter.

The benefits and costs of DS resources will depend significantly on where and how the resource is operated—the 'use case.'

Storage technologies such as pumped hydropower and compressed air tend to be connected at the transmission, not the distribution, level and therefore do not meet the definition of DS.

The fundamental BCA principles (Table 3-1) can help identify the relevant benefits and costs for DS. Perhaps more than any other DER type, the benefits and costs of DS resources will depend significantly on the use case for the DS under evaluation. The use case for DERs will depend on many factors, as discussed in the sections below.

11.3. Benefits and Costs of Distributed Storage Resources

The tables in this section summarize the potential benefits and costs typically associated with DS resources (see Chapter 6 for definitions of impacts). Each impact receives a designation as a benefit, a cost, or either, depending on the most common use cases for these technologies. There might be some less common use cases where an impact categorized as a benefit could be a cost, or vice versa. The tables include notes on applicability that provide further explanation for those impacts that may be either a benefit or cost.

Table 11-1 presents the potential benefits and costs of DS resources on the electric utility system. All storage utility system impacts presented in these tables should be included in BCA tests if they are relevant and material to the use case scenario under review, consistent with NSPM *Principle 2: Treat DERs as a Utility System Resource*.

Natural gas utilities typically do not implement or otherwise support DS programs for host customer storage of natural gas (as shown in Chapter 6, Table 6-5). Further, DS programs implemented or otherwise supported by electric utilities typically do not have impacts on the natural gas utility system or other fuels. As such, unlike other DER specific chapters in the NSPM, there are no corresponding tables.

[46] EV batteries can also act as a storage resource.

The remaining storage impacts presented in Table 11-2 (Host Customer) and Table 11-3 (Societal) should be included in BCA tests to the extent they are relevant and material to the jurisdiction's applicable policy goals, consistent with NSPM *Principle 1: Align with Applicable Energy Policy Goals* (see Section 4.4).

Table 11-1. Typical Impacts of Distributed Storage: Electric Utility System

Type	Utility System Impact	Benefit or Cost	Notes/Typical Applicability
Generation	Energy Generation	🟢	Primarily a benefit; depends on relative costs during charging and discharging; costs can arise because storage technologies require more energy to charge than they discharge
	Generation Capacity	🟢	Primarily a benefit; depends on the storage use case; costs can arise if storage device charges during peak periods
	Environmental Compliance	🟠	Benefit or cost; depends on system environmental profile during charging and discharging times
	RPS/CES Compliance	🟠	Storage technologies require more energy to charge than they discharge; storage can be used to avoid curtailment of renewable generation
	Market Price Response	🟢	Primarily a benefit; depends on market conditions during charging and discharging times
	Ancillary Services	🟠	Benefit or cost; depends on the storage use case and the utility's ability to direct or control the operation of the storage device
Transmission	Transmission Capacity	🟢	Primarily a benefit; depends on the storage use case; costs arise if storage device charges during transmission peak periods
	Transmission Line Losses	🟢	
Distribution	Distribution Capacity	🟢	Primarily a benefit; depends on the storage use case; costs arise if storage device charges during distribution peak periods
	Distribution Line Losses	🟢	
	Distribution O&M	🟢	
Cross-cutting GT&D	Risk	🟢	Primarily a utility system benefit if the storage is controlled by the utility; primarily a host customer benefit if the storage is controlled by the host customer
	Reliability	🟢	
	Resilience	NM	
General	Financial Incentives	🔴	Costs (to the extent relevant, such as utility performance incentives)
	Direct Utility Investment	🔴	
	Program Administration Costs	🔴	
	Utility Performance Incentives	🔴/NR	
	Credit and Collection Costs	🟢	Benefit; lower bills and improved energy management increase revenue requirement realization, especially for low-income customers

🟢 = typically a benefit for this DER type; 🔴 = typically a cost for this DER type; 🟠 = either a benefit or cost for this DER type, depending upon the application of the DER; NM = not material for this DER type; NR = not relevant for this DER type.

Table 11-2 presents the potential host customer impacts of DS, while Table 11-3 presents the potential societal impacts of DS.

Table 11-2. Typical Impacts of Distributed Storage: Host Customer

Type	Host Customer Impact	Benefit or Cost	Notes/Typical Applicability
Host Customer	Host portion of DER costs	●	Cost to customer
	Transaction costs	●	Cost to customer
	Interconnection Fees	●	Cost to customer
	Resilience	●	Benefit; depends on the storage use
	Tax Incentives	●	Typically a benefit
	Host Customer NEIs	●	Benefit or cost; depends on the NEI (see Section 11.4.8)

● = typically a benefit for this DER type; ● = typically a cost for this DER type; ● = either a benefit or cost for this DER type, depending upon the application of the DER; NR = not relevant for this DER type.

Table 11-3. Typical Impacts of Distributed Storage: Societal

Type	Societal Impact	Benefit or Cost	Notes/Typical Applicability
Societal	GHG Emissions	●	Benefit or cost; depends on system environmental profile during charging and discharging times
	Other Environmental	●	
	Public Health	●	Benefit or cost; depends on system environmental profile during charging and discharging times
	Resilience	●	Benefit; depends on the storage use case and the utility's ability to direct or control the operation of the storage device

● = typically a benefit for this DER type; ● = typically a cost for this DER type; ● = either a benefit or cost for this DER type, depending upon the application of the DER; NR = not relevant for this DER type.

11.4. Key Factors that Affect Distributed Storage Benefits and Costs

11.4.1. Technology Characteristics

DS resources have several characteristics that will significantly affect when and how much they can operate, which will have important implications for their benefits and costs.

DS resources require a certain amount of time to store energy (charge) and will have only a limited amount of time to produce energy (discharge). The charging and discharging durations will depend on the specific DS technology. In some cases, DS resources can reduce the rate of discharge (in terms of kW) to extend the duration of the discharge.

DS resources have less than 100 percent round-trip efficiency, which is the measure of the energy output divided by the energy input for one cycle of charging and discharging. This means that they are a net consumer of energy and the amount of energy consumed will depend upon the round-trip efficiency of the technology used.

Because DS resources can provide a variety of benefits, but not all of them simultaneously, it is important to determine its primary purpose; this will determine its operation and therefore its benefits and costs.

Given that they are net consumers of energy, the primary purpose of operating DS resources is to charge during low-cost periods and discharge during high-cost periods or during outages. This means that the temporal charging and discharging patterns must be matched with temporal avoided cost inputs in the BCA test, both in terms of energy ($/kWh) and capacity ($/kW) to ensure that benefits and costs are accurately determined. Further, the avoided cost inputs require sufficient temporal and locational granularity to capture the temporal operating characteristics of the DS resource (for instance, hourly or sub-hourly).

Another key consideration is the choice of DS operating mode, which can affect the useful lifetime of the resource. As the number of cycles (switching from charging to discharging) and depth of discharge (the ratio of how much the storage resource is charged and discharged relative to its full capability) increase, the expected lifetime of the storage asset will decrease.

While DS resources have the potential to provide a variety of benefits, discussed below, their operating characteristics limit the benefits they can provide at any one time. Thus, the BCA test will need to make assumptions regarding which benefits will be relevant for the DS resources in question.

11.4.2. Resource Ownership and Control

The entity that owns and/or controls the DS resource will determine when and how it is operated, which will have significant implications for the resource's benefits and costs. A variety of entities might own and/or operate a DS resource, including the utility, a host customer, a developer, or a distributed resource aggregator. Further, there are a variety of ownership and control arrangements where one party owns the DS, but another party controls its operation. For example, a developer might own the DS resource, but the host customer is able to operate the resource for their own purposes; or a customer owns the DS resource but the utility controls operation for its purposes.

For the purposes of a BCA test, the party that has control of the operation of the DS resource is most important because the choice of when and how to operate the resource will determine its benefits and costs. The party controlling the DS resource will likely determine the primary purpose of the resource. Further, the party controlling the DS resource will decide when and how to operate it depending on the financial incentives in place.

11.4.3. Primary Purpose and Associated Benefits of the DS Resource

Because DS resources can provide a variety of benefits, but not all of them simultaneously, it is important to determine its primary purpose; this will determine its operation and therefore its benefits and costs. The three main purposes of DS resources include selling the power into wholesale markets, meeting utility system needs, and meeting the host customer site needs.

Selling into Wholesale Markets

The following characteristics are relevant to DS resources intended for wholesale markets:

- Selling into wholesale markets may be the primary purpose if the party controlling the DS resource is the utility, the host customer, a DS developer, or a DER aggregator.
- When selling into wholesale markets, the potential benefits might include revenues from capacity markets, energy markets, ancillary services markets, or reliability products. While it might be possible to sell to multiple markets (such as capacity and energy) it might not be possible to sell into all of them simultaneously (as with reliability and energy).
- Market prices will inform the specific hours of operation of the DS resource, with charging likely to occur when market prices are lowest and the discharging likely to occur when prices are highest.
- The charging and discharging constraints of the DS resource will limit the extent to which a particular DS resource can sell into any one market or multiple markets.
- Host customers and third-party operators may face costs for metering systems and data provision to verify operations and to secure market payments.

Meeting Utility System Needs

The following characteristics are relevant to DS resources intended for accommodating system needs:

- Meeting utility system needs may be the primary purpose if the party controlling the DS resource is the utility.
- For meeting utility system needs, the potential benefits might include avoiding peak generation capacity costs, avoiding peak energy costs, avoiding peak transmission costs, avoiding peak distribution costs, mitigating renewable curtailment, ancillary service, and supporting system reliability.
- The hours of DS operation will depend on how the utility can maximize these benefits.
    - If a utility is especially short of generation capacity, then it could focus the operation time during times of generation capacity peak demand.
    - In the case in which it is especially short of transmission capacity, then it could focus the DS operation during times of transmission peak demand.
    - If a utility wants to use a DS resource as part of an NWS, then it could focus the DS operation during times of distribution peak demand.

Note that in all these examples, there may be benefits to parts of the system that are not of primary focus. For example, if the DS resource is intended as an NWS, there will still be generation capacity, energy, and transmission benefits. However, these secondary benefits would be based on the specific operating hours of the DS resource, which might not be the peak hours for the secondary type of benefit. In other words, for an NWS, the timing of distribution system peak might be different from that for generation, energy, or transmission. It is appropriate for the BCA test to include the temporal values for each type of benefit corresponding to the operating hours of the DS resource.

Meeting Host Customer Site Needs

The following characteristics are relevant to DS resources intended for accommodating host customer site needs:

- Meeting host customer site needs may be the primary purpose if the party controlling the DS resources is the host customer or a developer or aggregator representing the host customer.
- For meeting host customer needs, the hours of DS operation will depend on the potential benefits to the host customer, which will be determined by the price signals provided through rate designs. Such price signals often come in the form of time-varying rates and demand charges, where customers pay a charge for the highest demand they have during the course of a day or a month. Ideally, utilities will design their time-varying rates to correspond to the system peak demands. In this way, the DS operation can maximize the potential utility system benefits in terms of generation, transmission, or distribution benefits, while also maximizing the incentives to the host customer.

For meeting host customer needs, the hours of DS operation will depend on the potential benefits to the host customer, which will be determined by the price signals provided through rate designs. Such price signals often come in the form of time-varying rates and demand charges.

- The DS resource could potentially provide utility system benefits in terms of avoiding peak generation capacity costs, avoiding peak energy costs, avoiding peak transmission costs, avoiding peak distribution costs, and supporting system reliability needs (especially in the context of reliability-based DR programs).
- The DS resource could also provide benefits to the host customer site, in terms of the host customerresilience needs. This would be especially likely for customers seeking back-up power or customers in a micro-grid. In the case where DS resources are sited a critical facilities (e.g., hospitals, police and fire stations, etc.) benefits extend to society as a whole.

Meeting Multiple Purposes

There may be situations where the party controlling the DS resource can meet several of the purposes described above. For example, a utility could use the DS resource for arbitrage in the wholesale energy market and could also divert it for reliability purposes if a reliability need arises.

11.4.4. Financial Incentives for DS Operation

The purpose for which a DS resource is installed and operated will determine the financial incentives for the party controlling the DS resource. That is, the incentives for selling into wholesale markets will be different than those for meeting system needs, which might be different than those for meeting host customer site needs. The financial incentives will, in turn, affect how a DS resource is operated. There are three key factors affecting DS financial incentives: market rules, utility system avoided costs, and host customer rate designs.

The purpose for which a DS resource is installed and operated will determine the financial incentives for the party controlling the DS resource.

Wholesale Market Rules

DS resources can earn market revenues by providing services to the wholesale grid. This typically occurs when utilities or DER aggregators combine multiple DS resources together to provide sufficient power to participate in such markets. Federal Energy Regulatory Commission (FERC) Orders 2222, 2222-A, and 2222-B are designed to facilitate DER participation in regional electricity markets through aggregation (FERC 2020, 2021a, 2021b, 2025).

Wholesale market rules determine the prices offered for different services, such as capacity, energy, and ancillary services. These prices then provide the primary financial incentives dictating when and how DS resources should charge and discharge to get the lowest costs and the highest revenues. Market rules also tend to contain other constraints to participation, such as the size of resource and guarantees of availability.

Utility System Benefits

DS resources can help avoid utility system costs such as generation capacity, energy, transmission capacity, and distribution capacity. Chapter 6 describes the full set of utility system costs that might be avoided by DS resources.

In addition, DS resources offer the opportunity for utilities with large amounts of renewable generation to mitigate the need to curtail that generation when it exceeds customer demand. Further, DS resources might be able to provide ancillary services for those utilities that have increasing amounts of renewables and fewer thermal generation resources to provide ancillary services.

The utility system avoided benefits and costs of optimizing renewable generation create the financial incentives that will determine when it is best for utilities to charge and discharge DS resources. These charging and discharging practices will, in turn, determine the resource's benefits and the costs.

Rate Designs and Demand Response Programs

When a host customer controls a DS resource, the customer's rate design will provide the primary financial incentives for operating the resource. This will include any time-varying rates provided by the utility. This will also include demand charges, often applied to large C&I customers.

Some host customers might get financial incentives from DR programs that offer bill credits or payments for curtailing demand during peak periods or to meet system reliability needs. In addition, customers hosting paired DS and DG systems may be able to realize benefits under time-differentiated net metering or net billing tariffs.

These financial incentives to host customers will determine the optimal times for charging and discharging DS resources, which will determine the DS benefits and costs.

11.4.5. Location on the Grid

As with other DERs, where DS is interconnected will affect its costs and, particularly, its benefits.

First, the benefits and costs will depend on whether the DS is located FTM or BTM. FTM DS resources might offer greater economies of scale than BTM storage, but they might have siting and permitting restrictions. FTM DS resources would be less likely to be used for the purpose of

meeting host customer site needs, which would rule out the potential benefits associated with that purpose.[47]

Second, the location of the DS resource on the electricity grid will likely affect both the extent to which it can provide distribution benefits and the magnitude of those benefits. For example, a utility that controls a DS resource located on a region of the electricity grid that is long on distribution capacity might provide very little value in terms of avoided distribution system costs and therefore might focus its operation on generation capacity, energy, or transmission capacity benefits. Conversely, a utility that controls a DS resource located in a region where the electricity grid is constrained for distribution capacity might focus its operation on avoiding distribution peak demands. Similarly, the location of the DS resource will affect the extent to which it can participate as part of an NWS.

Third, a heavily constrained local distribution system might have limited capabilities for supporting new generation injected when the DS resource is discharging. This would occur, for example, if the purpose of the DS resource is to obtain wholesale market revenues or mitigate generation capacity costs at times when the distribution system is already fully loaded. In such cases, there might be distribution system upgrade costs incurred to support the DS resource, or the resource might need to modify its purpose and operational patterns to work within the constraints of the current distribution system.

11.4.6. Other Fuel Impacts

The primary way that DS resources can affect other fuels is when the DS resources can be used to offset or avoid DG used for back-up purposes. For example, if a host customer uses a gas-fired or diesel-fired generator for reliability purpose, then a DS resource could replace that generation when its cost is lower than that of the back-up generator.

11.4.7. Air Emissions Impacts

DS resources can reduce air emissions, increase air emissions, or have immaterial air emissions impacts. The relevant impacts will depend on the use case for the DS technology, the marginal emission rates during charging times, the marginal emission rates during the discharging time, and the round-trip efficiency of the storage resource.

Air emission impacts should account for two important factors: (a) the time period for which the storage is utilized for charging or discharging and (b) the marginal emission rates of the utility system at the time when the storage is utilized. DS devices can potentially have significant intra- and inter-day variation in operating modes and levels, making it especially important to account for the detailed time periods in which they are expected to operate.

Principle 4: Ensure Symmetry in the Treatment of Benefits and Costs requires accounting for both reduced and increased air emissions from DS resources to the extent that they occur.

11.4.8. Host Customer Non-Energy Impacts

Table 11-4 presents a summary of host customer NEIs, both benefits and costs, that DS resources might create. The presence, direction, and magnitude of DS NEIs will depend upon many factors,

[47] Except that micro-grids might use FTM DS resources to meet some of the host customer site needs.

including the use case for the storage, the characteristics of the host customer (low-income, residential, commercial, industrial), the host customer's needs, and the rate design in place.

Table 11-4 indicates whether the category of NEIs is typically a cost, a benefit, or either, in most common applications and provides examples of impacts. The actual direction of the impact, however, may vary and would be determined on a case-by-case basis.

Table 11-4. Potential Host Customer Non-Energy Impacts of Distributed Storage

Category	Benefit or Cost	Examples
Asset value	●	Benefit; increased building value
Productivity	●	Benefit or cost; benefits from productivity gains from having a consistent power source; costs from safety, operational, and maintenance obligations imposed on host
Economic well-being	●	Benefit or cost; benefit from less effective rate volatility; cost from added debt and maintenance costs
Comfort	●	Benefit or cost; benefit or cost associated with thermal comfort; cost from any noise pollution
Health & safety	●	Benefit or cost; benefit from having continuous energy for health devices during outages; cost of safety concerns associated with operation of storage equipment
Empowerment & Control	●	Benefits or costs; psychological benefit in the form of personal empowerment and energy independence; costs from safety, operational, and maintenance obligations imposed on host
Satisfaction/Pride	●	Benefit; benefit from sense of contribution to addressing environmental concerns, increasing energy independence, and mitigating grid cost increases for other customers

● = typically a benefit for this resource type; ● = typically a cost for this resource type; ● = either a benefit or cost for this resource type, depending upon the application of the resource.

11.5. Common Challenges in Determining DS Benefits and Costs

11.5.1. Determining the Operating Profile and Resulting Benefits

With all the different considerations described above, DS resources can have a variety of different use cases that will result in different benefits and costs. The most important step in determining the benefits and costs of a specific DS storage resource is to identify how all these factors will affect its operating profile and resulting benefits and costs.

Table 11-5 presents several different ways DS resources can be controlled and operated, as well as the potential benefits they can provide. This table helps to illustrate the steps needed to determine the benefits and costs of the DS resource under evaluation, including:

1. Determine who will operate the DS resource. This could be a utility, a DER aggregator, or the host customer.
2. Determine the primary purpose of the DS resource. This might include selling to a wholesale electricity market, meeting utility system needs, meeting host customer needs, or some combination of these purposes.

3. Identify the financial incentives that will determine the optimal operation of the DS resource. This might include market prices, system peak costs, or price signals to the host customer. In each case, determine the values of each incentive, ideally on an hourly basis, to help identify which incentives will be paramount. For example, for meeting utility peak system needs, the operating periods of the DS resource will depend on which of the potential benefits in Table 11-1 are highest. As another example, for meeting host customer needs, the specific time-varying rate in place will determine when the DS resource should charge and discharge.

> The most important step in determining the benefits and costs of a specific DS storage resource is to identify how all these factors will affect its operating profile and resulting benefits and costs.

4. Account for operational constraints. This primarily includes the limited times available for charging and discharging the DS resource, which will affect the duration and frequency of charging and discharging opportunities. This might also include constraints that limit operation for one benefit (e.g., wholesale energy market arbitrage) that would conflict with operation for a different benefit (e.g., wholesale market reliability).
5. Account for location. This includes whether the DS resource will be FTM or BTM, which might affect its primary purpose. This will also affect the values of some of the benefits, particularly the value of the distribution system benefits.
6. Identify the DS charging periods. All the factors listed above will indicate the best periods for charging the DS resource. Apply these charging periods to the temporal values of energy costs to determine the costs of charging the DS resource.
7. Identify the DS discharging periods. All the factors listed above will indicate the best periods for discharging the DS resource. Apply these discharging periods to the temporal values of avoided costs to determine the benefits from discharging the DS resource.

Table 11-5. Potential Benefits of DS Resources

Control	Utility, Aggregator, or Host Customer	Utility	Host Customer
Primary purpose	*Sell to market*	*Meet system needs*	*Meet customer needs*
Incentives for Operation	*Market prices*	*System peak costs*	*Price signals**
Potential Benefits			
Generation capacity	✓	✓	✓
Energy	✓	✓	✓
Transmission capacity	-	✓	✓
Distribution capacity	-	✓	✓
Ancillary services	✓	✓	-
Renewable curtailment	-	✓	-
System reliability	✓	✓	✓
Host site resilience	-	-	✓
Societal resilience	-	-	✓

**The host customer incentives, provided by the price signals set by utilities in time-varying rates or demand charges, will determine which of these benefits the host customer will seek to achieve. In addition to price signals, host customers are likely to operate storage in response to outages. In these situations, host customers that are critical facilities can create societal resilience benefits.*

11.5.2. Accounting for Interactive Effects

DS installed behind the meter frequently operates along with other DERs such as DG, DR, and building electrification-related DERs (e.g., heat pumps). Where the analyzed use case includes the operation of additional and different DERs, interactive effects also warrant consideration. Chapter 13 identifies key issues that arise in BCA of multiple on-site DERs, including interactive load impacts and altering the level at which DERs are evaluated. It is also important to account for whether the DS system use case is based on the system's participation in a non-infrastructure solution such as an NWS program, a virtual power plant, or a microgrid.

11.5.3. Accounting for Provision of Multiple Services

While all DERs can provide multiple types of benefits, DS offers unique considerations. The dispatchability of DS, within technology capability limitations, allows for targeted application to various services. Evaluating a DS resource requires attention to which services it provides and how it will balance potential conflicts that prevent the resource from fully meeting all of its intended use cases (e.g., operation during one part of the day rendering the resource unavailable for another service later that day). Three examples illustrate this limitation.

- *Example 1 – Competing Host Customer Priorities*. In this example a host customer's purpose for a BTM storage system is to realize (a) bill savings from time-varying rates and (b) revenues from participating in a reliability DR program. If the storage system has a maximum of four hours of full discharge capacity and the time-varying rates' peak periods plus the system reliability events span more than those four hours, the customer will not be able to obtain both types of benefits without also varying the discharge rate.

- *Example 2 – Competing Utility System Generation Capacity and Distribution Capacity Opportunities*. In this example a utility's purpose for the DS resource is to obtain (a) generation capacity benefits and (b) distribution capacity benefits. However, if the distribution capacity need period is from noon to 4:00 p.m. and the generation capacity need is from 4:00 to 8:00 p.m., a four-hour storage system cannot serve both needs at the full discharge rate in a single day.
- *Example 3 – Competing Utility System Distribution Capacity and Ancillary Service Opportunities*. In this example a utility's purpose for the DS resource includes (a) distribution system capacity deferral that requires a discharge to the grid and (b) as-needed ancillary services such as voltage regulation support that requires taking a charge from the grid. A temporal overlap in the distribution capacity need and the voltage regulation need would require the DS resource to simultaneously provide energy and take energy from the grid, which is not technically possible.

Further work is needed to define a framework that stipulates rules governing DS resource's ability to provide multiple services.[48] Ultimately, while there may be standardized aspects of a framework guiding the ability of DS resources to stack multiple services, there may also be variation across jurisdictions given the unique market, policy, and regulatory environment of each.

11.5.4. BCA Tests that do not Include Host Customer Impacts

As described in Chapter 4, some BCA tests might not include host customer impacts. This includes the UCT and any JST where the jurisdiction concludes that accounting for host customer impacts is not clearly articulated in policy goals. It might also include secondary tests where the test excludes host customer impacts to examine how those impacts affect the cost-effectiveness results. These cases warrant special consideration to separating host customer impacts from either utility system, developer, or aggregator impacts. This is especially true for the costs of DS resources.

11.6. Common Interactions with Other DERs

While DS measures can interact with other DER types, the most common interactions to consider when conducting BCAs are DS interactions with DG measures and EVs, include the following:

- **DPV paired with batteries.** DPV technologies are increasingly paired with distributed batteries. Such pairing is unlikely to affect the operation of the distributed solar, because solar operation is dictated by solar insolation. On the other hand, pairing a battery with DPV technology allows the battery to charge and discharge at times that are most economical to the host customer (for instance, charging during solar generation periods). Pairing a battery with distributed solar technologies can also allow the host customer to operate independently of the rest of the grid during short outages. As noted above, BCA of batteries requires a definition of the use case to establish how the batteries will operate and which benefits and costs apply. Thus, when conducting a BCA of DPV paired with batteries, it is important to determine just how the battery will be deployed in conjunction with the solar.

[48] The California Public Utilities Commission and New York Public Service Commission have focused on whether the storage resource is providing reliability-based services and whether services can be differentiated in terms of timing or the storage resource's capacity dedicated to meet each service (CPUC 2018).

- **EVs with V2G capability to function as DS.** While many EVs allow only one-way electricity flows (from the grid to the vehicle for charging), some have two-way flow capability (also allowing vehicle-to-grid flows). EVs with that unique feature can serve as grid storage. This allows not only charging during periods of low prices and/or low net demand but also pushing electricity back onto the grid during periods of high prices and/or high net demand. Thus, unlike other electrification measures, EVs with V2G capability even have the potential to reduce total electric generation (energy) costs—if costs avoided when EVs put power onto the grid are high enough to offset the costs of increased consumption when they are taking power off the grid (see Chapter 12).

11.7. Changes in Revenues and Rate Impacts

This section discusses how DS can influence customer rates, why BCA tests cannot accurately evaluate those impacts, and options for appropriately assessing and addressing rate impacts.

Under the BCA Framework, cost-effectiveness analyses for DS (or any DER) do not include lost and increased revenues or potential rate impacts. Instead, jurisdictions should separately analyze reduced or increased revenues and rate impacts from DS resources using rate, bill, and participation analyses (see Appendix B). In general, several key factors affect the extent to which DERs might create rate impacts:

- *Increases in utility system costs* will put upward pressure on rates—for example, added demand due to round-trip efficiency losses for storage.
- *Reductions in utility system costs* will put downward pressure on rates. For example, storage can make lower-cost stored energy available to serve loads during periods of higher system costs.
- *Reductions in sales* from DER resources will put upward pressure on rates. This is not a typical situation for DS.
- *Increases in sales* from DER resources will put downward pressure on rates. This effect occurs when DS increases overall sales during the period between rate cases.
- *Rate design* will affect the amount of lost or increased revenues created by the DER. For example, storage hosts may change charging or discharging behavior to take advantage of incentives embedded in applicable rates.

DS resources will typically increase utility system costs because of financial incentives or program administration costs; however, they will reduce utility system costs by avoiding GT&D costs (see Table 11-1). In many cases, DS resources will reduce net utility system costs, except where the DS resources primarily serve reliability or resilience purposes. DS resources will typically create lost revenues by (a) allowing host customers to reduce their energy bill by reducing their energy consumption during high-price hours and (b) allowing host customers to reduce their energy bills by reducing demand-charge payments, where such charges are in place. Such revenue impacts may be largely or completely offset by net reductions in utility system costs.

Regulators and other stakeholders concerned about DS rate impacts could consider:

a) Conducting a long-term rate, bill, and participation impact analysis.
b) Implementing rate designs and storage initiatives to mitigate rate impact equity concerns.
c) Expanding participation rates, especially among low- and moderate-income customers.
d) Periodically reviewing impacts as DS deployment rates increase.

12. ELECTRIFICATION-RELATED DERS IN BCA

This chapter describes the benefits and costs most relevant to electrification-related DERs. The chapter identifies key factors that affect electrification benefits and costs and provides guidance on addressing common challenges with electrification cost-effectiveness analyses.

12.1. Summary of Key Points

- Electrification is not in and of itself a DER but rather can include DER technologies that replace other fuels in residential and commercial buildings (e.g., heat pumps), industrial facilities, and the transportation sector (e.g., EVs).
- The cost-effectiveness of electrification technologies is often analyzed as part of a utility's EE portfolio (e.g., in case of heat pumps), or in the context of utility EV or transportation electrification plans.
- Electrification-related DERs (ELEC, or simply 'electrification') will increase net electric-utility-system costs because it requires increased generation of electricity and potentially greater transmission and distribution capacity (and related costs). However, they will also reduce costs associated with the fuels that electricity replaces. Consequently, electrification is likely to be cost-effective only when a jurisdiction's BCA test includes the benefits of reducing other fuel consumption.
- The additional costs to the electric grid resulting from electrification will depend on several factors, including the season and the times of day when electric technologies operate. These usage patterns can depend on the efficiency and other performance characteristics of electric technologies, utility rate structures, and interactions with other DERs (see Chapter 14).
- DG and DS (including EVs with V2G capabilities—meaning they can both draw power from the grid to charge their battery and send power from a charged battery back to the grid) can mitigate increased costs to the grid.
- Electrification DERs can reduce net air emissions (both GHG and other pollutants) if the marginal emissions rate from the electricity grid is lower than that of the displaced fuel.
- Electrification DERs increases revenues for electric utilities, which can lead to reduced energy rates if the magnitude of the added revenue exceeds the added cost of serving the electrified loads. That will often be the case when electrification measures do not increase peak grid demand (such as electrification of space heating in utility service territories that are summer peaking). However, as set forth in Chapter 3 and Chapter 4, BCA tests do not include increases or decreases in revenue. Rate impacts should be assessed separately from BCAs (see Appendix B).
- Electrification DERs decreases revenues for natural gas utilities. These decreases might lead to higher rates, depending on the magnitude of lost revenue and any reductions in natural gas utility system costs.

12.2. Introduction

Electrification is defined as the conversion of energy use from non-electric fuels to electricity. In this Manual, electrification includes:

- Electrification of buildings and industry (for any of a wide range of potential end uses, including space heating, water heating, and industrial processes).
- Transportation electrification (e.g., light-, medium-, and heavy-duty EVs).

Electrification-related DERs can be 'partial' (such as a plug-in hybrid EV or a heat pump retrofit in a home where the existing fossil fuel furnace or boiler remains as a secondary system) or 'complete' (such as a battery-only EV or a home that switches entirely to electric heat).

The efficiency of electrification technologies can have important implications for their cost-effectiveness. The more efficient the electrification measure, the lower the added costs to the electric system for the same amount of displaced fossil fuel.

The benefits and costs of electrification that are relevant to BCA will depend on the categories of impacts included in a jurisdiction's JST. In many cases, determining whether a particular benefit or cost is relevant to electrification requires defining the specific technology and use case.

12.3. Benefits and Costs of Electrification-Related DERs

The tables in this section summarize the potential benefits and costs typically associated with electrification-related DERs (see Chapter 6 for definitions of impacts). Each impact is described as a benefit, a cost, or either, depending on the most common, current electrification use cases. The tables include notes on applicability that provide further explanation for those impacts that may be either a cost or a benefit. In less common applications, there may be cases where what is typically a cost can be a benefit, or vice versa.

Table 12-1 presents the potential benefits and costs of electrification-related DERs on the electric utility system, while Table 12-2 presents the impacts of such DERs on the natural gas utility system. It is important for BCA tests to include all utility system impacts of the utility that is funding the electrification initiative (whether an electric or natural gas utility), consistent with NSPM *Principle 2: Treat DERs as a Utility System Resource*, though recognizing that not all impacts may be relevant and material to the electrification applications being analyzed.

By definition, electrification-related DER programs or strategies decrease the use of natural gas and/or other fuels. Key considerations in accounting for electrification impacts are:

- If an electric utility is funding an electrification initiative, the BCA should also include the natural gas or other fuel impacts shown in Table 12-2 and Table 12-3, respectively, if accounting for 'all fuels' is consistent with the jurisdiction's applicable policy goals.
- If a natural gas utility is funding an electrification initiative, the BCA should also account for the electric utility system impacts in Table 12-1, if accounting for 'all fuels' is consistent with the jurisdiction's applicable policy goals.

In addition, electrification-related Host Customer impacts presented in Table 12-4, and Societal impacts provided in Table 12-5, would also be included in the BCA test to the extent they are relevant and material, and align with the jurisdiction's applicable policy goals and objectives, consistent with NSPM *Principle 1: Align with Applicable Energy Policy Goals* (see Section 4.4).

Many electrification measures have the potential to function as DR resources. In addition, EVs with V2G capability can function as storage resources. The characterization of impacts in Table 12-1 as benefits or costs, does not focus on the DR or storage features of these technologies, instead it focuses on the electrification features of these technologies because:

- Not all electrification measures can provide DR and/or storage functionality;
- For any DR or storage functionality to have impact it must be activated through a utility system initiative or through a system operator; and
- Not all electrification technologies with DR and/or storage capability utilize those capabilities.

Chapters 9 and 11, respectively, address the impacts of DR and DS. The impacts of multiple DERs—which could encompass electrification and DR, for example—are discussed in Chapter 13.

Table 12-1. Typical Impacts of Electrification-related DERs: Electric Utility System

Type	Utility System Impact	Benefit or Cost	Notes/Typical Applicability
General	Energy Generation	●	A cost because electrification increases electricity generation
	Generation Capacity	●	Most electrification measures add some demand at system peak; electrification of space heating in summer-peaking areas can be an exception, as advanced heat pumps are often more efficient at cooling than the central A/Cs they replace; peak demand increases can be mitigated through DR (see Chapter 9)
	Environmental Compliance	●	By adding load to the grid, electrification can increase the electric costs of compliance
	RPS/CES Compliance	●	Increasing the electricity load increases the quantity of renewables needed to meet the RPS
	Market Price Effect	●	Any increase in electricity consumption will raise market-clearing prices in competitive wholesale markets, if jurisdiction is in a wholesale market
	Ancillary Services	NM	Electrification could increase ancillary services costs, but very modestly; both EVs and water heaters can provide ancillary services when enabled through DR; if that capability is utilized, this can become a benefit (See Chapter 7)
Transmission	Transmission Capacity	●	Most electrification measures will add some demand at system peak; electrification of space heating in summer-peaking areas can be an exception, as high-performance heat pumps are often more efficient at cooling than the central A/Cs they replace; increases in peak demand can be mitigated through DR (see Chapter 7)
	Transmission System Losses	●	Any consumption increase will increase losses
Distribution	Distribution Capacity	●	Many electrification measures increase demand during distribution system peaks; electrification of space heating in summer-peaking areas can be an exception, as high-performance heat pumps are often more efficient at cooling than the central A/Cs they replace; increases in peak demand can be mitigated through DR (see Chapter 9)
	Distribution System Losses	●	Any consumption increase will increase losses
	Distribution O&M	●	Any consumption increase will increase O&M

Type	Utility System Impact	Benefit or Cost	Notes/Typical Applicability
Cross-cutting GT&D	Risk	●	Adding load to the grid can increase electric system risk; there may be risk reductions associated with other fuels, but those impacts are reflected in Tables 12-2 and 12-3
	Reliability	●	Adding load to the grid may decrease electric system reliability, except for EVs operating in V2G mode
	Resilience	NM	Most resilience benefits affect only host customers
General	Financial Incentives	●	Costs, where relevant
	Direct Utility Investments	NR	
	Program Administration Costs	●	
	Utility Performance Incentives	● / NR	
	Credit and Collection Costs	●	Impact likely depends on magnitude of electricity cost increases relative to other fuel savings

● = typically a benefit for the DER type; ● = typically a cost for the DER type; ● = either a benefit or cost for the DER type, depending upon the application of the resource; NM = typically not material; NR = not relevant for the DER type.

Table 12-2. Typical Impacts of Electrification-related DERs: Natural Gas Utility System

Type	Utility System Impact	Benefit or Cost	Notes/Typical Applicability
Energy/Supply	Natural Gas Commodity	●	Any decrease in demand for natural gas due to electrification will lead to cost reductions for natural gas
	Capacity	●	To the extent that electrification reduces peak demand for natural gas, it can avoid the need for capital investment in system capacity; electrification of new construction also eliminates the capital costs associated with connecting to natural gas-delivery systems
	Environmental Compliance	●	By reducing consumption of natural gas, electrification may reduce the cost of compliance with environmental regulations (depending on how the regulations are structured)
	Market Price Effects	●	Any decrease in consumption of natural gas resulting from electrification will lower market-clearing prices for natural gas
Transportation	Pipeline Capacity	●	Electrification can defer or avoid capital investments in pipeline capacity
	Pipeline Losses	●	
Distribution	Local Delivery Capacity	●	Electrification can defer or avoid capital investments in pipeline capacity
	Local Delivery Losses	●	
Cross-cutting Energy, T&D	Risk	●	Lowering other natural gas would reduce the risk associated with the cost of that fuel
	Reliability	●	Lower consumption of displaced natural gas increases the reliability of its supply
	Resilience	NR	Most resilience benefits affect only host customers
General	Financial Incentives	●	A cost to the extent that a natural gas utility is funding electrification (e.g., for natural gas non-pipe solutions or to meet climate policy obligations)
	Program Administration Costs	●	
	Utility Performance Incentives	● / NR	A cost in jurisdictions that offer them to the extent that a gas utility is funding electrification
	Credit and Collection Costs	●	Impact likely depends on magnitude of electricity cost increases relative to natural gas savings

● = typically a benefit for DER type; ● = typically a cost for DER type; ● = either a benefit or cost for DER type, depending upon the application of DER; NM = typically not material for DER type; NR = not relevant for DER type.

Table 12-3. Typical Impacts of Electrification-related DERs: Other Fuel Systems

Type	Other Fuel Systems Impact	Benefit or Cost	Notes/Typical Applicability
Other Fuels (oil, propane, wood, gasoline)	Commodity	●	Any decrease in demand for other fuels due to electrification will lead to cost reductions for those fuels
	Environmental Compliance	●	By reducing consumption of other fuels, electrification may reduce the cost of compliance with environmental regulations for those other fuels (depending on how the regulations are structured)
	Market Price Effects	●	Any decrease in consumption of other fuels resulting from electrification will lower market-clearing prices of those fuels

● = typically a benefit for DER type; ● = typically a cost for DER type; ● = either a benefit or cost for DER type, depending upon the application of DER; NM = typically not material for DER type; NR = not relevant for DER type.

Table 12-4. Typical Impacts of Electrification-related DERs: Host Customer

Type	Host Customer Impact	Benefit or Cost	Notes/Typical Applicability
Host Customer	Host portion of DER costs	●	Both the cost of the electric products (e.g., EVs or heat pumps) and possible costs to upgrade electric service necessary to use them (including EV charging equipment and related electrical upgrades)
	Transaction costs	●	Cost to customer
	Interconnection Fees	NR	Potentially a cost for V2G, otherwise not applicable
	Resilience	● / NR	V2G storage capability can be a benefit to host customers if used as back-up power during grid outages; otherwise, it is not relevant
	Tax Incentives	●	Potentially a benefit where relevant
	Host Customer NEIs	●	Benefit or cost depending on NEI (see Section 12.4.4)

● = typically a benefit for the DER type; ● = typically a cost for the DER type; ● = either a benefit or cost for the DER type, depending upon the application of the DER; NM = typically not material; NR =not relevant for the DER type.

Table 12-5. Typical Impacts of Electrification-related DERs: Societal

Type	Societal Impact	Benefit or Cost	Notes/Typical Applicability
Societal	GHG Emissions	●	Depends on use case and hourly environmental profile of electricity grid relative to fossil fuel combustion emissions displaced by the appliance/vehicle
	Other Environmental	●	
	Public Health	●	Same as GHG emissions and other environmental
	Resilience	NR	Depends upon whether reduced natural gas consumption affects critical customers and whether increased electricity consumption stresses the grid

● = typically a benefit for the DER type; ● = typically a cost for the DER type; ● = either a benefit or cost for the DER type, depending upon the application of the DER; NM = typically not material; NR = not relevant for the DER type.

12.4. Key Factors that Affect Electrification Benefits and Costs

12.4.1. Technology Characteristics

Electrification can entail a variety of end uses, including transportation; space heating, water heating, cooling, cooking, drying, and other uses in homes and businesses; and industrial processes. There are also many different technology options for each of those end uses. Put simply, not all EVs, heat pumps, electric water heaters, or electric cooktops are the same. The different characteristics of those technologies can affect the cost-effectiveness of electrification in various ways.

Because they can only add cost to the grid, electrification measures can only be found cost-effective if the BCA test includes non-electric system impacts.

First, the efficiency of electrification technologies can have important implications for their cost-effectiveness. The more efficient the electrification measure, the lower the added costs to the electric system for the same amount of displaced fossil fuel. For example, a heat pump can be two to four times more efficient at providing electric heat than an electric resistance heating system. Thus, electrifying space heating with a heat pump may cost the grid 50 percent to 75 percent less than electrification with electric resistance heat. However, heat pumps are more expensive to install and maintain than electric resistance heating. Depending on who would bear the added cost and whether a jurisdiction's BCA test includes host customer impacts, that added cost may also belong in the BCA test.

Different applications and different types of electrification technology can significantly affect the value of host customer NEIs. For example, electric induction cooktops can enhance cooking performance relative to natural gas or propane cooktops. In contrast, standard electric-coil cooktops offer less heat control than natural gas or propane (though all electric cooktops provide health and safety benefits relative to natural gas or propane). However, induction cooktops typically cost more than standard electric coil cooktops. Thus, in jurisdictions whose policies dictate that cost-effectiveness assessments include host customer impacts, it will be essential to be clear about the baseline, which electric technology is being assessed, and the specific attributes of each technology.

12.4.2. Technology Operating Profile

The impacts of electrification on the grid will depend considerably on the location and time-of-use load shape of electricity consumption (see Chapter 7). For example, electricity consumption for residential space heating is naturally concentrated in the winter[49] and often greater at night when outdoor temperatures are lowest. Heating patterns may or may not be similar on weekdays and

[49] Customers who electrify space heating with a heat pump will also affect summer cooling load profiles. Those that add the ability cool their homes (or a larger portion of their homes) that they otherwise may not have added, will cause summer electricity consumption to increase. In cases in which customers install a heat pump instead of a new central air conditioner and/or use of window air conditioners, there may be a change in cooling electricity consumption—often a reduction—depending on differences in cooling efficiencies between the heat pump and the air conditioner that otherwise would have been used or installed.

weekends.[50] In contrast, electricity consumption for electrified industrial processes can be similar across all seasons of the year, and even relatively consistent across all operating hours of the day. For instance, industrial electricity consumption can be similar across all 16 hours of a two-shift manufacturing facility. However, depending on whether the facility operates five, six, or seven days a week, there could be substantial differences between weekdays and weekends.

There can also be differences in load shapes across different technologies used for a given electric end use. For example, the shape of the electric demand for space heating will differ for electric resistance heating, standard air-source heat pumps, cold-climate air-source heat pumps, and ground-source heat pumps. These differences are a function of the heat source for each system type. Electric resistance generates heat, so its efficiency is unaffected by outdoor conditions. In contrast, because air-source heat pumps *move heat* rather than generate it, their efficiency declines as outdoor air temperature drops. At sufficiently low outdoor temperatures, heat pumps may no longer meet the building's heating needs and may need to rely on comparatively less efficient electric resistance backup heat. The outdoor temperature at which that changeover occurs will depend on the heat pump. (It occurs at much lower temperatures for cold-climate heat pumps than for standard air-source heat pumps.) Ground-source heat pumps can produce heat relatively efficiently regardless of outdoor air temperature because they draw heat from the ground or from water, whose temperature varies much less than air temperatures do, particularly in cold climates.

Similarly, as discussed in Section 12.5.2 below, EV load shapes can differ depending on the extent to which customers rely on home chargers and have access to chargers at work, as well as on the type of charger they use (level 1, level 2, and/or direct current fast charging).

Finally, as discussed above and in Section 12.5.1, load shapes for a given electric end use can vary significantly depending on rate design (for example, whether customers pay time-varying rates or flat rates), as well as the extent to which their electrified loads are managed or controlled through DR programs (see discussion of common interactions between electrification and other DERs in Section 12.6).

12.4.3. Other Fuel Impacts

Because they can only add cost to the grid, electrification measures can only be found cost-effective if the BCA test includes non-electric system impacts. Among the most important potential non-electric system benefits are reductions in gasoline, diesel fuel, natural gas, fuel oil, propane, and/or other fuels. For jurisdictions that include other fuel impacts in their BCA tests (consistent with jurisdictional energy policies), it is important to recognize that the other fuel system impacts from electrification can extend beyond just energy or commodity/fuel impacts. For example, when electrification lowers demand during gas system peak periods, it can help defer the need for future capital investments to upgrade gas transmission and/or distribution system infrastructure.[51]

[50] There may be some differences between weekdays and weekends for commercial buildings and for residential customers who set back thermostats during weekday work hours when no one is home.

[51] If an electric utility was funding an electrification initiative in a jurisdiction that includes other fuel impacts in its BCA test, the test would include such potential gas infrastructure cost savings. If a gas utility was funding an electrification investment (such as part of a non-pipe solution) such potential infrastructure cost savings would be treated as a utility system impact.

In addition, electrification of buildings can obviate the need to connect them to the natural gas distribution system (including the installation of a gas meter), thereby saving the cost of those connections. This can occur in the following examples:

- In the case of new construction, when all end uses that might otherwise have used natural gas—space heating, water heating, drying, cooking, etc.—are instead met entirely with electricity. In such cases, the builder would save the cost of connecting the building to the gas distribution system. Any ongoing fixed costs (meter reading, billing, etc.) of supplying natural gas to the home in subsequent years would also be avoided.
- In the case of fuel-switching existing buildings using fuel oil, propane, or other unregulated fuels to either (a) natural gas, which is not currently locally available, or (b) electricity, which is already available at the building. In such cases, assessments of the relative cost-effectiveness of the natural gas conversion should include consideration of the cost of bringing the gas distribution infrastructure to the building (whether relatively modest because gas is already 'at the curb' or more substantial because the gas pipe would need to be brought to the town and then to the building) as well as ongoing fixed annual costs of supplying gas to the building.

12.4.4. Host Customer Non-Energy Impacts

Table 12-6 summarizes host customer NEIs that may result from electrification. The table describes each NEI as a benefit, a cost, or either, depending on the most common, current electrification applications. The actual direction of the impact, however, would be determined on a case-by-case basis. The presence, direction, and magnitude of electrification NEIs will depend upon many factors, including the use case for the technologies, the type of host customer (e.g., low-income, residential, commercial, or industrial), and the host customer's needs.

Table 12-6. Potential Host Customer Non-Energy Impacts of Electrification

Host Customer NEI	Buildings & Industry	EVs	Examples
Operation & maintenance costs	●	●	• Buildings: O&M cost differences will vary by technology • EVs: Reduced O&M costs
Comfort	●	●	• Buildings: heating comfort may be better or worse • Buildings: heat pumps may add cooling capability in summer • Buildings: heat pump water heaters can be noisier than conventional water heaters • EVs: noise reduction
Health & safety	●	NR	• Buildings: reduced indoor air pollution
Amenity	●	●	• Buildings: in some homes, heat pumps may add cooling capability • Buildings: induction cooktops enhance cooking control and performance, while electric resistance cooktops reduce control and performance relative to natural gas or propane cooktops • EVs: reduced need to stop to refuel when charging at home or work • EVs: increased time to refuel when charging on the road, and potential range anxiety in the case of long trips
Satisfaction & pride	●	●	• Satisfaction from helping to address environmental concerns

● = typically a benefit for this example; ● = typically a cost for this example; ● = either a benefit or cost for this example, depending upon the application of the resource; NR = not relevant for this example.

Key examples include:

- *Operation and Maintenance* cost savings are an important benefit of EVs. EVs do not need oil changes, and they tend to have fewer moving parts and therefore fewer mechanical problems as the vehicle ages. O&M costs for EVs can be as much as half the costs for internal combustion engine-driven vehicles (Logtenberg et al. 2018).
- *Heating Comfort* can be either a benefit or a cost, depending on the type of heating system installed. For example, customers can experience comfort issues when buildings are retrofitted with heat pumps that are unsuitable for their climates (ERS 2014). Homeowners or building managers can address that concern by matching heat pump selection to the climate (e.g., cold-climate air-source heat pumps or ground-source heat pumps). Heat pumps with advanced features, such as variable speed inverter compressors, room temperature sensors, and variable air flow, may improve comfort by keeping temperatures steadier.
- *Cooling/Dehumidification Comfort* is often a benefit. For example, when a heat pump is installed for space heating in homes that do not have (and would not otherwise have installed) cooling, the ability to also cool a room, house, or business becomes an added amenity (though at an added cost to the electrical system).
- *Noise Reduction* is usually a benefit. EVs run more quietly than internal combustion engine-driven vehicles. Advanced heat pumps that modulate the amount of heat provided to a room or building are often quieter than fossil fuel furnaces or boilers that are typically either 100 percent 'on' (or 100 percent 'off'). On the other hand, heat pump

water heaters can be noisier than gas water heaters (though standard electric resistance water heaters are not).

- *Cooking Control* can be either a benefit or a cost, depending on the type of electric cooking technology installed. Natural gas or propane cooktops provide instant heat and near-instant response to changes in the amount of heat applied to a pot or pan. Electric coil cooktops cannot offer such instantaneous control; however, electric induction cooktops can. In addition, electric induction cooktops can reach high heat—for instance, boil a large pot of water—faster than gas cooktops (Hope 2022; Frontier Energy et al. 2019).
- *Driving Range Limitations* and related limitations on availability of fast-charging stations—sometimes called 'range anxiety'—are a cost of owning an EV. These concerns may diminish as the range of EVs continues to improve and access to fast-charging facilities increases.
- *Health and Safety* are generally a benefit of electrification. Electric appliances eliminate indoor air pollution that would otherwise result from the use of fossil-fuel-burning appliances. That is perhaps most notable for fossil fuel cooktops, but also for heating and water-heating appliances that are not properly vented, have cracked heat exchangers, and/or experience back-drafting. Also, because electric induction cooktops use electromagnetism to produce heat and cook food in metal pots or pans, it is the pot or pan that becomes the 'heater.' The cooktop produces no heat once the pot or pan is removed from the cooktop, resulting in reduced risk of inadvertent fires or burns.
- *Driving Responsiveness* can be increased by EVs, and thus a benefit; EVs typically react more quickly than internal combustion engine-driven vehicles when accelerating and have excellent torque (DOE n.d.-c).

12.4.5. Air Emissions Impacts

Electrification measures increase air emissions from the electric grid. However, they will reduce net air emission impacts of both GHGs and other pollutants when the marginal emissions from the electricity grid are low enough relative to the marginal emissions of the displaced fuel. As discussed in Chapter 6, DER air emission estimates should account for two important factors: (a) the time period during which the DER operates; and (b) the long-run marginal emission rates of the utility system at the time when the DER operates.

For electrification measures, there are several additional factors to account for regarding emission rates:

- The efficiency of the baseline technology (such as an internal combustion engine vehicle or a fossil-fuel-burning furnace, boiler, or water heater) will affect fuel savings and, therefore, air emission rates.
- The efficiency of the electric technology (such as an EV, a heat pump, or a heat pump water heater) will affect the magnitude of increased electricity consumption and, therefore, air emissions from the grid.
- The long-run marginal emission rates of the fuels that electrification would displace (such as gasoline, diesel, natural gas, propane, and fuel oil).

12.4.6. Increased Electricity Costs

As discussed above, electrification measures will generally increase electric system costs by increasing the amount of electric energy production needed and by adding to electric system and/or T&D system peak demands.

There are a variety of factors that dictate the extent to which increased consumption of electric energy adds cost to the system. Below is a partial list of such factors:

- The operating profiles of the electrification measures, including the extent to which electrification loads coincide with current system and/or T&D peaks, with such profiles themselves potentially affected by electric rate structures and/or DR measures designed to shift consumption to off-peak and lower-cost hours
- Variable energy costs, generation capacity costs, and T&D capacity costs, which often vary from season to season as well as during different times of day within the same region
- The amount of excess system generation capacity and/or excess T&D capacity on the grid

All these factors could vary widely from one service territory to another.

Estimating potential impacts on system and/or T&D peak demands requires consideration of more than current grid load profiles. Jurisdictions will want to also consider how current peaks might change over time, both absent electrification (for example, 'duck curve' effects associated with increasing deployment of solar generating capacity) and/or because of electrification (such as by adding enough electric heat to change a system from summer-peaking to winter-peaking). It is also important to consider how the costs of electric energy, capacity, and T&D investments are likely to evolve, including changes driven by decarbonization policies.

Estimating potential impacts on system and/or T&D peak demands requires consideration of more than current grid load profiles. Jurisdictions will want to also consider how current peaks might change over time.

For electric heat pumps, jurisdictions will need to understand the potential impacts on both winter and summer peaks. For example, there may be cases where heat pumps are adding cooling capacity to buildings that did not previously have it and would not have added it absent an electrification initiative.[52] Conversely, for buildings that already have or are planning to add cooling absent electrification, summer peak demands could be reduced if the heat pumps installed are more efficient in cooling mode than the air conditioners they would displace. This scenario is often the case, especially for high-performance cold-climate models.

[52] It is important not to assume that the baseline for a building currently without cooling would remain without cooling. Indeed, several evaluations of cold-climate heat pump programs in New England found that many homes participating in such programs were initially interested in adding air conditioning and were convinced by the programs to purchase heat pumps instead of air conditioners (ERS 2014).

12.5. Common Challenges in Determining Benefits and Costs

12.5.1. Seasonal and Daily Load Profiles

As discussed in the preceding sections, the impacts that electrification measures will have on the grid will depend upon their use case, particularly their load shape. Load shapes have been used to estimate impacts in EE program cost-effectiveness analyses for decades. However, developing profiles for electrification measures can be more challenging than for efficiency measures.

For the electrification of buildings and industry, the end-use load shapes already used for EE analyses for similar end uses can help address this challenge, with appropriate modifications. Examples of conditions that would require modification of EE building and/or industrial end-use load shapes include the following:

- If an end use is only partially electrified—such as where electric heat pumps are only partially displacing fossil fuel heating, and the fossil fuel heating systems remain to help serve loads during very cold temperatures (what is often called a 'hybrid-heating' solution)—EE load shapes will need modification.
- If customers are likely to modify any electrified loads in response to new rate structures (such as time-varying rates) and/or controlled through different forms of DR, load shapes will need modification.

Electrification BCA tests will require development of load shape assumptions for several factors:

- EVs whose charging patterns can be highly variable and influenced by rate design (SEPA 2019b)
- Availability of charging infrastructure for EVs
- Fast-evolving technology (particularly around EV batteries)
- Other factors

Overall, jurisdictions will need to develop assumptions to address each of these modifications or needs, and initial assumptions will likely involve considerable uncertainty. However, jurisdictions can mitigate that uncertainty over time as additional analyses inform updated assumptions.

12.5.2. Charging Methods Used by EV Consumers

The grid impacts of EVs will depend, in part, on the charging options used by EV consumers, for example, Level 1, 2, or 3 (DCFC) chargers. Over an entire service territory, differences in electricity draw amount and duration associated with different charging options may be smoothed out with diversification of charging times across a large customer population. However, widespread use of high-voltage, high-speed (level 3) DC Fast Chargers could reduce such diversification and raises concerns specific to the technology:

- Large 'spikes' in level 3 charging consumption can have significant effects on the peak demands of localized distribution system elements that serve them (though the average EV load shape for parts of the grid with high usage of rapid charging may be very different than for other parts of the grid or for the system as a whole).
- Even if use of a level 3 charging station were more evenly spread across all hours of the day (for instance, because it serves large multi-family buildings, a truck stop, fleet

vehicle facility, other institutional customers, or any other location with many vehicles charging at different times) the impact on the grid could be different than more dispersed use of level 1 and level 2 chargers. This difference would be due to the greater geographic concentration of Level 3 chargers.

To address this challenge, jurisdiction can consider the potential differences in grid impacts across charging levels, particularly T&D system impacts, and estimate the expected mix of charging methods. This assessment would include charging needs for large commercial fleets. To the extent that rate design, DR, non-wires solutions, and/or BTM storage could mitigate any adverse effects, such mitigation should also be factored into analyses.

12.5.3. Impacts on Curtailment of Renewable Resources

In some areas, at some times of the year, local generation from wind, solar, and other sources (such as must-run generators) can exceed local demand. If transmission capacity is insufficient to move all excess generation to different areas, the system operator might need to curtail that generation. The installation of electrification measures near transmission-constrained renewables may help reduce curtailment of those resources by raising the area's electric demand when extra energy is available.

To the extent that electrification can use energy resources that would otherwise have been curtailed, the marginal cost of serving electrified end uses with those resources is zero during those curtailment hours. Electrification measures might even provide a cost savings to the electric system if they displace or defer any transmission additions that would otherwise be built to enable access to curtailed renewables. Thus, all else equal, geo-targeting electrification to areas experiencing, or forecast to experience, significant renewables curtailment could be more cost-effective than systemwide electrification initiatives. See Chapter 7 and Chapter 11 for further discussion of curtailment and BCA.

12.6. Common Interactions with Other DERs

While electrification measures can interact with other DER types, interactions are most common with EE and DR. It is becoming increasingly common for the design and delivery of electrification initiatives to be integrated with EE and/or DR programs. Key interactions to consider when conducting cost-effectiveness assessments include the following:

- **Building envelope efficiency upgrades lower winter peak demand from electrified heating**. Insulation upgrades, air leakage reduction, and duct sealing can also reduce the magnitude of electric demand during winter peak hours. For systems that are or will become winter peaking, this can be a substantial benefit. It is appropriate to address these interactions in a BCA test when space heating electrification and efficiency are co-delivered.
- **Building envelope efficiency upgrades allow for downsizing heat pumps installed for electrification**. By reducing the amount of heat production needed, insulation upgrades, air leakage reduction, and/or duct sealing can also reduce the capacity required of the new heat pump to electrify space heating in a building. The result is smaller, lower-cost heat pumps.
- **Some electrification enables DR**. Many electrification measures can be managed by customers to minimize grid costs (especially if customers see hourly price signals)

and/or controlled directly through DR programs. EVs and electric water heaters are particularly well-suited to load management through DR programs.

- **EVs with V2G capability can function as DS**. While many EVs allow only one-way electricity flows (from the grid to the vehicle for charging), some have two-way flow capability (also allowing vehicle-to-grid flows). EVs with that unique feature can serve as grid storage (see Chapter 11). This allows not only charging during periods of low prices and/or low net demand but also pushing electricity back onto the grid during periods of high prices and/or high net demand. Thus, unlike other electrification measures, EVs with V2G capability have the potential to reduce total electric generation (energy) costs.[53] EVs with V2G capability may also *reduce* net system peak demands and/or net T&D peak demands, the extent to which depends on whether vehicle owners have their vehicles plugged in and accessible to the grid at the times that their storage capabilities may be needed.

12.7. Changes in Revenues and Rate Impacts

This section discusses how electrification-related DERs can influence customer rates, why BCA tests cannot accurately evaluate those impacts, and options for appropriately assessing and addressing rate impacts.

Electrification will increase electricity sales and, therefore, electric utility revenues. However, such increases in revenues, as with revenues lost from investments in EE or DG, do not belong in cost-effectiveness analyses. The increase in electric revenues resulting from electrification will mean that the recovery of fixed and/or past sunk costs can be spread over a broader base of sales.

However, the way in which fixed and past sunk costs are recovered is a rate impact concern rather than a cost-effectiveness concern. While increased (or lost) revenues and related rate impacts are often of regulatory interest, it is appropriate to analyze them separately from and in parallel with cost-effectiveness analyses (see Appendix B).

Note that reduction in consumption of natural gas that results from electrification will require recovery of fixed and/or sunk costs over a smaller volume of gas sales. Unless significant new gas utility system costs are avoided (such as when electrification is part of a non-pipe solution that avoids new infrastructure investment) such reductions in sales can lead to gas utility rate increases.

[53] For example, consider the following hypothetical example in which total electricity used for driving an EV was 3000 kWh per year, where the EV storage functionality was used to put 500 kWh per year onto the grid when energy prices averaged $0.25/kWh (a cost savings of $125), and where the average energy cost during times the EV was taking its 3500 kWh off the grid for charging was $0.03/kWh (a cost of $105). In this hypothetical, the net generation cost for the EV would be -$20 (or a $20 cost savings), before accounting for any capacity cost savings.

PART IV

Benefit-Cost Analysis for Multiple Distributed Energy Resources Scenarios

13. Analyzing Specific DER Scenarios

This chapter describes key considerations for analyzing DERs within the context of certain specific scenarios, which adds a layer of complexity to the already analytically intensive exercise of DER BCA. Scenarios include multiple on-site DERs, infrastructure DER solutions, virtual power plants, and microgrids. This guidance builds upon material covered in Chapter 7, Cross-Cutting Benefit and Cost Consideration, and Chapters 8–12, to help BCA practitioners understand how these key considerations apply specifically to each DER scenario.

13.1. Summary of Key Points

- The following specific scenarios are addressed within this chapter:
  - ***Multiple On-Site DERs:*** When more than one DER is installed in the same building (or facility), or at buildings (or facilities) within a contiguous geographic site such as a campus.
  - ***Non-Infrastructure DER Solutions:*** DERs typically sited at more than one location are utilized to defer or avoid a utility infrastructure investment (e.g., non-wires or non-pipe solutions), or to improve system performance and/or customer satisfaction while waiting for the completion of an infrastructure solution.
  - ***Virtual Power Plants***: An aggregation of multiple DERs that can be dispatched to benefit the grid and/or participate in a market.
  - ***Microgrids***: Coordinated operation of DERs on a portion of the electric grid in a configuration that allows islanding (functioning independently of the rest of the grid) and potentially adds resource value when operating in parallel with the grid.
- While most often these scenarios entail an aggregation of multiple DERs (either from the same category or from multiple categories), it is possible to have a non-infrastructure DER solution, VPP or microgrid comprised only of a single DER. A prominent example is a single, large FTM battery utilized to power a microgrid for several hours during a wider grid outage.
- These scenarios are not mutually exclusive; often situations arise in which a particular DER project will encompass multiple scenarios. For instance, a VPP comprised of smart thermostats and EV chargers can be leveraged as an NWS to help provide load relief to an overloaded feeder.
- Each specific DER scenario, and the technology variations thereof, has its own set of BCA issues that arise and add complexity to properly analyzing the cost-effectiveness of DERs.
- While there are many unique issues that may occur for any specific DER situation or combination thereof, this chapter focuses on the following nine key BCA considerations that can arise during specific DER scenario analyses:
  1. Passive interactive load impacts between DERs

2. Active interactions, use case, and balancing competing priorities
3. Unlocking novel value streams and threshold dependent value quantification
4. Accounting for uncertainty when avoiding tangible grid investments and/or performing as grid assets
5. Evaluating the value of flexibility
6. Time-dependent value quantification
7. Location-dependent value quantification
8. Supporting system costs
9. Existing DER impacts

13.2. Introduction

Combining multiple DERs (either of the same type or of multiple types) can provide value to the electricity grid in a multitude of different ways, including impacts such as reducing GHG and other emissions, mitigating or reducing the need to build new infrastructure, and providing ancillary grid services. This section highlights key considerations specific to conducting BCA for four specific scenarios in which multiple DERs are often aggregated: Multiple DERs On-Site, Non-Infrastructure DER Solutions (e.g., non-wires or non-pipe solutions), VPPs, and microgrids. This chapter first introduces each of the four scenarios before discussing each key consideration its own section.

The key considerations discussed here encompass many relevant issues that are either unique or of focal interest for these specific DER scenarios. However, this is not a complete list and various issues raised throughout this Manual are often applicable to these specific DER scenarios as well. See Chapters 8–12 for issues related to specific single DERs, as well as Chapter 7 addressing cross-cutting DER issues. For example, the selection of an appropriate discount rate (discussed at length in Section L.2.7) is a relevant and important consideration for conducting a BCA on a VPP, but since there is nothing distinct to address about this issue in relation to this specific scenario it is not included as a key consideration in this chapter. It is important to use this chapter as part of the broader Manual, rather than as a checklist for appropriately conducting BCA for a specific scenario of interest.

It is important to use this chapter as part of the broader Manual, rather than as a checklist for appropriately conducting BCA for a specific scenario of interest.

While the four scenarios most often entail an aggregation of multiple DERs (either from the same category or from multiple categories), the non-infrastructure solutions and microgrid scenarios can be comprised of a single DER (e.g., a large battery).

Furthermore, the scenarios are not mutually exclusive constructs, and in practice it is becoming increasingly common that situations arise in which a particular utility DER initiative will encompass multiple scenarios. Table 13-1 provides examples of utility DER initiatives that span multiple scenarios. For instance, a utility may aggregate residential smart thermostats so that they are part of a VPP and then utilize that VPP for distribution system peak load relief as part of a non-infrastructure DER solution, as an NWS for an overloaded substation. Another common overlap is a microgrid that, when grid connected, is leveraged by a utility as a VPP. Because of the significant amount of overlap that exists between each of these scenarios, it is critical to determine which

scenario definitions are applicable to any specific utility initiative to properly assess the key considerations relevant for BCA.

Table 13-1. Examples of Utility DER Initiatives That Span Multiple Scenarios

Example Projects	Multiple DERs On-Site	Non-Infrastructure DER Solution	Virtual Power Plant	Microgrid
A utility **demand flexibility program** enrolls 10,000 smart thermostats so the utility can control assets to: • provide load relief on the local substation during peak times, and • reduce demand during off-peak times to increase available generation for bidding into wholesale energy market.		●	●	
Partial capacity from two 10 MWh batteries in a **microgrid** serves as a VPP to provide ancillary services when the microgrid is grid-connected.			●	●
A utility does a **direct install program** for a community as part of an **NWS** to avoid upgrading a rural distribution line; members receive: • free attic insulation and air sealing, and • replacement of electric resistance baseboard heaters with cold climate mini-split heat pumps.	●	●		
A utility builds a **microgrid** to cost-effectively avoid undergrounding an isolated distribution line prone to outage during storms; customers receive monthly incentives for participating in a bring-your-own-device **demand flexibility** program in which: • customers allow the microgrid controller to control smart thermostats, EV chargers, and smart water heaters to manage load during islanding, and • the microgrid controller can dispatch assets to provide peak capacity relief to the broader grid during grid-connected operation.	●	●	●	●

Table 13-2 summarizes the nine key considerations addressed in this chapter and identifies the applicable scenarios for each consideration. In cases where the scenarios overlap, the considerations for all overlapping scenarios are relevant even if a specific consideration may not be inherently relevant to a certain scenario. For instance, if a VPP is functioning as an NWS, then the issues for both VPPs and DER non-infrastructure solutions are applicable to the initiative BCA.

Table 13-2. Key Considerations for Conducting BCA Analysis for Specific DER Scenarios

Key Consideration	Multiple DERs On-Site	Non-Infrastructure DER Solution	Virtual Power Plants	Microgrids	Description
1. Passive interactive load impacts between DERs	●				Often when multiple DERs are located on-site, passive interactions between DERs (meaning interactions which do not result from changes in DER dispatch) can meaningfully alter the load impacts of the DERs and therefore the resulting value. These types of passive interactions most commonly occur between EE and other DER resources, such as home weatherization reducing the quantity of heating load that can be shifted with a smart thermostat DR program (see Sec. 7.6, Interactive Impacts)
2. Use case, balancing competing priorities, and active interactions	●	●	●	●	When a DER aggregation contains dispatchable assets, the use cases for the specific utility initiative determine which value streams are relevant and the potential competing priorities to be balanced. For example, if a battery's primary use case is for host customer backup, then will have less ability to provide load relief as part of an NWS. When multiple DERs are part of an aggregation, this results in the potential for active interactions in which the dispatch of one DER is influenced by the presence of other DERs (see Sec. 7.7, Resource Ownership and Control)
3. Unlocking novel value streams and threshold-dependent value quantification		●	●	●	Due to their unique attributes, DER non-infrastructure solutions, VPPs, and microgrids can unlock unique value streams that other DERs cannot provide. In most cases, DERs must meet performance thresholds to unlock these novel value streams. For instance, for a microgrid to provide resilience benefits when the broader grid goes down (a value unique to microgrids), it must be able to provide enough power to meet the critical load needs of its host customers and to society (see Sec. 7.10, Importance of Program Scale and Threshold Dependent Valuation)
4. Accounting for uncertainty when avoiding tangible grid investments or performing as grid assets		●	●		Since the purpose of a DER non-infrastructure solution is often to avoid planned upgrades/enhancement to the grid, it is essential to ensure the DER solution is a reliable substitute even under uncertainty. The same is true of VPPs when they function as a critical grid asset, such as providing ancillary services.
5. Evaluating the value of future flexibility			●		Because VPPs can dispatch their resources in response to changing conditions, a BCA test should capture the value of this flexibility. This requires evaluating the performance of the VPP under the range of expected future planning conditions (see Sec. 7.5, Grid and Demand Flexibility)
6. Time-dependent value quantification		●	●	●	While DERs often benefit from improved temporal granularity for valuation, DER non-infrastructure solutions' principal value stream of avoided/deferred transmission/distribution is inherently time-dependent and warrants temporally granular evaluation. The same is true for microgrids for their principal value stream of host customer and societal resilience, and for VPPs that provide time-dependent critical grid functions such as ancillary services (see Sec. 7.3, Temporal Impacts)

Key Consideration	Multiple DERs On-Site	Non-Infrastructure DER Solution	Virtual Power Plants	Microgrids	Description
7. Location-dependent value quantification		●	●	●	For several of the specific scenarios, locational specificity with regard to the utility system is integral to quantifying DER value. The most evident example of this is with an NWS/NPS, in which the value that DERs bring depends on the specific costs of the infrastructure being deferred or avoided (see Sec. 7.4, Temporal Impacts)
8. Supporting system costs	●		●	●	Most of the specific DER scenarios discussed here often necessitate investment in additional infrastructure beyond the cost of the DERs themselves. For instance, with a VPP, a utility may invest in a DER management system to be able to manage and orchestrate the dispatch of DERs within the VPP. It is important to thoughtfully consider how the BCA test will address these supporting infrastructure costs.
9. Existing DER impacts	●	●	●	●	When a utility initiative leverages existing DER assets as part of a DER aggregation, BCA of the aggregation will need to avoid double-counting the value that existing DERs were already providing to the grid. For instance, if a previously installed PV system on a customer's roof is added to a community islandable microgrid, then the microgrid BCA test would not include the GHG benefits of solar power because they are not incremental benefits.

13.3. Multiple DERs On-Site: Overview

The simplest specific DER scenario is that in which multiple DERs are implemented at the same building or site. A common example is a residential utility customer that installs an efficient air conditioner with support from a utility incentive and participates in utility smart thermostat program for DR events. These types of multiple DER scenarios can result in additional considerations for accurate BCA, particularly in cases where the technologies impact the same end use and therefore are likely to have interactive load impacts.

Analyzing multi-DERs on-site does not require that the DERs be of multiple types, only that there are multiple DER measures.

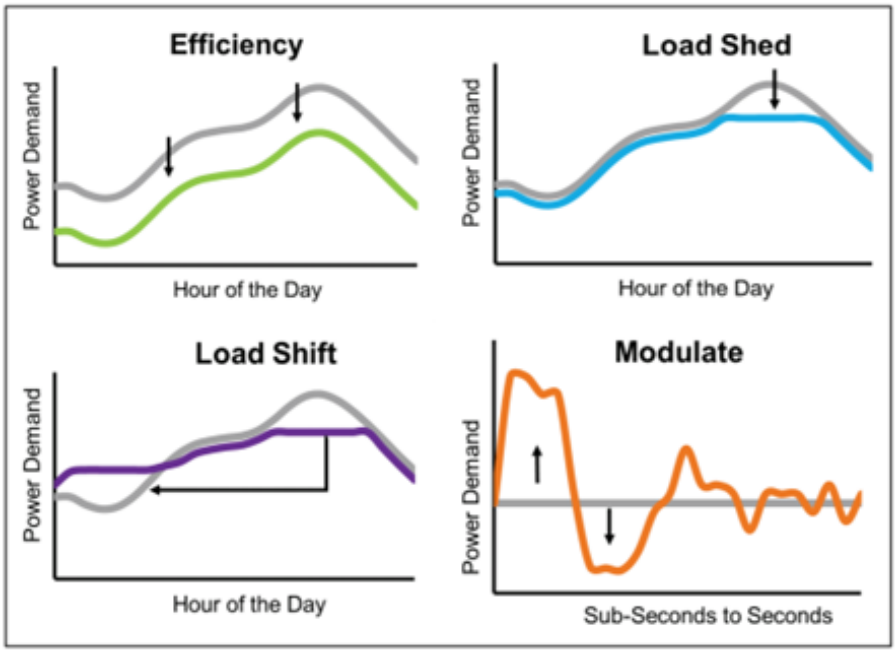
The scenario of Multiple DERs On-Site can occur with the combination of two different types of DERs, or even with the combination of different DER measures of the same type (e.g., EE). For instance, an efficient air conditioner combined with the replacement of single-pane windows with efficient double-pane windows is also a Multiple DERs On-Site scenario. Both the efficient air conditioner and the efficient windows are considered EE measures; however, there is still a need to account for the interactive impacts between them to accurately value these resources in a BCA test. This is because the more efficient windows, particularly if they are located on the south-facing façade, will reduce the building cooling load and therefore impact how long the efficient air conditioner needs to run.

A construct that is directly applicable to the specific scenario of Multiple DERs On-Site is what the U.S. Department of Energy refers to as Grid-interactive Efficient Buildings (GEBs). A GEB is defined

as an energy-efficient building with smart technologies characterized by the active use of DERs to optimize energy use for grid services, occupant needs and preferences, and cost reductions in a continuous and integrated way (DOE 2019b). GEBs use efficient, connected, smart, and flexible resources such as DS, DG, DR, and EE to reduce, shed, shift, and modulate load, thereby easing constraints on the grid (DOE 2019a), as shown in Figure 13-1. Because of their inclusion of flexible resources, GEBs readily lend themselves to utility initiatives that overlap the Multiple DERs On-Site and VPP scenarios. For instance, a building owner may enroll the smart thermostat and BTM storage assets of a GEB in a utility VPP program. illustrates changes in building load profiles for each of the operational modes of a GEB.

While the ability to manage load at both the residential and commercial levels is often an attribute of multi-DER on-site scenarios, load management (or demand flexibility) is not a required component of this type of scenario. Another example of multiple on-site DERs is that of combining EE and building electrification in the form of weatherization and air-source heat pumps. This combination is a strategy used by utilities in northern United States to mitigate winter peak demand impacts from electrifying space heating.[54]

Figure 13-1. Grid-interactive Efficient Building Flexibility Load Curves



Source: DOE 2019a. The gray curves represent the example baseline building load and the green, blue, purple, and orange curves show the building load after each specific type of load profile change.

For many situations, the scenario of Multiple DERs On-Site will be equivalent to multiple DERs located at the same building. However, this is not always the case and there are times when it

[54] In some states, utilities offer increased program incentives for installing heat pumps at sites which either meet weatherization requirements or agree to weatherize prior to heat pump installation. In New York, regulators approved a 'weatherization tier' incentive for heat pump installations in 2026. This tier offers significantly higher rebates to homes that have either already met weatherization standards or participate in a utility weatherization program prior to or in conjunction with a heat pump installation (NYS Clean Heat 2026-2030 Implementation Plan 2025).

makes sense to widen the boundary to a site that contains multiple buildings and/or facilities. For instance, a university may decide to install rooftop PV on multiple buildings across its campus and pair the renewable generation with a centrally located battery storage system. Based on the definitions of a site documented by DOE, this Manual defines a site as:

> *A contiguous piece of land or property upon which a single building or group of buildings are located. A site may be divided by public rights of way. (DOE 2025)*

Often, a site can mean all buildings hooked up to a single utility meter, but this is not required to define a group of buildings as being co-located on a site. It is also common that a site contains only one utility customer; however, this is also not a requirement—sites such as campuses may contain multiple utility customers[55]. Figure 13-2 below illustrates the different potential formulations for which the scenario of Multiple DERs On-Site may occur. These range from the simplest example of a single building with a single occupant, to the most complex example of a campus with multiple buildings in which each building is for a different utility customer and has its own meter.

Figure 13-2. Progression of Complexity of 'Sites' to Which Multiple DERs On-Site May Apply



13.4. Non-Infrastructure DER Solutions: Overview

The second DER scenario considered in this chapter is Non-Infrastructure DER Solutions. Often, the impact of DERs on the T&D system is valued at the aggregate bulk system level, comparable to impacts on energy generation and capacity. In practice, this usually translates into the use of a system average avoided distribution and/or transmission capacity cost to value the impact of peak load changes from DERs. By contrast, in the case of Non-Infrastructure DER Solutions, utilities look to extract locational- and temporal-specific values from DERs in relation to the distribution or transmission grid in two primary ways:

1) ***Non-Wires Solution for electric systems or Non-Pipes Solution for gas systems:*** Through the deferral or avoidance of specific, planned infrastructure projects.
2) ***Bridging Solution:*** Using DERs to avoid or reduce utility spending on temporary solutions such as diesel generators used to maintain system reliability prior to infrastructure solutions coming online.

[55] Multifamily apartment buildings can also be an example of one site having multiple meters when each tenant has their own unit electricity meter.

13.4.1. Non-Wires Solution

On the electric side, the concept of deploying DERs in specific geographic locations to defer or avoid investment in transmission or distribution system upgrades has been referred to as: 'targeted demand-side management,' 'geo-targeting,' 'non-wires alternative,' 'non-transmission alternative,' and 'non-wires solution.' This Manual uses the term Non-Wires Solution (NWS) to refer to all these applications and defines NWS as:

> *[The use of] target DERs to meet narrowly identified requirements . . . to defer, mitigate, or eliminate the need for a subset of traditional distribution (and transmission) investments. To be effective as [NWSs], DERs must avoid both the otherwise needed utility distribution investment and the introduction of any other problems based on engineering analysis (LBNL 2021).*

An NWS uses the load-reduction, load-shifting or load-shedding capability of DERs to reduce strain on the grid and to defer or avoid a planned investment. In addition to providing this key value stream of reduced distribution or transmission system investment, NWSs can also provide value streams such as allowing faster customer interconnections through increased headroom (in other words, more room on the local wires) for DERs.

13.4.2. Non-Pipes Solution

On the gas side, this Manual uses the term Non-Pipes Solution (NPS), and defines NPS as:

> *An investment or activity that defers, reduces, or avoids the need to construct or replace gas system infrastructure. Rather than address system issues with traditional capital projects, utilities can leverage demand-side [NPS] resources, such as energy efficiency and electrification, and supply-side [NPS] resources, such as locationally deployed liquified natural gas, to reduce customer costs and reduce the risk of stranded assets (Nelson 2023).*

An NPS can help to reduce the need to build pipelines that may only be needed for the earlier portions of their expected lifespans. This reduction helps reduce the costly risk of stranded assets on the gas system. An NPS can entail traditional demand-side reductions such as gas EE, as well as alternatives such as deploying liquid natural gas at constrained portions of the system.

In summary, NWS and NPS are alternatives to discrete planned projects (typically forecasted in the utility's near-term capital budget) and therefore provide quantifiable deferral value that the BCA test can include.

13.4.3. Bridging Solutions

A second important way that DERs can help with aging and inadequate traditional infrastructure is through a geographically targeted solution that this Manual refers to as 'Bridging Solution.' The aim of the solution is to reduce the need for utility spending on temporary solutions, such as backup diesel generators, that a utility uses to maintain system reliability while waiting for the planned infrastructure upgrade to be completed. In this type of scenario, the 'non-infrastructure solution' provided by the DER is an alternative stop-gap measure that is a lower cost to the utility system as compared to the traditional solution. Therefore, these bridging solutions also provide a tangible distribution system benefit by avoiding and/or reducing the needed investment in temporary solutions.

A note on bridging solutions: In some special cases, a bridging solution may be a temporary solution that does not avoid or defer any utility spending on permanent or temporary solutions. In this type of scenario, the 'bridging solution' provided by the DER is a type of bridge that helps provide grid and/or societal value, rather than deferring or avoiding any planned investments. An example of this would be a utility leveraging an existing demand flexibility program in a geo-targeted manner to selectively reduce or eliminate loads on a damaged portion of the distribution grid after a storm. By flexibly energizing loads to maintain a reliable grid under damaged conditions, the utility could significantly improve service to customers while impacted grid infrastructure is being repaired or replaced.

13.5. Virtual Power Plants: Overview

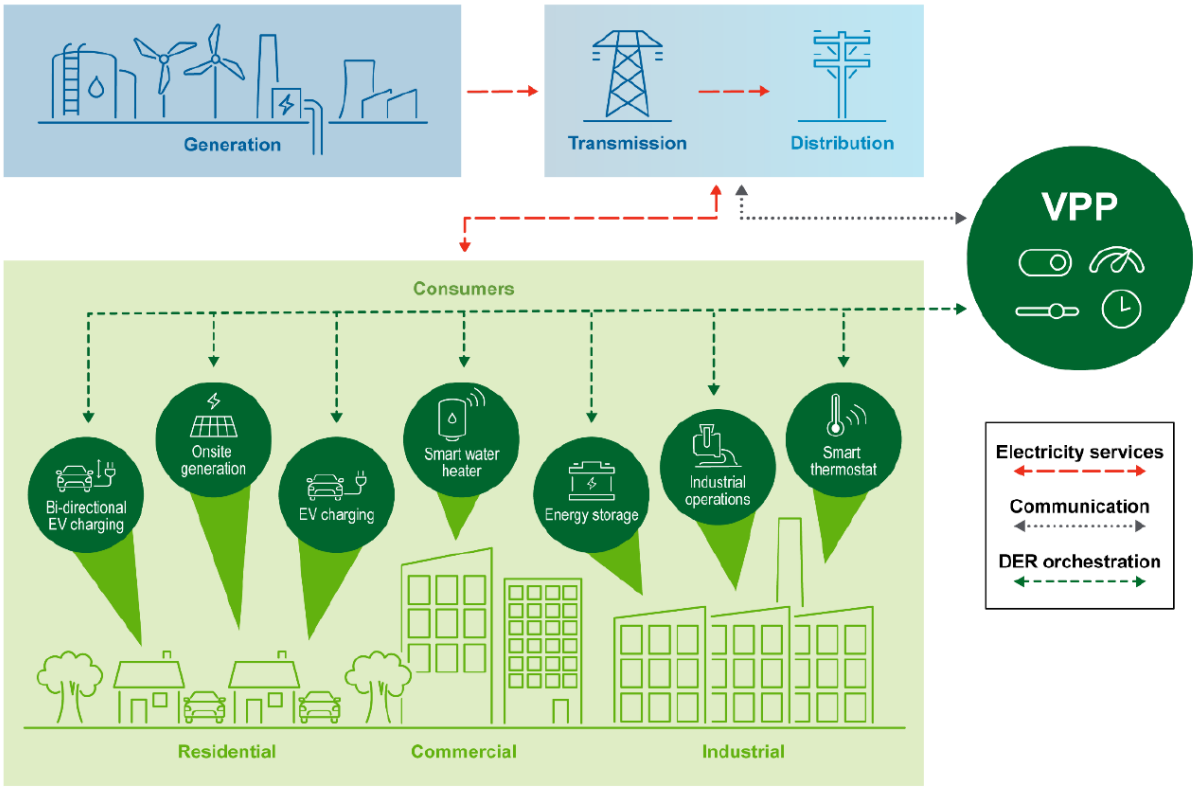
Definitions of VPPs vary considerably across the industry (LBNL 2025d). For the purposes of this Manual, the definition used is as follows:

> *Virtual Power Plants are aggregations of DERs—such as rooftop solar with (BTM) batteries, EVs and chargers, electric water heaters, smart buildings and their controls, and flexible C&I loads—that can balance electricity demand and supply and provide utility-scale and utility-grade grid services like a traditional power plant (DOE 2023a).*

A VPP may comprise one asset at a single building/site, such as a large utility-owned FTM battery, or multiple assets spread across sites, such as a VPP program that controls thousands of EV chargers. Figure 13-3 shows the conceptual layout of a VPP. As highlighted in the graphic, a key component of a VPP is the aggregation and orchestration of DER resources so they can seamlessly provide both bulk and geotargeted services to the grid.

The aggregations of DERs to provide grid benefits in this manner has occurred for decades. For instance, utility DR programs have been providing critical services such as peak capacity relief from aggregations including residential air conditioning load switches and interruptible C&I loads as far back as the 1980s. The modern VPP concept adds the management and dispatch of many distinct DERs for a coordinated purpose. Utilities are looking to centralize control of dispatchable assets, with a focus on developing VPP control platforms able to integrate both multiple DERs of the same type and multiple types of DERs.

Figure 13-3. Conceptual Layout of a Virtual Power Plant



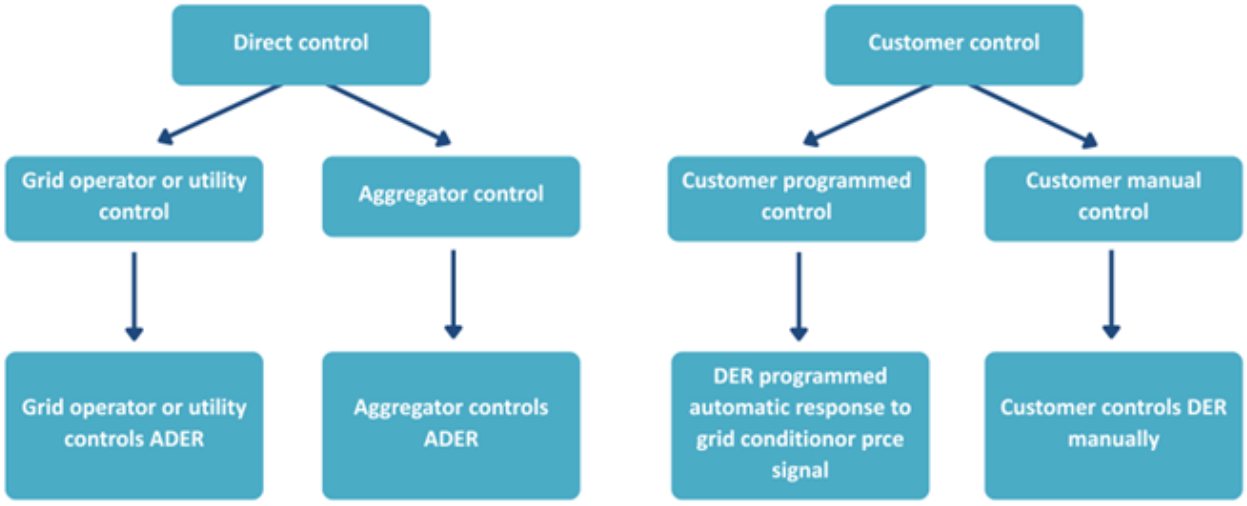
Source: DOE 2023a.

The key differentiating characteristic of DER assets in a VPP is their ability to be dispatched. As shown by Figure 13-4, there are two different ways to control DERs within a VPP: direct control and customer control. With the customer control path, the customer can control the DER resource. In the simplest form, this translates into manual control in which the customer receives a signal, such as a text message from the utility to turn up their thermostat during a summer peaking event, and the customer then manually implements the change.

The key differentiating characteristic of DER assets in a VPP is their ability to be dispatched.

Another form of customer control, which allows for faster response times, is to automate the response of the DER to signals provided by the utility. In this setup, the customer still chooses how the DER is programmatically controlled, but the resource can respond in real time. This type of control is much closer to the direct control path, in which the utility/grid operator/or aggregator directly controls the DER. In this type of control, the customer permits external control of the resource under certain conditions. Typically, the controller notifies the customer, who can opt out of the control if desired. Due to the limited reliance on the host customer, this path provides the largest opportunity for VPPs to provide grid support and can be a required control mode for providing critical ancillary services, such as operating reserves. Therefore, the control strategy is integral in determining what specific value streams a VPP can provide.

Figure 13-4. Virtual Power Plant Control Strategies



Source: NARUC-NASEO 2022.

13.5.1. VPPs in Wholesale Markets

The concept of a VPP is particularly relevant in the context of DERs providing grid services in wholesale electricity markets.[56] Within this context, it is important to distinguish between the concept of a DER aggregation and a VPP. A DER aggregation can be any collection of DER resources bundled to provide value to the grid. The distinguishing factor for a VPP is the ability to react comparably to a traditional power plant to balance supply and demand, which necessitates the inclusion of either dispatchable generation, energy storage, or flexible loads. This Manual assumes that all VPPs are DER aggregations, but that all DER aggregations are not VPPs.[57] This is because a VPP *must be dispatchable* to react to grid needs to balance supply and demand, and non-dispatchable resources such as EE and DPV (without a smart inverter) therefore cannot be included in a VPP. However, these resources could be part of a broader DER aggregation that also contains resources from a VPP.

[56] A significant driver is the Federal Energy Regulatory Commission's (FERC) Order 2222, which enables aggregations of DERs to participate in the electricity markets run by RTOs and ISOs across the country (DOE 2024c; FERC 2020a). The order requires all RTOs and ISOs to have clearly defined rules in place and allow DER aggregations to participate in markets by 2030 at the latest, with many RTOs and ISOs completing their compliance significantly earlier. For instance, the California ISO (CAISO) implementation of 2222 was complete as of November 2024 (CAISO 2024).

[57] Not all VPP publications or organizations include all DERs as VPP resources. Some, for example, do not include EE on the basis that it is not typically dispatchable e.g., CEC, ERCOT (LBNL 2025d, DOE 2023a), yet FERC Order 2222 recognizes EE as a DER that can be aggregated to provide grid services.

This Manual assumes that all VPPs are DER aggregations, but that all DER aggregations are not VPPs.

The discussions below on key BCA considerations related to VPPs pertain to the situations in which the utility itself is the aggregator of the DERs and controller of the VPP, or when the utility has hired a third party to operate a VPP on its behalf. The situation of a third-party aggregator operating a VPP for its own interest is not applicable to this Manual, since this would not require a BCA to justify utility funding or involvement.

13.6. Microgrids: Overview

Microgrids are a key tool that utilities use to address the challenges of grid resilience. They are defined as:

> *"A group of interconnected loads and DERs within clearly defined electrical boundaries that act as a single controllable entity with respect to the grid. A microgrid can operate in either grid-connected or in island mode, including entirely off-grid applications." (DOE 2024c)*

The ability of microgrids to maintain power when the rest of the grid is down provides communities with resilience to maintain critical infrastructure such as water treatment, medical care, telecommunications, and shelter during wider grid outages (NARUC-NASEO 2022). In addition, a microgrid can export clean, low-cost energy to customers; can participate in voltage and frequency regulation; and can even provide inertia response[58] (ORNL 2024). Note though that the provision of these benefits requires the microgrid to also be functioning as a VPP, meaning this would be a utility initiative where two specific scenarios overlap. The specific value streams that a microgrid provides to the grid and to its customers depends on the specific DERs that make up the microgrid. Additionally, the time that a microgrid spends islanded versus connected to the grid will also impact which specific value streams it is able to provide and to what degree.

As shown in Figure 13-5, microgrids can contain a broad range of DER types. A core component of any microgrid is the ability to generate its own electricity, whether through renewable means such as solar PV, fossil-fuel-based methods such as CHP or natural gas generation, or (for microgrids only concerned with providing short-term backup) battery storage. EE and DR are also core components of a well-balanced microgrid, as they reduce the need for power generation and for cycling off non-critical loads to sustain power supply to the microgrid.

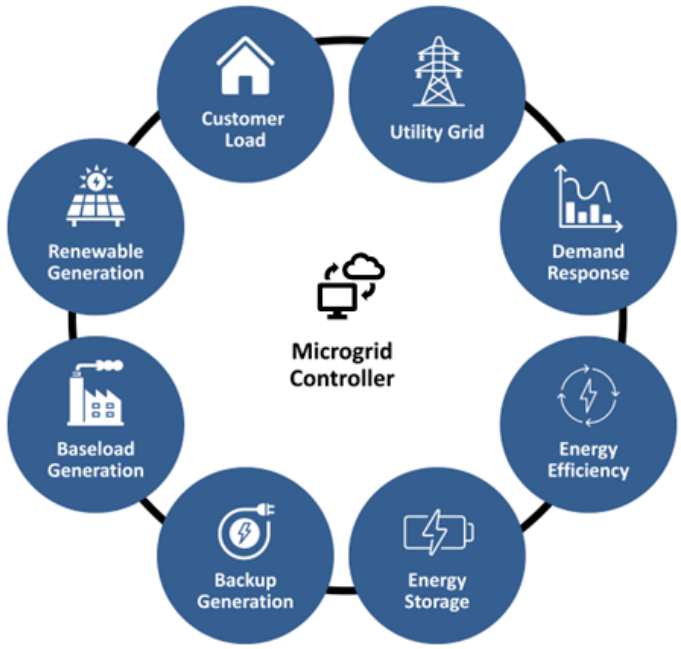
As shown in the examples below, configurations for a microgrid can range from a single customer microgrid to more complex designs that serve multiple customers, such as campus or neighborhood-style microgrids:

- A single customer microgrid is located BTM or at a point of common coupling that serves one customer's or building's load and acts as a single controllable entity. Customers may install microgrids to meet their own needs and/or support neighboring or system needs.
- A campus microgrid is like a single customer microgrid except it serves multiple buildings that can be contiguous or non-contiguous. Universities, hospitals, and military bases are common examples of campus microgrids.

[58] Inertia response is the instantaneous response of synchronous generators (such as in a combined heat and power plant) to a sudden imbalance between supply and demand.

- Multi-customer microgrids can serve multiple users' loads that are on contiguous or non-contiguous properties. The ownership, operation, and/or management of the microgrid assets vary between the customers and a third-party developer. Examples include mixed-use real estate development and data centers (SEPA 2019a).

Figure 13-5. Microgrid Potential Components



Additional variables useful for defining a microgrid include size or capacity of the project, types of assets included in the project, primary operating mode, point of interconnection (BTM, FTM, or none), public rights of way, and on-site generation versus imported electricity (SEPA 2019a). Most microgrids with a connection to a larger grid spend the bulk of their time in grid-connected mode; however, a grid connection is not a requirement for a microgrid. In fact, the concept of a microgrid, historically, was borne out of small, islanded grids with no broader system to connect to (e.g., a small island grid running on diesel generators).

As with Non-Infrastructure DER Solutions, it is possible to have a microgrid with only one DER, such as the previously noted example of a natural gas generator. But in practice this is rarely the case, both due to the desire for microgrids to be powered by clean, renewable energy, and the need for EE and DR to reduce the power supply requirements of the microgrid.

13.7. Key Consideration: Passive Interactive Load Impacts Between DERs

When a specific DER scenario encompasses multiple DERs (either of different types or multiples of the same type) there is the potential for the load shape of one DER to be impacted by another DER. Below are two types of potential interactions, referred to in this Manual as 'interactive effects':

- ***Passive Interactions:*** This is when one DER impacts the load shape of another, but their impacts are not the result of active changes in dispatch strategy. For instance, when a home is weatherized, the heating and cooling load of the home is reduced. This lowers the

energy required to heat or cool the building, thus reducing savings potential of equipment efficiency measures installed at the same time (such as an efficient heating system) as compared to if the equipment were installed in isolation with the higher baseline loads.

- ***Active Interactions:*** This occurs when the load shape of a dispatchable DER is purposefully changed based on the installation in combination with another DER. A common example of this is a battery installed with a DPV system. If the battery is installed by itself, then the customer may dispatch the battery in response to pricing signals such as a time-of-use tariff. However, if the battery is installed with a DPV system, then the customer may choose to use as much of the DPV energy on-site as possible and therefore alter the dispatch of the battery to charge during times of excess solar generation.

Active interactions between DERs result from a change in the use case of the DER aggregation, and this issue is further discussed in Section 13.8. This section focuses on passive interactions, which occur primarily between multiple EE measures, EE and DR resources, or EE and electrification-related DERs when combinations of these DERs are co-located.[59]

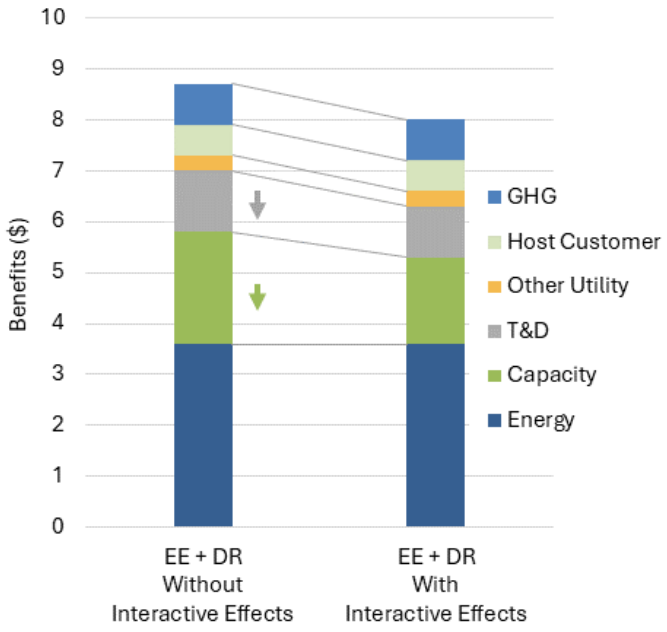
13.7.1. Multiple DERs On-Site

Interactive effects most commonly occur under the Multiple-DERs On-Site scenario when DERs impact the same end use, such as the above example of weatherization and efficient HVAC equipment both impacting the space-cooling and space-heating end uses.

Figure 13-6 presents an illustrative example of how passive interactive effects might influence the impacts of DERs. The bar on the left indicates the potential benefits of EE and DR when each is the only resource installed on a site. The bar on the right indicates the potential benefits of EE and DR when they are both installed on the same site. For simplicity, this example assumes that the costs of each DER type remain unchanged when they are installed together. In this example, the generation capacity and T&D benefits are lower in the case with EE and DR combined. This is because the EE resource in this example reduces the host customer demand during the generation and T&D peak periods, thereby reducing the potential for DR to lower customer demand and subsequent system benefits during those times.

[59] There are some edge cases of measures such as a high reflectivity roof that may lower roof temperatures and therefore increase rooftop PV system efficiency, but these are few and far between.

Figure 13-6. Example of Interactive Effects on EE and DR Resources



It is important for BCA tests to account for interactive effects on DER load shapes whenever such effects are likely to be material. Proper accounting for the interactions between DERs can necessitate advanced modeling such as building energy simulation to account for the heat transfer and load impacts between measures (ACEEE 2019, 2020a; SEE 2020b; RAP 2019a).

When modeling the impacts of passive interactions, such as between weatherization and HVAC system efficiency improvements, a key decision to be made is whether to distribute the interactive impacts across both measures, or to assume a hierarchy where one measure is not impacted. For instance, with a hierarchy approach prioritizing the weatherization measure, the savings for weatherization would remain the same as it was without the HVAC. The modeling would assume the weatherization measure would reduce the load for the HVAC system efficiency measure, resulting in lower measure savings for the HVAC efficiency improvement.

Proper accounting for the interactive impacts between DERs can necessitate advanced modeling techniques such as building energy simulation to account for the heat transfer and load impacts between measures.

On the other hand, if the modeling distributes the interactive impacts across both measures, then the measure level savings for both the weatherization and HVAC efficiency measures will be reduced. The choice of which type of accounting methodology to implement will depend on the policies and priorities of a utility. For instance, many utilities prioritize longer-life measures, which is a stance that would support a hierarchy approach favoring measures such as weatherization.

When addressing interactive impacts between measures, the implications of what method to utilize for distributing impacts becomes even more impactful in the context of analyzing building electrification measures. For example, if a hierarchy approach is utilized in which electrification

measures are prioritized, then weatherization measures will have no fuel savings, and will instead have electric savings since the electrification measure will claim 100% of fuel savings.

While the examples presented above are cases where two or more DERs are installed *at the same time* for a particular building or site, the guidance also applies to multiple DERs installed *at different times*. For instance, if in the example from Figure 13-6 the EE measure was to be installed first and the DR measure a year later, then for the time during which they are installed together there would be a reduction of benefits from the interactive impacts between the measures. This illustrates the need to accurately understand and define the baseline conditions when evaluating a DER, as DERs already installed at the site can potentially have significant impacts on the value that the incremental DER is able to provide.

There is a need to accurately understand and define the baseline conditions when evaluating a DER, as DERs already installed at the site can potentially have significant impacts on the value that the incremental DER is able to provide.

13.7.2. Non-Infrastructure DER Solutions

The consideration of passive interactive load impacts can be relevant to Non-Infrastructure DER Solutions in the case when an NWS/NPS or bridging solution leverages a utility initiative in which multiple DERs are installed on the same site. However, passive interactive load impacts are not inherently a relevant issue for this scenario.

13.7.3. Virtual Power Plants

Passive interactive load impacts are only relevant to the BCA of VPPs within the context of accounting for potential impacts that efficiency programs may have on reducing the potential controllable load of demand flexibility VPPs. For instance, if a utility initiative is simultaneously installing weatherization measures and smart thermostats that automatically enroll participants in a VPP, then the demand flexibility potential of the smart thermostats will need to reflect the reduced heating and cooling loads as a result of weatherization.

13.7.4. Microgrids

If improving customer building efficiency is part of the strategy for the creation of a microgrid, then the scenario of Multiple DERs On-Site can directly overlap and make passive interactive load impacts a relevant issue for microgrids. However, this consideration is not inherently relevant for microgrids.

13.8. Key Consideration: Use Case, Competing Priorities, and Active Interactions

For utility initiatives that contain dispatchable DER assets, the use cases for the initiative are foundationally important in determining the applicability and relative impacts of value streams to include in the BCA test. Within the context of this Manual, the use case means the purpose for which the DER, or aggregation of DERs, is deployed. This key consideration of use case is not relevant in the same way for non-dispatchable DER aggregations; since they cannot be dispatched, the way in which they impact load does not change in light of their intended purpose.

A DER aggregation can, and often does, have multiple use cases. Furthermore, the specific scenarios discussed in this chapter are themselves use cases, such as a VPP being employed as an NWS.

Because a goal is often to extract the maximum value out of a DER aggregation, one aggregation can have multiple use cases. For example, the primary use case of an aggregation of residential battery storage systems may be to function as an NWS to provide load relief on a substation during distribution peaks. However, during non-peak season times this aggregation could also be used for a secondary use case of energy arbitrage, storing energy during times when the price of wholesale electricity is low, and discharging during high price times.

Most often, these multiple use cases will result in competing priorities for the DER aggregation. For instance, if a smart-inverter-enabled DPV system is to be used for ancillary services support such as spinning reserves, then its ability to produce electricity will be reduced. This is because spinning reserves must be able to rapidly increase power output to react to grid needs, which would not be possible if it were producing maximum possible output during the time the spinning reserve was needed (which would be the case if it were solely focused on producing energy).

Note that the different specific scenarios discussed in this chapter are themselves use cases, as evidenced by the previous example where a battery storage aggregation could have the primary purpose of an NWS (Non-Infrastructure DER Solution) and secondary purpose of wholesale energy arbitrage (VPP). Furthermore, a specific scenario may entail multiple use cases, such as a VPP used for both generation capacity peak load relief and absorbing excess renewable energy generation to avoid curtailment.

When a utility aims to leverage a dispatchable DER aggregation for multiple use cases, BCA can inform the best way to operate the DER assets to provide the maximum value. Table 13-3 shows the 6-step process for determining the best DER aggregation operating profile from a BCA perspective. This process is applicable whether dealing with a DER aggregation that overlaps multiple specific scenarios or only encompasses a single one. Furthermore, this process is the same whether one or more use cases are considered. In practice, when there is only one use-case, the steps in this process are relatively straightforward and linear since there is no need to balance simultaneous competing priorities. However, the process becomes complex when balancing multiple use cases. In these situations, mathematical optimization is useful for maximizing total value and appropriately balancing the different objectives and constraints.

Table 13-3. Steps for Determining the Operating Profile of a Dispatchable DER Aggregation

Step	Process Step Description
1	Identify and prioritize the use cases for which the DER aggregation is designed
2	Identify the relevant value streams and their calculation methods
3	Enumerate the objectives and constraints of each use case
4	Enumerate the operations/technical limitations of the DER aggregation
5	Quantify the operating profile (and associated load impacts) based on dispatching the DER aggregation to accommodate the relevant objectives and constraints of the use cases and operational/technical limitations of the DER aggregation
6	Quantify each applicable value stream based on the load impacts

When a utility initiative includes multiple DERs, whether co-located or not, then the use case of the DER aggregation will determine what active interactions occur between the DERs. As defined in Section 13.7, active interactions occur when the load shape of a dispatchable DER is purposefully changed based on the installation in combination with another. For example, if a DPV and storage system is being used as an NWS that requires load relief after sundown, then the controller will customize dispatch of the battery to provide the required nighttime load relief.

It is also important to note that for BTM assets, the use case will not only include the ways in which the utility plans to dispatch a DER, but also the use cases of the host customer. For instance, if a host customer wants to use their battery storage system to provide backup power during a wider grid outage, this would introduce an operational constraint on the utility's dispatch of the resource (such as retaining a 40 percent state of charge on the battery system at all times). Constraints such this can substantially impact the ability of the resource to provide value to the wider utility grid.

Finally, the regulatory environment in which a DER operates will also influence which use cases can be simultaneously applied to an asset and therefore which value streams can be provided. For example, an ISO/RTO may prohibit a DER asset from participating in both the ancillary services market and the energy market, due to fear of overcompensation and/or insufficient availability for market participation.

The key consideration of use case and implications on competing priorities and active interactions is best discussed simultaneously considering all specific scenarios, since scenarios themselves can be use cases (for example, Non-Infrastructure DER Solutions). Therefore, this chapter includes no additional discussion of each specific scenario in isolation.

13.9. Key Consideration: Unlocking Value Streams, Threshold-Dependent Valuation

Due to their novel attributes, Non-Infrastructure DER Solutions, VPPs, and microgrids have the capability to unlock unique value streams that DERs outside of these specific scenarios might not be able to provide. For instance, a microgrid is the only scenario in which a BCA test would include host customer and societal benefits in terms of reducing time without power during outages.[60]

[60] As discussed in the microgrid introduction section, a single customer with a backup generator and islanding capability is a microgrid of 1, even though microgrids are commonly conceptualized as including multiple customers.

Table 13-4 shows the unique value streams unlocked by each of the four specific scenarios covered in this chapter, whereby the 'unique' value streams that can be provided are not always exclusive to the specific scenarios. Rather, the way in which they can be valued is unique to the specific scenario. For example, EE resources can claim ancillary services benefits in a BCA test. This is due to a benefit attributed for load reductions translating into a lower overall need for ancillary services on the system. However, EE resources cannot directly provide ancillary services to the grid and claim that value as a dispatchable resource (a condition for a VPP).

Table 13-4. Unique Value Streams Unlocked by Each Specific Scenario

Specific Scenario	Unique Value Stream(s) Unlocked
Multiple DERs On-Site	No inherently unique value streams
Non-Infrastructure DER Solutions	Deferral/Avoidance of specific, planned distribution infrastructure investments (depending on the project can show up as avoided distribution capacity, distribution O&M, etc.)
Virtual Power Plants	Ancillary services
Microgrids	Host customer resilience Depending on project, can be distribution capacity, distribution O&M (in case of unique NWS opportunities) Novel societal environmental opportunities

While each specific scenario can unlock different value streams, a common thread is that often particular performance thresholds must be met to access these value streams. For instance, in the case of an NWS, if a DER aggregation cannot provide the required amount of load relief on a constrained distribution asset, then the BCA test would not include any NWS benefit since the upgrade of the traditional asset cannot be deferred. These performance thresholds are often closely tied to program scale. However, there are also performance thresholds that are not tied to scale but are similarly important for enabling a DER aggregation to claim value for a particular type of impact. An example would be the response time of a DER aggregation for ancillary services support. Because of this close link between unique value streams and performance thresholds, this section covers them together as one key consideration rather than as separate factors.

13.9.1. Multiple DERs On-Site

The key consideration of unique value streams and threshold-dependent value quantification is not inherently applicable to Multiple DERs On-Site but can be relevant when this scenario overlaps with one of the other specific DER scenarios. For instance, if a utility proposes a GEB program in which associated GEB generation, storage, and/or demand flexibility will be enrolled as part of a VPP, then the considerations relevant to VPPs are potentially applicable and warrant review.

13.9.2. Non-Infrastructure DER Solutions

Non-wires and non-pipes solutions have the unique ability to defer tangible, specific T&D investments[61]. This may not be considered a novel value stream, as in practice many DERs which are not part of NWSs/NPSs are often credited with avoided T&D capacity benefits based on average

[61] Similarly, bridging solutions avoid specific utility spending on temporary solutions to maintain grid reliability prior to the traditional solution coming online.

avoided $/kW prices. However, those avoided T&D capacity benefits are markedly different from the value from deferring and/or avoiding a tangible project. Those benefit calculations typically use system averages to assign value to a DER for deferring capacity investment, with a result that is more a theoretical potential than a specific identified value.

For load reductions to translate into reduced spending for T&D systems, thresholds must be met to reliably eliminate the need for the traditional infrastructure. For example, if 640 kW of load relief is required to defer the need for replacing a transformer that will cost $700,000, then achieving 320 kW of load relief would not provide half of the deferral benefits. Instead, if the threshold 640 kW is not met, then the Non-Infrastructure DER solution is not able to defer the need to replace the transformer, and therefore it does not provide any avoided distribution costs.

The total locational avoided cost value that an NWS or NPS can provide depends on the specific traditional infrastructure project intended to be deferred or avoided. In most cases, the cost of the traditional solution is determined based on an established utility planning process and has been evaluated as the least-cost, best-fit solution from a grid infrastructure perspective. The benefit (or avoided cost) that the NWS can provide is either deferral of the installation of the traditional investment to a later date (assuming that construction costs are not escalating more aggressively than the time value of money i.e., discount rate utilized for the analysis) or avoid the traditional solution completely. The traditional infrastructure cost, together with the size of the constraint are the key factors that drive the formulation of the NWS/NPS-specific avoided costs for the BCA test:

- *Locational T&D infrastructure Cost:* An NWS/NPS can be targeted to any element of the T&D system, such as on the electric side a substation or a high-voltage transmission line, or on the gas side a compressor station upgrade or a distribution pipe with larger throughput capacity. The specific constraint will impact cost-effectiveness: all else equal (including the cost of the NWS/NPS), the more expensive the traditional solution, the greater the benefit of the NWS/NPS deferral/avoidance.
- *Constraint size:* NWS/NPS cost-effectiveness will also depend on the size of the specific constraint. For instance, an NWS could seek to address a circuit-specific summer peak capacity constraint or a broader substation-level constraint.

For an NWS, the constraint size is defined as the load reduction required. However, the goal of the load reduction is not to avoid supplying electricity to a customer or group of customers in general; it is to reduce the demand for the infrastructure. In contrast to an NWS, the primary goal of an NPS could be to fully electrify a particular set of customers and therefore eliminate the need for gas service. This type of full electrification NPS is difficult to achieve though, given that gas companies, as with all utilities, have an obligation to serve. Therefore, if even one customer in a group wants to have gas service, the opportunity to avoid the construction of new gas infrastructure (or retirement of aging infrastructure) is not possible.

Finally, while the analogous situation of avoiding providing electricity to a specific customer base does not exist as an NWS scenario, there is the potential for an NWS to completely avoid the need to construct or maintain a distribution line when a microgrid is considered as the NWS (see Section 13.9.4 for further discussion).

13.9.3. Virtual Power Plants

A key value stream unlocked by VPP is the ability to directly provide ancillary services to the grid.

A key value stream unlocked by VPP is the ability to directly provide ancillary services to the grid. The type of ancillary services that a VPP can unlock, and therefore the potential benefits that can be claimed in a BCA, are dependent on two key characteristics of the VPP: the DER composition, and dispatch control strategy.

- **DER Composition:** The composition of DERs that make up the VPP is the first foundational characteristic in determining which ancillary services a VPP can provide, since not all DER types are able to meet performance thresholds such as response time for different ancillary services. For instance, an aggregation of batteries could directly provide ancillary services such as spinning reserves due to the ability of the batteries to respond to dispatch signals on the order of seconds. In contrast, a VPP comprised only of smart thermostats would not be able to directly provide spinning reserves due to the inability of HVAC systems to be cycled on and off on such a granular time interval.
- **Dispatch Control:** The second layer requiring consideration is the dispatch control strategy leveraged, which can be either direct control or customer control. Manual control of DERs by customers is not conducive to unlocking most ancillary services value streams, since the grid operator does not have a direct line of control to dispatching the resource when needed. Automated customer control allows for real-time response of the VPP since direct customer participation is not required for each event. However, since the customer is still in control of determining the automated response, there is still a layer between the grid operator/utility and the DER. For VPPs providing ancillary services, direct control by the grid operator is the ideal control type and can even be required for some ancillary services such as operating reserves.

When a utility has a VPP comprised of multiple resource types, it may be the case that only a portion of the VPP is able to provide ancillary service support due to the technology or dispatch strategy constraints. Furthermore, as noted in Section 13.8, the designation of a VPP's capacity for ancillary services support often involves tradeoffs with other value streams, such as energy generation. Therefore, the economic merits of providing ancillary services support need evaluation that accounts for the full range of benefits that a VPP can produce from other potential impact streams.

13.9.4. Microgrids

The ability of a microgrid to disconnect a customer (or a group of customers) from the broader grid and maintain power when the rest of the grid is down unlocks unique value streams that are impossible with any other individual DER types or combinations. The list of these unique value streams is shown in Table 13-5.

Table 13-5. Key Value Streams Unlocked by Microgrids

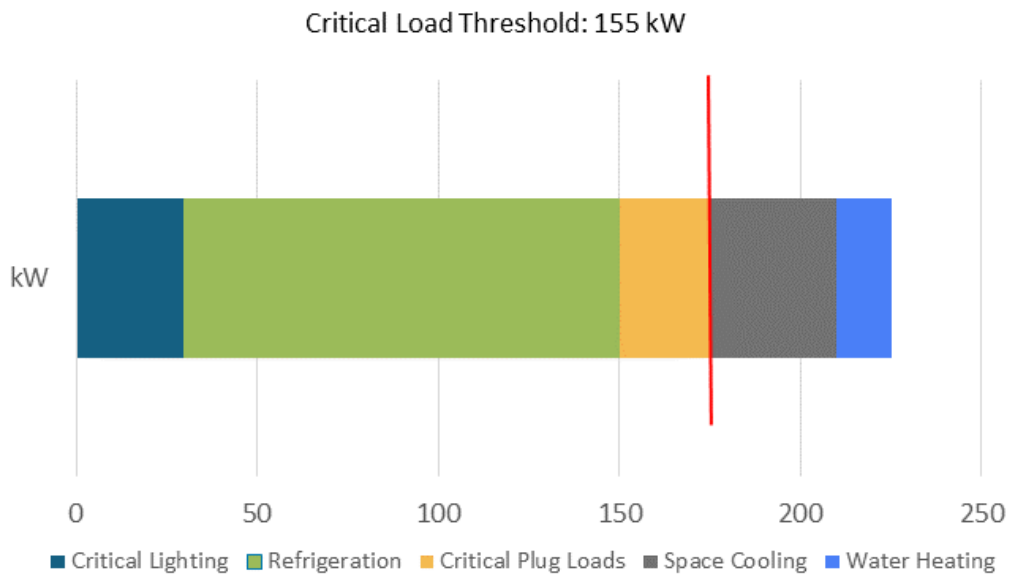
Category	Value Stream
Utility System	Distribution capacity, or Distribution O&M, etc. (in the case of unique NWS opportunities)
Host Customer	Resilience
Societal	Resilience, Other Environmental

The first two key value streams unlocked through microgrids are the host customer and societal resilience benefits, due to the ability to supply power during short- and/or long-term outages. As previously noted, a microgrid can be composed of a single DER, such as a generator or battery energy storage system, as long as the DER is paired with the capability of the customer to island during a grid outage and therefore provide backup power.

To provide tangible host customer resilience benefits, microgrids must meet performance thresholds which ensure they provide value to the host customer. This can entail metrics such as the critical power load in kW that the microgrid needs to be able to sustain while the grid is down. For instance, as shown in

Figure 13-7 a backup system for a grocery store would need to be able to power essential functions such as refrigeration and essential lighting. Performance thresholds must also include longevity metrics such as hours or number of days islanded that the microgrid can support critical loads. For instance, some critical infrastructure requires a 30-day supply of fuel on-site for resilience considerations.

Figure 13-7. Example Backup Power Requirements for a Grocery Store



While host customer and societal resilience are the most prominent benefits unique to microgrids, they can also serve as NWSs to avoid high-cost infrastructure investments—particularly in

situations where a NWS would be impossible with any other type of DER combination. For example, a utility could use a microgrid to avoid the costs of upgrading an isolated feeder for a small town that is susceptible to storm damage. This microgrid could avoid costly investment such as underground power lines, since the microgrid can keep delivering power to customers while crews repair damage to the feeder caused by a storm. Fully islanded microgrids for new developments take this concept of avoiding distribution investment even further; they can circumvent the need for connecting a new development to the grid and installing wires in the first place.

Finally, there is a unique societal environmental benefit of microgrids to be able to turn off selected power lines for safety purposes. This is particularly pertinent in states using microgrids to reduce wildfire risks: during high fire risk weather conditions, there is risk that damaged grid infrastructure can spark a fire and contribute to significant environmental and societal damage. In this instance, a microgrid powered by a combination of DPV, storage, and backup generators could enable a rural mountain community to maintain power for days even when wildfire risk requires power lines feeding the community to be shut off.

While these two additional value streams are not focused directly on the host customer, similar performance threshold metrics of critical load power requirements and duration time of islanding are relevant. This is because these secondary value streams depend on the microgrid fulfilling the power and energy needs of its host customers to be able to island.

13.10. Key Consideration: Accounting for Uncertainty When Avoiding Grid Investments

A DER aggregation's role in impacting the utility system will determine a BCA test's tolerance for uncertainty. Often, BCA tests entail monetizing the impacts of DERs using forecasted load shapes that represent 'on average' how the DER will perform. This type of average estimation is sufficient for valuing many utility system value streams, such as avoided energy. Because the implications of the analysis are financial, there is no significant reliability threat to the grid if the "average" impacts over- or under-project the actual impacts that occur. However, evaluation of DERs aimed at replacing or offsetting traditional infrastructure involves considerably higher stakes. The DER aggregation needs to be reliable not only under 'average' conditions, but also under worst-case conditions. In addition, when DERs serve as a grid asset, such as a VPP providing ancillary services into a wholesale market, the situation requires the same ability to perform under worst-case conditions due to the market's reliance on the resource. Both situations illustrate cases in which uncertain factors must be accounted for to properly value the contribution from the DER aggregation.

13.10.1. Multiple DERs On-Site

While the consideration of accounting for uncertainty when DERs are avoiding tangible grid investments and/or performing as grid assets can be relevant to Multiple DERs On-Site, it is not inherently a relevant issue for this scenario. The consideration is only relevant when this scenario overlaps with one of the other specific DER scenarios. For instance, if an NWS uses the demand flexibility and efficiency of a GEB, then this consideration would be directly applicable to a situation in which multiple DERs are installed at the same site.

13.10.2. Non-Infrastructure DER Solutions

Utility infrastructure planning teams (e.g., transmission planning, distribution planning, and gas system planning) need confidence that an NWS/NPS can perform as well as a traditional solution. As such they will plan for a variety of conditions and future scenarios under which the DER solution will be expected to perform. The DER BCA test used to evaluate the NWS/NPS will also need to account for those future scenarios. This requires a proper accounting of risk and uncertainty. While these topics are discussed in Appendix L. *Uncertainty and Risk*, there are particular considerations relevant to an NWS/NPS that warrant attention in this section. Specifically, there are three key types of uncertain future scenarios that can impact the value quantification for an NWS/NPS:

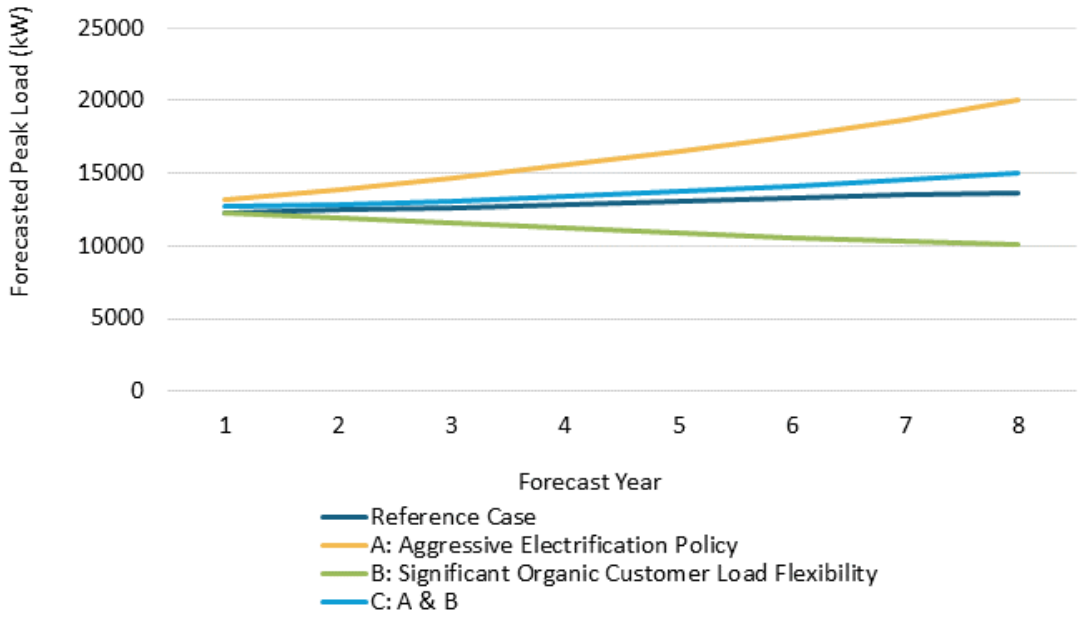
1) ***Different grid operating scenarios***

   Since grid configurations can vary over time (e.g. due to planned or unplanned maintenance, switching, and reconfiguration), the determination of the load relief required for an NWS/NPS may be needed for multiple grid configurations. For instance, under regular operating conditions (N-0 conditions), an NWS may need the ability to provide load relief of 5 MW for 4 hours. However, during an equipment outage (N-1 conditions), the NWS might have to provide a load relief of 7 MW for 4 hours. This difference in load relief required during different scenarios is mirrored by a difference in mapping of targeted or involved customers during different grid conditions. This can impact which BTM DERs (and FTM DERs, depending on placement) are able to provide load relief during each scenario. For example, load relief under N-0 conditions might involve 50 of the 150 DER resources installed on a feeder; but under N-1 conditions, it may involve 120 of the 150 DER resources.

2) ***Different load forecast scenarios***

   Another scenario assumption that heavily influences the analysis is projection of future load growth on the relevant portion of the system, as illustrated in Figure 13-8. The amount of load growth a utility projects for a particular portion of the system directly impacts the amount of load relief that an NWS/NPS would need to provide. The forecasting of long-term future loads is challenging due to uncertain factors such as government policies, the rate at which customers will adopt transformational technologies (e.g., EVs), and the future flexibility of customer load consumption patterns. All this uncertainty makes it difficult to place a high degree of confidence in a single number for estimating the load growth on a particular portion of a utility's T&D system. Thus, it is hard to confidently conclude if a traditional solution can be deferred for 5 years, 10 years, or be completely avoided.

Figure 13-8. Example Load Forecast Scenarios



3) Different DER performance (load shape) scenarios

Finally, there is inherent uncertainty in the performance of the DER itself. In the context of quantifying a system-wide value, there is less of a concern that the 'average' savings load shape of a single measure be accurate for valuation; many deviations across large numbers of DER measures typically cancel each other out. However, within the context of infrastructure deferral or avoidance, the DER assets must produce the required load relief at a specific time and location. As a result, calculations of a distribution or transmission deferral value stream should capture the minimum value that a DER controller can guarantee to provide even under worst-case conditions, not the average value that can be expected from the project.

The importance of this issue varies by DER type. For DERs such as lighting DR with a commercial customer that has the same schedule 365 days a year, there may be very low uncertainty in the performance of DER even at the individual building level. On the other hand, for a program such as a smart thermostat HVAC program, there is wide variation on a building-by-building basis in customer set points, cooling loads, and overrides. But as participant population size increases, the uncertainty on an individual building level matters less and less, and the gap between worst case and average performance closes. Therefore, it is important for a BCA test to account for uncertainty in DER performance, as well as participant population size, to accurately quantify the load impacts that a DER can be relied upon to produce.

Due to the multiple degrees of uncertainty, the level of complexity in thoroughly analyzing these scenarios could quickly become a large investment in both time and money. It is important in practice for BCAs to balance accuracy and practicality in the way it addresses uncertainty. Even more importantly, the analysis must align with distribution or transmission planning teams' need to ensure the DER solution is indeed able to replace the traditional solution. As noted in Appendix L.

Uncertainty and Risk, the techniques used to address uncertainty can range from the simple, such as conducting scenario analysis, to the highly sophisticated, such as conducting a probabilistic-based uncertainty analysis (for instance, a Monte Carlo simulation).

13.10.3. Virtual Power Plants

This key consideration is relevant to VPPs whenever they are functioning as critical grid assets. In many cases, this function results from a VPP serving as an NWS. In addition to the opportunity for VPPs to provide alternatives to wires-based solutions, VPPs also can defer or avoid a planned generation infrastructure investment. However, this is not a unique value stream for VPPs since resources such as EE can also help defer specific, planned plants. Whether a VPP is avoiding a substation upgrade or a gas peaker plant, it is important for the BCA test to account for the same foundational principles regarding uncertainty in the external conditions (such as the projected load forecast) as well as in the performance of the DER aggregation itself.

> VPPs can defer or avoid specific, planned generation infrastructure projects. However, this is not a unique opportunity for VPPs as non-dispatchable resources which reduce peak load could also be aggregated for this purpose.

The key consideration of accounting for uncertainty when performing as a grid asset is also relevant to VPPs when providing critical grid functions such as ancillary services. Since the VPP is being relied upon to serve as a grid asset, there is the same need to account for uncertain conditions rather than just relying on average potential impacts.

13.10.4. Microgrids

Similar to VPPs, when a utility or other entity leverages a microgrid as an NWS, this key consideration applies. However, when a microgrid is not being leveraged to defer or avoid a planned infrastructure investment, this consideration is not relevant. This does not mean that in general, uncertainty should not be considered in the context of BCA for a microgrid. In fact, the opposite is true. However, uncertainty within the context of avoiding tangible grid investments is, by definition, irrelevant if there are no tangible grid investments involved.

13.11. Evaluating the Value of Future Flexibility

As discussed in Section 13.10, even though the future of the grid contains many uncertainties, such as the amount of load growth in the next decade, utility BCA tests commonly evaluate DER resources using a single ‘certain’ future. While the previous key consideration focused on uncertainty in both external analysis assumptions (such as load growth) and DER performance, this section focuses on the potential value of using flexible DER resources to meet the demands of an uncertain future. As discussed in Section 7.5, demand flexibility is the ability of dispatchable resources to increase and/or decrease load in response to external conditions. Dispatchable resources’ flexibility allows them to adapt and respond to changing needs over time, thereby providing an incremental value to the system that non-dispatchable resources cannot provide in the context of long-term utility planning. The incremental value that arises from dispatchability has often been referred to within this context as option value or insurance value.

13.11.1. Multiple DERs On-Site

The consideration of valuing flexibility can be relevant to Multiple DERs On-Site when this scenario overlaps with VPPs but is not inherently a relevant issue for this scenario. For instance, if a VPP uses the on-site generation and demand flexibility of a GEB, this consideration would be directly applicable to a situation in which multiple DERs are installed at the same site.

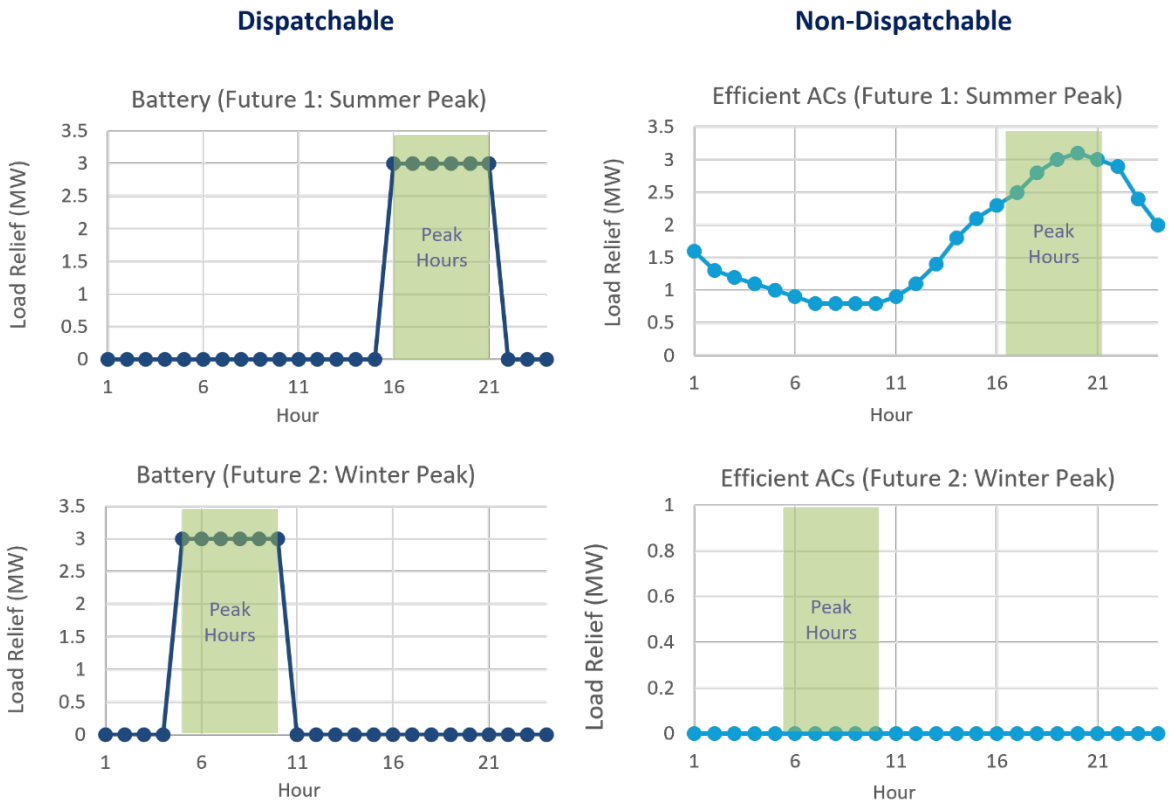
13.11.2. Non-Infrastructure DER Solutions

The consideration of valuing flexibility can be relevant to Non-Infrastructure DER Solutions when a VPP serves as a Non-Infrastructure DER Solution but is not inherently a relevant issue for this scenario.

13.11.3. Virtual Power Plants

Since VPPs contain only dispatchable resources, flexibility is a key characteristic of this specific DER scenario. Proper quantification of the value of flexibility from VPPs requires examining multiple scenarios for the future environment in which the VPP may operate, as well as accounting for the ability of the VPP to adapt to that environment. For most value streams, in practice this will mean creating a unique load shape for the VPP for each future as shown in Figure 13-9, which maximizes the benefits the VPP can provide by tailoring dispatch to each set of conditions.

Figure 13-9. Example Load Shapes Under Two Different Future Scenarios



Consider the evaluation of the two different types of DERs shown in Figure 13-9, the first being a VPP based on DS and the second a utility program that incentivizes efficient air-conditioning

systems. If analysis of one future scenario assumes the utility will be summer-peaking for the entire analysis period, then both DER programs could provide significant generation capacity benefits. However, if there is a chance that the peak would shift to winter within the next 5 years, then this analysis would overlook the ability of the VPP to continue to provide capacity benefits[62] in this alternative scenario. This case warrants the evaluation of two scenarios: one with a continuing summer peak and one with a transition to winter peak. Then the battery storage load shape can be modified for each scenario to maximize benefits, while the efficient air-conditioner load shape would remain the same since it is a non-dispatchable resource.

While the general consideration of the value of flexibility applies to any dispatchable single DER, this section highlights it because of the unique nature of VPPs (which allows utilities to use this flexibility for the benefit of the system). See Chapter 7 for additional discussion on flexibility in general.

13.11.4. Microgrids

The consideration of valuing flexibility can be relevant to microgrids when a grid-connected microgrid serves as a VPP but is not inherently a relevant issue for this scenario.

13.12. Time-Dependent Value Quantification

With many DERs, examination of load impacts at a finer time resolution improves the accuracy value estimates. For example, quantifying avoided energy on an hourly basis for a lighting control measure that decreases lighting loads during peak times will result in more accurate benefit quantification, assuming the utility has a higher marginal avoided energy cost during peak times. This general issue of the increased accuracy from more granular analysis is not unique to the specific DER scenarios in this chapter (see Section 7.3 for an overview on this issue).

This section discusses unique scenarios for which more granular time resolution is essential for accurately assessing the value that DERs can provide. Most notably, for Non-Infrastructure DER Solutions such as NWSs, the specific time window when load relief is required necessitates examining cost-effectiveness for T&D benefits on an hourly (or potentially even more granular) basis. Stated more broadly, the specific use case of a DER (such as serving as an NWS) determines which value streams are applicable and in turn what temporal granularity is necessary to accurately quantify the benefits and costs.

13.12.1. Multiple DERs On-Site

The consideration of time-dependent value quantification can be relevant to Multiple DERs On-Site when this scenario overlaps with a relevant use case such as DERs acting as an NWS. However, it is not an inherently relevant issue for this scenario.

13.12.2. Non-Infrastructure DER Solutions

The time that peak loading conditions occur for any particular part of the transmission or distribution system will be unique based on the specific mix of customers served by that

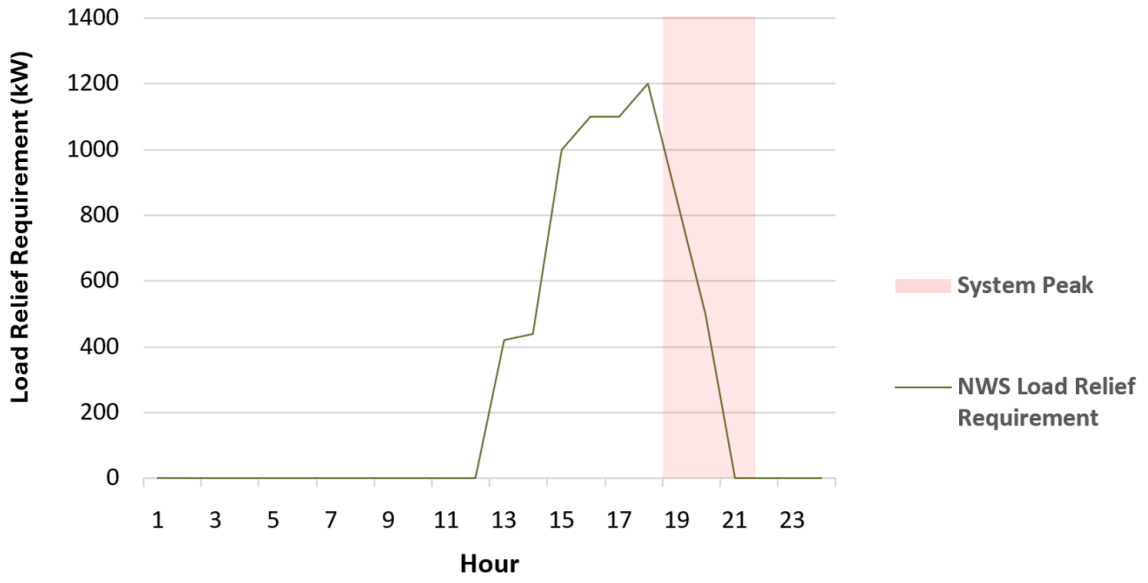
[62] The BCA would likely assume that capacity is the most lucrative value stream and therefore the VPP would want to change its dispatch pattern to continue to claim this value stream, rather than pivoting to another usage such as ancillary services support.

infrastructure. For instance, consider a feeder in a hot climate that serves primarily single-family homes. This feeder may have a late summer evening peak as people turn up their air conditioners when they get home. Because of the unique loading on any given portion of infrastructure, a critical part of quantifying the load relief required for the NWS/NPS or bridging solution is the specific timing, magnitude, and duration when the system is anticipated to experience peak loading.

Electric utility cost-effectiveness analysis: Practitioners often use a single number to quantify peak load impacts. For example, they may use a deemed savings single peak kW value on the electric side for the system peak day. But this is inadequate for an NWS as it does not identify the timing or duration of the load relief required, and it may or may not line up with the constraint for the specific portion of the distribution or transmission system in question.

Figure 13-10 shows a hypothetical load relief requirement for an NWS as compared to the broader system peak hours. In this example, there is modest overlap between the distribution system load relief requirement and the bulk system peak, as the load relief that the NWS needs to provide is earlier in the day. This could result from differences such as a larger concentration of commercial customers (which tend to peak earlier) in the specific region under consideration for the NWS.

Figure 13-10. Example of Load Relief Requirement Versus System Peak Window



The figure also shows how the amount of load relief required is not constant throughout the window, but rather is a curve centered around the time of the historical highest loading. In practice, how historical loading patterns translate into a defined load relief curve is informed by the risk preference of a utility. Adjustments to the key parameters of the curve timing, shape, and duration to add a factor of safety can give the utility confidence in the performance of the NWS as compared to the traditional solution. It is good practice for a BCA test to determine the load relief curve in parallel with how to consider different future scenarios, discussed in Section 13.10, since both are focused on addressing uncertainty.

As highlighted in this example, the timing of the distribution and system peaks may align to a greater or lesser degree. When the timing of the peaks does align, this offers a greater potential for

claiming benefits from both distribution avoided capacity and system generation avoided capacity. The reason for this is the use case of providing distribution system load relief is not competing against the use case of providing system generation capacity load relief. For further discussion on use cases and competing priorities, see Section 13.8.

Gas utility cost-effectiveness analysis: On the gas system side, the requirement for time granularity is more nuanced. Unlike the electric system which requires supply and demand to be continuously closely matched, the need to match supply and demand on a particular portion of the gas system contains a greater degree of flexibility. In general, the bigger the pipe, the more flexibility there is due to the ability to pack the line.[63] Therefore, gas supply planning at the transportation level (equivalent to transmission level on the electric side) generally happens on a daily basis. As a result, most large-scale non-pipe solutions targeted at upstream capacity could be evaluated on a peak day basis, without concern for hourly variation. However, on the distribution side of the citygate[64] pipeline capacity is reduced and as a result the modeling for an NPS may need to be done on a four-hour, one-hour, or even sub-hourly basis.

Bridging solutions: It is important to note that the same concept of the critical importance of temporal granularity that applies to NWS/NPS also applies to bridging solutions, since just like NWSs/NPSs these solutions are being deployed on a portion of the system to help mitigate a specific issue for a specific amount of time.

A note on data granularity: The requirement for a more granular time resolution only applies to the avoided transmission and/or distribution benefit value stream. Due to the modular nature of BCA, it is possible to conduct a BCA where only this value stream gets this granular. However, if load shapes are created for the purpose of quantifying this value stream, then it is easier to increase the precision of other value stream calculations as well (assuming the avoided cost data is available). Evaluating more value streams at a higher granularity can have the added benefit of ensuring that shifting load, such as for an NWS, does not result in unintended consequences. For instance, if carbon emissions are valued hourly then BCA can help ensure that load is not shifted to times when the marginal emissions rate of the grid is higher (which would result in unwanted environmental damage).

13.12.3. Virtual Power Plants

The consideration of time-dependent value quantification can be relevant to VPPs depending on the VPP use case. For instance, when a VPP serves as an NWS, then the requirement for quantifying the impact on an hourly basis during the distribution system load relief period is applicable.

Due to VPPs' unique ability to directly provide ancillary services as discussed in Section 13.9, they can also be relevant to the consideration of time-dependent value quantification in a novel way unrelated to load shape granularity: the value of ancillary service support comes from a VPP's ability to respond to the required sub-hourly grid needs at any particular point in time. Therefore, a static load shape is not appropriate for quantifying this value stream since a static load shape cannot quantify dispatchability. Instead, evaluating the benefit requires a separate calculation that

[63] By injecting more gas into the pipeline system and raising pressure, operators can store gas within the pipeline itself. This inherent storage capability allows the system to smooth out intraday swings in customer demand.

[64] The citygate is boundary between transportation and distribution gas pipelines.

accounts for the VPP's ability to modulate load at intervals such as seconds and minutes (whatever is required by the ancillary service the VPP is to provide).

13.12.4. Microgrids

For microgrids, the consideration of time-dependent value quantification is relevant when use cases, such as using a microgrid for an NWS, require examination on a more granular time interval. Furthermore, as with VPPs, the novel value streams that microgrids enable (including host customer and societal resilience) have unique time-dependent considerations that necessitate modeling of granular time impacts.

For both VPPs and microgrids, the novel value streams that these scenarios can enable (e.g. host customer and societal resilience) necessitate modeling of granular time impacts.

This modeling requirement is due to the applicable resiliency metrics (such as the number of hours that a microgrid can support critical loads in islanded mode, which an hourly 8760 analysis of system load impacts cannot quantify). However, as noted in the previous section, while static DER load shapes are not helpful for quantifying this value stream, the impacts of using the DERs to provide this value will likely have a meaningful impact on their load shape. For example, if the batteries in a microgrid are always kept 50 percent full so that it is ready for islanding during a grid outage at any time, then their ability to provide avoided energy value from energy arbitrage will be significantly reduced.

13.13. Location-Dependent Value Quantification

The specific location of a DER on the electric or natural gas system can influence the value it can bring to the utility system. This general concept is covered in Section 7.4 with the relevant example of an electric grid which covers multiple ISO/RTO zones. If energy prices for the market are settled on a zonal basis, then the use zone-specific prices (rather than system average impacts) can improve the level of precision for quantifying energy generation impacts.

As in Section 13.12 on time-dependent value quantification, the focus of this key consideration goes beyond the general principle that increased locational specificity in a BCA test can more accurately quantify the value a DER brings to the utility system. Rather, the focus of this section is that locational specificity with regard to the utility system is integral to quantifying DER value for several of the specific scenarios. The most evident example of this is with an NWS/NPS, in which the value that DERs can bring is dependent on the specific costs of the infrastructure being deferred or avoided.

13.13.1. Multiple DERs On-Site

This consideration can be relevant to Multiple DERs On-Site when this scenario overlaps with another such as NWS; however, it is not an inherently relevant issue for this scenario.

13.13.2. Non-Infrastructure DER Solutions

For NWSs and NPSs, the key value stream of avoided or deferred distribution/transmission infrastructure must be locationally specific.[65] The use of a system average price for distribution or transmission impacts (whichever is relevant for the specific project) would effectively negate the purpose of a BCA test for an NWS/NPS. As discussed in Section 13.9, the key factors in determining the location-specific avoided costs are the cost of the traditional infrastructure solution, the constraint size, and the amount of time for which the solution can be deferred (which in the case of complete avoidance is indefinitely).

It is crucial that the DERs deployed are located on the portion of the grid that will have an impact on the identified constraint. However, the use of BTM solutions in this use case complicates BCA calculations, especially when existing programs are part of the infrastructure solution. These complications are due to issues such as a difference in the geographic boundary of program marketing for the existing program, as compared to the geographic boundary of the customers on the particular part of the grid that will impact the constraint. In cases such as this, the BCA test will need to account for the marketing 'spillover' customers, which will participate in the program but will not contribute towards the load relief required to meet the constraint.

13.13.3. Virtual Power Plants

For a VPP, this consideration can apply if the purpose of the VPP is wholesale market participation. This is because market participation rules govern whether aggregations of DERS are allowed across multiple zones/nodes. These regulations on multi-node market participation, in combination with the regulations on minimum aggregation size for market participation, may mean that a VPP is able to generate value from participation in a wholesale market only if it can aggregate enough resources located within the same pricing zone.

In addition, when VPPs serve as part of an NWS and the operators want to participate in a wholesale market as well, location-dependent value quantification becomes a key consideration.

13.13.4. Microgrids

The specific location of a microgrid on the broader utility system is foundational in determining the performance threshold requirements and the resulting quantifiable value, as discussed in Section 13.9. For example, if a particular feeder commonly experiences outages of two hours in duration, then a microgrid that can only island for one hour would provide significantly less reliability benefit than a system that can island for over two hours.

In addition, when a microgrid is part of a VPP participating in a wholesale market or an NWS, then the key specific considerations for those scenarios are also applicable.

13.14. Key Consideration: Supporting System Costs

For many applications of the specific DER scenarios discussed in this chapter, the utility often incurs additional infrastructure costs beyond solely the cost of the DERs involved in the specific scenario. Consider the case of a VPP, for which a utility may invest in a DER management system

[65] The same is true for the case of a bridging solution in which the value that can be obtained by avoiding or reducing utility spending on temporary solutions prior to the traditional infrastructure upgrade is inherently locationally specific.

so it can manage and orchestrate the dispatch of DERs within the VPP. It is important to thoughtfully consider and determine how the BCA test will address these infrastructure costs so that benefits and costs receive symmetrical treatment (see Principle 4 in Chapter 3). This is particularly relevant for ensuring the BCA test does not neglect the long-term benefits enabled by short-term supporting system costs.

13.14.1. Multiple On-Site DERs

In the context of Multiple DERs On-Site, this issue is not widely relevant. However, it is applicable to nuanced situations such as a homeowner purchasing rooftop PV and pairing it with an inverter that can support both solar and storage, without purchasing the storage. This type of situation leads to an 'enabling effect' of the inverter, in that it reduces the potential costs for the homeowner to install storage down the line. If there is data to support a high probability that the homeowner will install storage (such as data showing 50 percent of all homeowners that install storage-enabled DPV in isolation follow up with a battery within three years), then including the full cost of the inverter without the potential additional benefits and costs of installing storage results in not fully accounting for all relevant impacts. Possible methods for determining the potential benefits and costs include weighting them with the expected probabilities and appropriately discounting them based on timeline expectations.

13.14.2. Non-Infrastructure DER Solutions

This consideration can apply to Non-Infrastructure DER Solutions when they overlap with one of the other specific scenarios, but it is not an inherently relevant issue for this scenario.

13.14.3. Virtual Power Plants

As utilities look to leverage VPPs comprised of multiple types of DERs, there is often the need to aggregate these resources under central control systems that allow for coordinated control of multiple DER types—often referred to as DERMS. It is important for a VPP BCA test to also include the costs of such supporting infrastructure whenever it includes the benefits specific to the VPP.

Depending on whether a utility builds or buys a DERMS, these systems can entail upfront costs that initially keep the VPP from appearing cost-effective. However, as additional DER resources are added into the VPP, it is often the case that minimal incremental supporting system costs are incurred for each additional participant. Therefore, for the purposes of a VPP BCA test, it is important to consider any plans to scale the VPP over time beyond just the immediate program cycle/pilot. This assessment will provide a more symmetrical examination of benefits and costs that accounts for the non-linear way in which a VPP might scale and incur costs.

13.14.4. Microgrids

Even to a greater degree than VPPs, microgrids inherently require supporting infrastructure costs beyond the costs of the DERs that supply, reduce, and otherwise modify energy consumption for participating customers. To provide stable microgrid operation, a central microgrid controller to monitor loads/dispatch resources and hardware capable of disconnecting the microgrid during times of islanding are required. These supporting costs

Incremental microgrid supporting system costs, such as a microgrid controller, should be included in a BCA whenever the analysis is claiming the incremental benefits provided by the microgrid such as host customer and societal resilience.

are essential to providing the unique functional ability of the microgrid, and so a BCA test should always include them whenever the analysis includes the incremental benefits provided specifically by the microgrid (such as host customer and societal resilience benefits for avoiding outages). This will ensure symmetrical treatment of benefits and costs.

13.15. Key Consideration: Existing DER Impacts

One of the principles of sound BCA is to accurately quantify the incremental impact of the measure, program, or portfolio under evaluation (see *Principle 5: Conduct Forward-Looking, Long-Term, Incremental Analyses*). A key consideration when implementing this is to avoid including the impacts of existing DERs as benefits or costs in the BCA test. Separating out these pre-existing impacts can be complex because a utility initiative may leverage an existing asset but change its use case, as previously discussed in Section 13.8. When this occurs, the BCA test should only include the new value streams induced by the utility initiative, and the remainder of the benefits and costs of the existing asset are irrelevant.

13.15.1. Multiple On-Site DERs

While the consideration of properly accounting for existing DER impacts is relevant to the scenario of Multiple DERs On-Site, the application of this issue is the same as for a single DER analysis. Consider the example of a customer enrolling their smart thermostat in a utility BYOD DR program and getting a rebate for a heat pump water heater (HPWH) through the utility appliance EE program. In this case, the EE savings that the smart thermostat is providing to the customer would not be counted as part of the EE BCA test, since the customer was already realizing these savings prior to participation in the DR program. This would be true regardless of whether the customer decided to install the HPWH, and so is applicable to both single and Multiple DERs On-Site. The potential for existing DERs to influence the load shape impacts of any new DERs installed (such as an existing efficient air-conditioning unit reducing the impact of efficient windows) is a separate topic and is covered in Section 13.7.

13.15.2. Non-Infrastructure DER Solutions

For Non-Infrastructure DER Solutions, the issue of existing DER impacts is especially relevant to baseline quantification and load forecasting. When considering an analysis of an NWS/NPS, it is important that DERs included as part of the solution to avoid infrastructure are incremental to the baseline load forecast used to quantify the NWS/NPS load relief requirement. For instance, if the forecasted load on a substation already accounts for the expected levels of EE savings that would result from operating existing territory-wide EE programs in a business-as-usual manner, then the BCA test would not count the expected demand savings from these programs towards the NWS.

The exception would be when a geo-targeted version of the program with increased incentives and marketing is utilized to drive higher participation. However, in that case the BCA test would include as part of the NWS only the demand savings from participation above and beyond the levels already built into the load forecast. Conversely, even though the demand savings of only the incremental customers can be counted, the incremental increase in incentive costs for the existing EE program

When geo-targeted versions of existing programs are leveraged for an NWS, only incremental impacts are relevant for NWS BCA.

participants must be counted. This is because they would have participated even with the lower incentive, and so this incremental cost is attributable to the NWS.

13.15.3. Virtual Power Plants

In the case of a VPP, a portion of the DER assets aggregated for utility control may already be deployed in the field, while others may potentially be adopted based on incentives offered by a VPP program. For example, a customer may decide to purchase a smart thermostat from a utility marketplace in which all smart thermostats are auto-enrolled in a demand flexibility VPP program unless the customer specifically opts out. In this case, the efficiency gains that the smart thermostat can provide, as well as the impacts of the demand flexibility program, are incremental benefits that the VPP BCA should include.

In contrast, if the utility implements a BYOD VPP program in which the customer already has a smart thermostat, then the EE savings of the smart thermostat are not incremental benefits to the program, and the BCA test would not include them. Since the customer was already realizing these benefits without any involvement from the utility, they should not be credited to the initiative. These two different avenues for VPP participation illustrate the overarching broader principle that needs to be considered for this specific scenario: it is critical that the BCA test includes only the incremental impacts of the VPP to accurately value both benefits and costs.

13.15.4. Microgrids

Similarly to VPPs, microgrids may use existing DER assets in their configuration. For instance, a community may already have a large penetration of rooftop DPV prior to a utility initiative turning the area into an islandable microgrid. The large presence of DPV may provide benefits *to* the microgrid, such as lowering the costs of the microgrid by reducing the amount of generation required to allow sufficient islanding capability. However, these are not incremental benefits of the microgrid.

As for all specific DER scenarios, it is important that the BCA test includes only the incremental impacts of the DERs that result from the utility initiative.

PART V

Quantifying DER Impacts

14. METHODS FOR CALCULATING DER IMPACTS

This chapter describes different approaches that jurisdictions can use to account for relevant benefits and costs in their BCA test(s) using monetary values. It also describes when and how to use quantitative and qualitative information in the absence of monetary values. For comprehensive guidance on methods, refer to NESP's *Methods, Tools, and Resources Handbook (MTR Handbook),* a companion document to the NSPM, which can help users identify and understand the range of methods, tools, and resources available for calculating the benefits and costs of DERs.

14.1. Introduction

The previous chapters of this Manual focus on Phase 1 of the BCA Framework (described in Chapter 2), which provides guidance on developing BCA tests and addresses a host of BCA considerations in the context of different DER types and specific DER scenarios. After development of a jurisdiction's BCA test(s), Phase 2 of the BCA Framework centers on identifying methods to account for the range of impacts in the jurisdiction's BCA test(s), and Phase 3 focuses on conducting the BCA and presenting BCA results (alongside any other complementary analyses).

While this Manual's primary purpose is to provide guidance on Phase 1 of the BCA Framework, this chapter provides general guidance on Phases 2 and 3.

For Phase 2, users of this Manual are encouraged to refer to NESP's *Methods, Tools, and Resources for Quantifying DER Impacts (MTR Handbook)* for how to estimate the values of DER benefits and costs using monetary or non-monetary approaches. The MTR Handbook is a comprehensive technical guide that serves as a companion document to this NSPM. It describes a range of methodological options, tools, and resources for use in calculating DER impacts, including examples, references to existing studies, and links to relevant analytical tools.

Users of this Manual are encouraged to refer to the **MTR Handbook** for how to estimate the values of DER benefits and costs using monetary or non-monetary approaches.

NSPM *Principle 3: Account for All Relevant and Material Impacts* requires that BCA tests account for all relevant and material impacts. In this context, *relevant impacts* are those chosen to be included in the BCA test, and *material impacts* are those likely to be of sufficient magnitude to affect the BCA results. BCA tests should, ideally, account for DER impacts in monetary terms to enable direct and consistent comparison of DER impacts.

Jurisdictions might, however, face constraints in conducting in-depth analyses of all relevant and material benefits and costs, and some impacts might be especially challenging to monetize. In these cases, alternative approaches are available to account for DER impacts. Table 14-1 summarizes approaches for calculating or otherwise accounting for relevant and material DER impacts. The following sections further discuss these approaches.

Table 14-1. Different Approaches to Account for Relevant and Material Impacts

Approach	Description
Monetary values	Rigorous jurisdiction-specific studies offer the most accurate approach for estimating and monetizing relevant DER impacts.
Values from other jurisdictions	If jurisdiction-specific studies are not available for a relevant and material DER impact, studies from other jurisdictions or regions can be useful for determining the impact, where appropriate.
Proxy values	If monetized values for a relevant and material DER impact are not available, well-informed and well-designed proxies can serve as a simple, approximate substitute.
Quantitative metrics	If monetary values for a relevant and material DER impact are not available, quantitative metrics are useful for assessing specific outcomes, e.g., number of units installed, number or percentage of customers served, or tons of emissions reduced.
Qualitative information	If monetary values or quantitative metrics for a relevant and material DER impact are not available, qualitative information can help to generally describe the impact.
Alternative thresholds	If a relevant and material DER impact is especially challenging to address with either monetary, quantitative, or qualitative approaches, alternative BCR thresholds (i.e., other than 1.0), can serve as a simple, approximate way to account for it.

14.2. Monetary Values

This section provides additional guidance on conducting jurisdiction-specific (or regional) studies to develop DER impact value streams in monetary terms, as introduced in Section 14.2.1 above.

The general guidance provided herein is based on the comprehensive technical guidance provided in NESP's *MTR Handbook* (NASEO 2026). Figure 14-1 summarizes the process for quantifying the benefits and costs of DER investments, followed by a brief discussion of each step.

Figure 14-1. Key Steps to Calculating BCA Values



14.2.1. Identify Impact Metrics

After identification of the impacts for inclusion in the BCA test, the next step is to determine the metrics for estimating the impacts. For most impacts this is straightforward. For example, the metric for electric energy impacts is in megawatt-hours (MWhs); the metric for electric capacity impacts is in megawatts (MW); the metric for gas impacts is in therms or million British thermal units (MMBtus); the metric for greenhouse gas impacts is tons of GHG emissions. For some impacts the choice of metrics is less obvious. For example, estimates of reliability, and to some extent resilience, impacts might rely upon a variety of different metrics, such as SAIDI, SAIFI, and CAIDI (see Chapter 6).

Application of these metrics to the marginal DER impacts can inform the dollar value of the impact. For example, multiplying the DER energy savings (in MWh) by the marginal energy impact (in $/MWh) determines the monetary energy value (in $).

14.2.2. Identify the DERs to Evaluate

Identify the types of DERs to analyze in a BCA test, i.e., whether EE, DR, DG, DS, etc. or some combination of these DERs. It is also important to initially establish the scale of the DERs under evaluation, i.e., the approximate capacity (MW) and energy (MWh or MMBTU) of each DER type, in each year assessed.

The type and magnitude of DERs under evaluation will have important implications for determining DER load impact profiles (Section 14.2.4), for determining the DER case (Section 14.2.5), and for determining marginal impacts (Section 14.2.6).

14.2.3. Determine the Study Period

The BCA study period is the number of years over which the test will analyze benefits and costs. Ideally, the study period will be long enough to include the full operating life of the DERs under analysis. For example:

- For a BCA of an EE plan that includes three years of EE installations, the study period would include the three years of the installations plus enough years to span the lifetime of the EE measures with the longest life. If the longest life is 20 years, then the study period would include at least 23 years to capture the full impacts of the EE measures installed in the third year.
- For a BCA of a one-year distributed solar photovoltaic (PV) program with a 25-year operating life, the study period would be 25 years. For a BCA of a 10-year distributed PV installation program, the study period would be 35 years to capture the full impacts of the PV installed in the 10th year of the program.

Load impact profiles can vary widely for different DERs, and the value of the DER resource can vary over different seasons of the year, days of the week, hours of the day, and even within shorter periods of time.

14.2.4. Determine DER Load Impact Profiles

The term ‘load impact profile’ in this Manual indicates a DER’s hours of operation as well as the magnitude of the energy and capacity impacts produced in those hours. Since load impact profiles

can vary widely for different DERs and the value of the DER resource can vary over different seasons of the year, days of the week, hours of the day, and even within shorter periods of time, it is often necessary to define DER load impact profiles to determine DER utility, host customer, and societal impacts. Examples of differences include:

- Some EE resources might reduce customer demand consistently every hour of the year, while other EE resources might reduce demand only during peak periods of the day or year.
- The load impact profile for DS resources might vary significantly depending upon whether they are controlled by the utility or the host customer, and, if the latter, depending upon the host customer's rate design.
- Combinations of multiple DER types might also lead to different load impact profiles than if they were separate installations. For example, a storage technology might have a substantially different load impact profile when paired with a DG resource (e.g., DPV), because the customer might charge the storage resource when DPV output exceeds on-site energy needs rather than charging it when energy prices are low.
- Some DER types are highly dispatchable while others are not. For example, distributed PV resources and many EE resources are not dispatchable, while storage and some DR resources are highly dispatchable.

Ideally, DER load impact profiles would be developed on an hourly basis for each year of the BCA study period. Some DERs, such as distributed PV and storage resources, are likely to operate at markedly different levels throughout the day, which requires hourly information to capture the actual impacts at those different levels of operation. Some cases of EE and DR might not require hourly marginal impacts and load impact profiles, in which case the use of averages for key sub-annual periods (such as winter and summer or on- and off-peak periods) might be sufficient.

The MTR Handbook (NASEO 2026) provides a detailed discussion of how to develop load impact profiles for different DER types and combinations of DER types.

14.2.5. Determine Reference and DER Case Assumptions

In general, BCA tests require a comparison of two scenarios: one without the proposed DERs (the Reference Case) and one with the proposed DERs (the DER Case). The difference in the incremental benefits and costs between the two cases indicates the 'marginal impacts' of the DERs included in the DER Case. Understanding this construct of taking the difference between two scenarios is foundational to many of the methodologies described in the MTR Handbook.

Under the BCA Framework, the Reference Case is based on the most likely forecast of customer demand, except that it does not include the effects on customer demand of the DERs under evaluation. This case should, however, account for the impacts of all DERs already installed, and future DERs not under analysis in the BCA test. For example, a BCA test that seeks only to determine the value of EE should include the expected impacts from EV and DPV adoption in the Reference Case load forecast.

The difference in the incremental benefits and costs between the Reference Case (without DERs) and the DER Case indicates the *marginal impacts* of the DER(s) in the DER Case.

The MTR Handbook provides further guidance on defining the reference and DER case, including when both the reference and DER cases involve comparing different DER scenarios.

14.2.6. Determine Marginal Impacts

Marginal impacts represent the changes that would occur to utility systems, host customers, and society if the proposed DERs were to be implemented. *Marginal impacts are one of the core elements of any BCA and it is important to properly define and calculate them*. This section describes the rationale for using marginal (versus average) impacts, and for using long-run (versus short-run) marginal impacts.

Marginal Versus Average Impacts

When conducting BCA, marginal impacts are appropriate to use rather than average impacts. Marginal impacts are explicitly designed to capture the effects of adding DERs or other resources onto the electricity or gas system, such as the avoided cost of not having to produce an incremental unit of energy. Average impacts, on the other hand, blend the impacts of the DERs in with the costs of serving the rest of energy demand, and thus do not isolate the change in costs created by the DERs. Marginal and average impacts are defined as follows:

- *Average impacts* - the cost of producing a product divided by the number of products produced
- *Marginal impacts* - the change in per-unit costs as the result of a small change in output

Table 14-2 shows the general calculations for average and marginal impacts for electric and gas utilities. In practice, however, many impacts are lumpy rather than following a smooth, continuous function. Capacity costs, in particular, may be zero (or negative) when there is surplus capacity but then skyrocket when there is a shortage. For this reason, marginal impacts are sometimes calculated over larger increments of output (e.g., 50 MW), and then presented as unit costs (e.g., $/kW). It is possible to calculate both average and marginal impacts for different time periods, e.g., hours, days, months, seasons, years.

Table 14-2. Calculating Average and Marginal Impacts for Electric and Gas Utilities

	Average impacts	Marginal impacts
Annual electric energy cost ($/MWh)	Total variable energy costs (in $) / total energy production (in MWh)	Change in the annual energy costs (in $) as the result of a small change in energy demand (e.g., one kWh)
Annual electric generating capacity cost ($/kW-year)	Total generation capacity cost (in $) / total capacity provided (in kW-year)	Change in annual capacity costs (in $) as the result of a small change in peak demand (e.g., one kW)
Annual gas production cost ($/MMBtu)	Total gas cost (in $) / total annual gas production (in MMBtu)	Change in annual gas costs (in $/MMBtu) as the result of a small change in gas demand (e.g., one MMBtu)

Long-Run Versus Short-Run Marginal Impacts

When conducting BCAs, long-run marginal impacts are appropriate to use rather than short-run marginal impacts. Otherwise, the results may significantly understate DER impacts.

When conducting BCA tests, long-run marginal impacts are appropriate to use rather than short-run marginal impacts. This is necessary to ensure the analyses properly account for all benefits and costs experienced over the study period, which typically lasts 20 years or more. Using short-run marginal impacts may significantly understate the potential impacts of DERs.

Short-run costs are defined as the costs that occur before capital investments are made to increase production capacity. For electric and gas utilities, the following applies:

- Short-run marginal *electricity* costs include those costs, such as fuel, O&M, and labor costs, incurred to produce electricity without requiring additional investments in new generation, transmission, or distribution capacity.
- Short-run marginal *gas* costs include those costs, such as fuel, O&M, and labor costs, incurred to produce gas without requiring additional investments in new capacity for production, transportation, or delivery of gas.

Long-run costs treat all costs as essentially variable, including capital costs. These include short-run costs as well as capital investments to increase production capacity. It is appropriate for long-run costs to include all costs incurred over the full BCA study period. For electric and gas utilities, the following applies:

- Long-run marginal *electricity* costs include all short-run marginal impacts plus the costs associated with new GT&D capacity investments. Long-run costs will also need to account for any reductions in capacity, such as the retirement of existing GT&D facilities.
- Long-run marginal *gas* costs include all short-run marginal impacts plus the costs associated with new capacity for production, transportation, or delivery. Long-run costs will also need to account for any reductions in capacity, such as the retirement of existing production, transportation, and delivery facilities.

In sum, short-run costs assume there are no new capital investments or new production capacity, whereas long-run costs assume new production capacity and include the costs associated with that new capacity. *Therefore, it is important to use long-run marginal impacts in BCAs for DERs because DERs can potentially postpone, avoid, or add to capacity costs not included in short-run costs*.

Timing and Magnitude of Marginal Impacts

Marginal impacts are based on a change in the amount of electricity or gas production as a result of the proposed DER. The timing and magnitude of DER impacts can significantly affect the marginal cost. For example:

- A 1 MW change in demand during a *peak hour* of the year would result in higher marginal impacts than would a 1 MW change in demand during an *off-peak hour* of the year.

- A 1 MW change in demand for each hour of the year would result in different marginal impacts than would a 1 GW change for each hour of the year.

A DER Case will ideally include a forecast of the magnitude of proposed DERs to be implemented in each year and account for the hourly load impact profile of the proposed DERs throughout each year. For example:

- For a DR program that reduces peak demand by 20 MW each month, the DER Case will reflect a 20 MW reduction in peak demand each month, for each year the program operates.
- For a DG compensation mechanism that encourages residential distributed PV resources, the DER Case will reflect a reduction in demand for each hour the PV resources are expected to operate each day of the year, for each year the distributed PV resources operate.
- For a DS program, the DER case will reflect the hourly increases and decreases in demand caused by the storage technology, for the years that the DS operates. For those storage resources expected to provide ancillary services or be used for sub-hourly energy arbitrage, it would be better to reflect sub-hourly changes in demand.

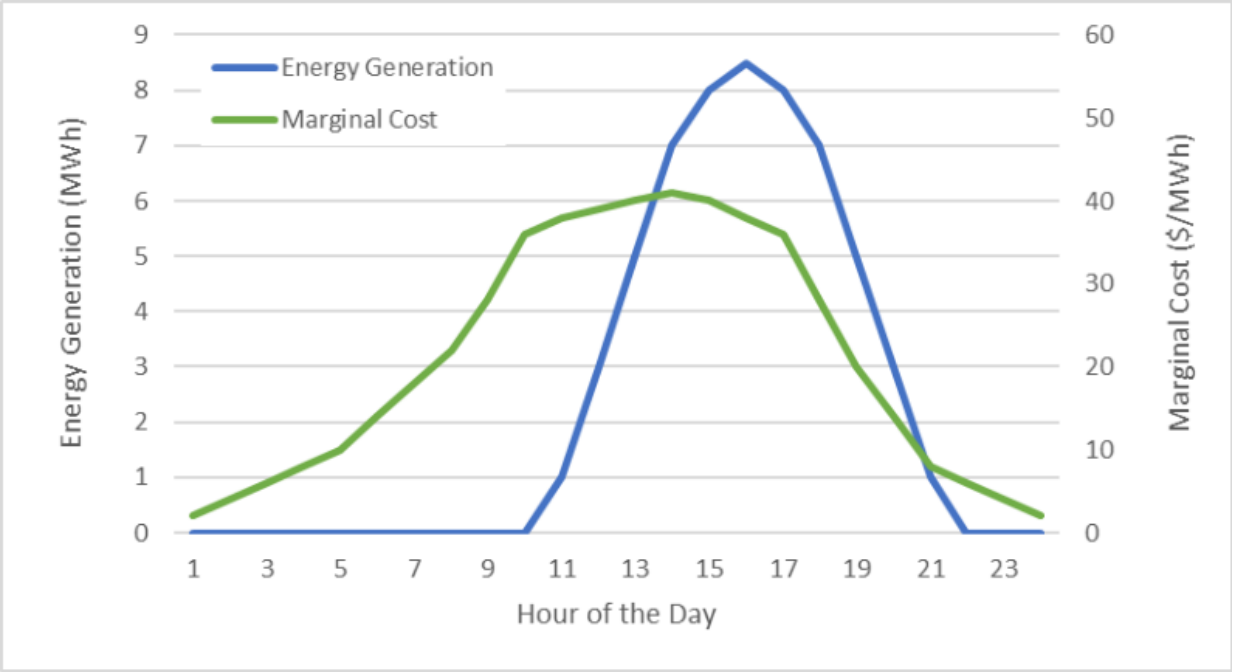
The exact approach used to calculate the marginal impacts on the utility system from the proposed DER might have relatively small implications when expected DER installations are few, because small amounts of load reduction might not significantly change the marginal resources on the system. When large amounts of DER installations are expected (relative to the total resources on the system), however, then the assumptions made about marginal changes to the system can have significant implications for the results of the BCA test. The MTR Handbook (NASEO 2026) provides additional examples and guidance.

14.2.7. Calculate the Dollar Value of Marginal Impacts

The dollar value of an impact is determined by multiplying the relevant metric (e.g., MWh, kW, MMBtu, ton of pollutant) by the marginal cost (e.g., $/MWh, $/kW, $/MMBtu, $/ton of pollutant). It is important to 'map' the marginal impacts onto the DER load impact profile; in other words, base the marginal impacts on the same time period when the DER is operating (hour, day, week, month, season, or year, depending upon the DER and data available).

Figure 14-2 shows how hourly marginal impacts can be mapped onto the hourly DER load impact profile for an illustrative distributed PV resource. The blue line indicates the PV load impact profile, while the green line indicates the marginal energy cost. Both the marginal cost and the energy generation vary throughout the day. To properly calculate the dollar value of the PV generation, the hourly marginal costs will be multiplied by the hourly energy generation, for each hour of the day.

Figure 14-2. Illustration of Mapping Marginal Impacts onto DER Load Impact Profile



Note: Values are meant to be illustrative and do not represent an actual PV project or actual marginal costs.

14.2.8. Summary

Table 14-3 below provides a summary of the key steps to calculating BCA impacts. Many of these (or similar) steps appear in the methods described throughout the MTR Handbook.

Table 14-3. Key Steps to Calculate BCA Impacts of DERs

Step 1	**Identify impact metrics:** Once the relevant impacts for the BCA test are identified, these impacts will define the relevant metrics to use in estimating the value of marginal impacts, e.g., MWh, kW, MMBtu, others.
Step 2	**Determine DER load impact profiles:** The DER load impact profiles are useful for estimating the energy and capacity impacts of the proposed DER, i.e., the magnitude and timing of MWh, kW, MMBtu, or other impacts.
Step 3	**Develop the Reference Case:** The Reference Case creates a baseline against which to compare the DERs.
Step 4	**Develop the DER Case:** The DER Case should include all the incremental DERs under evaluation in the BCA and should not include all the other resources impacted by those DERs.
Step 5	**Determine the marginal impact:** The marginal impact can be calculated as the difference between the value of the relevant metric(s) for the DER Case minus the value of the relevant metric(s) for the Reference Case.
Step 6	**Calculate the dollar value of the impacts:** The dollar value is determined by multiplying the relevant metric by the marginal impact. The marginal impacts should be 'mapped onto' the DER load impact profile.

Using the above steps, Table 14-4 provides examples for some key DER impacts.

Table 14-4. Overall Structure for Calculating the Value of Several DER Impacts

Step	Calculation	Electric Energy	Electric Capacity	Gas Energy	Reliability
Identify Impact Metric(s)	Determine based upon type of impact	MWh	kW	MMBtu	SAIDI & SAIFI
Determine DER Load Impact Profiles	Determine based upon DER type and use case	MWh	kW	MMBtu	kW, MMBtu
Develop Reference Case	Calculate the magnitude and value of relevant metrics	$ and MWh	$ and kW	$ and MMBtu	$ and hours of outage time
Develop DER Case	Calculate the magnitude and value of relevant metrics	$ and MWh	$ and kW	$ and MMBtu	$ and hours of outage time
Determine Marginal Impact	Calculate the difference between DER and Reference Cases	$/MWh	$/kW	$/MMBtu	$/hour
Calculate Dollar Values	Map marginal impact onto load impact profile	$	$	$	$

Note: For Step 5, the per-unit costs (in $/MWh, $/kW, $/MMBtu, and $/hour) are calculated by dividing the difference in cost (in $) by the difference in the metric (MWh, kW, MMBtu, or hour), where the differences are equal to the values from the DER Case (from Step 4) minus the values of the Reference Case (from Step 3).

Note that not all impacts/metrics need to be calculated using the above structure. In some cases, determination of the marginal impact does not require a full analysis or comparison of a Reference and a DER Case. See the MTR Handbook for further guidance on simpler approaches to calculating DER impacts, such as for Other Fuel impacts and GHG and other emission impacts.

14.3. Values from Other Jurisdictions

In some cases, and for some impacts, a jurisdiction-specific study might not be available for some of the information needed for a BCA test. In these cases, it may be appropriate to use results from other jurisdictions to the extent the data from those studies is deemed sufficiently transferable. This could include studies prepared for other utilities, other states, other jurisdictions, or other regions. It could also include regional or national studies that do not necessarily focus on any one jurisdiction or region.

However, DER planners should ensure that the value of a particular benefit or cost in another jurisdiction is sufficiently comparable to the value in the jurisdiction of interest. If not, it may be necessary to adjust values from other jurisdictions before using them. For example, labor costs in one part of the country might be significantly different from other parts of the country. Adjusting values according to an appropriate methodology can account for these differences.

As one example, Lawrence Berkeley National Laboratory has developed a list of jurisdiction-specific studies currently used to quantify NEIs in EE cost-effectiveness tests, as well as information on the transferability of the values and/or methodologies produced in the studies (LBNL 2020b).

14.4. Proxy Values

For the purpose of DER BCA tests, a proxy is a simple, quantitative value that can serve as a substitute for a value not monetized by conventional means. Proxies are appropriate for any type of benefit or cost that is hard to monetize and is expected to be of significant magnitude.

While proxy values are typically based on professional judgment, they should not be developed or perceived as arbitrary values. It is good practice to develop proxies by making informed approximations based upon the best information currently available regarding the relevant impact. This includes a review of relevant literature on the specific impact, as much quantification of the impact that is both feasible and reasonable, a review of proxy values used by other jurisdictions, and consideration of conditions specific to the relevant jurisdiction.

Proxies are most frequently used to account for EE impacts such as low-income and host customer non-energy benefits (ACEEE n.d.).

14.4.1. Proxies and Levels of Application

The application of proxy values can range from a single proxy value that applies to an entire portfolio of DERs to different proxy values for each DER impact.

When choosing the level of detail to apply to a proxy, there may be a tradeoff between accuracy and feasibility. More detailed proxies will likely more accurately represent the magnitude of the specific impact in question than simple proxies. However, proxies that are more detailed are also likely to require more information and cost more to develop.

One advantage of detailed proxies is that they are more transferrable across programs, across utilities, and over time. For example, an impact-level proxy such as improved health and safety, applied to residential retrofit efficiency programs, is likely to be generally applicable to other residential retrofit programs and remain relatively constant over time. Conversely, a sector-level proxy to account for all participant non-energy benefits for the residential sector will, in theory, be different for different programs and could change over time as the mix of distributed resources changes over time.

14.4.2. Types of Proxies

Accounting for DER impacts can entail several different types of proxies:

- *Percentage Adder:* A percentage adder approximates the value of non-monetized impacts by scaling up monetized impacts. This type of proxy is the simplest and easiest to apply.
- *Electricity Savings Multiplier ($/MWh):* An electricity savings multiplier approximates the value of non-monetized benefits or costs relative to the quantity of electricity saved by a DER.
- *Gas Savings Multiplier ($/therm):* A gas savings multiplier approximates the value of non-monetized benefits or costs relative to the quantity of gas saved by a DER. It offers the same advantages and disadvantages of electricity multipliers.
- *Fuel Savings Multiplier ($/MMBtu):* A fuel multiplier approximates the value of non-monetized benefits or costs relative to the total quantity of fuel saved by a DER, regardless of the type of fuel saved (e.g., electricity, gas, oil, propane).

- *Customer Adder ($/customer):* A customer adder (or subtraction) approximates the value of non-monetized benefits relative to the number of customers served by a DER program.
- *Measure Multiplier ($/measure):* A measure multiplier (positive or negative) approximates the value of non-monetized benefits or costs relative to the number of measures implemented as part of a DER program.

As with the choice of level of application for a proxy, the choice of which type can result in a tradeoff between accuracy and feasibility. Proxies that are more focused (e.g., by measure, by customer, or by fuel) are more likely to accurately represent the magnitude of the impact in question. However, the more-focused proxies are likely more difficult and expensive to develop.

14.5. Quantitative Values and Qualitative Information

If monetary values of some DER impacts are not available or feasible, the analysis can use quantitative values or qualitative information to account for these impacts. While it is inaccurate to add the quantitative and qualitative information to the other monetary impacts, these values can nonetheless provide useful insight in parallel with other monetary impacts when considering whether to invest in the DER. The following steps can guide consideration of quantitative and qualitative information where needed.

Provide As Much Quantitative Evidence as Possible

For those impacts that remain non-monetized, it may be possible to put them into quantitative terms. Quantitative values generally provide more concrete information for decision-makers to consider, relative to qualitative values or no values at all. It is important to document quantitative values of DER impacts in detail, and to provide justification for why and how the values are relevant to the BCA.

Metrics offer a quantitative way to assess the extent of a benefit or cost in the absence of monetary values for this purpose. For example, if the utility does not monetize host customer or societal resilience impacts for its BCA, regulators can establish metrics to indicate the extent to which these benefits (or costs) will be experienced. Example metrics in the case of resilience, for example, can include SAIDI, SAIFI and CAIDI (see Chapter 6) to track the frequency, duration, and recovery from electricity outages. The data obtained over time for these metrics can inform future calculations to monetize DER impacts for BCAs, as valuation efforts to translate metrics to monetary values improve.

Provide As Much Qualitative Evidence as Possible

For impacts that are relevant and material but are not monetized or quantified, it is appropriate to address them qualitatively. While not ideal, qualitative information can provide some evidence for decision-makers to consider, which is better than providing no information at all. In addressing these DER impacts qualitatively, DER planners can develop and present as much qualitative evidence as possible regarding those impacts. This evidence includes, for instance, a justification for why the considerations are relevant to the BCA.

For example, a jurisdiction might choose to consider incremental market transformation benefits without quantifying or monetizing such benefits. In this case, regulators or distribution planners would consider the incremental market transformation benefits, without necessarily estimating what those benefits are either in terms of energy savings or dollar savings.

Decide Upon the Implications of the Quantitative and Qualitative Evidence

BCA results should present any non-monetized impacts of DERs alongside the monetary impacts. This allows the regulators and other decision-makers to compare the monetized, quantitative, and qualitative factors and evidence to decide whether a DER is cost-effective. In some cases, the monetary results alone might be sufficient to make this decision (for instance, if the monetary benefits exceed the monetary costs, and all the non-monetary evidence indicates there will be additional benefits). The cost-effectiveness decision might also be easy if the monetary benefits are slightly less than the monetary costs, but the non-monetary benefits are clearly significant enough to make up the difference.

In other cases, the decision might not be so clear. For example, if the monetary benefits do not exceed the costs, the non-monetary benefits may not be substantial enough to make up the difference. In these cases, regulators and other decision-makers will need to make a cost-effectiveness determination based on all the evidence presented and with input from stakeholders.

Document and Justify the Decision

Finally, it is essential to fully document and justify the cost-effectiveness decision. This provides transparency about the decision for the resource in question and provides guidance on how similar decisions will be made in future BCAs.

14.6. Alternative Thresholds

Alternative thresholds are another approach for addressing hard-to-monetize impacts. They entail the use of pre-determined BCRs that are different from one (1.0) to determine if DERs are cost-effective. Regulators can apply a BCR of greater than one (1.0) to account for non-monetized DER costs, or a BCR of less than one (1.0) to account for non-monetized benefits.

Alternative thresholds are, by design, a simplistic way of recognizing that the hard-to-monetize impacts are important enough to influence the BCA. The primary advantage of this approach is that it does not require the development of specific monetary or proxy values. Rather, it provides a general reflection of the regulators' willingness to be flexible in accounting for certain impacts.

Using alternative benchmarks can essentially have the same effect as applying a proxy value. For example, an alternative portfolio-level BCR benchmark of 0.9 is equivalent to a portfolio-level benefit multiplier of 11 percent; and an alternative benefit-cost ratio benchmark of 0.8 is equivalent to a benefit multiplier of 25 percent.

Regulators have a role to play in ensuring alternative thresholds are as transparent as possible and established prior to the BCA process. For clarity, regulators should articulate to which resources the alternative thresholds apply, what those thresholds are, and the basis for choosing the thresholds.

14.7. Conducting BCAs Using Models/Tools

Phase 3 of the BCA Framework (per Chapter 1) involves the process of conducting the BCA itself using a model or tool and presenting results. Many utilities either retain external contractors to conduct their BCA tests (using proprietary tools typically) or conduct the BCA tests using internal models.

The NESP's OpenBCA tool is also an option for jurisdictions to conduct BCAs for the full range of DERs covered in this Manual. The OpenBCA tool allows jurisdictions to create and optimize their primary (and secondary) BCA tests for single or multiple DER portfolios, ensuring that cost-effectiveness tests reflect the jurisdiction's energy policy priority goals and objectives and regulatory needs. The tool allows users to select traditional cost tests (e.g., UCT, TRC test, SCT) to serve as secondary tests, as well as to assess associated rate impacts. The OpenBCA tool design can simplify and streamline the evaluation of a wide range of value streams for DER investments. Its formulas align with the range of methodologies discussed above and in the MTR Handbook.

Access the OpenBCA tool here

14.8. Presenting BCA Results

Phase 3 of the BCA Framework (per Chapter 1) also includes presenting BCA results to inform DER investment decision-making. Appendix K presents various examples of how to present results. These example formats for presenting results are either available as part of existing tools/models (e.g., the *OpenBCA* tool) or can be developed simply by generating graphs/charts using modeling data outputs and excel spreadsheets.

There are two main ways to present BCA results: net benefits and BCRs. Both options require first estimating the present values of benefits and costs. Appendix H provides guidance for determining the appropriate discount rate for calculating present values.

14.8.1. Net Benefits

Net benefits are equal to the difference between the cumulative present value of benefits and the cumulative present value of costs, as per the formula below. This metric is useful as a benchmark for determining cost-effectiveness: If a DER's net benefits are greater than zero, its benefits exceed its costs, and it is considered cost-effective.

$$Net\ benefits\ (dollars) = NPV \sum benefits - NPV \sum costs$$

The net benefits metric is useful for indicating the extent to which benefits exceed costs in monetary terms that are readily understandable (for instance, in terms of millions of dollars over the life of the DER). Net benefits also provide important information not provided by BCRs, by indicating the magnitude of the benefits to be gained by the DER. For example, a BCR of 2.2 does not indicate how much money the resource will save. It might save $1 million, $10 million, or $100 million.

14.8.2. Benefit-Cost Ratio

A benefit-cost ratio is equal to the ratio of the cumulative present value of benefits to the cumulative present value of costs, as per the formula below. This metric is useful as a simple benchmark for determining cost-effectiveness: If a DER's BCR exceeds 1.0, its benefits exceed its costs, and it is considered cost-effective.

$$Benefit\text{-}Cost\ Ratio = \frac{NPV \sum benefits\ (dollars)}{NPV \sum costs\ (dollars)}$$

The BCR metric can be useful for comparing DERs with each other (a higher BCR indicates one resource is 'more cost-effective' than another) because it effectively normalizes the results for DERs of different sizes. This metric is also useful for comparing DERs across utilities and jurisdictions of different sizes, again because it effectively normalizes the results for any differences in size.[66]

The BCR metric provides important information not provided by net benefits by indicating the relative effectiveness of the money spent on the resource (how many dollars of benefits are received per dollar spent). For example, a net benefit of $10 million in present value dollars does not indicate how much money was needed to generate those net benefits. It could have cost $90 million, with benefits of $100 million and a BCR of 1.1. Or it could have cost $4 million, with benefits of $14 million and a BCR of 3.5.

[66] However, in making such comparisons it is important to recognize that different utilities and jurisdictions might have different benefits for the same amount of savings. Different jurisdictions might also include different impacts in their resource assessment test.

Appendix A. Valuing Energy Resources in Different Contexts

This appendix supports Chapter 5 by describing how the benefits and costs of DER investments and other energy resources and strategies are commonly used in a variety of contexts. It then presents how the NSPM principles and concepts can apply in each of these different contexts to help promote efficient and economic energy resource decision-making.

A.1. DERs and Other Resource Valuation Involving Benefits and Costs

There are many situations or contexts that entail evaluating the benefits and costs of DERs and other energy resource investments to assess the cost-effectiveness—and identify the optimal mix—of resources to serve energy customers that meets a jurisdiction's specific energy policy goals and objectives. Applying the NSPM principles and concepts consistently across these contexts, whether regulatory or non-regulatory, helps to promote efficient and economic decision-making in resource investments.

The range of entities that may be involved in resource planning and investments is summarized in Chapter 5 (Table 5-1). Energy resource planning and decision-making practices are overseen by a wide range of government agencies operating in different contexts. In these contexts, a common objective is to determine the benefits, costs, and/or cost-effectiveness of utility-system and public investments and strategies, regulations, and programs. For example, ratepayer-funded EE program valuations typically take place in regulator dockets focused on EE investments, T&D investments are evaluated in dockets focused on grid modernization, and State Energy Offices consider building energy code and DER rebate programs using state general funds.

Applying the NSPM principles and concepts consistently across different regulatory and other contexts promotes efficient and economic decision-making.

Table A-1 below presents a summary of various contexts where benefits and costs of energy resources are evaluated, and the associated questions addressed by each context. This appendix provides further details on each of these contexts, with a focus on the assessment and uses of DER cost-effectiveness. The concepts can also apply broadly to all energy resource valuation efforts, as described herein.

In each of these contexts, state agencies, municipal authorities, utilities, and other stakeholders may assess the relevant benefits and costs, where applicable, to support DERs and other resource investment or strategy decisions. However, these assessments typically occur separately from each other in different processes. As a result, the practices, assumptions, and methods used to evaluate benefits and costs are often not consistent or coordinated when applied within a jurisdiction. This can lead to different conclusions about the cost-effectiveness of different resource options—and thus suboptimal investments in resources—that can make it difficult for the jurisdiction to meet its mandated energy policy goals and objectives. This appendix addresses this concern and how the NSPM can support consistency in assessment of energy resources.

Table A-1. Contexts for Evaluating Benefits and Costs of Energy Resources and Key Questions

Context	Examples	Example Questions to Be Answered
DER programs	Review of programs including EE, DR, DG, DS, EVs, multi-DER programs (e.g., GEBs, NWS/NPS, VPPs)—both prospective and retrospective	Should there be an investment in the DER program? Can DER programs be designed to increase net benefits?
Utility-scale generation	Review of utility investment in large-scale, front of the meter generation, before the investment has been made	Is the generation resource necessary, and will it meet public needs at lower cost than alternatives?
Resource procurements	Procurements from third parties of energy and capacity, renewable generation, DERs, NWS/NPS, or VPPs	What is the maximum amount that should be paid (i.e., ceiling price) to procure the resource?
Energy price signals	Rate design in rate cases, DR programs, time-varying rates; paying for grid services through price signals	What price signal will optimize customer demand profiles and the adoption of DER?
Grid modernization	Review of grid modernization investments such as grid-enhancing and grid-hardening technologies, AMI, DERMS, ADMS	Should the grid modernization investment be made?
Dynamic system planning	Assessment and evaluation of multiple energy resource types relative to a dynamic set of alternative resources, such as Integrated Distribution System, Resource, Grid and/or Electricity Planning	Which portfolio of large-scale and distributed energy resources will provide the greatest benefits?
Retrospective prudence reviews	Review of utility investments after the investments have been made, often during a rate case	Was the capital investment in question expected to provide net benefits to customers at the time it was made?
Performance incentive mechanisms	Determining PIMs to incentivize utilities in context of EE programs, resource procurements, GHG and other emissions, grid modernization, etc.	How much should a utility be rewarded or penalized, based on the costs or benefits experienced?
State energy policies, planning and programs	Support and implement a variety of state energy policies, legislation, plans, and programs (distinct from regulation or regulated utilities)	Will the state's policies, planning, and program efforts help to meet its specific energy goals and objectives by providing net benefits to the state?

The roles and responsibilities of State Energy Offices and Public Utility Commissions are summarized below. While this appendix largely presents regulatory-focused contexts—led by Public Utility Commissions and that involve State Energy Offices—additional contexts for valuing DERs and other resources in state policies, planning and programs are addressed in Section A.10. The common categories of state initiatives that address valuing energy resources typically involve legislative and executive order authority to support DERs, potentially with state general funds versus utility ratepayer funds (NARUC-NASEO n.d.).

Public Utility Commission and State Energy Office Roles

Public Utility Commissions and State Energy Offices each fill vital and unique roles in the delivery of energy and other essential services to the residents of a state. Whereas Public Utility Commissions regulate the activities of utilities that provide monopoly service of public goods, including electricity and natural gas, State Energy Offices develop and implement energy policy and programs on behalf of their governors across all energy providers and sectors in their states. In this role, they sometimes intervene in Public Utility Commission proceedings or provide analysis and research to regulators, depending on state laws and regulations. Public Utility Commissions are responsible for implementing the policies enacted by the State Energy Offices or the governor if these policies affect regulated utilities in the state.

State Energy Offices inform their governors and state legislators on energy policy development and decisions, undertake initiatives to demonstrate, finance and deploy DERs and other energy resources, and oversee a range of policy, planning, and program efforts that are relevant to valuing DER and other resource assessments. The specific roles and initiatives of each State Energy Office depend upon their state's evolving legislation, regulations, and policy goals.

Many State Energy Offices engage formally or informally in regulatory proceedings before their respective public utility commissions. This often includes engagements in dockets covering the range of contexts described in this appendix, where they bring important perspectives that inform valuation of DERs and other resources, particularly with respect to ensuring that applicable state policies and goals are considered in such assessments. Thus, while State Energy Offices have authority, goals, initiatives, and responsibilities that are usually distinct from state Public Utility Commissions (and public and co-op utility boards), they also have an interest in considering and informing resource valuation in state decision-making processes. State Energy Offices also regularly convene stakeholders and facilitate stakeholder processes to solicit input from a variety of different perspectives including customers, government, businesses, and industry.

Public Utility Commissions, sometimes also called public service commissions, serve as quasi-judicial economic regulators of utility services. In this role, they ensure the establishment and maintenance of utility services and ensure that those services are provided at rates and conditions that are fair, just, and reasonable for all consumers. Commissions universally regulate investor-owned electric and natural gas utilities, while some also regulate water utilities, telecommunication services, rural electric cooperatives, municipal electric utilities, and other public services to varying degrees. Depending on the state, commissions may also engage in rulemaking or regulation-writing processes, quasi-judicial proceedings, and/or non-contested investigatory matters that cover the range of contexts addressed in this appendix.

Commissioners' actions are driven by their interpretation of state statute and evidence brought before them in quasi-judicial proceedings. In all states, the commissioners and the Public Utility Commission must abide by administrative procedures and make objective decisions based on the record presented by the parties to a case.

Source: Informed by the National Council on Electricity Policy

A.1 Consistent Application of NSPM Guidance

A.1.1 Rationale for Consistent Application

Accounting for utility resource benefits and costs consistently across all regulatory and other contexts helps to ensure that a jurisdiction can achieve its energy policy goals at the lowest cost. If treatment of benefits and costs is inconsistent, then resource investment decisions will be inconsistent and might lead to undesired outcomes.

For example, if a jurisdiction evaluates utility DS programs with a BCA test that does not include resilience benefits, but for grid modernization projects it uses a BCA test that does include resilience benefits, then DS programs will be undervalued relative to grid modernization investments. This might encourage the utility to underspend on DS programs and overspend on grid modernization investments, potentially resulting in higher costs to customers.

Treating benefits and costs consistently across all contexts offers additional advantages:

- Jurisdictional policies. Using a BCA test, methods, and assumptions that consistently reflect a jurisdiction's policies will help promote those policies across all relevant contexts.[67]
- Stakeholder input. If robust stakeholder input informs the development of BCA tests, methods, and assumptions in one context, then that stakeholder input will benefit the other relevant contexts where stakeholder input was not available or practical.
- Administrative efficiency. Using consistent BCA tests, methods, and assumptions across relevant contexts will enhance the administrative efficiency of utility investment reviews. This will result in benefits for commission staff, utilities, intervenors, and other stakeholders.

Guidance in this Manual can apply to the range of valuation contexts listed in Table A-1. The key guidance areas are:

- Fundamental BCA principles,
- Use of a primary BCA test,
- Use of any secondary BCA tests,
- Methods and assumptions for calculating resource impacts,
- Planning parameters e.g., study period and discount rate, and
- Conducting complementary analyses.

In some resource valuation contexts, guidance in all the areas above might be applicable, while in others only a portion of the guidance might be applicable. For each relevant context, a jurisdiction will need to review the context to determine how the NSPM applies to it and identify ways to apply the guidance consistently to it.

A summary of how the key areas of NSPM guidance are likely to apply to various contexts is provided below, followed by details on each context in Sections A.2 through A.10.

[67] As noted below, there might be some regulatory contexts where different policies apply. In these cases, any differences in the BCA test, methods, or assumptions should be justified by those different policies.

Fundamental BCA principles

Applying the BCA principles provided in Chapter 3 across all relevant contexts will promote consistency regarding fundamental analytical concepts across contexts. The principles are relevant to the evaluation of benefits and costs, regardless of whether the evaluation is for the purpose of reviewing DER investments or valuing other resource investments.

One of the fundamental BCA principles is to ensure transparency. Transparently presenting the benefits, costs, methods, and analytical results from each relevant context consistently will facilitate comparison and improve administrative and economic efficiency across related contexts.

Ensuring that utility investments across relevant contexts are optimized requires accounting for the same list of benefits and costs in each context as what is accounted for in the primary BCA test, to the extent the impacts are applicable.

Primary BCA Test

Ideally, jurisdictions will develop or already use a primary BCA test based on the NSPM multi-step process (see Chapter 4). Using the same primary BCA test—specifically the same list of benefits and costs as in the primary BCA test—across all relevant contexts as applicable will promote consistency across contexts.

Using the same primary test across all relevant contexts might be challenging in some jurisdictions due to legislative requirements, commission precedents, or other policies. Nonetheless, establishing this as an aspirational goal might help to advance discussions of those challenges and move towards greater consistency across contexts. Any differences that remain in the BCA test merit explanation by articulating those different policies.

Using the same primary test across all relevant contexts might be challenging in some jurisdictions due to legislative requirements, commission precedents, or other policies. Nonetheless, establishing this as an aspirational goal might help to advance discussions of those challenges and move towards greater consistency across contexts. Any differences that remain in the BCA test should be explained by articulating those different policies.

If there are multiple primary BCA tests already in use across relevant contexts, the most appropriate BCA test would be the one that reflects the most recent regulatory goals, the most recent direction from legislation, the most recent and robust stakeholder input, and with the most support or approval from regulators.

Chapter 6 describes how a BCA test might include some impacts that warrant assessment to determine whether they are applicable or material for each DER type. A similar process might be required for each regulatory context because some impacts might be applicable and material in one context but not in another. For example, reliability and resilience impacts might be important when evaluating grid modernization investments but are not necessarily material when reviewing the procurement of utility-scale solar from third parties.

In addition, there might be situations where it is impractical or infeasible to account for some impacts in the primary BCA test in one context that are accounted for in another. In these cases, any impacts not quantified can be described and discussed qualitatively.

Secondary BCA Tests

Secondary BCA tests answer different questions than primary BCA tests (see Appendix G). It is important for secondary BCA tests to be consistent across relevant contexts, to the extent that the same questions are relevant in each context. For example, if the Utility Cost Test serves as a secondary test in the context of DER programs and portfolios to help prioritize those programs, then it is good practice to use the same secondary test in the context of infrastructure investments to prioritize those investments.

Methods and assumptions

Applying the same methods and assumptions for estimating the values of each benefit and cost across all relevant contexts will promote consistency across contexts. For example, the same avoided energy costs used to evaluate DER programs and portfolios would also be used to evaluate resource procurements or utility-scale generation facilities. The avoided costs might need modification to account for any locational or temporal differences in the resource being evaluated, but if so, underlying methods and assumptions for the avoided costs should be consistent.

Applying the same methods and assumptions for estimating the values of each benefit and cost across all regulatory contexts will promote consistency across contexts.

In some cases, different values of the same benefit or cost in different contexts are used because they were estimated at different times and in different forums—or with different levels of certainty in their estimations. Typically, the most appropriate estimates to use in these instances will be those based on the most recent information, the most stakeholder input, and the most regulatory review.

Planning Parameters

Applying the same planning parameters across all relevant contexts, to the extent applicable, will promote consistency across contexts. The two main planning parameters are discount rates and study periods.

There might be situations where one of the planning parameters is not applicable to the context. For example, discount rates are not applicable to setting energy price signals. Further, there might be situations where planning parameters should differ between contexts for good reason. For example, the study period for an infrastructure investment that has a 10-year life will be shorter than the study period for a utility-scale generation facility that has a 40-year life. In both cases, the study period is based on the same standard of being long enough to cover the full extent of the benefits and costs of the resource in question.

Complementary Analyses to BCA

Applying complementary analyses consistently across all relevant contexts, to the extent appropriate and feasible, will promote consistency across contexts. For example, if a DER program and portfolio context requires an analysis of rate impacts to inform the decision of which programs to pursue, then the IRP context would also include rate impact analyses to guide the selection of the optimal resource portfolio.

There might be contexts where complementary analyses are not applicable. For example, if economic development/job impacts are articulated as a state energy policy goal, then it might be

appropriate to conduct a job impact analysis for DER programs and portfolios, utility-scale generation facilities, or infrastructure investments. However, it does not make sense to conduct such analysis when setting energy price signals because job impacts are not directly related to the long-term marginal costs typically used to influence consumption (see Appendix C).

Transparency in Assumptions and Results

One of the fundamental BCA principles is to ensure transparency in conducting BCAs (see Chapter 3), and this applies to all relevant contexts. Presenting the benefits, costs, and analytical results from each relevant context consistently facilitates comparison and improves administrative efficiency across contexts.

A.1.2 Summary of Consistent Application Across Different Contexts

Table A-2 presents a summary of which aspects of NSPM BCA guidance apply to different contexts. As indicated, application of NSPM guidance to different contexts varies depending upon whether the guidance is relevant and appropriate for that context. Sections A.2 through A.10 below provide additional details.

Table A-2. Summary of How to Apply NSPM Guidance Consistently Across Different Contexts

Context	Principles	Primary BCA Test	Secondary BCA Test	Methods & Assumptions	Planning Parameters	Complementary Analyses*
DER programs	✓	✓	✓	✓	✓	✓
Utility-scale generation	✓	✓	✓	✓	✓	✓
Resource procurements	✓	✓	Potentially	✓	✓	✓
Energy price signals	✓	✓	No	✓	Partially	No
Grid Modernization	✓	✓	✓	✓	✓	✓
Dynamic system planning	✓	✓	✓	✓	✓	✓
Prudence reviews	Yes, consistent with the practices when the investment decision was made					
Performance incentive mechanisms	✓	✓	No	Yes, if regulators want to create utility incentives to promote outcomes consistent with the primary BCA test		

*Note: This table is illustrative and there might be conditions in jurisdictions that warrant different applications of NSPM guidance. * Complementary analyses are only relevant where consistent with a jurisdiction's policies.*

The concept of promoting consistency across relevant contexts relates to the BCA Framework described in Chapter 2 (Figure 2-1), which illustrates the alignment of benefits and costs identified in a jurisdiction's primary BCA test—along with underlying methodologies and ultimately value streams—across the different contexts. Such alignment helps to ensure optimal resource investment decisions.

A.2 DER Programs and Portfolios

A.2.1 Description

This context refers to situations where utilities (or other entities) design, plan for, and implement DER programs to encourage customers to adopt DERs. This includes single-DER programs such as EE, DR, DG, DS, and electrification-related DERs. (See Chapters 8-12.) It also includes multiple DER projects, such as GEBs, NWS, NPS, and VPP projects. (See Chapter 13.)

A.2.2 Role of Benefits and Costs

Analysis of benefits and costs determines whether a DER program or portfolio will provide net benefits relative to a scenario without the DER. The metrics used for this purpose include benefits, costs, net benefits, and benefit-cost ratios.

The BCA costs include all the costs of the DER over the study period. The BCA benefits include the costs avoided by the DER over the study period—in other words, all the costs that would be incurred in the absence of the DER.

Prospective BCAs are commonly used to inform DER program design and determine whether to invest in programs and portfolios. Retrospective BCAs are commonly used for program evaluation, measurement, and verification purposes, and to improve program design going forward. Jurisdictions might also use retrospective BCAs to determine whether to continue investing in programs or portfolios.

A.2.3 Consistent Application of NSPM Guidance

It is important to apply all aspects of the NSPM guidance —including the principles, primary tests, secondary tests, methods and assumptions, planning parameters, complementary analyses, and presentation—to the evaluation of DER programs or portfolios.

A.3 Utility-Scale Generation Facilities

A.3.1 Description

This context refers to situations where utilities must demonstrate the need or the benefits of a new utility-scale generation facility. Such a situation might occur when a utility needs to obtain a CPCN to build a new power plant, repower an existing facility, or convert an existing plant to use a different fuel.

A.3.2 Role of Benefits and Costs

BCA determines whether the proposed facility is the lowest-cost option and will help achieve policy goals. In the case of CPCNs, the utility usually must demonstrate that the facility is necessary and will meet public needs. The metrics typically used for this purpose include benefits, costs, and net benefits. Consistency with approved resource plans may also be a factor in approval.

The BCA costs include all the costs of the proposed facility over the study period. The BCA benefits include the costs that are avoided by the facility over the study period—that is, all the costs that would be incurred in the absence of the facility.

A.3.3 Consistent Application of NSPM Guidance

It is important to apply all aspects of the NSPM guidance —including the principles, primary tests, secondary tests, methods and assumptions, planning parameters, complementary analyses, and presentation—to evaluation of the proposed facility.

A.4 Resource Procurements from Third Parties

A.4.1 Description

This context refers to situations where utilities use competitive bidding processes to purchase resources from independent generators or third-party vendors. Such situations can include procurement of power from fossil or nuclear resources, from utility-scale renewable resources, from single-DER programs, or from multiple-DER programs. The purchases can entail a variety of different contract types such as an asset purchase, a tolling agreement, a power purchase agreement for energy, or a power purchase agreement for energy and capacity.

A.4.2 Role of Benefits and Costs

Competitive resource procurement processes frequently use a ceiling price to determine the maximum amount the utility is willing to pay for the resource. Sometimes the ceiling price is only for internal purposes, and the utility does not reveal it to the potential bidders, while sometimes the utility reveals the ceiling price. Ideally, the ceiling price reflects the benefits provided by the resource being procured. In this way, the utility can ensure that all proposals with lower costs than the ceiling price will result in net benefits.

The benefits of the resource being procured are equivalent to the benefits included in a BCA test for that resource. The benefits calculation entails comparing the costs of two scenarios: one with the resource and one without it.

Some resource procurements might seek proposals for different types of energy products (for instance, energy, capacity, system peak demand, or distribution peak demand). In each case, it is important that the ceiling price reflects the benefits of the energy product being procured. For example, a procurement for system peak demand would use the temporal benefits associated with when the system peak demand occurs, but a procurement for distribution peak demand would use the locational and temporal benefits for where and when the distribution peaks occur.

Most of the costs of the resources procured will be determined by the bids received from third parties. In other words, most of the costs will be market-based, as opposed to being determined administratively by the utility. There might be other costs incurred beyond those included in the proposals from third parties. For example, additional costs of the procurement might include the following:

- Administrative costs for the utility for running the competitive bidding process
- The utility's cost of integrating the resource into the system, e.g., interconnection costs to support the integration of DG or DS proposals

- Environmental impacts, such as air emissions from diesel generators
- Host customer costs from DERs

A.4.3 Consistent Application of NSPM Guidance

It is important to apply all aspects of the NSPM guidance —including the principles, primary tests, secondary tests, methods and assumptions, planning parameters, complementary analyses, and presentation—to the evaluation of resource procurements from third parties. Nevertheless, this context requires special considerations and potentially some modifications:

- *Ceiling price:* Under the BCA Framework, the resource procurement ceiling price is based on all the benefits included in the jurisdiction's primary BCA test. In some cases, it might be appropriate to modify the ceiling price due to the additional utility system costs described above. If the utility expects to incur utility system costs that will not be included in proposed resource costs, such as administration or interconnection costs, then the utility can subtract these costs from the ceiling price, thereby ensuring that the remaining costs will be less than the benefits.
- *Non-utility system procurement costs:* Similarly, because of the additional non-utility system procurement costs listed above, it might be appropriate for utility requests for proposals to require bidders to reveal any such non-utility system costs in their proposals. Relevant examples would be environmental or host customer costs. The utility could then add these impacts to the bidders' proposed costs to determine the total cost consistent with the primary BCA test.
- *Secondary tests:* Secondary tests typically do not appear in the context of resource procurements. Nonetheless, a jurisdiction could apply secondary tests if it wishes to answer different questions than the primary test. For example, if a jurisdiction wishes to prioritize across many different resource procurement proposals, it could apply the UCT for that purpose.
- *Complementary analyses:* Complementary analyses are typically not applied in the context of resource procurements. Nonetheless, a jurisdiction may choose to apply these analyses if it has a policy directive to evaluate rate, job, or equity impacts of resource procurements. For example, a utility could conduct a rate impact analysis based on the proposed bids plus any additional utility system costs; a utility could use DER participation rates for priority populations as one of the factors in selecting among bids for single- or multiple-DERs; or a utility could use employment of priority population workers as one of the factors in selecting bids for utility-scale generation.

A.5 Energy Price Signals

A.5.1 Description

This context refers to situations where utilities set electricity or gas prices to provide price signals to customers to influence their demand profile. There are many situations where utilities set prices for this purpose:

- Standard rate design in rate cases, where rates are designed to reflect long-run marginal costs

- DR programs based on price signals, either for emergency or peak demand purposes
- Time-varying rates, such as critical peak pricing, peak time rebates, and more
- Procurement of resources from customers and third parties where the payment for the resources is driven by the price signal

A.5.2 Role of Benefits and Costs

Changes in long-run marginal costs reflect the benefits of customers changing their consumption patterns by an incremental amount.[68] Economic theory suggests that the most efficient price signals reflect long-run marginal costs. When prices reflect long-run marginal costs, consumers pay the true cost of producing an additional unit of energy, theoretically leading to sustainable resource use and preventing underproduction or overproduction of energy.

Economic theory suggests that the most efficient price signals reflect long-run marginal costs.

For this reason, under the BCA Framework, benefits are based on long-run marginal costs (see Chapter 14 and NESP 2022). The long-run marginal costs reflect the benefits of reducing energy demand by an incremental amount (such as through DERs that decrease load). They also reflect the costs of increasing energy demand by an incremental amount (such as through DERs that increase load).

Long-run marginal costs are the appropriate choice both for sending efficient price signals and for determining benefits for input in a BCA test. These long-run marginal costs should be consistent in both contexts.

In the case of pricing signals there is no need to estimate the costs of the changed consumption pattern or to compare any such costs to the benefits. Setting the price to reflect the appropriate estimate of long-run marginal costs is sufficient to promote an economically efficient outcome.

A.5.3 Consistent Application of NSPM Guidance

While it is important for the long-run marginal costs used for setting price signals to be consistent with the benefits included in the jurisdiction's primary BCA test, there are situations when it is appropriate to set prices at different levels:

- *Rate designs to promote equity:* A good example is modification of rate designs to promote equity (such as discounted rates for low-income customers). As another example, peak time rebates and critical peak pricing programs might set peak period prices well above the long-run marginal costs to induce customers to respond to them. The justification for these high price signals is that they help overcome the barriers that customers face when altering consumption patterns. The utility typically offsets the high prices using especially low prices during off-peak periods so that both prices balance out.

[68] Short-run costs are defined as the marginal costs that occur before capital investments are made to increase production capacity. Long-run costs treat all costs as essentially variable, including capital costs. These include short-run costs as well as capital investments to increase production capacity.

- *Host customer costs:* For those jurisdictions where the primary BCA test includes host customer costs, the question arises as to whether the long-run marginal benefits should include those avoided host customer costs. On one hand, this would be consistent with the primary BCA test. On the other hand, it might not be appropriate to increase price signals to all customers to help host customers avoid the cost of implementing DERs. Host customers typically experience higher benefits than costs and so are better off even if their costs are not avoided. Consequently, there is no need to increase price signals for all customers to help avoid this cost.
- *Procurement of specific types of resources and services:* Some price-based utility procurement practices might focus on specific types of resources and services, in which case the prices, based on benefits, should be consistent with those services. For example, if an electric utility were to use price signals to procure grid services from a distributed battery, where the grid services were primarily for the reduction of local distribution system peaks, then it would be important that the prices reflect the value of battery discharge at the relevant time and location of the distribution peak demands. In these instances, the prices are based on the long-run marginal benefits of those specific resources.
- *Secondary tests:* Secondary tests are not common in the context of setting energy price signals.
- *Timeframe and discount rates:* The appropriate timeframe for calculating the energy price signals is the same long-term timeframe as the BCA test. Discount rates are not typically applied when determining price signals.
- *Complementary analyses:* Complementary analyses do not typically factor into utility pricing practices. Rate impacts or job impacts would be problematic to include in estimates of long-run marginal costs for ratemaking purposes, because these impacts are not directly related to long-run marginal costs. Equity issues, however, can be considered in ratemaking practices. For example, utilities can provide discounted rates for low-income customers to address equity concerns, as described above.

A.6 Grid Modernization Investments

A.6.1 Description

This context refers to situations where utilities evaluate the cost-effectiveness of specific grid modernization investments that might not fall within their traditional investment practices.

For example, this might include utility-facing grid modernization investments such advanced metering infrastructure, DER management systems, advanced distribution system management systems, outage management systems, volt-var optimization, and more. This might also include situations where jurisdictions use BCA tests with static avoided costs (as opposed to dynamic system planning practices that use dynamic avoided costs as described in Section A.7 to evaluate other types of distribution infrastructure investments.

Utilities sometimes seek some form of regulatory preapproval before making these non-traditional capital investments. Further, regulators sometimes require utilities to demonstrate cost-effectiveness before making such capital investments. Both cases may entail a BCA test to demonstrate whether the investment will result in net benefits.

A.6.2 Role of Benefits and Costs

As noted above, analysis of benefits and costs shows whether the investment will provide net benefits. The metrics used for this purpose include benefits, costs, net benefits, and benefit-cost ratios.

A.6.3 Consistent Application of NSPM Guidance

It is important to apply all aspects of the NSPM guidance—including the principles, primary tests, secondary tests, methods and assumptions, planning parameters, complementary analyses, and presentation—to the evaluation of the infrastructure investments.

For some of these non-traditional utility investments, the main benefits might include improved reliability and resilience, which are challenging to monetize. Further adding to the challenges of conducting BCA, many of these technologies are interrelated and benefits and costs for one technology will depend upon the implementation of other technologies. Nonetheless, best practice is to apply the BCA principles and concepts outlined in this Manual to the greatest extent practical in this context (DOE 2021; LBNL 2025a).

A Note on Least-Cost Best Fit Analyses

Description: The 'least-cost, best-fit' (LCBF) approach is a utility resource evaluation technique sometimes used as an alternative to BCA in the context of distribution system planning and grid modernization investments. The LCBF approach helps narrow down options once the need for a particular investment or project is already established. After identification of the infrastructure or technology option (or options) most likely to meet that need, the final step is to identify the lowest-cost way of implementing the chosen infrastructure or technology.

Utilities have used LCBF for many years for distribution and transmission investments where new infrastructure is clearly needed to provide service or maintain reliability. In these cases, the need for the infrastructure is clear. The only questions to address are which technologies are the best fit and how to implement them at the lowest cost. In recent years, utilities have applied LCBF to other infrastructure investments (such as grid modernization) after asserting that the infrastructure is needed and therefore an LCBF is warranted. (LBNL 2025a)

In general, BCA offers several advantages over LCBF:

- BCA is more transparent and provides more information because it presents the benefits, costs, net benefits, and benefit-cost ratio, whereas LCBF presents only the costs.
- BCA allows for a more transparent, comprehensive, and robust assessment of alternative investments.
- By assessing the benefits and costs of alternative investments, BCA allows for testing the presumption that an investment is actually needed.

Role of benefits and costs: LCBF practices focus on the costs of the infrastructure or technology options determined to be the best fit. LCBF does not require assessment of benefits.

Consistent application of NSPM guidance: Ideally, the costs used in an LCBF analysis will be consistent with all relevant aspects of the jurisdiction's BCA test, which would be based on NSPM guidance. If the jurisdiction's BCA test includes costs evaluated using complementary analyses (i.e., rates, equity, jobs), then these impacts should be accounted for consistently as well.

A.7 Dynamic System Planning Practices

A.7.1 Description

As described in the Chapter 1, DERs analysis can happen at three different levels:

- *Single-DER analysis*: assessment of one DER type in isolation from other DER types and relative to a static set of alternative resources, i.e., static avoided costs.
- *Multiple-DER analysis*: evaluation of multiple DER types together relative to a static set of alternative resources, i.e., static avoided costs.
- *Dynamic system planning*: assessment and evaluation of multiple DER types relative to a dynamic set of alternative resources. Under this approach, the goal is to optimize both DERs and alternative utility-scale resources.

This context refers to dynamic system planning. There are multiple variations of dynamic system planning. They share the same core elements:

- The primary goal is to identify lowest-cost set of resources while meeting reliability and other policy goals.
- They typically model multiple resources and comprehensive portfolios dynamically to determine the optimal resource mix.
- They often require the use of optimization models, scenario analyses, and sensitivity analyses.
- They typically involve significant data collection, analyses, forecasts, stakeholder input, and regulatory review.

The primary difference between dynamic system planning practices is that they cover different parts of the energy system. Table A-3 summarizes examples of dynamic planning practices.

Table A-3. Examples of Dynamic Planning Practices

Type of Dynamic System Planning	Planning Practice Accounts for:				
	Distribution System	DERs	Transmission System	Utility-Scale Generation	Electric + Gas
Integrated distribution planning	✓	✓			
Integrated resource planning		✓		✓	
Integrated grid planning	✓	✓	✓	✓	
Integrated energy planning	✓	✓	✓	✓	✓

Dynamic system planning and BCA practices share many common attributes:

- They have the same objective: to identify lowest-cost options while meeting reliability and other policies.

- They use similar inputs and methods for estimating benefits and costs.
- They use similar planning practices, such as long-term study period, forecasts, discount rates, consideration of policy goals, and more.

A.7.2 Role of Benefits and Costs

The core of the optimization process in dynamic system planning is similar to a BCA test, where analysis of benefits and costs of portfolios determine the portfolio that results in the greatest net benefits.

Dynamic system planning practices typically include the costs of all the resources relevant to the analysis. However, practitioners typically do not break out the benefits of the resources separately. Instead, they compare the benefits of one portfolio relative to another by the extent to which one portfolio costs less than another. It is possible to identify the benefits of specific resource types, if desired: for example, modeling one portfolio without any DERs and comparing it to another portfolio with DERs optimized, to indicate the benefits of all those DERs combined.

A.7.3 Consistent Application of NSPM Guidance

Under the BCA Framework, dynamic system planning practices use all the benefits and costs included in the jurisdiction's primary BCA test. As noted above, the costs are paramount in this context, and the benefits are the difference between the costs of two scenarios. There are several special considerations related to application of NSPM guidance for this context:

- *Modification of planning processes:* Some of the planning processes might need modification to account for all costs in the jurisdiction's primary BCA test. For example, many jurisdictions evaluate DERs using a primary BCA test that includes transmission and distribution benefits. In these cases, it is good practice for the IRP practices to also account for transmission and distribution benefits. Similarly, integrated grid planning practices should include transmission benefits as well as distribution benefits.
- *Differences due to calculation methodologies:* In calculating benefits and costs in dynamic planning practices, there might be differences stemming from the calculation methodologies used for those impacts in BCA contexts. For example, dynamic planning allows for a more sophisticated assessment of impacts on the system using computer optimization models that analyze benefits and costs based on the dispatch of power plants, whereas DER BCA uses a much simpler static set of avoided costs. On the other hand, BCA practices using static avoided costs and detailed program inputs tend to allow for more detailed assessment of DER programs and program designs.

Despite the differences in methods and assumptions that might naturally arise between BCA practices and dynamic system planning practices, it is important for utilities to attempt to apply methods and assumptions as consistently as possible between relevant contexts. Where consistency is not appropriate or feasible, the utility should explain its reasons for the use of different approaches.

In addition, dynamic planning practices should also use planning parameters consistent with those used in the primary BCA test. This includes using the same discount rate and study period.

Dynamic planning practices should also use planning parameters consistent with those used in the primary BCA test. This includes using the same discount rate and study period.

It will also be important for dynamic planning practices to use complementary analyses consistent with those used in the primary BCA test. Any such impacts, e.g., rates, jobs, or equity, should be assessed separately from (exogenous to, in modeling terms) the computer optimization models because it is incorrect to add monetary values for these impacts to the monetary values of the resource costs.

A.8 Retrospective Prudence Reviews

A.8.1 Description

This context refers to situations where regulators conduct reviews of utility investments to determine whether investments are prudent, used, and useful. Prudence reviews typically occur during rate cases when a utility is seeking cost recovery for a large capital investment (such as a power plant, a transmission line, or distribution infrastructure) in situations where the value of the investment is in question. Prudence reviews can also apply to utility programs, including DER programs.

Most prudence reviews happen retrospectively, after completion of the investment. In these cases, regulators typically require BCA that uses impacts, inputs, and assumptions based on those that would have been used at the time the utility decided to undertake the investment.

A.8.2 Role of Benefits and Costs

Prudence reviews are essentially BCA to determine whether the investment in question was expected to provide net benefits to customers and therefore was a prudent decision.

The BCA costs include all the costs of the investment. The BCA benefits include the costs avoided by the investment—in other words, all the costs that would have been incurred in the absence of the investment.

A.8.3 Consistent Application of NSPM Guidance

Under the BCA Framework, retrospective prudence reviews use the same benefits and costs, secondary tests, methods and assumptions, planning parameters, and complementary analyses as the primary BCA test. The key difference in this context is that all of these should be based on the primary BCA test that was in place when the utility decided to make the investment in question.

A.9 Performance Incentive Mechanisms

A.9.1 Description

Performance incentive mechanisms (PIMs) are financial rewards or penalties designed to incentivize utility companies to achieve specific performance goals. Regulators often establish PIMs within a performance-based regulation (PBR) framework, and they can also establish PIMs under traditional regulation practices.

There is currently a wide variety of PIMs used in the United States. Some of them cover traditional performance areas such as reliability, customer service, fuel costs, generation performance, and cost control. Other PIMs cover more performance areas such as resilience, affordability, customer

engagement, DER implementation, equity, electrification, GHG emissions, grid modernization, and more. (RMI 2025)

A.9.2 Role of Benefits and Costs

For some PIMs, benefits and costs are central to their design. For example, the purpose of "shared savings" or "shared net benefit" PIMs is to allow the utility to share a portion of the net benefits of a particular investment, program, or purchase. Typically, most of the net benefits are allocated to utility customers, and a small portion is allocated to utility as an incentive. These PIMs encourage utilities to maximize net benefits, either by increasing benefits, reducing costs, or both. Shared savings PIMs have been widely used for many years to support EE programs, and their use has expanded more recently to support other DER types, NWSs, NPSs, power procurements, and more.

Some PIMs might require assessment of benefits and costs as part of their design or implementation. For example, PIMs to encourage cost control or to promote cost-effective investments might require estimating and reporting benefits or costs as part of determining how well the utility met performance targets.

Some PIMs do not involve monetary benefits or costs in their design or implementation. For example, a PIM to encourage a utility to reduce DER interconnection time might not require a monetary estimate of the costs to reduce that time or the monetary benefit of doing so. These types of PIMs are based on the premise that the incentive paid to the utility is worthwhile because of the presumed benefits. Similarly, PIMs that only provide penalties for poor performance need not require calculating the costs associated with poor performance or the benefits of improving performance. In these instances, there is no need to ensure that the PIM applies NSPM guidance.

A.9.3 Consistent Application of NSPM Guidance

For those PIMs that include benefits or costs in their design or in their implementation, using the same benefits and costs as the primary BCA test will result in utility incentives that are aligned with the BCA test. Utilities are naturally going to implement DERs to maximize their PIM incentives, and if the PIM benefits and costs are materially different from those in the BCA test, then the benefit and cost outcomes of those DERs will be inconsistent with those of the BCA.

A.10 State Energy Policies, Planning, and Programs

A.10.1 Description

BCA are typically an element of assessing, implementing, and evaluating initiatives (e.g., programs, regulations, and standards) that result from state DER and other energy resource policies. These BCAs are conducted by and acted on by different public entities, which can include State Energy Offices and other state agencies (such as housing development agencies or community action agencies).

The following sections focus on common categories of state initiatives that can involve DER BCAs. The first section describes example state initiatives where valuation of DERs is relevant, and ideally where consistency in valuation would be implemented. The section then summarizes how consistency can be achieved via application of NSPM guidance, where applying such guidance can

benefit entities involved in these state initiatives, such as State Energy Offices, other state agencies, and stakeholder groups.

A.10.2 Illustrative State Energy Initiatives

Development and Implementation of DER Programs

Many states have programs that support implementation of DERs, including EE,[69] distributed PV (including community solar), DS, microgrids, and other initiatives to address peak loads, reduce costs, and promote resilience. These programs may operate independently or in parallel with programs offered by investor-owned or publicly owned natural gas and electric utilities. The programs can take the form of research and demonstration, marketing and outreach, and tax and direct incentives.

While developing such programs, state agencies (e.g., the State Energy Office) will often analyze the cost-effectiveness of various program design and delivery options.[70] In addition, other entities, from legislative committees to stakeholder advocates, may conduct their own analyses prospectively, to support program design, or retrospectively to support assessment of program success and future program design and policies. BCA tests in these cases play a similar role as the BCA tests conducted by utilities for their DER programs and by the Public Utility Commissions, public utility boards, and/or interested advocates. However, two differences may be that (a) the energy policy goals guiding state DER programs may account for DER benefits not reflected in BCA test used to evaluate utility DER programs,[71] and (b) the primary BCA perspective may be the 'participant' (e.g., state facilities or low-income consumers) rather than the utility system or society.

Implementation of Federal Weatherization Assistance Programs

Designated local agencies implement weatherization assistance programs at the state level that provide home EE retrofit measures for qualifying low-income customers (DOE n.d.-e). The U.S. Department of Energy (DOE) manages these congressionally appropriated programs, and it has a long-standing requirement that the programs demonstrate cost-effectiveness using a savings-to-investment ratio (SIR) based on the program participants' bill savings. Characteristics of DOE's SIR analysis include the following:

- The SIR compares the present value of the expected energy savings to the present value of the costs of implementing the program over the life of the weatherization/EE measures.

[69] State programs have also focused on supporting low-income consumers, incenting distributed PV, including community solar, as well as storage, microgrids, and other initiatives to address peak loads, reduce costs, and promote resilience. in municipal facilities, schools, and hospitals, residences, and businesses.

[70] For example, Maine's Department of Energy Resources evaluated options for the procurement of energy storage resources for the state, pursuant to a legislative requirement. In conducting that evaluation, the State Energy Office used the BCA Framework and a jurisdiction-specific test for Maine to evaluate the benefits and costs of different approaches (GEO 2024).

[71] BCA practices used to evaluate regulated utility DER programs are often not aligned with the state's applicable energy policy goals, hence the NSPM guidance to ensure that there is such alignment (see *Principle 1: Align with Applicable Energy Policy Goals* in Chapter 3).

- The bill savings to the host customer are calculated as the reduced energy consumption times the customer's specific utility rates.
- The SIR costs include the costs to DOE to implement the federal weatherization assistance program.
- The program is designed to cover all the costs of the efficiency measures, so there is no need to include host customer costs in the SIR.
- The discount rate for the SIR is determined by DOE and varies over time (DOE 2024b).[72]

In sum, the SIR is equivalent to the participant cost test or PCT (see Appendix E). DOE requires states to use this test for documenting whether to implement specific weatherization assistance programs (WAP). This approach may deviate from other tests used by state entities, such as a JST that may be developed for state general fund or ratepayer-funded programs.

Management of State Facilities

Some states have energy programs for state-owned or leased buildings and facilities. Objectives can include minimizing the cost to operate the buildings or facilities, improving resilience and reliability, reducing environmental impacts, and "leading by example."[73] Therefore, when considering DER investments in their buildings, they may conduct BCA tests from the perspective of the host customer, which is the organization that ultimately pays for the energy bills of the building. That is, states may use the PCT as the primary test for deciding whether to adopt EE or DER. The benefits include the host customer energy savings based on the changes to energy consumption times the host customer's specific utility rates. The costs include all the costs to implement the DER measure, which in this case is all host customer costs.

State Building Energy Codes, Performance Standards and Appliance Standards

Building Energy Codes

State agencies can play a variety of different roles in the development, adoption, and implementation of building energy codes (NASEO n.d.). While national organizations often develop model energy codes, some State Energy Offices develop state-specific codes, or even optional stretch codes that municipalities can choose to adopt. The State Energy Offices might also help with the regulatory process of certifying and adopting building code regulations; technical assistance to local governments, building officials, architects, and other industry professionals; and/or the promotion of code implementation and compliance.

BCAs —typically referred to as cost-effectiveness evaluations—are used to evaluate proposed building energy codes or code updates. The primary purpose of the BCA is to provide data to state legislatures, building code councils, and other stakeholders (builders, homeowners, etc.) to demonstrate that the long-term energy and cost savings outweigh the initial incremental

[72] The 2024 published rate is 2 percent real.

[73] For example, initiatives that demonstrate the value (cost-effectiveness) of highly efficient buildings and energy management practices to private and public sector architects, builders, and owners.

investment cost.[74] States often rely on the methodologies and guidance provided by DOE, which also performs BCA for national model codes (DOE n.d.-b). DOE uses several approaches to assess the benefits and costs of building codes (DOE n.d.-a). They are conducted from the perspective of the customer owning or operating the building.

- For residential building codes, DOE conducts a life-cycle cost analysis, a cash flow analysis, and a simple payback. The life-cycle analysis considers the benefits of energy savings, based on reduced energy bills. The costs include all the initial investments, based on them being financed through increased mortgage costs. The study period is 30-years, based on a 30-year mortgage.
- For commercial building codes, DOE focuses on the life-cycle cost analysis. It conducts one scenario for publicly owned buildings, one scenario for privately owned buildings, and one scenario using inputs established by the American Society of Heating, Refrigerating and Air-Conditioning Engineers. The discount rates vary across these scenarios based on the time preference of different host customers.

Building Performance Standards

Building performance standards are similar to building codes, except that codes usually apply to just the construction and major rehabilitation of buildings, while building performance standards apply to the operation of existing buildings. BCA is often part of the development of a state's building performance standard. These BCAs would include modeling of the relevant building stock to simulate the energy performance of a representative sample of buildings. The costs typically include the costs of different compliance measures such as EE measures, electrification of equipment, and ongoing maintenance costs. The benefits include the energy cost savings to the host customer over the lifespan of the building improvements. In some cases, the benefits might include societal impacts such as reduced GHG and other emissions or improved public health. Examples of BCA used to inform building performance standards include:

- *Colorado:* BCA was a significant part of the development of Colorado's building performance standard rules. These BCAs included modeling the relevant building stock based on actual building types and energy-use benchmarking data collected through Building Performance Colorado (BPS), the state's benchmarking program, to simulate the energy performance of these buildings and account for compliance with established performance targets. The costs to meet Colorado's BPS included those of different compliance measures, such as EE measures, equipment electrification, commissioning and controls, and ongoing maintenance. Within these compliance costs, an additional layer of analysis included the use of renewables in Building Performance Colorado.[75] The benefits include the energy cost savings to the host customer over the lifespan of the building improvements. In Colorado's case, the benefits also accounted for societal impacts such as the social cost of carbon. (CDPHE 2023)
- *California:* A Long-term System Cost Metric (LSC), developed by the California Energy Commission, is used specifically to evaluate the long-term benefits of California's building energy efficiency standards. LSC aligns code compliance with state policy goals—such as building decarbonization and support for DERs—by accounting not only for when energy is used, but also for how that usage

[74] For example, the Massachusetts energy office conducted a "residential cash flow analysis" for its 2023 stretch code that quantified the net benefits and costs of the more stringent code to home buyers for various illustrative new buildings (PSD Consulting 2025).

[75] Per Colorado's BPS, renewables can be used for compliance only after demonstrating that a building owner has exhausted cost-effective energy-efficiency and electrification measures for the covered building.

affects system costs and emissions over a 30-year period. LSC uses a price shape derived from the hourly marginal cost of generation produced by a production simulation model. This price shape reflects the aggregated forecast of California's transmission and distribution costs, emissions costs, ancillary services, peak capacity costs, system losses, and other energy system costs. (CEC 2025)

Appliance Efficiency Standards

Some states develop their own appliance efficiency standards for appliances without federal standards. State agencies might be involved with prohibition of non-compliant products or in the enforcement of appliance standards (which might include public reporting, investigation and remediation, collaboration with legal authorities, and imposing penalties for non-compliance).

States might want to use consistent methods and assumptions across all their BCA practices. This will facilitate comparison of BCA results across the relevant initiatives and ensure all the initiatives are using the most appropriate and up-to-date data available. In addition, considering BCA practices that are consistent with electric and gas utility BCA practices in the same state can help align the state's initiatives with the activities and programs of public and private utilities to most effectively meet the state's energy policy goals.

BCA is a critical element in the development of appliance efficiency standards. These BCAs are based on the perspective of the consumers that purchases the appliance, often aggregated over all users of that appliance type in the state. A life-cycle cost calculation might be used to compare the incremental cost of purchasing the more efficient compliance to the energy saved by the appliance over its full operating life.[76] In some cases, the benefits might also include societal impacts such as reduced GHG and other emissions or improved public health. A common metric for such BCAs is payback period for consumer energy savings to offset any initial incremental purchase price.

A.10.3 Consistent Application of NSPM Guidance

Applying the NSPM guidance to DER initiatives, and particularly the relevant NSPM principles, can support BCA consistency across all of a state's energy-related initiatives. The following are some points about those principles and their application to state DER initiatives.

Principle 1: Align with Applicable Energy Policy Goals. The primary BCA test should account for impacts that reflect state policy goals. This principle applies to state initiatives because the state agencies and programs should be aligned with and support achieving state policy goals.

Principle 2: Treat DERs as a Utility System Resource. This principle does not necessarily apply to state initiatives because they would not typically include use of utility or ratepayer funds and states have different responsibilities and provide different services than utilities.

Principle 3: Account for All Relevant and Material Impacts. One of the implications of this principle is that if a test includes host customer costs, then the test should also include all material host customer benefits as well, including host customer NEIs (see Chapter 4). This

[76] For example, the California Energy Commission (CEC) is active in developing appliance standards for products not covered by federal regulations. The CEC (the State Energy Office) has established a standardized process under Title 20 of the California Code of Regulations. CEC staff publish a "staff report" for proposed regulations that quantifies the aggregate annual energy and monetary savings associated with the proposed rule from the participant perspective. Environmental benefits are addressed in the report but not included in the BCA (CEC n.d.).

principle suggests that BCAs conducted to support state initiatives should include all material host customer NEIs as part of the PCT used to evaluate their initiatives.

Principle 4: Ensure Symmetry in the Treatment of Benefits and Costs, Principle 5: Conduct Forward-Looking, Long-Term, Incremental Analyses, Principle 6: Avoid Double-Counting Impacts, and Principle 8: Ensure Transparency. These principles apply to analyzing state initiatives, as well as to all other contexts, as discussed above. The basic concepts of accounting for all relevant and material impacts, conducting forward-looking, long-term, incremental impacts, avoiding double-counting, and ensuring transparency are appropriate for all BCA tests regardless of the actors involved.

In addition, states might want to use consistent methods and assumptions across all their BCA practices. This will facilitate comparison of BCA results across the relevant initiatives and ensure all the initiatives are using the most appropriate and up-to-date data available. In addition, considering BCA practices that are consistent with electric and gas utility BCA practices in the same state can help align the state's initiatives with the activities and programs of public and private utilities to most effectively meet the state's energy policy goals.

Principle 7: Consider Conducting Separate but Complementary Analyses to BCAs. This principle applies to analyzing state energy policy and planning initiatives as well as informing regulated utility DER investments. States might be interested in analyzing rate and bill impacts, economic development and job impacts, or equity impacts of their initiatives. (See Chapter 4, Appendix B, Appendix C, and Appendix D.)

Primary and Secondary BCA Tests

As noted in the initiatives described above, the PCT is commonly used as the primary test for evaluating programs, including implementation of DER programs; implementation of federal weatherization assistance programs; supporting EE investments in state-owned buildings; or oversight of building codes, building performance standards, or appliance efficiency standards. Using the PCT as the primary test makes sense because one of the key goals of these programs is to improve the electricity services to the program participants.

Further, as noted above, *Principle 2: Treat DERs as a Utility System Resource* does not necessarily apply to these initiatives because they have different responsibilities and funding sources than regulated utilities. This means that the primary BCA test does not necessarily have to include all material utility system impacts.[77]

State might want to use secondary BCA tests in addition to the primary BCA test to evaluate the implications of achieving policy goals not accounted for in a PCT. This would involve adding non-utility system impacts and non-participant impacts to the PCT test. The difference between the results of the PCT and the results of this secondary test would indicate the benefits and costs of the policy-based impacts that were added to the PCT.

Alternatively, states might want to compare the cost-effectiveness of their programs with that of utility ratepayer-funded programs. This could be achieved by applying the same BCA test that the utilities in their state use as a secondary test to the state initiatives.

Methods and Assumptions

States might want to use consistent methods and assumptions across all their BCA practices. This will facilitate comparison of BCA results across the relevant initiatives and ensure all the initiatives are using the most appropriate and up-to-date data available.

For consistency, BCAs for state initiatives should ideally use the methods and assumptions that utilities use for their BCA practices, especially in cases when those methods are more up to date, have been developed with robust stakeholder input, or have been developed on a statewide basis.

Methodologies for monetizing or quantifying the impacts of DERs are documented in the *Methods, Tools, and Resources for Quantifying DER Impacts (MTR Handbook)*, a companion document to the NSPM. The MTR Handbook provides guidance on the full range of utility system and non-utility system impacts, as summarized in Chapter 14.

Complementary Analyses

Depending on a state's articulated state energy goals, the state may be interested in conducting certain complementary analyses alongside BCA tests to understand the impact of DER investments on those goals, and to help track progress towards meeting those goals. State agencies such as State Energy Offices may want to conduct one or more of the following example complementary analyses:

- Rate and bill analyses (RBA)—to assess the implications of their initiatives on customer affordability. State Energy Offices may also want to advocate for commissions to require RBAs to assess the implications of utility DER programs. (See further details in Appendix B.)
- Economic development analyses (EDA)—to see how their initiatives or utility investments will affect jobs and economic development in their state. (See details in Appendix C.)
- Distributional equity analyses (DEA)—to assess equity impacts (e.g., impact of DER investments on one customer group relative to all other customers) to inform the design, implementation, and evaluation of a State Energy Office initiatives, as well to assess the equity implications of utility resource investments to promote state energy equity goals. (For more information see Appendix D.)

Transparency

State initiatives often involve stakeholder input processes. Ensuring transparency in valuing DERs and other resource investments—consistent with guidance in this Manual—is directly applicable to State Energy Offices, especially in areas where they account for policy goals in their BCA practices.

Appendix B. Rate and Bill Impacts

This appendix explains how DERs can lead to rate impacts, how rate impacts are different from cost-effectiveness, and why the two require separate analyses. It also describes the key elements of a meaningful rate, bill, and participation impact analysis.

B.1 The Cause of Rate and Bill Impacts

DERs, as with all utility resources, will impact customer rates.[78] Some DERs are likely to increase rates, while others are likely to reduce rates. Some DERs may have very little effect on rates at all. The extent to which DERs will impact rates depends upon many factors, including the extent to which they reduce or increase utility system costs and the extent to which they reduce or increase utility sales.

In general, regulators set electricity and gas utility rates to equal utility system costs (i.e., revenue requirements) divided by sales (i.e., billing determinants). Therefore, analyzing DER rate impacts requires determining how DERs affect utility sales and costs, and accounting for the regulatory practices that recover those costs.

The extent to which DERs will create rate impacts typically depends upon several key factors:

- **Increases in utility system costs will put upward pressure on rates.** These might include, for example: program administration costs; generation, transmission, or distribution costs; financial incentives to developers and customers; and performance incentives (see Table 6-1).
- **Reductions in utility system costs will put downward pressure on rates.** These might include, for example: avoided generation capacity costs; avoided environmental compliance costs; avoided RPS/CES compliance costs; market price suppression effects; avoided transmission costs; and avoided distribution costs.
- **Reductions in sales from DER resources will put upward pressure on rates.** Reduced sales lead to lost revenues which might require increased rates to recover past sunk costs over fewer sales.
- **Increases in sales from DER resources will put downward pressure on rates.** Increased sales lead to increased revenues, which might allow reductions in rates because the increased revenues can help pay for recovery of past sunk costs by spreading them over more sales.[79]

[78] This appendix discusses both rate impacts and bill impacts. Changes in rates will also create changes in bills. Most of the text here refers to rate impacts for simplicity, even though there will be corresponding bill impacts. When there are specific implications for bill impacts, the text specifically calls them out.

[79] The changes in sales can also lead to changes in utility system costs. That is, when sales decline there might be less need for certain utility investments, and when they increase there might be more need. The BCA captures these changes in costs due to changes in sales, which will therefore flow into the RBA.

- **Rate design will affect the amount of lost or increased revenues created by the DER.** Fixed customer charges mitigate the effect of DERs on lost or increased revenues. Similarly, demand charges might mitigate the effect of DERs on lost revenues or increased revenues, depending on the charge's structure and the extent to which the DER allows a customer to reduce payments for the demand charge.

A comprehensive understanding of rate impacts requires a long-term analysis of all the factors described above, consistent with the study period used for BCA tests.

Rate impacts do not necessarily occur immediately upon installation and operation of DERs. Rates first need adjustment to reflect changes in costs being recovered or changes in sales. Some rate adjustments might occur fairly quickly (as in the case of reconciling rate riders to recover EE program costs, or in the case of fuel and purchased power costs automatically passed through to customers in rate riders). Other rate adjustments might occur over a slightly longer period, such as in jurisdictions with decoupling, performance-based ratemaking adjustments, or lost revenue recovery mechanisms. Other rate adjustments might occur as a result of a rate case. In the absence of rate adjustments, or until such time as all the rate adjustments are made, utility shareholders rather customers will experience the impacts of DERs on costs and sales.

Similarly, changes in utility system benefits and costs do not occur immediately upon installation and operation of DERs. Some benefits, such as avoided capacity costs, might take several years to be realized. Further, there might be a delay in passing benefits and costs on to customers, depending upon the ratemaking schedule of the jurisdiction.

DER rate impacts can vary from year to year. It is common for many DER costs to occur in the early years, whereas benefits typically materialize throughout DER operating life. Consequently, rate impacts are sometimes greater in the short term than over the long term. A comprehensive understanding of rate impacts requires a long-term analysis of all the factors described above, consistent with the study period used for BCA tests.

B.2 Cost-Effectiveness and Rate and Bill Impacts

In some cases, DER host customers (i.e., participants) will experience higher rates but lower bills, while those that do not install DERs (i.e., non-participants) may experience higher rates and therefore higher bills. Consequently, the rate impacts of DERs are a matter of customer equity between DER host customers and other customers.

BCA does not address customer equity. Rather, it focuses on the benefits and costs to customers and the utility system as a whole. There are two key reasons for conducting BCA tests separately from rate impact analyses, as described below.

- BCA accounts for future, incremental benefits and costs, as set forth by the NSPM *Principle 5: Conduct Forward-Looking, Long-term, Incremental Analyses*. Rate impacts can stem from lost revenues or increased revenues that are not driven by new, incremental investments in DERs. Rate increases from lost revenues are largely caused by the need to recover past costs

Rate impacts are partly driven by lost revenues or increased revenues, but these revenue changes from DERs are not driven by a new, incremental cost created by investments in those resources. They are largely caused by past, or 'sunk' costs.

over fewer sales, and rate reductions from increased revenues are caused by the ability to recover past costs over greater sales. DERs do not cause these past costs, which result from historical investments in other utility resources that need to be recovered through bills over time (often over many decades). In economic terms, these existing fixed costs are 'sunk' costs. In economic theory, assessments of future investments exclude sunk costs because the costs exist regardless of any future investment.

- BCA answers a different question than rate impact analyses: BCA tests determine which utility DER investments are expected to have benefits that exceed costs. The purpose of rate impact analyses is to answer the question of how much will utility DER investments impact rates. Attempting to answer these two questions in a single analysis conflates the two questions and thus does not provide helpful information on either the cost-effectiveness of the DER investment or the extent of the rate impacts (and to which customers).

Table B-1. Comparison of Benefit-Cost Analysis and Rate and Bill Analysis

Key Considerations	Benefit-Cost Analysis	Rate Impact Analysis
Question answered	Which utility DER investments are expected to have benefits that exceed costs? Cost-effectiveness indicates the extent to which different utility investments will reduce utility costs and achieve other policy goals, regardless of how the benefits and costs are distributed across different customers.	How much will utility DER investments impact rates?
Form of analysis results	Present value of revenue requirements, benefit-cost ratios, and net benefits: These metrics are important for regulators and other stakeholders to understand cost-effectiveness but do not provide any information relevant to rate impacts.	Long-term impacts on rates (in ¢/kWh or percent changes to rates) or in terms of long-term bill impacts (in $ per month or percent changes to bills): These metrics are important for regulators and other stakeholders to understand rate impacts but do little to inform benefit-cost analyses.

Note: Fully understanding the impacts of DER investments across different customers requires a comparison of the bill impacts on host customers—the combined effect of (a) rate impacts and (b) any savings or costs directly incurred as a result of DER investment—versus the bill impacts of other customers (which only experience rate impacts). (See Section B.4.)

Many utility resource investments create rate impacts and customer equity issues. For example, some utility infrastructure investments such as distribution substations serve only a subset of customers but are socialized across all customers. In addition, there are other aspects of electricity and gas regulation that create inequities, such as rate designs that are not fully cost-based. The issues discussed in this appendix refer to only those equity issues created by DERs. When considering rate and equity concerns about DERs, it is important to keep in mind that rate impacts and customer equity issues occur for many reasons beyond just DERs. For additional discussion on equity issues related to DER impacts on specific populations (such as vulnerable or disadvantaged customers) see Appendix D.

B.3 The Rate Impact Measure Test

The *California Standard Practice Manual* presents the RIM Test to account for rate impacts in EE cost-effectiveness analysis (CPUC 2001). The RIM Test is the same as the UCT (sometimes alternatively called the PACT) except that it includes the lost revenues from DER programs as one of the costs of the DER (or it includes the increased revenues as one of the benefits). (See Appendix E.)

Most jurisdictions have rejected use of the RIM Test for EE cost-effectiveness analysis because it acts more as a "lost sales" measure than a true cost-effectiveness screen by inaccurately treating reduced utility revenue as a cost. Some regulators and stakeholders continue to consider the results of this test as a secondary test but are not clear on how to use the results.

In the case of other DERs types, especially DPV that might create upward pressure on rates and electrification resources that might create downward pressure on rates, the RIM test is often used to assess cost-effectiveness, but unfortunately use of the RIM test has important limitations, as described below:

- Cost-effectiveness analyses should account for only future, incremental benefits and costs, as required by *Principle 5: Conduct Forward-Looking, Long-Term, Incremental Analyses*. As described in Section A.1, rate increases from lost revenues are caused by the need to recover past sunk costs over fewer sales, and rate reductions from increased revenues are caused by the ability to recover such costs over greater sales. These costs stem from historical investments in other utility resources that need to be recovered from current and future customers. The RIM Test includes those historical costs, thereby violating this principle.
- The RIM Test attempts to answer two different questions in a single analysis, which conflates the two questions and thus does not provide helpful information on either one.
- The RIM Test does not provide useful information about what happens to rates in terms of the magnitude of impact due to a DER investment. A RIM BCR of less than 1.0 indicates that rates will increase (all else being equal) but does not inform the extent of the rate impact—either in terms of the percent (or ¢/kWh) increase in rates or the percent (or dollar) increase in bills. In other words, the RIM Test results do not provide any context for regulators and stakeholders to consider the magnitude and implications of the rate impacts.

The RIM Test does not provide useful information about what happens to rates in terms of the magnitude of impact due to a DER investment.

The RIM Test can be used (a) to determine whether rates are likely to increase or decrease, and (b) to determine whether to conduct a rate, bill, and participation analysis.

- Screening out DERs based on the RIM Test will not result in the lowest cost to customers on average. Instead, it might lead to the lowest rates (all else being equal). However, achieving the lowest rates is not the sole objective of DER planning. Other goals include providing reliable, low-cost service while achieving applicable energy policies.
- Screening out DERs based on the RIM Test can lead to perverse outcomes. The RIM Test can lead to the rejection of significant reductions in utility system costs to avoid what may

be insignificant impacts on customers' rates. For example, a DER might offer millions of dollars in net benefits under the UCT (through net reductions in utility system costs) but be rejected as not cost-effective if it fails the RIM Test. It may well be that the actual rate impact would be so small as to be unnoticeable. Rejecting such large reductions in utility system costs to avoid de minimus rate impacts is not in the best interests of customers overall.

- Putting the RIM Test results in terms of net benefits can be misleading. For a DER investment with a RIM BCR of less than one, the net benefits (in terms of present value dollars) will be presented as negative benefits. A negative net benefit implies that the DER investment will increase costs. However, as described above, the costs that drive the rate impacts under the RIM Test are not new incremental costs associated with DERs. They are existing costs that are already in current electricity or gas rates. Any rate increase caused by lost revenues would be a result of recovering those existing fixed costs over fewer sales rather than as a result of incurring new costs. However, utilities and others frequently present their RIM Test results as negative net benefits, implying that the DER investment will increase costs when in fact it will not.

The RIM Test can be useful for two purposes, both of which are related to rate impacts but not to cost-effectiveness:

- To determine whether a DER or set of DERs is likely to increase or decrease rates; and
- To help inform whether a long-term rate, bill, and participation impact analysis is warranted.

For example, if a RIM Test result indicates DERs are likely to reduce rates (with a RIM BCR of greater than 1.0) or are likely to increase rates a small amount (with a RIM BCR of less than but close to 1.0) then there may be no need to conduct a rate, bill, and participation analysis. If, on the other hand, the RIM Test results indicate a substantial rate increase (BCR of less than 0.9) then a rate, bill, and participation analysis might be warranted.

The RIM Test can be useful for two purposes, both of which are related to rate impacts but not to cost-effectiveness.

B.4 Better Approaches for Analyzing Rate Impacts

A thorough understanding of the implications of DER rate impacts and cost-shifting requires analysis of three important factors: rate impacts, bill impacts, and participation impacts.

- *Rate impacts* indicate the extent to which rates for all customers might increase or decrease due to DERs.

- *Bill impacts* indicate the extent to which customer bills might decrease for those customers that install DERs.
- *Participation impacts* indicate the portion of customers that will experience bill reductions or bill increases. DER host customers will typically experience bill reductions while other customers might see rate increases or decreases leading to bill increases or decreases.

Taken together, these three factors indicate the extent of the impact on customers from DERs, and the extent to which DERs might lead to equity concerns between DER program participants and non-participants.

Comprehensive rate impact estimates account for all factors that affect rates, including all factors that might exert downward pressure on rates and all factors that might exert upward pressure on rates.

The appropriate level for rate, bill, and participation analyses for DERs is an aggregated level, partly for the need to keep the analyses simple and accessible and partly because customers will experience the rate impacts from DERs in an aggregated fashion. Further, regulators and other stakeholders may prefer to see rate, bill, and participation analyses that account for the impacts of all DERs combined because this offers the advantage of seeing how rate impacts of one DER type might offset, or exacerbate, rate impacts of other DER types.

B.4.1 Rate Impact Estimates

Comprehensive rate impact estimates account for all factors that affect rates, including all factors that might exert downward pressure on rates and all factors that might exert upward pressure on rates. In addition, there are other best practices for effective rate impact estimation:

- Rate impact estimates should reflect only the actual impact on rates according to the jurisdiction's ratemaking practices, such as decoupling, lost revenue recovery mechanisms, and the frequency of rate cases.
- To capture the full period over which the efficiency savings will occur, rate impact estimates require a long timeframe. The study period should include all the years in which DERs are operational.[80]
- To allow regulators and other stakeholders to properly consider and weigh rate impacts, the analysis will express the results using meaningful context. For example, it is helpful to put results in terms of ¢/kWh impacts, dollars per month, percent of total rates, or percent of total bill.
- Because rate impacts can differ across customer types, it might be useful to analyze the rate impacts for different customer sectors. However, conducting a rate impact analysis for every customer class might be too burdensome and unnecessary. Instead, analyses can be conducted for key customer types such as residential, small commercial, and large C&I.

Methods for Estimating Rate Impacts

There are many ways to estimate rate impacts. Two options include a top-down approach and a bottom-up approach.

[80] In practice, rate impacts can last even after the operating life of the DER.

Top-Down Approach for Estimating Rate Impacts

A simple formula for estimating rate impacts of DERs is 'rates = costs/sales.' Practitioners can apply this formula to determine rates for a scenario without the DER, and a scenario with the DER. The difference in rates between the two scenarios will be the rate impacts. The box below provides more details.

Top-Down Approach for Estimating Rate Impacts

Rate impact of the DER in $/kWh = R2-R1

Rate impact of the DER in percentage terms = R2/R1 – 1

where

R1 = C1 / S1. Estimate C1 using R1 and S1, which are generally available from public sources such as the U.S. Energy Information Administration.

R2 = C2 / S2. C2 = C1 plus changes in costs caused by the DER (the incremental utility system costs minus the incremental utility system benefits) from the BCA. S2 = S1 plus change in sales caused by the DER, from the BCA.

and

1 = scenario without the DER
2 = scenario with the DER
C = utility system costs ($)
S = utility system sales (kWh)
R = C / S = utility rate ($/kWh)

This method accounts for both the upward and downward pressure on rates from utility system costs by subtracting utility system net benefits (benefits minus costs) from C1 when calculating C2. This method also accounts for both the upward and downward pressure on rates from lost revenues or increased revenues by accounting for the changes in sales when calculating S2.

This method does not require an explicit estimate of the lost or increased revenues from DERs. By including the reduced or increased sales in the denominator for R2, the calculation implicitly accounts for lost or increased revenues.

Bottom-Up Approach for Estimating Rate Impacts

The bottom-up approach includes estimating each of the four factors that will affect rates: increased costs, reduced costs, lost revenues, and increased revenues. Each of these factors are then combined to determine the total impact on rates in terms of either dollars or $/kWh. The box below provides more details, where the rate impacts can be positive or negative, depending on the magnitudes of the net benefits and the change in revenues. The box below provides more details.

Bottom-Up Approach for Estimating Rate Impacts

Rate impact ($) = net benefits ($) + change in revenues ($) = (C2-C1) + (B2 – B1) * participants

Rate impact ($/kWh) = dollar rate impact ($) / S2 (kWh)

Rate impact (%) = rate impact ($/kWh) / R1 ($/kWh)

where

B1 = average annual bill for customer without DER
B2 = average annual bill for participating customer with DER
Change in revenues from DER ($) = (B2-B1) * number of participants

and

1 = scenario without DER
2 = scenario with DER
R1 = rate ($/kWh) without DER
S2 = system sales (kWh) with DER
C1 = utility system costs ($) without DER
C2 = utility system costs ($) with DER
Net benefits of DER ($) = C2-C1

The estimate of changes in revenues, calculated by subtracting the average bill for a customer with DER from the average bill for a customer without DER, will ideally account for the rate design of the customer type in question. In other words, it accounts for customer charges, demand charges, or time-varying rates.

Considerations for Both Approaches

Both approaches described above estimate the largest amount of rate impact the DERs might cause, because they assume the ratemaking practices in the jurisdiction allow for rates to be updated annually. For jurisdictions with decoupling mechanisms, where they reconcile rates annually to account for changes in sales, both approaches will provide a good estimate of the timing and magnitude of rate impacts. For those jurisdictions that do not have decoupling mechanisms, where they change rates less frequently through rate cases, an additional step is required to account for the fact that base rates are not adjusted each year. For example, in a jurisdiction that typically holds rate cases every four years, the rate impacts will be only one-quarter of those estimated using the methods above.

Both approaches described above estimate the largest amount of rate impact that might be caused by the DERs, because they assume that the ratemaking practices in the jurisdiction allow for rates to be updated annually.

Practitioners can apply both approaches either to average rates for an entire utility or to specific customer groups such as residential, small commercial, and large C&I. Estimating average rate impacts for an entire utility is less burdensome and might provide high-level results sufficient to make reasonable conclusions that roughly apply to all customers. Estimating rate impacts by customer categories will be more burdensome but might help identify differences that might result from different rate designs or usage levels of different customer types.

Both approaches require a forecast of rates over the long term (over the BCA study period) for the scenario without the DER. Such forecasts can use simple assumptions of likely growth in rates over time. The forecasts do not need to be highly precise to be useful for estimating rate impacts, because the rate impacts are based on the difference between the scenarios with and without the DER. If the forecast of rates in the scenario without DER turns out to be inaccurate, that inaccuracy will have little impact on the differences calculated; it will slightly affect the percentage difference in rates, but it will not affect the absolute difference.

While rate impacts apply to every customer within a rate class, bill impacts will vary between DER participants and non-participants.

B.4.2 Bill Impact Estimates

The calculation for DER bill impact estimates relies on the rate impacts estimates. While rate impacts apply to every customer within a rate class, bill impacts will vary between DER participants and non-participants.

- Bill impacts for DER non-participants will be proportional to their rate impacts. The rate impacts from DERs will typically affect the variable portion of customers' rates, but not fixed portions such as the customer charge or the demand charge. Thus, accurate determination of bill impacts for non-participants requires accounting for these rate design aspects.
- Calculating bill impacts for DER participants (host customers) requires another step because the participants will experience a change in consumption in addition to the change in rates. To determine the full change in participant bills, it is necessary to add reduced or increased energy consumption to the rate impact. The participants' change in consumption will depend on the type of DER, the customer's behavior, and the customers' rate design.

As with rate impact estimates, bill impact calculations can encompass all customers on average or specific customer groups such as residential, small commercial, and large C&I. Bill impact calculations can also be done by program, by customer sector, or for the DER portfolio. Estimating average bill impacts for an entire utility is much less burdensome than estimating by customer groups and might provide high-level results sufficient to make reasonable conclusions that roughly apply to all customers. Similarly, estimating average bill impacts for the portfolio of DERs, as opposed to each program, is much less burdensome and might provide results sufficient to make reasonable conclusions about impacts on all customers.

As with rate impact estimates, bill impact estimates require a long timeframe to capture the full period over which the DER is operational. It is also important to express bill impacts results within a meaningful context so DER planners and regulators can properly consider and weigh them. For example, the analysis can express the results in terms of dollars per month or percent of total bill.

B.4.3 Participation Estimates

The most useful way to express participation estimates is in terms of participation rates, measured by dividing participating DER host customers by the total population of customers eligible for the DER program. Participation rates provide context and more meaningful information relative to a simple number of program participants. Participation rates are also helpful in comparing participation across DER initiatives, DER types, across utilities, and across jurisdictions.

Below are several best practice considerations related to participation rates:

- It is best to estimate participation rates for each year of DER implementation, and then to compare these results across a range of years to indicate the extent to which customers are participating in DERs over time. The analysis should account for participation in multiple DERs and across multiple years to the extent possible.
- Program participation rates should account for unique participants, which means a customer who participates in a program in multiple years should be counted only once. Similarly, customers participating in more than one program in a year should be counted only once. One of the key goals of the participation analysis is to identify the portion of customers who do not participate in any DER programs.
- It is possible to mitigate or even eliminate many equity concerns driven by rate impacts by promoting greater customer adoption of DERs. This approach applies particularly well to EE, DR, and other DER programs that can be offered to all customers. Program participation information is useful for encouraging more customers to install DERs and thereby experience lower bills. Utilities and other entities promoting DERs could be charged with the responsibility of reaching out to those customers that have not yet implemented some form of DER.
- To enable meaningful estimates in jurisdictions where program participation information is not currently available, it is important to collect this information as soon as possible to allow development of participation estimates in future years. This type of information is critical for assessing the rate impact and related equity issues of DERs.

Many equity concerns driven by rate impacts can be mitigated or even eliminated by promoting greater customer adoption of DERs, particularly EE, DR, and other DER programs that can be offered to all customers.

B.4.4 Presentation of Rate, Bill, and Participation Impacts

Figure B-1 below demonstrates a useful way to present the results of a long-term rate impact analysis. This example shows the estimated long-term rate impacts, in terms of percent changes in rates, for six different DER types. It also shows the long-term rate impacts of all the DERs combined. In this case, the long-term rate increases from EE and DG resources are nearly offset by the rate reductions from the other DER types.

Figure B-1. Example Presentation of Long-Term Rate Impacts

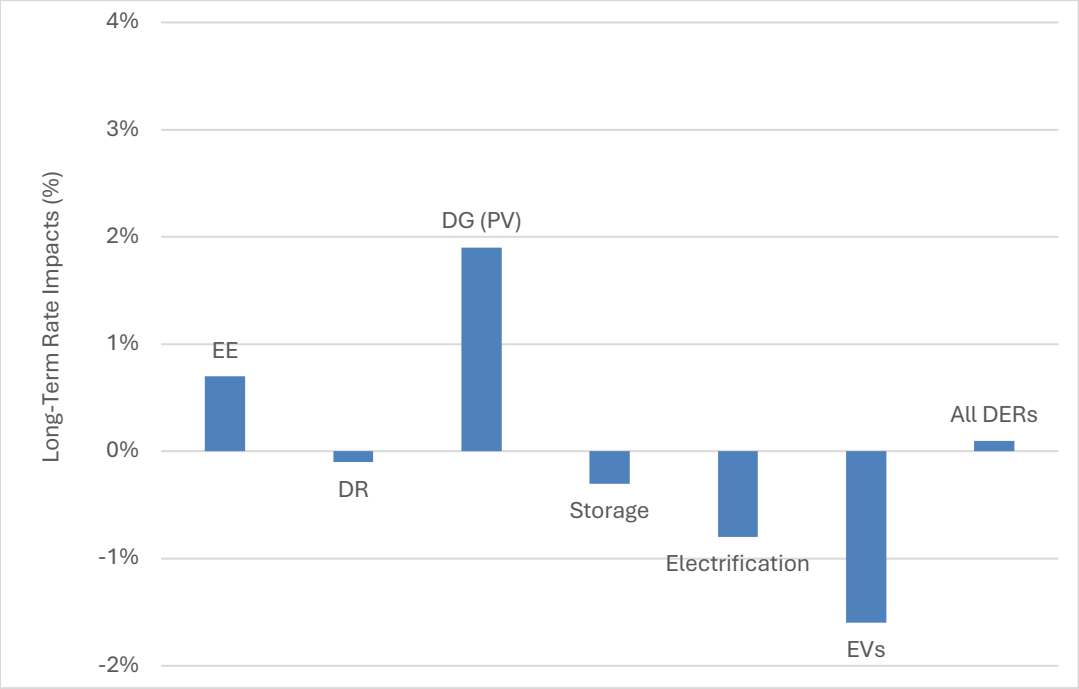


Figure B-2 shows a useful way to present the results of a long-term bill impact analysis. This analysis includes the average bills across all utility customers (it includes the bills of both DER host customers and other customers). Also, for those resources that affect multiple fuel types, such as electrification and EVs, this analysis reflects the impact on the combined bills for all the fuels affected by the DER.

Figure B-2. Example Presentation of Long-Term Average Combined Bill Impacts

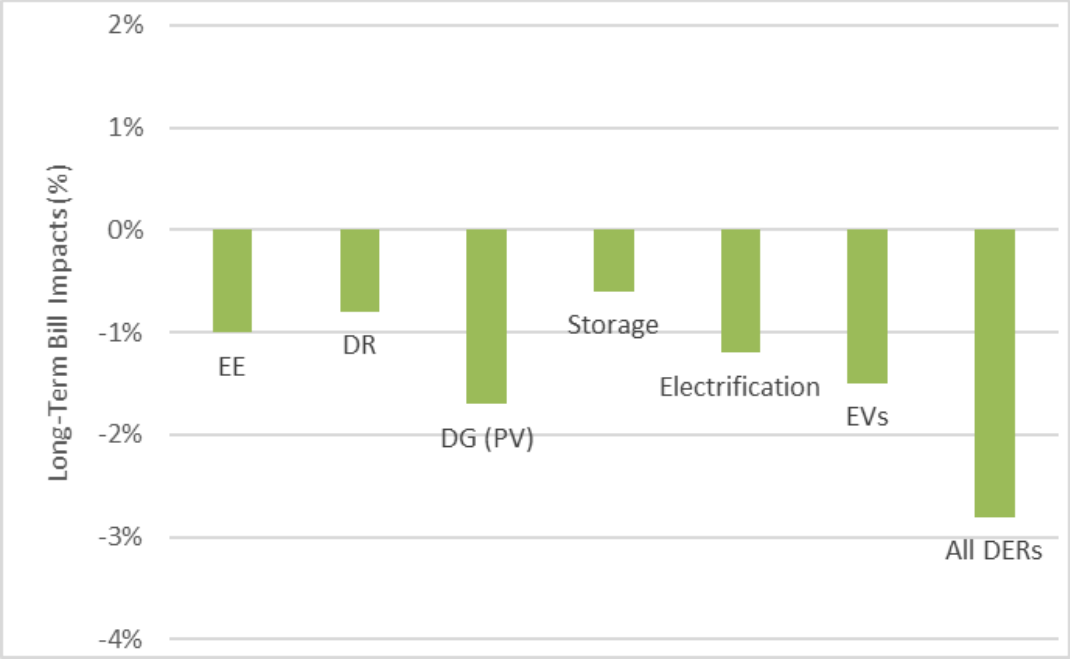
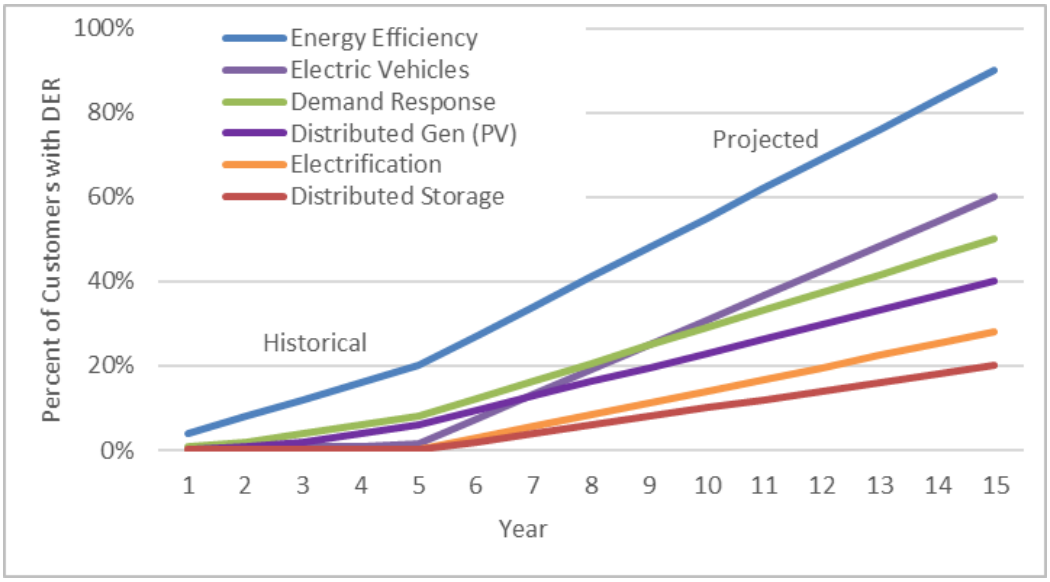


Figure B-3 shows a useful way to present the results of a long-term participation analysis. It presents five years of historical DER participation rates, as well as 10 years of projections of future participation rates. Ideally, the participation rates would account for customers who participate in more than one program or install more than one type of DER. That would allow for the presentation of the percentage of DER host versus non-host customers, which would help inform discussions about customer equity.

Figure B-3. Example Presentation of Long-Term Participation Impacts



The DERs and long-term rate, bill, and participation results presented in these figures are purely illustrative and not based on specific DERs in a specific jurisdiction. Actual results could be significantly different from those presented here. Further, results will vary within the DER types presented here—the figures bundle DER types together for simplicity.

Note also that for a given set of DERs, these results will not vary depending on the test used because rate and bill impact estimates include only utility system benefits and costs; other benefits and costs will not affect rate or bill impacts.

Regulators and other stakeholders can use these analyses to assess whether any expected long-term rate impacts are warranted in light of the BCA results, the bill reductions, and the participation rates.

B.5 Consideration of Rate and Bill Impact Analyses Results Alongside BCA Results

There is no specific methodology for how to balance BCA test results with the rate, bill, and participation analysis results. Regulators and other stakeholders can use these analyses to assess whether mitigating any expected long-term rate impacts are warranted in light of the BCA results, the bill reductions, and the participation rates.

Below are several examples demonstrating how utilities and regulators might strike a balance between BCA and rate, bill, and participation impacts. Each example is purely illustrative and not based on any actual real-world analyses.

Example 1. Energy Efficiency Portfolio

This example includes a large portfolio of EE programs.

- The BCA results indicate that the EE portfolio is cost-effective and will result in substantial net benefits.
- The rate, bill, and participation analysis indicates that long-term average rates will increase by 1.3 percent, and that there will be high levels of participation particularly among low-income customers.

Table B-2. Example 1 Sample Comparison of Results for EE Portfolio

Analysis	Impact	Result
Benefit-Cost Analysis	Net Benefits (mil PV$)	385
	Benefit-Cost Ratio	2.1
Rate Impact Analysis	Long-Term Rate Impacts (%)	1.3
	Bill Impacts Non-Participants (%)	1.2
	Bill Impacts Participants (%)	-3.4
	Participation Rate (%) Participation Low-Income (%)	48 56

Note: mil PV$ is millions in present value dollars.

In this example, the utility and regulators need to determine whether a long-term rate increase of 1.2 percent is acceptable in light of the net benefits of $385 million present value dollars (an average reduction in bills for participants of 3.4 percent) and participation rates of 56 percent for low-income customers and 48 percent for other customers.

Example 2. Demand Response Portfolio

This example includes a large portfolio of DR programs.

- The BCA results indicate that the DR portfolio is cost-effective but results in a modest amount of net benefits relative to the EE example above.
- The rate analysis indicates that long-term average rates decrease by a small amount. This is because the DR programs in this example have little to no lost revenues but can help reduce utility system costs.
- The participation analysis indicates that the participation rate is relatively low. This is because only a small portion of customers have the relevant end uses for the DR program and are interested in the small amount of bill savings from the program.

Table B-3. Example 2 Sample Comparison of Results for DR Portfolio

Analysis	Impact	Result
Benefit-Cost Analysis	Net Benefits (mil PV$)	45
	Benefit-Cost Ratio	1.4
Rate Impact Analysis	Long-Term Rate Impacts (%)	-0.1
	Bill Impacts Non-Participants (%)	-0.1
	Bill Impacts Participants (%)	-1.2
	Participation Rate (%) Participation Low-Income (%)	18 11

In this example, there is no need to strike a balance between cost-effectiveness and rate impacts. The program offers net benefits and a slight reduction in rates.

Example 3. Combined Analysis of Several DERs

This example includes the EE and DR portfolios from the previous two examples, plus portfolios of DG, DS, and EV programs.

- The BCA results indicate that the combination of all these DR portfolios together is cost-effective, with large net benefits.
- The rate analysis indicates that long-term average rates increase by a small amount. This is because the DERs that cause upward pressure on rates (EE and DG) have slightly more effect on rates than those that have downward pressure on rates (DR, DS, and EVs).
- This analysis also indicates that the participation rate is high. This is because many customers can participate in at least one of the several DER programs.

Table B-4. Example 3 Sample Comparison of Results for Multiple Portfolios

Analysis	Impact	Result
Benefit-Cost Analysis	Net Benefits (mil PV$)	605
	Benefit-Cost Ratio	1.6
Rate Impact Analysis	Long-Term Rate Impacts (%)	0.3
	Bill Impacts Non-Participants (%)	0.3
	Bill Impacts Participants (%)	-3.4
	Participation Total (%) Participation Low-Income (%)	76 64

In this example, the utility and regulators need to determine whether a long-term rate increase of 0.3 percent is acceptable in light of $605 million present value dollars of net benefits, average bill

reductions of 3.4 percent for participants, and participation rates of 64 percent for low-income customers and 76 percent for other customers.

Example 4. Heat Pump Electrification Program

This example includes a heat pump program that incentivizes customers who have inefficient gas space heating to switch to more efficient electric heat pumps. In this case, it is necessary to consider the rate, bill, and participation results for the gas customers, the electricity customers, and both sets of customers combined.

- **BCA results:**
  - For the gas customers in isolation, the program is highly cost-effective because of the substantial reduction in gas commodity costs.
  - For the electricity customers in isolation, the program is not cost-effective because the program results in the need for increased electricity infrastructure to meet the increased electricity consumption and does not result in any avoided electricity costs.
  - For the gas and electricity customers combined, the program is cost-effective, because the net benefits to gas customers outweigh the net costs to electricity customers.
- **Rate impact results:**
  - For the gas customers, the long-term rates increase because of the lost revenues from reduced gas consumption.
  - For the electricity customers, the long-term rates decrease because of the increased revenues from the increased electricity consumption.
  - For the gas and electricity customers combined, it is not possible to get the rate impact because impacts in terms of $/kWh cannot be added to those in terms of $/therm. For this purpose, it is necessary to consider the bill impacts in terms of dollars.
- **Bill impact results:**
  - For the gas customers, the participants' bills decrease due to the reduced gas sales but the non-participants' bills will increase due to the lost revenues from reduced consumption.
  - For the electricity customers, the participants' bills increase because of the increased electricity consumption but the non-participants' bills decrease because of the reduced rates.
  - For the gas and electricity customers combined, the participants' bills will decrease because the reduced gas bills outweigh the increased electricity bills but the non-participants' bills will increase because of the increase in the gas rates.
- **Participation rate results:**
  - For the gas customers, only a small portion participate because some of them do not have gas space heating and, of those that do have it, only a small portion has a heating system old enough to replace economically.
  - For the electric customers, an even smaller portion participate because many electricity customers do not have gas services or gas space heating.

Table B-5. Example 4 Sample Comparison of Results for Heat Pump Electrification Program

Analysis	Impact	Gas	Electric	Gas + Electric
Benefit-Cost Analysis	Net Benefits (mil PV$)	100	-20	80
	Benefit-Cost Ratio	1.6	0.5	1.3
Rate Impact Analysis	Long-Term Rate Impacts (%)	1.8	-0.6	not additive
	Bill Impacts Participants (%)	-40	30	-10
	Bill Impacts Non-Participants ($)	10	-2	8
	Participation Total (%) Participation Low-Income (%)	12 4	6 2	12 4

In this example, the utility and regulators need to determine whether the increased rates and bills for gas non-participants are acceptable in light of the net benefits provided by the program, the reduction in rates for all electric customers, and the relatively small participation rates for gas and electricity customers.

Options for Addressing Rate Impact Concerns

There are many different ways to address concerns about rate impacts once they are well understood. Regulators and other stakeholders may choose to modify proposed DER resources in order to strike a better balance between cost-effectiveness and equity issues. One option is to expand DER resources (especially EE and DR programs that can be offered to any customer) to include more participants and mitigate equity concerns. Another option is to revisit some of the DER designs to find ways to deliver them at lower cost (for instance, finding third-party financing or requiring host customers to pay larger portions of the DER cost). Another option is to emphasize DERs that have high participation rates over those that have lower participation rates, or to emphasize those that reduce rates over those that increase them.

Regulators and other stakeholders may choose to modify proposed DER resources in order to strike a better balance between cost-effectiveness and equity issues.

Appendix C. Economic Development Analysis

This appendix provides an overview of EDA for jurisdictions that have economic-development-related energy policies associated with utility DER investments. It explains how EDAs relate to BCAs, the key distinctions and overlaps between EDAs and BCAs, and why the results of an EDA should not be added directly into the BCA.

C.1 Introduction

Some jurisdictions have energy policy goals related to job creation and other economic development impacts from utility DER investments. In these cases, utilities are often required to analyze the economic development impacts of utility investments. These impacts may be evaluated formally through an economic development analysis (EDA). The results from an EDA can help decision-makers understand whether contemplated spending changes[81] will result in net positive or negative economic development impacts. The results can also provide additional context to consider alongside the results of a BCA.[82]

EDA and BCA overlap but address different issues. Adding their results together generates a convoluted picture and can result in double-counting.

BCAs measure the extent to which costs change as a result of the DER investment, while EDAs measure the extent to which economic activity changes, which is a very different type of impact. Further, EDAs and BCAs have a complex relationship in which the inputs and outputs of a BCA are used as inputs to the related EDA. For these two reasons, it is incorrect to add the results of an EDA to the results of a related BCA.

C.2 Overview of Economic Development Analysis

An EDA is a structured approach to evaluating the wider economic impacts that result from changes in spending. EDAs are commonly used to study the economic impacts of multiple factors, including resource investments, policy or programmatic changes, and changes in tax or fiscal policy, among other things. An EDA accounts for how initial economic changes cascade through the economy to generate positive and negative impacts on aggregate economic development. EDAs typically analyze local impacts within a defined geographic boundary such as a state or province.

For policymakers, one of the most important economic indicators is jobs.

[81] In this appendix, the term ‘spending change’ and similar formulations are shorthand for all of the different initial economic changes that may be analyzed through EDAs.

[82] In this appendix, the term ‘economic development impacts’ refers to the changes in economic activity estimated through an EDA. While some literature refers to these development impacts simply as ‘economic impacts,’ this term could also refer to the results of a BCA, and so this appendix avoids that term to prevent confusion.

C.2.1 Key Metrics Reported in EDAs

To quantify economic impacts, EDAs commonly report changes to three metrics: *employment, income,* and *gross domestic product*.

Employment

For policymakers, one of the most important economic indicators is jobs. The employment metric represents the change in total employment within the specified region.

Commonly used language about job impacts can be misleading if it lacks a time dimension. For example, a claim that a program creates 100 new jobs is imprecise. This could be interpreted to mean that there are 100 new jobs created that will remain in perpetuity. The more precise term, 'job-years,' includes a time dimension and is often how an EDA reports job impacts. One job-year is equal to one person working full time (40 hours per week) for a year, or two people working full time for half of a year (EPA 2018). Job-years allow EDAs to more accurately represent variation in the duration of jobs created from a new policy or program.

Incremental job gains or losses expressed in job-years may not actually mean job gains or losses but rather could manifest as changes in hours worked among those already employed, or a longer duration of a time-limited position. Similarly, since job-years are a statistical measure computed by dividing the change in employment hours by the total hours in a single job-year, to the extent that a change in job-years does result in creation of new job positions, these need not be full-time positions.

Income

Income changes typically include both changes in wage earnings of workers on payroll and changes in the earnings of proprietors of businesses. This metric may also include impacts to other forms of earnings, including social security and other government benefits, dividends, and interest. When interpreting income results, key questions include whether these results are pre-tax or post-tax, and whether they are 'fully weighted' (meaning they include both benefits and monetary compensation).

Employment and income impacts are often but not always directionally aligned: for example, a modeled investment or policy change could result in an increase in total employment but a decline in aggregate wages.

Gross Domestic Product

Gross domestic product (GDP) represents the final value of the goods and services produced within a region over a given period of time. GDP accounting specifically excludes the value of intermediate inputs so that only the *value added* within the given region is counted.[83]

[83] GDP estimates may use either an expenditure approach or an income approach. The former involves summing all of the money spent on goods and services. In contrast, the income approach is calculated by adding up all the incomes generated through the production process. The value added at each stage of production inside the region of interest is equal to the incomes generated by production. The 'income' results reported by IMPLAN or other EDA analytical tools will be lower than GDP because those results include other incomes such as rents, interest, and profits –incomes accruing to businesses– along with government income through taxes, plus depreciation (a kind of accounting income).

GDP should not be confused with *output*, which is another metric often calculated as part of an EDA. Output reflects the value of goods and services produced in a given region without netting out the value of intermediate inputs. In general, output is not an appropriate substitute for GDP. It may be confused with GDP and is generally larger in value.

When evaluating the job impacts of utility investments, it is important to assess the net economic impacts.

Other Metrics

In addition to the three common metrics discussed above, EDAs may also calculate changes in tax revenues, business incomes/earnings, and other metrics.

Changes in tax revenues at the federal, state, or other regional levels may be driven by increases or decreases in property taxes, payroll and income taxes, and sales taxes, among other drivers. Changes in tax revenues may also be partly or fully accounted through changes in the income and GDP metrics, since taxes are paid out of incremental incomes. GDP results include changes in income, and a portion of any growth in GDP will be remitted through taxes to the government.

Consider EDA Metrics Holistically

No one EDA metric provides a comprehensive picture of impacts on local economic activity.

No one EDA metric provides a comprehensive picture of impacts on local economic activity. For example, while income, GDP, and taxes are generally directionally aligned, employment changes may move in the opposite direction: a government program such as a jobs program may create many jobs, but a program that entails an economically inefficient use of resources could still result in a net reduction in GDP. On the other hand, economically efficient but disruptive changes may raise total GDP but still result in net job loss. Thus, it is critical to consider multiple EDA metrics together for a balanced understanding of how policy or spending changes will impact the economy.

Individual EDA metrics also have certain limitations. Job-years as an indicator of economic development impacts does not tell us anything about the type of jobs created: an increase in jobs does not signify an increase in *good* jobs. GDP is frequently used as a shorthand for economic health within a region. However, GDP is a very broad measure and does not directly translate to individual welfare. Since a region's GDP is a blunt measure of overall activity, the metric is likely to reflect many distinct kinds of transactions, ranging from the purchase of luxury goods to money spent on disaster relief or even spending on medical bills associated with the morbidity effects of worsening air quality. As a result, some have even argued that GDP is not a useful indicator of human welfare (Kapoor 2019; Aitken 2019).

C.2.2 Tiers of Impact in EDAs

Modeling of economic impacts typically involves three tiers: the *direct effects* of the modeled spending change, which are the most proximate impacts; the *indirect effects*, which are upstream or supply-chain impacts; and the *induced effects*, which refer to economy-wide changes in spending resulting from the cumulative impacts of the direct and indirect effects on funds available for consumption and investment spending.

Modeling of economic impacts typically involves three tiers: direct, indirect, and induced effects.

A hypothetical utility capital project demonstrates these tiers of impact. Investments in construction often generate short-term jobs as firms expand hiring to staff projects.[84,85] The employment of workers on-site is a *direct effect*. The associated growth in demand for construction materials may result in additional employment further up the supply chain. This supply-related hiring, along with the income and GDP gains associated with that incremental demand for materials, is an *indirect effect* of the construction project. Finally, newly hired workers generate additional economic impacts through re-spending their wages—an *induced effect* of the construction project's direct and indirect effects.[86] The construction project may also affect overall utility rates, producing an additional induced effect as customers respond to the change in rates by modulating their level of general spending in the wider economy.

C.2.3 Approaches to Conducting EDAs

There are several different approaches to conducting EDAs, including an input-output model such as IMPLAN[87] or through the use of more complex tools. Input-output models use multipliers to model how changes in spending flow through the economy to produce aggregate impacts. They are relatively simple, are less costly and less time-intensive than certain other models, and they also tend to be user-friendly and flexible.

EDAs may also use more complex, dynamic models of the economy. Tools such as IMPLAN are static. That is, their multipliers reflect the structure of the economy at a given point in time, with the underlying assumption that the modeled changes in demand will not change the structure of the economy itself. This simplifying assumption can be problematic when modeling large economic shocks or when the modeling horizon is sufficiently long to expect meaningful changes in the structure of the economy. Dynamic modeling approaches, such as REMI or others using

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[84] Increased spending may also result in the already employed putting in more hours. This alternative to expanded hiring is typically treated identically in EIA model outputs—as additional job-years. Notably, an individual worker could represent greater than one job-year over the course of a year.

[85] Unlike construction jobs, jobs supporting the O&M of a project are expected to last for the duration of the project's lifetime. This means that investment in O&M results in jobs that are sustained for the duration of the project lifetime, allowing for a sustained impact on net job-years created from an infrastructure project.

[86] Perspective plays a critical role in classifying impacts as direct, indirect, or induced. For example, while the re-spending of wages is an induced effect of direct spending on construction that results in hiring additional employees, the re-spending of wages also has its own trifecta of direct, indirect, and induced impacts.

[87] IMPLAN (Economic Impact Analysis for Planning, IMPLAN Group, LLC). IMPLAN is an industry-standard input-output model that accounts for both the direct and indirect economic impact of an industry. IMPLAN was developed by the U.S. Forest Service in the 1970s to deliver accurate and timely estimates of economic impacts of forest resources.

computable general equilibrium models, are more complex and costly to run but can capture changes in supply, demand, and price occurring over time and in response to input changes.[88]

C.2.4 Net vs. Gross Analyses

EDAs may be conducted on a 'net' or 'gross' basis. A gross analysis considers only the impacts associated with the contemplated spending change(s). A net analysis considers both the positive impacts of the contemplated spending change(s) and any downside economic effects that result from spending avoided by those changes.[89]

While EDAs and BCAs both aim to evaluate whether a given investment or policy change will provide benefits that exceed costs, they differ in the types of benefits and costs assessed.

When evaluating the job impacts of utility investments, it is important to assess the net economic impacts. This is consistent with NSPM *Principle 3: Account for All Relevant and Material Impacts*, which says that BCAs should include both benefits and costs associated with any given type of impact. Using a gross analysis that does not account for the downside economic impacts will systematically bias the analysis in a positive direction.

C.2.5 Geographic Scope

EDAs are region-specific. For utility investments, the region is typically the state where the utility operates. The region might include multiple states when a utility spans multiple states. EDAs can also apply to a different geographic region, such as all of New England or all of the states affected by a regional pipeline or transmission line.

When conducting an EDA, it is important to properly account for where the economic impacts occur. Direct effects occur within the modeled region. However, only a portion of indirect effects and induced effects will occur within the modeled region. Manufacturing supply chains are diffuse and span regional and national boundaries; many of the indirect, supply-chain impacts associated with energy resource manufacturing, for example, are apt to occur outside of a given state. The same is true for the economy-wide induced impact benefits associated with re-spending. These economic benefits or costs occurring outside the modeled region are termed 'leakages,' as they can be described as leaking out of the region.

C.3 Relationship Between EDAs and BCAs

BCAs measure the extent to which costs change as a result of the DER, while EDAs measure the extent to which economic activity changes, which is a very different type of impact. Further, EDAs

[88] REMI (Regional Economic Models Inc.) is a dynamic forecasting and policy analysis tool. The model forecasts the future of a regional economy, and it predicts the effects on that same economy when the user implements a change. REMI models have been used throughout the world for a wide range of topic areas, including economic development, the environment, energy, transportation, and taxation, forecasting, and planning.

[89] Economics is sometimes referred to as the 'science of scarcity' because every spending decision necessarily involves trade-offs. These trade-offs are referred to as *opportunity costs*. In the utility investment context, for example, a decision to invest in a new natural-gas-fired power plant comes at the cost of one or more of several alternatives *not* being purposed. These alternatives, or opportunity costs, might include investment instead in an offshore wind facility, greater reliance on the wholesale energy market, or, if feasible given resource needs, foregoing the expenditure entirely and leaving those incremental dollars in the pockets of customers and/or the bank accounts of shareholders.

and BCAs have a complex relationship where the inputs and outputs of a BCA test become inputs to the related EDA. For these two reasons, the results of an EDA cannot appropriately be added to the results of a related BCA test.

C.3.1 EDA and BCA Values Are Not Easily Comparable

BCAs and EDAs answer fundamentally different value questions:

- BCA: Will the total cost of energy services increase or decrease as a result of the DER? *Is the DER cost-effective?*
- EDA: Will the volume of economic activity increase or decrease as a result of the DER? *Will the DER create jobs, raise incomes, and/or increase GDP?*

While both EDAs and BCAs aim to evaluate whether a given investment or policy change will provide benefits that exceed costs, they differ in the types of benefits and costs assessed. A BCA test assesses how the cost of providing a product or service will change whereas an EDA assesses how the volume of local economic activity (measured in employment, GDP, or other terms) will change. EDA impacts have different societal, political, and economic implications than the benefits and costs in BCAs. Since BCAs and EDAs assess such fundamentally different types of impacts, they do not provide meaningful information when added together.

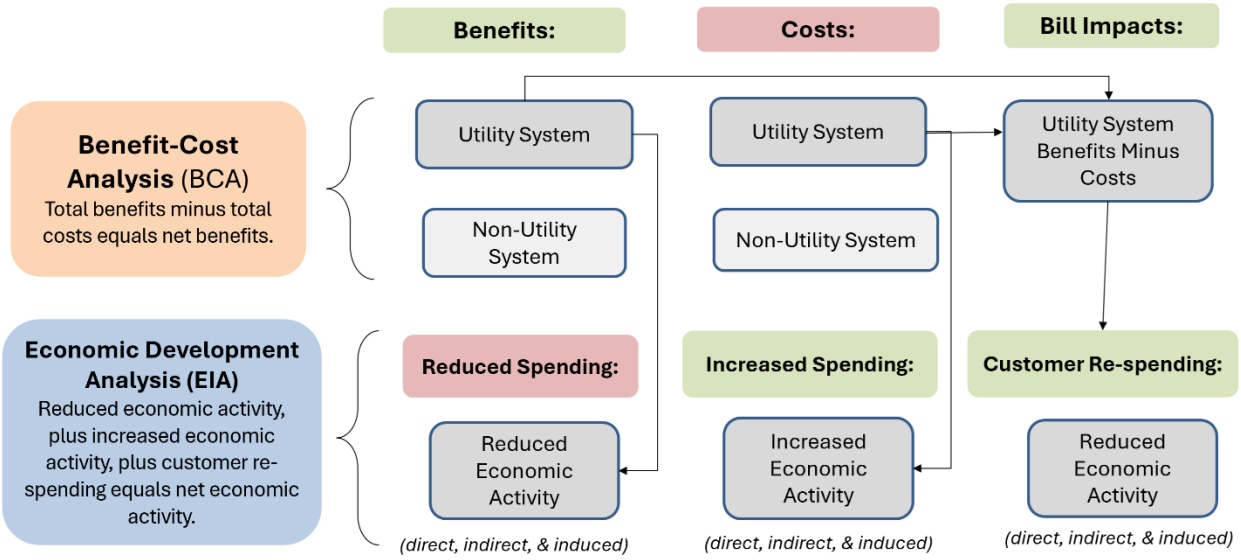
There are also accounting challenges when trying to add EDA results to BCA results. As noted above, the most common EDA metrics are employment, GDP, and income. None of the EDA metrics provides a complete picture of economic development impacts, yet adding more than one EDA metric to the BCA results would be incoherent and would introduce redundancy across the EDA metrics.

In addition, while BCA results are typically discounted to reflect the present value of benefits and costs, by convention EDAs do not usually include discounting because the EDA metrics do not represent costs that would be suited for discounting. This means that the results of BCA tests and EDAs have different ways of accounting for the value of impacts over time and thus cannot be consistently compared.

C.3.2 Combining EDA and BCA Results May Lead to Double-Counting

EDAs and BCAs have overlapping inputs and outputs. Consequently, adding the results of the two tests together can produce double-counting of the impacts. Figure C-1 illustrates how these two types of studies overlap and why they result in double-counting, using a hypothetical utility investment in a portfolio of EE programs.

Figure C-1. Overlaps between BCAs and EDAs for a Cost-Effective Energy Efficiency Portfolio



Note that 'Bill Impacts' are an outcome of BCA. They are not used as inputs to the UCT, TRC, SCT, or JST.

Figure C-1 illustrates the type and extent of quantitative overlaps between EDAs and BCAs.

- The top row of boxes shows the components of a BCA, including the benefits, the costs, and the bill impacts (which in this case are decreased bills because the EE portfolio in this example is assumed to have utility system benefits that exceed the utility system costs).
- The bottom row of boxes shows the components of an EDA, including the reduced spending (which results in reduced economic activity), the increased spending (which results in increased economic activity), and the customer re-spending (which results in increased economic activity because customer bills have decreased on average).

Not only is there overlap in the results of the BCA and the results of the EDA, the benefits and costs in the BCA translate into EDA impacts that work in the opposite direction.

In summary:

- Benefits determined by the BCA (a positive outcome) translate into *reductions* in economic activity determined by the EDA (a negative outcome).
- Costs determined by the BCA (a negative outcome) translate into *increases* in economic activity determined by the EDA (a positive outcome).
- Bill savings that result from a DER investment (a positive outcome) translate into *increased* customer re-spending determined by the EDA (also a positive outcome).

Thus, not only is there overlap in the results of the BCA and the results of the EDA, some benefits and costs in the BCA translate into EDA impacts that work *in the opposite direction* (higher utility system costs in the BCA create a positive outcome in the EDA's increased spending category, and lower utility system costs in the BCA creates a negative outcome in the EDA in the form of

decreased spending). This is a convoluted form of double-counting in which each analysis accounts for the same impacts, but the impacts work in opposite direction. There is no way to make sense of these results if they are added together. Further, there is double-counting of impacts in the conventional sense because reductions in utility system costs (i.e., BCA benefits) produce positive impacts in the EDA as a result of customer spending of their increased disposable income.

C.3.3 Consider the BCA and EDA Results Separately

For all the reasons discussed above, it is inappropriate to add EDA results onto BCA results. Instead, EDA results should be considered separately, as complementary to the results of BCA.

Stakeholder processes involved in developing and reviewing BCA results play an important role in considering complementary EDAs and associated results alongside the BCAs. This includes providing input and comments to regulators to help interpret the results and weigh the EDA results relative to BCA results. As noted above, EDA and BCA impacts may not point in the same direction; it is possible that a given investment option will appear cost-effective in the BCA test but result in reduced local economic activity per the EDA, and *vice versa*. In these cases, utilities, stakeholders, and ultimately regulators will need to balance the relative importance of concerns about energy costs versus concerns about local economic activity when making decisions.

Appendix D. Distributional Equity Analysis

This appendix applies to jurisdictions with policy goals that require, or articulate the importance of, addressing the equity implications of utility DER investments. The guidance herein describes how to conduct a DEA to help regulators and other state agencies, utilities, communities, and stakeholders answer questions about the equity implications of utility DER investments and to consider those implications alongside BCA test results. This appendix references a comprehensive 'DEA Guide' for more detailed guidance.

D.1 Distributional Equity Analysis - Overview

Some jurisdictions have established goals and processes to promote energy equity. Such goals pursue the fair distribution of energy system benefits and burdens across all populations, where inequities might include excessive energy burdens,[90] limited access to DERs or renewable energy, inadequate infrastructure to support those resources, exposure and vulnerability to environmental and public health impacts, greater risk of reliability and resilience issues, greater risk of service shutoffs, and lack of access to economic or job benefits.

Distributional Equity Analysis (DEA) can help support the fair distribution of benefits and burdens across all segments of a community and across generations. They can help utilities, regulators, State Energy Offices, communities, and other stakeholders to answer questions about the equity implications of utility DER investments and to consider those implications alongside BCA.

DEAs evaluate the distributional impacts of DER investment decisions on different customer groups, particularly priority populations (e.g., low-income or underserved communities) as defined by the jurisdiction. They involve analyzing the benefits, costs, and burdens of these decisions on priority populations, ***relative to other customer groups,*** to identify any disparities or inequities in DER program outcomes. This analysis can serve as complementary information to BCA results, which focus on whether costs will increase or decrease across the utility system as a result of a DER investment.

DEA can address affordability concerns for different customer populations by estimating the rate, bill, and participation impacts on priority customers relative to other customers (see Appendix B). In addition, DEA allows stakeholders to assess other important equity metrics not captured in a BCA test, as further described below.

DEA complements BCA by contributing important equity information to the overall evaluation of an investment. DEA can help to inform:

- Whether to pursue or invest in a new DER program or continue to support an existing one;
- Whether to modify or redesign a proposed or existing DER program; and/or
- How to prioritize investments across multiple DER programs.

[90] Energy burden refers to the percentage of a customer's income spent on energy bills.

This appendix is an abbreviated version of the *Distributional Equity Analysis for Energy Efficiency and Other Distributed Energy Resources: A Practical Guide* (referred to as the 'DEA Guide') (LBNL 2024a). It provides a summary of the DEA Guide, including an overview of the key stages in conducting DEA, illustrative examples, and the challenges that may arise when applying DEA in different jurisdictions.

D.2 Comparison of DEA and BCA

Regulators, utilities, and other decision-makers commonly rely on BCA tests when considering utility investments in DERs. BCA is an essential tool for understanding whether an investment will provide net benefits for all customers *on average*. However, BCA does not allow for assessment of the distribution of benefits and costs across customers with different characteristics (e.g., priority populations relative to all other customers).

Unlike BCA, DEA separates customers into two distinct groups—priority populations and all other customers—allowing analysts to assess how benefits and costs may affect each group. DEA also includes a broad set of metrics specifically chosen to estimate equity impacts, which allows analysts to assess additional benefits and costs that may not be captured in a BCA test. Applying the equity metrics to priority populations in DEA can help decision-makers understand whether DER investments have the potential to deliver equitable net benefits for priority populations relative to other utility customers.

Table D-1 summarizes the key differences between a BCA and DEA: their respective purposes, the questions each answer, the impacts analyzed, and example metrics. These differences illustrate why the two analyses are complementary to each other and should be conducted separately.

Table D-1. Differences between BCA and DEA

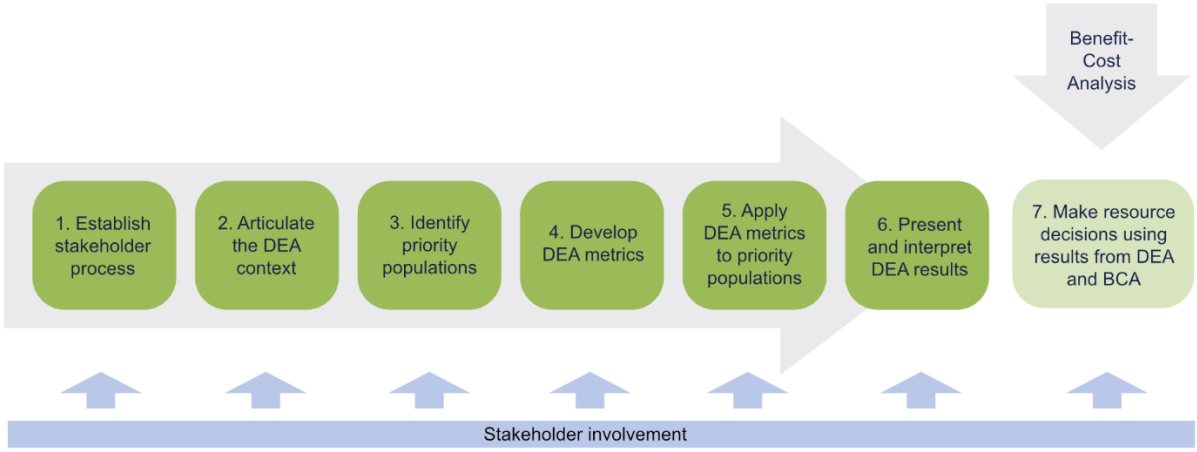
	Benefit-Cost Analyses	Distributional Equity Analyses
Purpose	To identify which DER programs utilities should invest in or support	To identify how DER programs impact priority populations relative to other customers
Questions Answered	What are the benefits and costs of a DER program across all customers?	How will DER impacts accrue to priority populations compared to other customers?
Impacts Analyzed	• Utility system impacts • Participant impacts • Societal impacts	• Participant and societal impacts • Rate, bill, and participation impacts • Distributional equity metrics
Example Metrics	• Costs (PV$) • Benefits (PV$) • Net Benefits (PV$) • Benefit-Cost Ratio	Disaggregated for priority populations and other customers: • Rates ($/kWh) • Bills ($/month) • Participation rates (% of eligible) • Energy burden (% of income on energy bills) Other metrics: health (ER visits), environmental impacts (particulate matter)
Scope	A single BCA to assess absolute DER program impacts	One analysis for priority population and another for other customers to compare impacts across groups

While the guidance herein focuses on applying DEA to DERs, in theory, the methods, concepts, and principles described are applicable to any type of major utility investment.

D.3 Distributional Equity Analysis - 7 Stage Process

Figure D-1 presents the key stages to conducting a DEA. Each stage is critical to conducting a robust DEA, though some jurisdictions may choose to perform the DEA in a different order than presented below, depending upon their circumstances.

Figure D-1. Seven Stages of Distributional Equity Analysis



A summary of each stage is provided below in Table D-2, followed by more in-depth descriptions of each stage, illustrative examples, and key considerations that can arise during certain stages.

Table D-2. Summary of DEA Stages

Stage 1: Establish a stakeholder process	Community and stakeholder input is necessary in every stage of the DEA to make it effective and meaningful. A robust community and stakeholder process requires inclusion of representatives from a broad variety of perspectives, especially those representing priority populations.
Stage 2: Articulate the DEA context	DEA can be applied in a variety of contexts. It is useful to determine up front how to apply DEA and over what timeframe.
Stage 3: Identify priority populations	Defining priority populations entails using demographic and socioeconomic indicators, depending on a jurisdiction's equity goals.
Stage 4: Develop DEA metrics	DEAs can use a range of metrics to assess energy inequities, such as electricity and gas rate impacts, bill impacts, participation in programs, energy burden. While BCA metrics are primarily presented in monetary terms, DEA metrics are presented in non-monetary terms.

Stage 5: Apply DEA metrics to priority populations	A core element of conducting a DEA is to develop estimates for each of the equity metrics, for both the priority population and the rest of the customers. This exercise typically requires large amounts of data, and analytical tools are available to facilitate the collection, assessment, and presentation of this data.
Stage 6: Present and interpret DEA results	DEA metrics can be presented using a variety of values and units of measurement that are often not in monetary terms. Some utilities, regulators, and communities and stakeholders might decide to use simple results, or results that contextualize the metrics with selected benchmarks. Others might decide to use analytical techniques that aggregate all the DEA metrics into a single net score for priority populations and a single net score for other customers. This appendix provides a description for presenting simple results, with other options described in the DEA Guide.
Stage 7: Make decisions using DEA and BCA results	The final stage of DEA is to consider DEA results alongside BCA results to inform a decision(s) on utility DER investment options.

D.4 DEA Stage Descriptions and Considerations

D.4.1 Stage 1: Establish a Process for Robust Community and Stakeholder Engagement

Community and stakeholder engagement is critical to the DEA process. As used in the DEA Guide, the term 'community' refers to any people with a shared identity within or across different geographic areas and includes urban, rural, tribal, and indigenous people. 'Stakeholder' refers to representatives or members of priority populations, advocates (e.g., environmental justice, low-income customer, consumer), and other interested or concerned parties. Communities may be underrepresented in legislative and regulatory practices and hence may not currently be active stakeholders. Communities and stakeholders are essential to the DEA process. They are critical for providing input and recommendations at every stage of the DEA, including playing a meaningful role in the ultimate decisions regarding utility DER investments. Engaging communities can include, for example:

- Working with community-based organizations that have a presence in and that understand how to engage with these communities as an effective way for regulators and utilities to engage stakeholders and bridge potential trust issues;
- Addressing language barriers which for some customers can be an obstruction to participating in DER programs, and in DEA processes;
- Providing resources in multiple languages to enable more stakeholder feedback; and
- Providing intervenor compensation in relevant regulatory dockets, which can be instrumental to ensuring representatives of CBOs can effectively participate in resource investment discussions and decisions.

As summarized in Table D-3, a typical approach is to convene a recurring stakeholder forum that gathers input from priority populations and other stakeholders throughout the DEA. Participants may include community organizations, utility staff for data access and sharing, and regulatory staff for process guidance.

Table D-3. Key Points for Stakeholder Input

Stage	Action
Identify priority population	Consider whether and how to enable communities to self-designate as a priority population
	Choose the set of indicators for the priority population
	Determine the scope of the priority population
Develop DEA metrics	Develop a full set of system-wide equity metrics
	Winnow down system-wide equity metrics to a set that is more appropriate for DEA
Apply DEA metrics to priority populations	Incorporate stakeholder input on data collection and analytical tools
	Review and critique data input to the DEA, i.e., ground-truthing
	Protect data privacy and encourage equitable data practices
Present and interpret DEA results	Develop benchmarks for metrics
Make decisions with BCA and DEA	Define or clarify DEA pass/fail criteria
	Draw conclusions from both the BCA and DEA results

D.4.2 Stage 2: Articulate the DEA Context

Jurisdictions can apply DEA to DERs in a variety of different contexts. It is important to articulate the context of a DEA upfront because the context might affect the choice of inputs, metrics, presentation of results, or how the results are used. The DEA application should be consistent with the BCA application of the DER under evaluation.

First, DEA is useful for different applications, i.e., different types and combinations of DERs. Table D-4 presents several of the most likely applications of BCAs and DEAs, with examples. In most contexts, broader applications (such as at the portfolio level, as shown at the bottom of the table) will be more useful than applications that are narrow in focus (such as assessing a single DER program, as shown at the top of the table).

Table D-4. Potential DEA (and BCA) Applications

Applications	Examples
Assess a single DER program serving priority populations	Low-income EE program, low-income community solar program, low-income microgrid program
Assess a single DER program serving all types of customers	Residential retrofit EE program, DG net-billing program, DS program
Compare across DER programs	Compare same type of DERs: one EE program vs. other EE programs, one DG net-billing program versus other DG net-billing programs Compare different types of DERs: EE versus DG, DG versus DS program, DR versus DS program
Assess a portfolio including programs of the same type of DERs	Portfolio of EE programs, portfolio of multiple DG programs, portfolio of multiple storage programs
Assess multiple portfolios including programs of multiple types of DERs	Portfolio including all types of DER programs (EE, DR, DG, batteries, EVs)

Second, as with BCA, jurisdictions can apply a DEA (a) prospectively before the DER investment to assess whether to make the investment, or (b) retrospectively after the DER investment to evaluate the effectiveness of the DER. Ideally, a DEA will account for the same timeframe and use the same data as the BCA it complements. Retrospective BCAs and DEAs should use actual, historical data as much as possible, while prospective BCAs and DEAs rely primarily on forecasts of future data.

D.4.3 Stage 3: Identify Priority Populations

A priority population refers to a defined customer segment that is the focus of the DEA. States, utilities, stakeholders, and communities can identify priority populations based on a jurisdiction's energy equity policies and goals, or designated indicators. Robust community and stakeholder input is essential in identifying priority populations.

The approach to determining priority populations can vary. Some states may have defined priority populations through legislation or regulation. Other jurisdictions may choose to have communities self-identify as priority populations. Some jurisdictions may use multiple approaches to determining priority populations.

Determining the priority population begins with selecting relevant indicators—characteristics that identify populations more likely to experience disproportionate burdens from the energy system. Possible indicators are numerous, and some may be more relevant based on the jurisdiction and DEA applications. Each category can contain multiple indicators, such as low-income, energy burden, health impacts, and more.

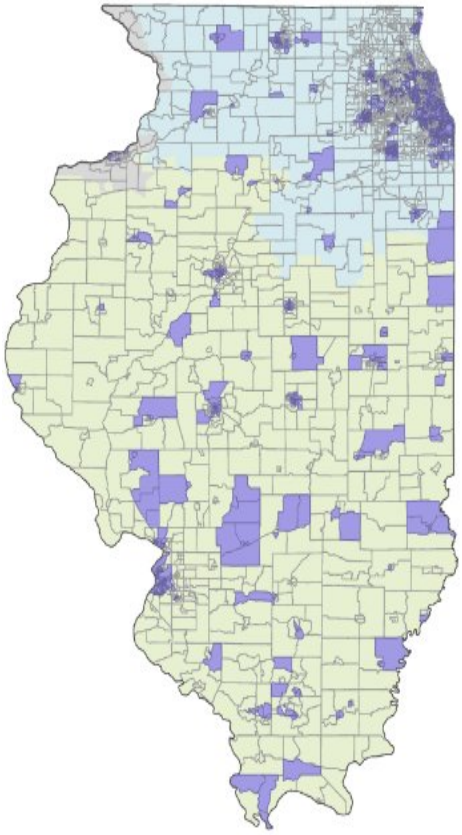
Another consideration when identifying a priority population is the cumulative impact that may occur due to multiple inequities or stressors. For example, some customers might face a high energy burden while other customers might face inequitable environmental impacts, and some customers might face both. One approach to address this challenge is a cumulative impact analysis—a quantitative framework to help prioritize customers who are at risk of experiencing multiple types of impacts. Table D-5 summarizes considerations for selecting priority populations.

Table D-5. Priority Population Definition Considerations

Consideration	Description
Equity goals	Alignment of the definition with the state's equity policy goals allows for relevant and actionable conclusions. Input by equity stakeholders is important, especially where there are no legislated equity goals.
Data resolution	The data resolution in utility plans, such as zip code, town, and customer segment will help inform the priority population definition. For example, if metric data is only available at the zip-code level, then it is appropriate to aggregate the demographic data at the census-tract level into zip codes. This reduces the resolution of the results, leading to potential uncertainties and inaccuracies.
Ease of comparison	Ideally DEA results for different programs will be comparable to one another, which will require consistent definitions.
Level of effort	Some definitions of priority populations will be harder to implement than others. It may be helpful to begin with state definitions found in state legislation rather than develop new definitions at start of the DEA process. Starting with state definitions may help facilitate the process for any potential modifications or changes.

The level of effort associated with using definitions developed outside of state legislation is context dependent. Jurisdictions may rely on statutory definitions, regulatory criteria, community-driven approaches, or hybrids, as appropriate. Using established state definitions may streamline process steps, but this should not be interpreted as inherently preferable over other approaches that better align with policy goals and local conditions. Figure D-2 provides an example of the distribution of a designated priority population as identified by a jurisdiction (for example, using census tract data), as shown in purple shading.

Figure D-2. Distribution of Identified Priority Population



D.4.4 Stage 4: Develop Distributional Equity Analysis Metrics

DEA metrics help determine the DER impacts and aspects of equity to be considered in the analysis. In some cases, metrics may already be defined and articulated in state policy/statute or in regulatory decisions/orders. These pre-existing metrics will need review, with stakeholder input. If there is no existing definition or articulation of metrics, co-developing DEA metrics with community members and stakeholders helps to ensure the metrics address the most important types of inequities facing priority populations.

Table D-6 shows an example set of metrics that could be used to evaluate DER investments using a DEA. It is important to emphasize that DEA metrics in Table D-6 are for illustrative purposes only. Further, some jurisdictions might choose only a portion of the DEA metrics presented below.

Table D-6. Illustrative Potential DEA Metrics to Evaluate Utility DER Investment

DEA Category	Subcategory	Example DEA Metrics
Access	Participation for the DER under evaluation	Participants as percent of eligible customers
Economy	Utility dollars invested	Utility funds invested in businesses and contractors located in priority populations
Affordability	Change in rates	Percent change in rates
	Change in bills	Percent change in bills
Public Health	Health impacts	Change in rates of emissions, avoided emissions
Shutoffs	Shutoffs	Change in number of shutoffs or frequency of shutoffs
Reliability and Resilience	Outages	Change in number and duration of outages at the customer level

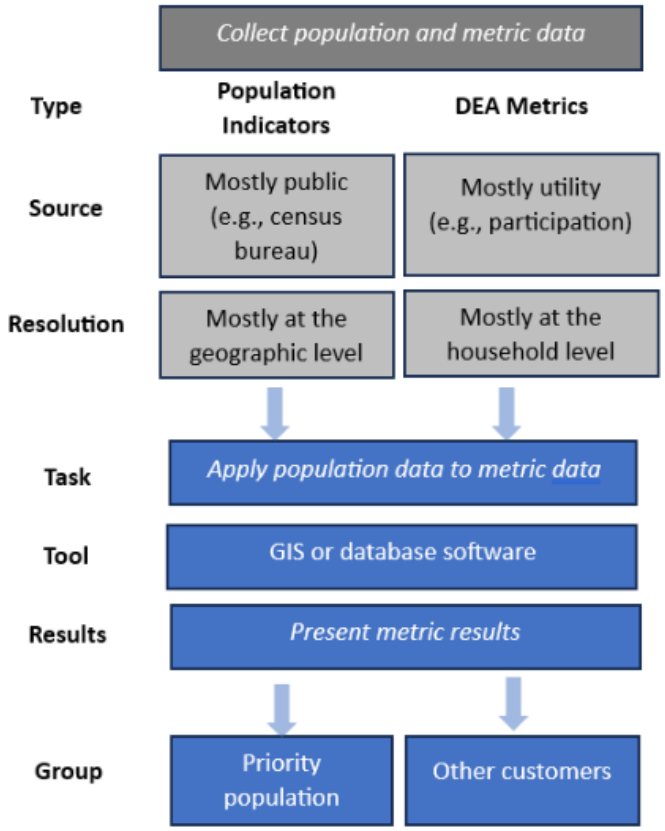
D.4.5 Stage 5. Apply DEA Metrics to Priority Populations and Other Customers

Applying DEA metrics to the priority populations and other customers requires combining the information from two datasets—population data and equity metrics data—to calculate the impacts of each DEA metric on the priority populations. Analytical tools to support this stage include mapping tools (such as geographic information system models), environmental justice screening tools, dashboards, and modeling tools.

Most data currently available to identify priority populations can be obtained from government entities and is available according to geographic location. Data used for metrics tends to be available from utilities and may be available at the customer level. Because these sources often provide data in different forms and levels of granularity, combining them requires careful consideration.

Figure D-3 summarizes the process used for applying priority population data to equity metric data, as well as the typical types and sources of data required for each. It also indicates the resolution of the data from different sources. To provide the most detailed results, the resolution of the data should be as granular as possible. The analysis and results can only be as detailed as the data source with the least granularity.

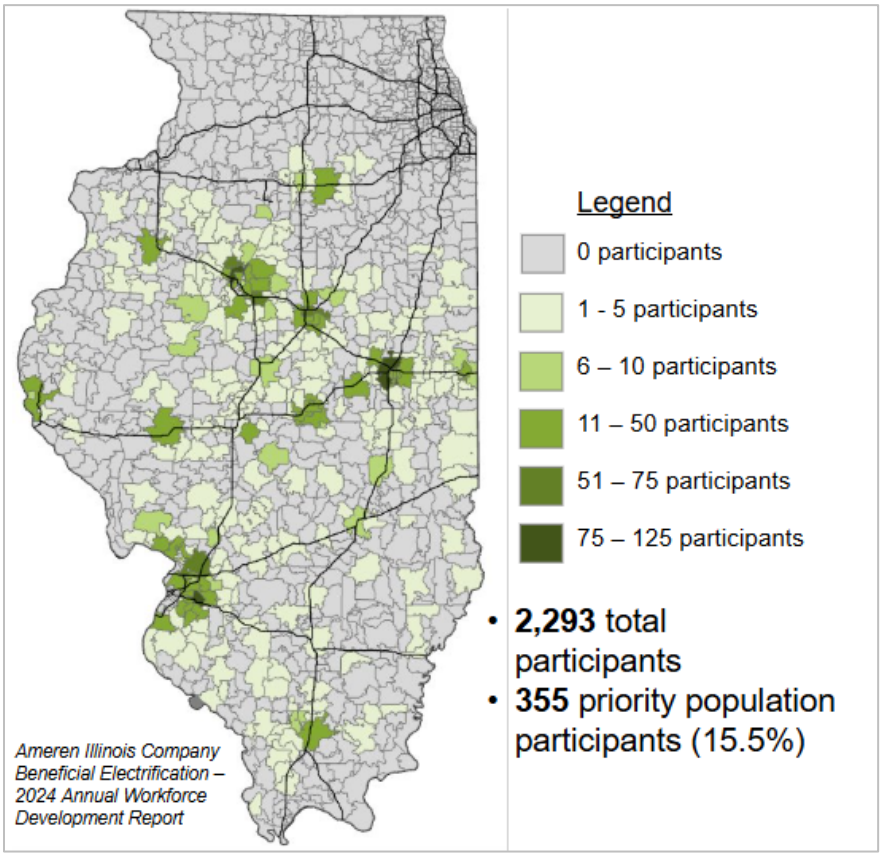
Figure D-3. Process for Applying Population Data to Metric Data



Analysts conducting DEA will need to protect data privacy to ensure the data made public does not create risks of data security, privacy, or misuse. Further, analysts conducting DEA should ensure that data collection does not disproportionately or negatively impact priority populations, and that the data used is not biased against priority populations due to historical inequities in data collection and processing.

Figure D-4 provides an example metric—in this case participation rates, and how participation in an illustrative DER program is distributed across the defined priority population (using census tract data) within a utility's service territory. Comparing the participation rates for the defined priority population relative to all other customers helps to inform whether there is equitable participation in a program.

Figure D-4. Mapping Program Participation to Priority Population Data



D.4.6 Stage 6: Present and Interpret DEA Results

To increase the accessibility and applicability of DEA, this appendix describes two variations of interpreting DEA results. The simplest variation applies DEA metrics to the priority populations and to other customers. These 'simple results' can indicate how a utility investment affects the priority populations and other utility customers for each of the metrics, but without additional context on the metrics.

The second variation builds on the simple results and adds benchmarks for each metric. Benchmarks compare the performance of the utility investment to a target or a preferred outcome. It is essential to determine DEA metric benchmarks with input from community members and stakeholders and to reflect the jurisdiction's equity goals.

Table D-7 provides an overview of the advantages and limitations of presenting the simple DEA results and the benchmarked DEA results.

Table D-7. Applicability of DEA Results

Results Type	Description	Advantages	Limitations
Simple results	Includes unadjusted results for each DEA metric separately for priority population and other customers	This format is simple, transparent, and does not require policy-based assumptions.	Metric results are not comparable to each other or aggregated for populations. It may be difficult to draw conclusions about the total equity impact.
Benchmarked results	Includes simple results for each metric alongside metric-specific benchmarks	This format provides additional context for the simple results, allowing analysts to draw equity conclusions for each DEA metric in isolation.	The benchmarks are goals that impact the objectivity of the results. Metric results are not comparable to each other or aggregated for populations.

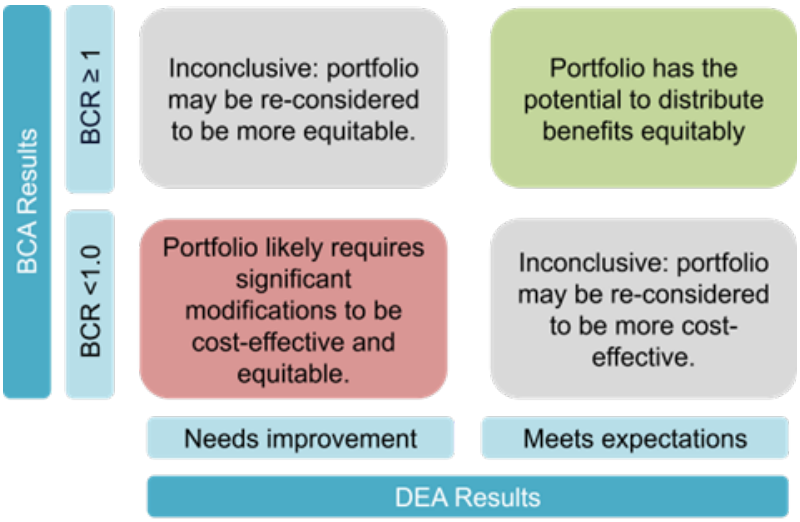
D.4.7 Stage 7: Make Decisions Using Both BCA and DEA Results

The final stage in conducting a DEA is to use the results of the DEA and BCA to inform decisions about utility DER investment. All three variations of DEA described above are applicable to this stage of the analysis.

BCA uses clearly defined monetary thresholds for determining whether an investment will have positive economic outcomes, for instance, when a BCA finds 'positive net benefits' or the BCR is greater than 1.0. In contrast, DEA does not have clearly defined criteria to determine what constitutes a sufficiently positive equity outcome. It is best to co-create these criteria with robust community and stakeholder input and to establish them before determining the results of the DEA.

Figure D-5 presents four types of outcomes for both BCA and DEA results. DER offerings that land in the top right quadrant of Figure D-5 are both cost-effective and have the potential to distribute benefits equitably if the program is implemented as planned. DER programs or portfolios that do not meet standards for one or both criteria may need reconsideration or to undergo modifications.

Figure D-5. Conclusions Matrix for the BCA and DEA



However, if an investment passes a BCA test and fails a DEA, or vice versa, the conclusion requires more consideration of the details of that investment, the jurisdiction's policy goals, and the specific results of the BCA and DEA.

- A DER that passes a DEA but marginally fails the BCA test might still be approved because the DER helps achieve the jurisdiction's equity goals. Utility low-income energy efficiency programs are one example where this might happen.
- A DER that marginally fails a DEA but passes the BCA test might still be approved because the DER has overall positive impacts that make it worthwhile. This might be the case if a DEA were applied to a commercial and/or industrial EE program in isolation from the other efficiency programs.

In all cases where an investment fails either the BCA or DEA results, it is especially important to present all the BCA and DEA results as transparently as possible, and to incorporate robust community and stakeholder input to: (a) make changes to the DER program to improve its DEA results; (b) make changes to the DER program to improve its BCA results; and ultimately (c) strike an appropriate balance between the BCA results and the DEA results.

D.5 Challenges to Conducting DEAs

Table D-8 below summarizes potential challenges that can arise during DEA, organized by DEA stage and with recommendations for how they can be addressed.

Table D-8. Common Challenges and Recommendations

DEA Stage	Common Challenges	General Recommendation
Stakeholder Engagement	Limited participation from community-based organizations (CBOs)	Offer clear participation stipends/incentives and conduct targeted outreach to CBOs.
DEA Context	Ongoing utility planning cycles can lead to challenges with data availability	Align analysis timing with program design or review cycles (e.g., conduct prospective DEAs during DER design; conduct retrospective DEAs during post-program review).
Priority Populations	Inconsistent definitions across programs can hinder cross-portfolio comparisons	Work toward consistent definitions across programs to support long-term alignment.
DEA Metrics and Data Access and Availability	Limited publicly reported census-tract-specific data for public health modeling	Continue studying how programs can improve public health for priority populations and the best ways to measure this impact for priority populations.
	Workforce and jobs data often lag and are not public	Develop methods to track local workforce impacts and prioritize underserved communities.
Data Access	Long or complex data-sharing processes between project teams and utilities	Establish partnerships and non-disclosure agreements early to streamline sharing.
	Difficulty identifying or retrieving utility database information	Collaborate with utilities to inventory available data and develop a clear request process.
	Stakeholders seeking data that utilities do not track or offer at finer granularity	Track and report available data on a census-tract level, ideally in a publicly accessible dashboard.

Appendix E. Traditional Cost-Effectiveness Tests

This appendix describes the traditional tests used for assessing DER cost-effectiveness and provides the theoretical underpinnings of what should be included in the traditional tests, which often differs from actual practice. Chapter 4 describes how use of the BCA Framework to develop a jurisdiction's primary test compares to these traditional tests. This appendix also emphasizes the distinction between BCA and rate impact analysis and refers to Appendix B for more detailed information and guidance on rate impact analyses.

E.1 Overview

This appendix provides information on the five traditional screening tests: the Utility Cost Test, (also known as the Program Administrator Cost Test); the Total Resource Cost Test; the Societal Cost Test; the Participant Cost Test; and the Rate Impact Measure Test. These traditional tests are presented in the *California Standard Practice Manual* (CPUC 2001) and have been used to assess cost-effectiveness for efficiency resources for several decades.[91]

As discussed in the introduction to this Manual and more fully in Chapter 4, jurisdictions that use the BCA Framework apply the 'regulatory' perspective when developing a primary cost-effectiveness test—referred to as the JST. The JST is likely to be unique to the jurisdiction because it reflects impacts that align with the jurisdiction's specific energy goals and objectives, though a JST could potentially fully align with one of the traditional tests described herein. This appendix describes the key elements of these traditional tests:

- A description of each test
- The relevance of each test for cost-effectiveness assessment
- The benefits and costs covered under each test
- Limitations of each test

Table E-1 provides a conceptual overview of the JST as compared to traditional cost-effectiveness tests. Table E-2 provides a summary of the various benefits and costs that, to be consistent with the analytical perspective each test is intended to represent, should be included in these tests. The sections that follow provide additional information on each test.

[91] While most jurisdictions have historically used the *California Standard Practice Manual* as the foundation for their cost-effectiveness tests, in practice many jurisdictions have deviated from those tests and developed modified versions.

Table E-1. Overview of the JST Compared to Traditional Cost-Effectiveness Tests

Test	Perspective	Key Question Answered	Impacts Accounted For
Jurisdiction-Specific Test	Regulators or decision-makers	Will the cost of meeting utility system needs, *while achieving applicable policy goals* be reduced?	Includes the benefits and costs experienced by the utility system, and other impacts (other fuels, host customer, and/or societal) associated with achieving applicable policy goals
Utility Cost Test	The utility system	Will utility system costs be reduced?	Includes the benefits and costs experienced by the utility system
Total Resource Cost Test	The utility system plus participating customers	Will utility system costs plus program participants' costs be reduced?	Includes the benefits and costs experienced by the utility system, plus benefits and costs to program participants
Societal Cost Test	Society as a whole	Will total costs to society be reduced?	Includes the benefits and costs experienced by society as a whole
Participant Cost Test	Customers who participate in a program	Will program participants' costs be reduced?	Includes the benefits and costs experienced by the customers who participate in the program
Rate Impact Measure Test	Impact on rates paid by all customers	Will utility rates be reduced?	Includes the benefits and costs that will affect utility rates, including utility system benefits and costs plus lost revenues

Note that while the Participant Cost Test (PCT) and the Rate Impact Measure (RIM) Test are sometimes used as BCA tests, they do not answer the foundational question of BCAs: *which DERs should be funded or otherwise supported by utilities on behalf of customers*. Instead, the PCT can be used to assist with program design and estimating customer participation. The RIM Test can be used (a) to determine whether rates are likely to increase or decrease, and (b) to determine whether to conduct a rate, bill, and participation analysis.

Table E-2. Impacts Included in the JST Compared to Traditional Cost-Effectiveness Tests

	Jurisdiction-Specific Test	UCT	TRC Test	SCT	PCT	RIM Test
Electric Utility System Impacts	✓	✓	✓	✓	NA	✓
Gas Utility System Impacts	✓	✓	✓	✓	NA	✓
Other Fuel Impacts	Depends	NA	✓	✓	✓	NA
Host Customer Impacts	Depends	NA	✓	✓	✓	NA
Societal Impacts	Depends	NA	NA	✓	NA	NA
Host Customer Bill Savings	NA	NA	NA	NA	✓	✓

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E.2 Utility Cost Test

Description: The purpose of the UCT is to indicate whether the benefits of a DER resource will exceed its costs from the perspective of only the utility system.[92] The UCT includes all benefits and costs that affect the operation of the utility system and the provision of electric and gas services to customers. For vertically integrated utilities, this test includes all of the benefits and costs that affect utility revenue requirements. For utilities that are not vertically integrated, this test includes all benefits and costs that affect utility revenue requirements, plus additional benefits and costs associated with market-based procurement of electricity and gas services.

- *Costs Included*: A comprehensive UCT accounts for all utility system costs incurred to implement the DER resource.
- *Benefits Included*: A comprehensive UCT accounts for all utility system costs avoided by the DER resource.

Relevance to DER Assessment: The UCT is useful for identifying the impact of a DER on utility-system costs and thus is consistent with the principle that DERs are a resource. It is also useful for identifying the extent to which utility investments will provide reduced costs to utility customers and therefore can have value (among other factors) for informing decisions on relative program priorities and/or limits on program spending. As discussed in Chapter 4, the UCT is a good foundation upon which a jurisdiction can build its primary BCA test. From this foundation, the jurisdiction can add other relevant impacts to align the test with its applicable policy goals.

The Total System Benefit Metric (CPUC)

The Total System Benefit (TSB) metric, developed by the CA Public Utilities Commission (CPUC), is used in the state by utility-run EE programs to value the economic benefits of EE to the grid, calculated as the sum of avoided costs (energy, capacity, T&D) plus reduced GHG emission compliance costs. The metric aids in evaluating whether EE programs provide sufficient, long-term, grid-wide value. The TSB value can be viewed as representing the numerator of a comprehensive and robust UCT. Starting in 2024, the TSB replaced traditional, fuel-specific savings metrics (kWh, kW, therms) for the state's investor-owned utilities to better target high-value, decarbonizing grid improvements. It acts as a 'fuel-agnostic' metric that evaluates the total value of energy savings, including avoided generation, transmission, distribution, and greenhouse gas compliance costs. It aligns energy efficiency goals with grid reliability and 'high-value' load reduction, such as encouraging efficiency during peak times. Alongside reporting on the TSB of efficiency investments, the California IOUs are also required to use the TRC test as the primary benchmark for cost-effectiveness.

The Long-term System Cost Metric (CEC)

The Long-term System Cost (LSC), developed by the California Energy Commission, is similar to the TSB metric but is used specifically to evaluate the long-term benefits of the state's building energy efficiency standards. LSC aligns code compliance with state policy goals—such as building decarbonization and support for DERs—by accounting not only for when energy is used, but also for how that usage affects system costs and emissions over a 30-year period. LSC uses a price shape derived from the hourly marginal cost of generation produced by a production simulation model. This price shape reflects the aggregated forecast of California's transmission and distribution costs, emissions costs, ancillary services, peak capacity costs, system losses, and other energy system costs.

[92] The UCT is sometimes referred to as the Program Administrator Cost test in the case of BCA of ratepayer-funded energy efficiency programs where programs are implemented by non-utility administrators. The UCT is a more accurate name because the benefits and costs included in this test are those that affect the utility system, not those that affect the Program Administrator.

E.3 Total Resource Cost Test

Description: One of the key principles of cost-effectiveness assessment is that jurisdictions should evaluate utility DER investments as a resource and compare them with other demand-side and supply-side resources. The TRC does so from the combined perspective of the utility system and participants. Thus, this test includes all impacts of the UCT, plus all impacts on the program participants.

- *Costs Included*: A comprehensive TRC Test accounts for all utility system and program participant costs incurred to implement the DER resource.
- *Benefits Included*: A comprehensive TRC Test accounts for the utility system and program participant benefits experienced because of the DER resource.

Relevance to DER Resource Assessment: The TRC Test provides more comprehensive information than the UCT by including the impacts on participating customers. As a result, this test includes impacts on other fuels, which allows for a comprehensive assessment of multi-fuel programs and fuel-switching programs. This test also conceptually includes other NEIs on participants. This is particularly important for low-income programs.

E.4 Societal Cost Test

Description: The purpose of the SCT is to indicate whether the benefits of a DER resource will exceed its costs from the perspective of society as a whole. This test provides the most comprehensive picture of the total impacts of a DER resource. This test includes all the impacts of the TRC Test, plus the additional impacts on society. The *California Standard Practice Manual* refers to the SCT as a 'variation' of the TRC Test (CPUC 2001). Since then, many jurisdictions and many studies have referred to the SCT as a separate test with different implications.

- *Costs Included:* A comprehensive SCT accounts for all costs incurred to acquire the DER resource, including all utility system and all non-utility system costs.
- *Benefits Included:* A comprehensive SCT accounts for all of the benefits that result from the DER resource, including all utility system and all non-utility system benefits.

Relevance to DER Resource Assessment: The SCT is useful for identifying the full range of economic impacts on society resulting from the investment in DER resources. It is particularly apt for jurisdictions that have particular interest in a range of societal considerations, such as environmental or economic development concerns, in addition to an interest in minimizing utility system and efficiency program participant costs.

E.5 Participant Cost Test

Description: The intended purpose of this test is to indicate whether the benefits of a DER program will exceed its costs from the perspective of the DER program participant. This test includes all impacts on the program participants, but no other impacts.

- *Costs Included*: A comprehensive PCT accounts for all costs incurred by the host customer to install, operate, and maintain the DER, including direct costs and non-energy costs.
- *Benefits Included*: A comprehensive PCT accounts for all benefits experienced by the host customer, including bill savings and non-energy benefits. This test should not include avoided utility system costs as a benefit.

Relevance to DER Resource Assessment: The PCT is not appropriate for assessing the value of DER as a utility system resource because, unlike the other four tests described here, it values benefits to the participant based on avoided electricity and gas *rates* rather than on avoided utility system *costs*. That violates *Principle 5: Conduct Forward-Looking, Long-Term, Incremental Analyses*. This principle states that cost-effectiveness analysis should be forward-looking, because electric and gas rates are designed to recover both variable (avoidable) costs and fixed (unavoidable) costs, some of which were incurred in the past. An example would be the cost of previous capital investments in the T&D system or generating capacity in vertically integrated utilities.[93]

That said, the PCT can have value for the purpose of informing program design (for instance, the level of financial incentives to offer prospective participants and/or the need for marketing to better inform participants of non-energy benefits that they may value) by providing insight into energy bill impact on participants.[94]

E.6 Rate Impact Measure Test

Description: The purpose of this test is to indicate whether a DER resource will increase or decrease electricity or gas rates (in other words, prices). This test includes all of the benefits and costs of the UCT, plus estimates of the utility lost revenues created by DER programs. When regulators take steps to allow utilities to recover the lost revenues of DER programs, through rate cases, revenue decoupling, or other means, then the recovery of these lost revenues will create upward pressure on rates. If this upward pressure on rates exceeds the downward pressure from reduced utility system costs, then rates will increase, and *vice versa*.

- *Costs Included*: A comprehensive RIM test accounts for all utility system costs incurred to implement the DER resource. It also includes lost revenues as a cost. The lost revenues are equal to the host customer bill savings.
- *Benefits Included*: A comprehensive RIM test accounts for all utility system benefits, such as avoided costs, attributable to the DER resource.

Relevance to DER Resource Assessment: As provided by the NSPM principles (Table 3-1), and further explained in B, the RIM Test is designed to address rate impacts and therefore answers fundamentally different questions than does a cost-effectiveness analysis. As such, the RIM Test cannot accurately determine if the benefits of DER investments to the utility system exceed their costs. This is because the RIM Test does not measure changes in net economic costs across a population; rather, it is a measure of distribution equity. Even in that context, the RIM Test considers only one of the three

The RIM Test cannot accurately determine if the benefits of DER investments to the utility system exceed their costs. This is because the RIM Test does not measure changes in net economic costs across a population; rather, it is a measure of distribution equity.

[93] They may be 'avoided' in part by participants, but typically only if a larger portion is then recovered by non-participants. Put another way, a portion of participant benefits is often just a shift in costs from one customer group (participants) to another (non-participants) rather than a true cost savings.

[94] The U.S. Department of Energy uses a different test to determine whether to include efficiency measures for participants in federally funded weatherization assistance programs. It uses the savings-to-investment ratio; where the numerator is the present value of net savings in energy, water, non-fuel, or non-water operation and maintenance costs attributable to the proposed energy or water conservation measure, and the denominator is the present value of the cost of the proposed energy or water conservation measure (see Appendix A for information on Savings Investment Ratio (SIR) cost-effectiveness methodology).

factors that regulators should consider when exploring distributional equity concerns. It does not consider bill impacts or participation rates, which are critical for understanding distributional equity (see Appendix D).

Table E-3 summarizes the purpose of each of the traditional tests, and the relevance to DER assessment.

Table E-3. Purposes of the JST and the Traditional Cost-Effectiveness Tests

Test	Purpose	Relevance to DER Assessment
Jurisdiction-Specific Test	Allows for assessing the extent to which DERs will reduce (or increase) utility system costs while achieving the jurisdiction's applicable policy goals	Most suitable for the jurisdiction's primary BCA test
Utility Cost Test	Allows for assessing the extent to which DERs will reduce (or increase) utility system costs	Provides a foundation for all resource BCA tests, as well as for rate and bill analyses
Total Resource Cost Test	Allows for a more comprehensive assessment of DER impacts than the UCT, including impacts of other fuels and other impacts on DER program participants	Helpful for programs addressing multiple fuels or having other impacts on participants
Societal Cost Test	Allows for assessing the full universe of benefits and costs of DERs	Indicates the full impact of DERs on society
Participant Cost Test	Useful in DER program design, to inform appropriate participant incentives	Not relevant for cost-effectiveness assessment / BCA
Rate Impact Measure Test	Useful for indicating whether DERs will cause long-term rates to increase or decrease, and can inform whether to conduct rate and bill analyses	Not appropriate for cost-effectiveness assessment / BCA

Appendix F. Establishing Geographic Boundaries for BCA Impacts

This appendix discusses the need for and provides guidance for making decisions about the geographic scope of impacts to include in a jurisdiction's BCA.

F.1 Introduction

For some BCA impacts, assessment of potential benefits and costs can use different geographic boundaries to define the scope of interest or concern in the context of a jurisdiction's BCA test. The choice of geographic boundary (global, national, regional, state, utility service territory, or other) can have a major impact on the magnitude of benefits and/or costs. Generally, the broader the geographic scope of interest, the larger the estimated impact will be. This appendix discusses several impacts for which it can be important to establish geographic boundaries of interest and offers guidance on how to make decisions on geographic boundaries.

Some types of BCA impacts require decisions regarding the geographic scope of interest. Ultimately, such decisions should be based on a jurisdiction's policy goals.

F.2 Impacts Requiring Geographic Boundary Decisions

There are four common BCA impact categories which require decisions regarding geographic boundaries:

- MPEs, both for electric energy and capacity and for gas
- Federal financial incentives (tax credits or rebates)
- Greenhouse gas emissions
- Criteria pollutant emissions (and/or public health)

Below is a brief discussion of each.

F.2.1 Market Price Effects

As discussed in Chapter 4, in jurisdictions with competitive wholesale markets for electric energy and/or capacity, investment in electric DERs can reduce energy and/or capacity costs if they avoid costs that would have been incurred to serve load displaced by the DERs, or the investment can increase those costs to serve newly electrified loads. However, these investments can also reduce (or increase, in the case of electrification) market clearing prices for energy and/or capacity for all other remaining electric sales. The same is true for gas utility investments in DERs. Not only is there a reduction in the number of gas commodity purchases that would otherwise have been required to meet loads avoided by EE investments, for example, but reductions in demand for gas commodity can lower the market clearing prices charged for all remaining gas sales.

Such changes in market clearing prices for energy and/or capacity will typically flow both to the customers of a given utility and to customers in the broader region served by the affected market.

For example, electric DER investments in any single New England state or utility service territory can affect market clearing prices throughout the six-state region served by the New England ISO. Effects on market prices for gas resonate across an even larger region. This raises the question of whether a BCA test should include the full effect of higher or lower market clearing prices for all customers affected within an affected regional market, or whether the test should only include the impacts on customers within a given state or utility service territory.

F.2.2 Federal Financial Incentives

Federal governments often provide tax credits, rebates, and other forms of financial incentives for investments in a wide variety of DERs. Jurisdictions that include host customer impacts in their JST will need to decide whether they should treat such incentives as reductions in costs to host customers or instead as 'offsetting transfers' (i.e., a benefit to customers investing in DERs offset by a cost to taxpayers) that have no impact on BCA test results (see Appendix M for a discussion of transfers).

F.2.3 Greenhouse Gas Emissions

The impacts of GHG emissions are inherently global. Once emitted, carbon dioxide and other GHGs travel the globe, remaining in the atmosphere for decades or more, depending on the specific pollutant. Thus, regardless of where they originate, GHG emissions contribute to *global* climate change and related *global* damages. Jurisdictions that include GHG impacts in their JST and that use the damage cost method of assigning a cost to emissions (and therefore a benefit to emission reductions) will need to decide whether to include the cost of global damages in the BCA test or only the portion of global damages experienced within the jurisdiction (or some other boundary less expansive than the globe).

F.2.4 Criteria Pollutant Emissions (and/or Public Health Impacts)

Emissions of criteria pollutants such as particulate matter and nitrous oxides also do not respect state, provincial, or national borders. Once emitted, such pollutants can travel great distances (though typically not as far as GHGs) and contribute to public health, environmental and other costs across a potentially large region. The size of the region can vary depending on the source of the pollutants, wind and other weather patterns, and other factors. Thus, as with GHGs, jurisdictions that include impacts on emissions of criteria pollutants (and/or related public health concerns) in their JST will need to determine whether they include all regional impacts included in the BCA or only the portion of the impacts felt within the jurisdiction (or some other boundary).

F.3 Informing Decisions Beyond Whether Investment Is Merited

The principal purpose of a jurisdiction's primary cost-effectiveness test is to inform decisions on whether DER investments are merited given the jurisdiction's policy goals. There may be situations where a secondary cost-effectiveness test can be useful for addressing other questions. One example might be the question of *how much* investment is appropriate for ratepayers to make in a DER. The UCT can be helpful in this regard by providing insight into the magnitude of just utility system benefits and costs.

Consider a jurisdiction whose policies suggest that a wide range of non-utility system impacts—such as host customer impacts, GHG impacts, and other environmental impacts—should be

included in its JST. Further, consider the hypothetical result of applying that JST to a given DER investment that is presented in Table F-1.

Table F-1. Hypothetical Comparison of JST and UCT Results (Millions of $)

Impact	JST			UCT		
	Cost	Benefit	Net Benefit	Cost	Benefit	Net Benefit
Utility Rebate	$5		($5)	$5		($5)
Utility Program Administration	$2		($2)	$2		($2)
Utility System Impacts (e.g., avoided energy/capacity)		$5	$5		$5	$5
Host Customer Portion of Measure Cost	$7		($7)			$0
Host Customer Non-Energy Impacts		$8	$8			$0
GHG Impacts		$3	$3			$0
Other Environmental Impacts		$1	$1			$0
Total	$14	$17	$3	$7	$5	($2)
Benefit-Cost Ratio			1.21			0.71

In this hypothetical example, the DER investment is reasonably cost-effective, with net benefits of $3 million and a BCR of 1.21 under the JST. However, the investment is not cost-effective under the UCT. In other words, the utility system costs exceed the utility system benefits. It is the non-utility system impacts, particularly the host customer non-energy benefits, that make the difference under the JST. In this example, barring other potential concerns unrelated to cost-effectiveness, a jurisdiction would conclude that the DER merits investment. However, if the jurisdiction employed the UCT as a secondary test and had concerns about the equity of non-participating ratepayers funding participant non-energy benefits, it could use the UCT results to inform modifications to the DER program. In particular, it may suggest reducing rebate levels (which could also reduce participation levels and therefore the overall size of the program) so that the program was at least closer to passing the UCT as well as passing the JST.

F.4 Considerations for Establishing Geographic Boundaries

Decisions about geographic boundaries of interest for different BCA impacts are fundamentally policy decisions. Thus, it is important that they ultimately be based on interpretation of a jurisdiction's policy goals and direction. When considering a jurisdiction's policy position on geographic boundary issues, it may be helpful to consider the following four questions:

1. **Does the jurisdiction have a policy that explicitly requires a purely societal perspective?** For market prices, GHGs, and criteria pollutants, this would require inclusion of all global impacts. For federal financial incentives, this would mean treating such incentives as offsetting transfers rather than as host customer cost reductions.
2. **Is there any policy language that articulates a particular geographic focus for one or more geographic boundary questions?** If so, such direction may be sufficient to determine geographic scope. For example, if a jurisdiction had policy direction to maximize leveraging of federal tax incentives, that would suggest a state boundary of interest with such incentives treated as reductions in host customer costs in the BCA test.

3. **If policy language is not explicit regarding geographic scope of interest, can one logically infer policy intent?** For example, would a jurisdiction have enacted GHG emission reduction goals if it was interested only in the benefits such local emission reductions would have on the local environment?
4. **How are geographic boundary issues addressed for traditional supply-side investments that DERs are deferring or avoiding?** NSPM principles (Table 3-1) require that jurisdictions assess DERs consistently with how they address traditional supply alternatives. For example, federal tax credits for wind and solar generation, federal tax incentives for oil and gas exploration, and federal indemnification of the nuclear power industry against liability claims all effectively lower prices for energy and capacity. Do a jurisdiction's analyses of the cost of traditional supply investments net out the effects of those federal financial supports?

F.5 Recommendations

Every jurisdiction will ultimately have to consider all the questions above—and perhaps others—in establishing geographic boundaries of concern for key BCA impacts in its JST. However, given experience to date in applying the NSPM principles (Table 3-1) in several jurisdictions, it may be appropriate to start with some default assumptions about geographic boundaries for different impacts and to modify the defaults when there are compelling local reasons to do so. Suggested defaults include:

- **MPEs – State/Provincial Boundary**. Very few, if any, jurisdictions have a policy directive to apply a purely societal view to BCA. In addition, most state/provincial regulators would not likely support DER investments that are cost-effective only because of price reduction benefits that accrue to customers in other states, provinces, or countries.
- **Federal Financial Incentives – State/Provincial Boundary (i.e., treating federal incentives as reductions in host customer costs)**. Very few if any jurisdictions have a policy directive to apply a purely societal view to BCA. In addition, if a jurisdiction treats federal financial incentives for DERs as 'offsetting transfers,' then it will need to apply that decision throughout the BCA test to many other costs affected by federal incentives. For example, that would mean increasing assumptions about avoided energy and capacity costs as a result of removing the effects that federal incentives wind and solar generation, oil and gas exploration, nuclear insurance, etc., have on such costs. This creates significant practical challenges as well as policy questions. Finally, many jurisdictions have policies that explicitly call for leveraging federal funds.
- **GHG Emissions – Global Boundary**. It is difficult to imagine any jurisdiction enacting limits on its own GHG emissions solely for the purpose of reducing the impacts of local emissions on the local environment. The cost of reducing local emissions would greatly outweigh the benefits that those local emission reductions would have just within a state or provincial border. Instead, it is likely that jurisdictions that have adopted GHG policies have done so out of a sense that their actions will lead to reciprocal actions in other jurisdictions to collectively address a 'tragedy of the commons' and out of moral obligation to contribute to a global solution.

- **Criteria Pollutant Emissions – Regional Boundary**. This decision may be the most challenging to make of the four described in this appendix. Policy interest in reduction in environmental pollutants is typically and inherently more a 'societal' concern than a parochial state concern, though that may not always be the case (e.g., cases in which there is concern about pollution from vehicles in local communities). Though less compelling than for GHGs, there is also a potential argument that there is some expectation of reciprocity with other jurisdictions.

Appendix G. Developing Secondary BCA Tests

This appendix provides guidance on the purpose of secondary tests, along with examples of secondary tests and how they might complement a primary BCA test.

G.1 Summary

While a jurisdiction's primary test informs whether a utility should fund or otherwise support DERs, it need not be used in a vacuum. Secondary tests can provide sensitivity analyses for informing regulatory decisions where primary BCA test results are inconclusive. They can also help to prioritize DER investments or inform program design. In some instances, secondary tests can enhance regulators' and stakeholders' overall understanding of DER impacts by answering other questions about utility DER investments.

Secondary tests can assist in the following ways:

- Inform decisions on how to prioritize DERs by considering perspectives other than the regulatory perspective (such as the utility or host customer perspective)
- Inform decisions about marginally cost-effective DERs
- Inform decisions beyond whether an investment is merited (which is the primary purpose of the JST) such as how much ratepayer investment may be appropriate

Different tests provide different information about the cost-effectiveness and impacts of DERs.

There is a range of options that regulators, utilities, and other stakeholders can consider for secondary tests. Examples include:

- *Utility Cost Test.* As a secondary test, the UCT can show how DERs will affect just utility system costs. It can also inform regulatory decisions on *how much* ratepayers should invest in DER initiatives, particularly if many of the benefits accrue outside of the utility system.
- *Societal Cost Test.* As a secondary test, the SCT can indicate how cost-effective DERs would be when accounting for the full range of potential benefits and costs.
- *A variation of the primary test, where the secondary test includes (or excludes) a particular non-utility system impact* that regulators and stakeholders want to investigate separately from the primary test. This might be useful for conducting a sensitivity analysis of that non-utility system impact, particularly if or when there are questions about how to interpret policy goals.

The purposes of the secondary analyses, discussed in more detail below, typically inform the decisions on which impacts to include in those tests.

G.2 Inform Decisions on How to Prioritize DERs

The primary test indicates whether a DER investment will provide net benefits or costs, while accounting for applicable policy goals. Yet cost-effectiveness is not the only concern. Most jurisdictions choose not to invest in all cost-effective DERs due to funding limits, potential rate

impacts, equity concerns, or other constraints. In these cases, regulators, utilities, and others may need to make choices among cost-effective DERs to decide which ones to implement.

Regulators and stakeholders may choose to prioritize programs based on the results of the primary test. For example, ranking DERs according to their JST net benefits or benefit-cost ratios facilitates choosing the lower-cost DERs over the higher-cost ones.

Alternatively, regulators may choose to use a secondary test to help prioritize DERs—with input from stakeholders—by considering different perspectives. For example, the UCT can support prioritizing DERs because it focuses on the direct benefits and costs to all utility customers (who are the ultimate funders of utility-sponsored DER investments).

G.3 Inform Decisions Regarding Marginally Cost-Effective Resources

In cases where a DER is marginally cost-effective, secondary tests can inform decisions about whether the utility should fund or otherwise support the DER. Secondary tests provide regulators and other stakeholders with additional information to assess whether certain DER investments will provide net benefits, and how the results compare to the primary JST.

Example of using a secondary test for marginally cost-effective resources

Regulators decide not to include GHG reduction benefits in the primary test for a jurisdiction where stakeholders could not agree on whether to account for those benefits. The jurisdiction decides to use a secondary test to provide additional information on the GHG reduction benefits for a particular DER.

- The proposed DER has a benefit-cost ratio under the primary test of just below 1.0, and a benefit-cost ratio under the secondary test of nearly 2.0. In this instance, the regulators with input from stakeholders might choose to invest in this DER because of the GHG benefits.
- Alternatively, if the benefit-cost ratio under the primary test is 0.85, and only 1.05 under the secondary test, regulators and stakeholders might choose not to invest in this DER.

In addition to showing how including a particular impact in the BCA test will affect the BCA results, sensitivity analyses can show how different estimates for an impact (e.g., low, medium, high estimates) will affect the BCA results.

If jurisdictions use secondary tests to inform decisions about marginally cost-effective DERs, regulators and other stakeholders may want to establish protocols for how to use them, Figure G-1 presents an example of protocols created for this purpose.

Figure G-1. Example Use of Secondary Tests for Marginally Cost-Effective DERs

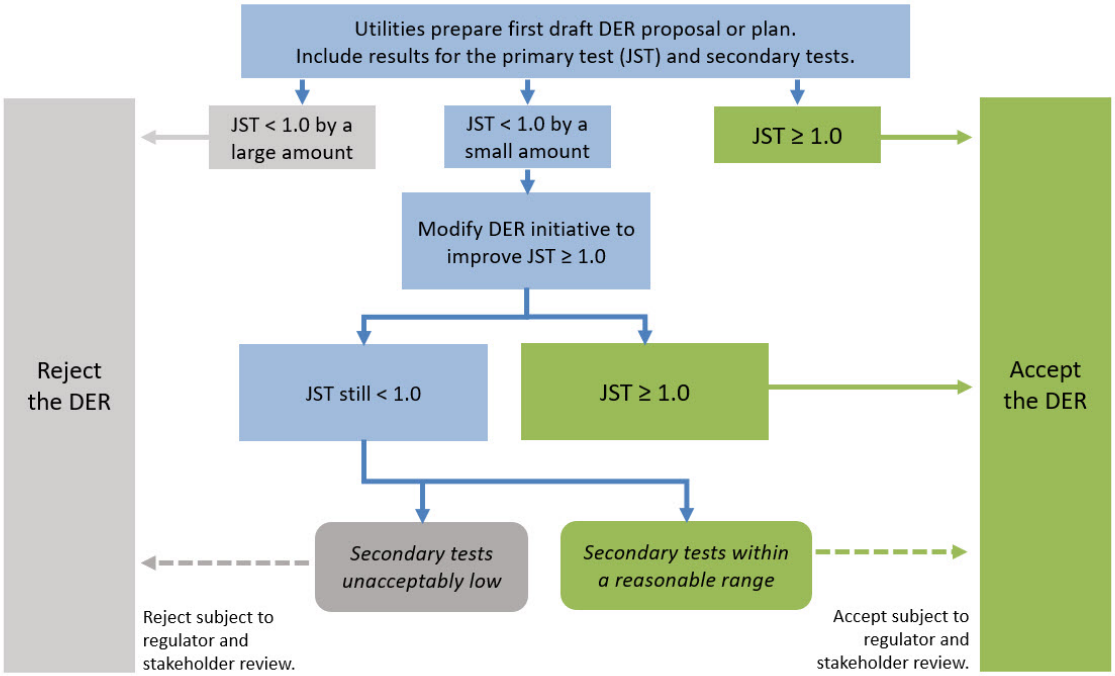


Table G-1 presents some examples of how secondary tests can inform decisions regarding marginally cost-effective DERs. In this example, the primary test includes all utility system impacts, low-income impacts, and other fuels. The secondary test includes those impacts plus benefits of reducing GHG emissions. The conclusions are as follows:

- *Case 1*. The primary test indicates the DER is highly cost-effective. There is no need to apply a secondary test. The DER is accepted for utility funding or support.
- *Case 2*. The DER is accepted for utility funding or support even though the primary test indicates the DER is marginally not cost-effective because under the secondary test it is highly cost-effective.
- *Case 3*. The primary test indicates that the DER is marginally cost-effective, but the secondary test indicates that the DER is not cost-effective after accounting for the cost of increased GHG emissions. The DER is not accepted for utility funding or support.
- *Case 4*. The primary test indicates that the DER is not even marginally cost-effective and so is not accepted for utility funding or support despite the secondary test indicating cost-effectiveness.

Table G-1. Examples of Secondary tests Used to Consider Marginal DERs

	Case 1	Case 2	Case 3	Case 4
Primary test (JST)	2.1	0.96	1.05	0.7
Secondary test	Not needed	1.8	0.4	1.8
Invest in DER?	Yes	Yes	No	No

Using secondary tests in this way may diminish the prominence of the primary JST test, as shown in Cases 2 and 3. On the other hand, the secondary test alone may not determine investment decisions, as shown in Case 4. This implies that secondary tests should be used carefully and with full documentation of the process and bases for making investment decisions.

Appendix H. Selecting Discount Rates for BCAs

This appendix provides guidance on how to determine a BCA discount rate that is consistent with the objective(s) of the BCA, whether for a jurisdiction's primary BCA test or for any secondary tests. The concepts described in this appendix are applicable to all DER types.

H.1 Summary

- Discount rates allow analysts to compare monetary benefits and costs that occur over different time periods on the premise that money in the future is not worth the same as money today.
- A higher discount rate gives more weight to short-term benefits and costs relative to long-term benefits and costs, while a lower discount rate weighs short-term and long-term impacts more equally.
- The choice of discount rate is a critical element of any BCA because it can have large impacts on BCA results.
- The discount rate reflects a particular 'time preference,' which is the relative importance of short-term versus long-term impacts. Different parties—such as utility investors, customers, society—have different time preferences based on their own economic conditions. Regulators and other decision-makers responsible for overseeing DER investments also have a time preference that reflects that of the entities they represent.
- For DERs and other utility investments, there are four categories of discount rates commonly considered, either separately or in some combination:
    - The weighted average cost of capital (WACC) for investor-owned utilities represents the time preference of utility investors.[95] Since utility investors' primary goal is to maximize the return on their investments, and the regulatory perspective is broader than this, an investor-owned utility WACC is not well suited for reflecting the regulatory time preference.[96]
    - A customer average discount rate represents the time preference of average utility customers. This rate can reflect the time preference of *current* utility customers. It can further represent 'intergenerational' time preference by capturing both current and future customers. Customer average discount rates are important because the purpose of the BCA is to identify resources that best serve customers, as it is the customers that experience the benefits and costs of those resources, both in the short and/or long terms.

[95] Publicly owned utilities have goals more aligned with customers interests than those of other utilities, and they tend to have a lower WACC that includes mostly or entirely debt.

[96] As described further below, investor-owned utilities will be able to recover their costs of debt and equity, and make their investors whole, regardless of the discount rate used in a BCA.

- A societal discount rate considers the value of resource investments over the longer term in achieving a jurisdiction's policy goals, such as reducing environmental impacts or improving public health.
- A low-risk discount rate can be used if a BCA does not directly account for utility system risk impacts as benefits or costs. This is based on the assumption that the DER in question has a lower risk profile than the resources that it avoids.

The choice of discount rate for BCA is a policy decision and should reflect the regulatory time preference, which considers current and future utility customers as well as any relevant policy goals in the jurisdiction.

- The choice of discount rate for BCA is a policy decision and should reflect the regulatory time preference, which considers current and future utility customers as well as any relevant policy goals in the jurisdiction.
- The choice of discount rate for a jurisdiction's primary BCA test is best informed by considering multiple factors. The steps below can help guide regulators and other decision-makers in determining a discount rate for the JST:
  - Establish that the regulatory perspective used to inform the JST serves as the basis for the regulatory time preference to inform the selection of the discount rate.
  - Consider the time preference of current utility customers.
  - Consider how much weight to give to future versus current utility customers.
  - Consider how other policy goals affect the regulatory time preference.
  - Consider whether risk has been adequately accounted for in the other assumptions in the BCA.
- The discount rate for a jurisdiction's secondary BCA test could be the same as for the primary test, or it could be different depending on the goal of the secondary test.
- All the discount rate concepts discussed in this appendix are applicable to BCAs used in other regulatory contexts, including BCAs for utility investments in GT&D resources.

H.2 The Purpose of Discount Rates

Discount rates are an essential tool for assessing any multi-year project or investment. They allow analysts to compare benefits and costs that occur over different time periods.

Some utility costs, such as power plant siting, licensing, and construction, usually occur in the short or relatively short term. Other utility costs such as fuel and O&M stretch into the long-term future. That is, the operating life of major utility investments is typically much longer than the development and construction period. Many DER resources can be implemented within a year or two and then operate for many years thereafter.

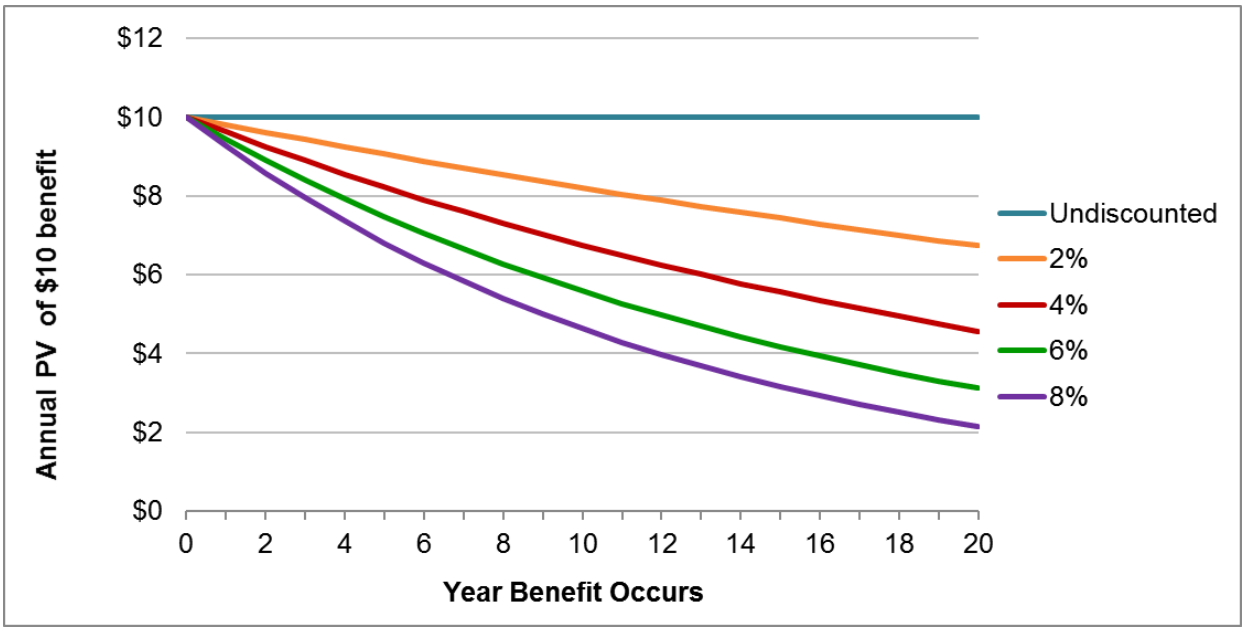
Applying discount rates turns benefits and costs experienced in different years into comparable values. The choice of discount rates is a critical element of any BCA because it has large impacts on the results.

As such, because DERs incur costs and provide value over time in the future, the dollars are not directly comparable values. Applying discount rates turns benefits and costs experienced in different years into comparable values. The choice of discount rates is a critical element of any BCA because it has large impacts on the results. This is especially

true when the analysis involves long-lived resources. Discounting allows comparison of benefit and cost streams of varying length to each other.

Figure H-1 illustrates how different discount rates can affect DER benefits calculations (for instance, avoided generating fuel costs). This example starts with an annual fuel costs savings of $10 per year over the course of a 20-year period. The blue line on top indicates the magnitude of the future avoided fuel costs assuming no discount rate. The other lines depict the annual present value of the avoided fuel benefit, depending upon the discount rate used. As indicated, higher discount rates will dramatically reduce the value of avoided fuel savings benefits in Year 20, while lower discount rates have a much smaller impact. For example, with an 8 percent discount rate, $10 in avoided costs 20 years from now would have a present value of only $2. With a 2 percent discount rate, $10 in avoided costs 20 years from now would be worth almost $7.

Figure H-1. Implications of Discount Rates (Annual Present Value Dollars)



Note: These benefits are presented as real dollars (i.e., adjusted for inflation), and the discount rates are real discount rates.

H.3 Different Time Preferences of Different Parties

BCAs can include benefits and costs that affect a variety of parties, including utility shareholders, public utility governing boards, current customers, future customers, and society. Each party has a different time preference; some might place a higher value on near-term benefits and costs while others might have a longer-term preference. The list below summarizes the time preferences for each of the key parties involved in BCAs.

Each party has a different time preference; some might place a higher value on near-term benefits and costs while others might have a longer-term preference.

- Investor-Owned Utility Time Preference: The utility WACC typically indicates the time preference for investor-owned utilities. It reflects the time preference of utility shareholders and bondholders, based on the utility authorized

return on equity, cost of debt, and debt-to-equity ratio. The key goal of utility investors is to maximize the returns on their investments; thus, their time preference is based on this goal.

- Publicly Owned Utility Time Preference*:* Publicly owned utilities, such as public power authorities, municipal utilities, and cooperatives, usually have a different time preference than investor-owned utilities. First, the cost of capital for publicly owned utilities is typically based solely on debt (including debt service coverage) and, therefore, is usually lower than the WACC of investor-owned utilities. Second, publicly owned utilities' time preference, by design, are likely to be more aligned with the time preference of their customers.
- Current Utility Customer Time Preference*:* Utility customers' time preferences often depend on their personal cost of capital. For residential customers, the cost of capital might be borrowing costs (e.g., loan interest rate for the DER investment) or the opportunity costs of investment options. For some C&I customers, the cost of capital might be based on their equity and debt costs. For some government customers, the cost of capital might be based on government bonds. For non-profit customers, the cost of capital might be based on a variety of public and private funding sources.
- Future Utility Customer Time Preference. Future utility customers' time preference is similar to that of current utility customers—with the important exception that they would place more weight on future benefits and costs than current utility customers.
- *Regulatory Time Preference*: As described in Chapter 4, the primary BCA test (the JST) reflects the *regulatory perspective*, which aligns with the jurisdiction's applicable policy goals and objectives as articulated in statutes, regulations, executive orders, and commission orders. Similarly, the regulator's *time preference* reflects the interests of current and future customers, as well as the jurisdiction's policy goals.

The regulator's time preference reflects the interests of current and future customers, as well as the jurisdiction's policy goals.

H.4 Commonly Used Discount Rates

Table H-1 summarizes several types of discount rates useful for energy resource cost-effectiveness assessment. For each type of discount rate, it indicates the time preference represented by that rate, a range of typical values, some brief notes, and sources for finding current values.

The values in Table H-1 appear in 'real' dollars as opposed to 'nominal' dollars. *Real dollars remove the effects of inflation whereas nominal rates include the effects of inflation*. It is appropriate to always apply real discount rates to real benefits and costs, and to always apply nominal discount rates to nominal benefits and costs. BCA practitioners will need to clearly identify which type of dollars they use for the benefits, costs, and discount rates.

The values in Table H-1 are for illustrative purposes based on typical ranges at the time of publication of this version of the NSPM. Other points to consider include that these values can change over time according to changing economic conditions, there are multiple methods and sources for determining discount rates, and different utility customers will have different time preferences.

Table H-1. Discount Rate Options for BCAs (Illustrative Values Are in Real Dollars)

Time Preference	Basis for Discount Rate	Illustrative Values (real dollars)	Notes and Sources
Investor-Owned Utility	Investor-owned utility's WACC	5 to 8%	Investor-owned utility costs of capital are available from the Federal Energy Regulatory Commission Form 1, Securities Exchange Commission 10k reports, and utility Annual Reports.
Publicly Owned Utility	Publicly owned utility's cost of borrowing	3 to 5%	Publicly owned utility costs of capital are available from the Federal Energy Regulatory Commission Form 1, Securities Exchange Commission 10k reports, and utility annual reports.
Utility Customers	Customers' cost of capital	3 to 7%	Customers' cost of capital can be represented by either the cost of borrowing or the opportunity costs of alternative investments (Pindyck and Rubinfeld 2001; DOE 2023b).
Regulatory	Current and future customers' cost of capital, accounting for applicable policy goals	Varies	The discount rate may be the same as another time preference or may represent a range of time preferences.
Societal	Societal cost of capital, adjusted to consider societal goals	0 to 3%	In addition to low-risk financing, government agencies have a responsibility to consider intergenerational equity by using a lower discount rate (OMB 2023b).
Low-Risk	Interest rate on 10-year U.S. Treasury Bonds	1 to 3%	Over the past 20 years the average real interest rate on 10-year U.S. Treasury Bonds was 1.3% real (USDT n.d.).

Note: Illustrative values of discount rates are in real terms, as opposed to nominal. The utility cost of capital should be the after-tax cost.

H.5 The Cost of Capital

H.5.1 The Utility Cost of Capital

The Weighted Average Cost of Capital

The utility WACC is a typical discount rate for the UCT. The reasoning is that the UCT represents the perspective of the utility, and the WACC is a good indicator of the time preference of the utility.

However, the UCT is not intended to represent the perspective of the utility investors or utility management. The UCT includes all the benefits and costs within the scope of the 'utility system' (in other words, the benefits and costs experienced to serve customers). This distinction between the 'utility' (meaning management or investors) and the 'utility system' (meaning all utility customers) is critical when considering whether the utility WACC is relevant for the UCT.

The time preference of utility investors is not the same as the time preference of utility customers, or a regulatory time preference.

The goal of the UCT is fundamentally different than the goal of utility investors. The goal of the UCT is to identify those resources that will best serve customers over the long term. The key goal of utility investors is to maximize the returns on their investments. Therefore, the time preference of utility

investors is not the same as the time preference of utility customers, or a regulatory time preference.

The same distinction applies to the TRC Test, the PCT, and the RIM test.[97] None of these tests represent the perspective of utility investors.

In sum, the utility WACC represents the time preference of utility investors, which is usually quite different than the time preference of current customers, future customers, societal, or regulatory time preferences. From this perspective, thus, the utility WACC is appropriate only for BCAs where the primary goal of the analysis is to maximize utility investor returns.

Unregulated Companies Versus Regulated Utilities

Using a company's WACC for a discount rate is conventional practice for unregulated businesses. For these companies, the WACC is the logical choice for a discount rate because it reflects the businesses' cost of capital, and it is consistent with their primary goal of maximizing investor returns.

However, regulated utilities are fundamentally different from unregulated businesses:

- Unregulated businesses provide different types of services, have different planning practices, and have different short-term and long-term goals.
- Unregulated businesses provide products and services in the context of competitive markets; they do not have monopoly franchises.
- Unregulated businesses typically seek to maximize the sales of their products and services, and one of their primary goals is to maximize the returns of their investors.
- Unregulated businesses do not have an obligation to serve customers.
- Unregulated businesses are typically focused on satisfying customers in the short term with no obligation to consider the intergenerational equity of customers over the long term.

The use of WACC for a discount rate is deeply embedded in the conventional practices of *unregulated* businesses but is not consistent with the goals *regulated* utility BCAs.

Regulated utilities, on the other hand, do have an obligation to serve customers and to provide them with safe, reliable, low-cost service over the short term and long term, while meeting regulatory policy goals. These differences between unregulated businesses and regulated utilities require the use of a different time preference and therefore a different discount rate for investment planning purposes. The use of WACC might be deeply embedded in the conventional practices of unregulated businesses, but it does not serve the goals of the utility or regulators.

Collection of Revenues to Pay for Debt and Equity

One argument for utility use of WACC as a discount rate is that investor-owned utilities need to collect sufficient revenues to pay dividends and interest to their investors. However, this rationale is invalid because the choice of discount rate for a BCA test has no impact on the ability of the utility to recover its cost of capital. The recovery of any debt and equity costs associated with

[97] As discussed in Chapters 3 and 4, and in more detail in B and C, the PCT and the RIM test are not appropriate for BCA purposes. Practitioners should conduct them separately because they answer different questions than a BCA.

resource acquisition is typically part of the calculation of each resource's benefits and costs in the BCA test.

For example, the avoided capital cost of a new power plant or distribution system upgrade is calculated in terms of annual revenue requirements, which include depreciation plus the recovery of debt, equity, and taxes over the book life of the asset.

Given that the recovery of debt and equity costs are included in all the relevant benefits and costs of the resources, there is no need to base the choice of discount rate on the utility collection of revenues to pay for debt and equity.

WACC should be used for cost recovery purposes, but the fact that it is used for such purposes has no bearing on what discount rate should be used to reflect the regulatory time preference.

Put another way, the use of WACC for cost recovery purposes has no bearing on what discount rate should be used to reflect the regulatory time preference in determining the cost-effectiveness of utility investments.

H.5.2 The Customer Cost of Capital

Another discount rate sometimes proposed for BCA is the utility customer cost of capital, due to the fact that BCA is ultimately meant to benefit customers. The customer cost of capital varies considerably across customer classes, and across customers within classes. However, each BCA test typically uses only a single discount rate.[98] Therefore, to the extent that the customer time preference is used to inform the determination of a discount rate, it should represent the time preference of a broad range of utility customers (an average cost among all customers).

The US DOE estimates discount rates for utility customers in the context of BCAs for appliance efficiency standards. These appliance standard discount rates are directly relevant to BCAs for DERs because both types of BCAs are designed to identify the long-term, cumulative present values of customer energy benefits and costs. For residential customers, DOE estimates discount rates as the weighted average real interest rates for both consumer debt and equity holdings. For commercial and industrial customers, DOE estimates discount rates based on the customer's weighted average cost of capital (DOE 2023b, page 8-27). The most recent DOE analysis finds the following:

- Residential real discount rates range from 3.0% to 4.9% and are roughly 4.2% on average (DOE 2023b, page 8-34).
- Commercial real discount rates range from 5.7% to 7.3% and are roughly 6.8% on average (DOE 2023b, page 8-37).
- Industrial and agricultural customer real discount rates are roughly 7.2% to 7.3% on average (DOE 2023b, page 8-37).

Further, a customer's cost of capital is only one factor that will influence a customer's time preference for how they spend their money. Customers often make purchasing decisions that are not driven by the ability to raise new funding. For example, a family might choose to forgo the purchase of a high-quality appliance that will save money over the long term and instead buy a

[98] As noted below, it is possible to apply different discount rates to different impacts in a BCA test, such as a different discount rate for monetary values of greenhouse gases. However, for simplicity and clarity, these exceptions should be limited to impacts that warrant a significantly different time preference.

lower quality appliance because they need to pay for more pressing household expenses or priorities (such as grocery bills or school tuition). Customers tend to make these day-to-day decisions without considering the interest rate for borrowing more money.

These points suggest that setting discount rates to reflect customers' time preference requires careful consideration of what makes sense for average customers and how much to rely upon the cost of capital for indicating the time preference.

H.6 Intergenerational Equity

A key aspect of the regulatory perspective and time preference is that regulators have a responsibility to consider the impacts on customers and the operation of the utility system over both the long term and the short term. This responsibility requires that regulators consider the intergenerational equity implications of the discount rate. Greater emphasis on protecting customers over the long term suggests the use of a lower discount rate.

This consideration of intergenerational equity is a policy goal that can apply to all BCA tests. Whether the BCA test is from the perspective of the utility system (i.e., all customers), host customers, the regulators, or society, the regulators have a responsibility to account for customers over the short, medium, and long term.

H.7 Risk Considerations

Risk is often cited as an important factor in choosing a discount rate, because risk can affect the value placed on long-term versus short-term impacts. However, there are different ways to represent risk in BCA, and when determining treatment of risk in the discount rate, it is important to consider how risk is addressed (or not) in the rest of the analysis. Not doing so could lead to double-counting or under-counting of risk (see Appendix L).

Risks can vary considerably across different types of utility resources. For example, EE resources tend to have relatively low risk. While there is some risk associated with them, they tend to reduce overall system risk by reducing customers' exposure to riskier alternatives: generators create different amounts of capital cost, siting, and construction risks; fossil-fueled generators create price escalation and volatility risks; and T&D facilities impose their own kinds of risks (Ceres 2012).

> Several states use a low-risk discount rate based on US Treasury Bill yields for BCA of EE resources to reflect the assumption that DERs offer lower risks than the resources avoided by them (ACEEE n.d.). When using information such as US Treasury Bill yields as an indicator of a low-risk investment, it is useful to consider the average yields over a long period of time (for instance, 20 years). This approach will align with the long-term study period for the BCA test and will avoid basing the discount rate on short-term swings in the Treasury Bill yields.

In general, it is preferable to account for resource and planning risk in developing benefit and cost inputs to a BCA test. However, there may be situations where a DER BCA test does not properly reflect resource or planning risks. For example, the cost-effectiveness inputs often do not fully capture the full set of risks associated with avoided costs (e.g., risks associated with avoided fuel costs, risks associated with construction costs). In these instances, one way to account for risk is to adjust the discount rate to be higher (to reflect greater risk) or lower (to reflect lower risk).

H.8 Determining the Discount Rate for the JST

Ultimately, the choice of discount rate is a decision about how much weight to give to long-term versus short-term benefits and costs. Under the BCA Framework, the choice of discount rate for the JST will be consistent with the goals of the BCA, which should align with the regulatory perspective; each jurisdiction determines a discount rate based on its own policies and goals.

The process below can guide regulators and other decision-makers in choosing a discount rate for the JST that best reflects the jurisdiction's regulatory time preference.

Under the BCA Framework, the choice of discount rate for the JST will be consistent with the goals of the BCA and align with the regulatory perspective; each jurisdiction determines a discount rate based on its own policies and goals.

1. Establish that the selection of the JST discount rate will align with the 'regulatory' perspective and a corresponding time preference.

As noted above, the goal of the primary BCA test is to identify utility investments that will provide net benefits to utility customers, while achieving any additional regulatory policy goals. The regulatory time preference thus determines the discount rate most aligned with this goal of BCA. Articulating this point at the outset will help work through the considerations in the following steps.

2. Consider the time preference of current utility customers.

The current customer time preference creates the starting point for choosing the regulatory time preference because a key goal of the BCA test is to identify investments that will provide net benefits to customers. For example, at the time of publication of this Manual, customers' real cost of capital ranges from roughly 3 to 7 percent. The average within this range is 5 percent.

3. Consider how much weight to give to future versus current customers.

This is a policy decision based on the policy goals of each jurisdiction. Regulators that put greater weight on intergenerational equity and protecting the interests of future customers would choose a lower discount rate than, for example, the current customer discount rate.

4. Consider how other policy goals should affect the regulatory time preference.

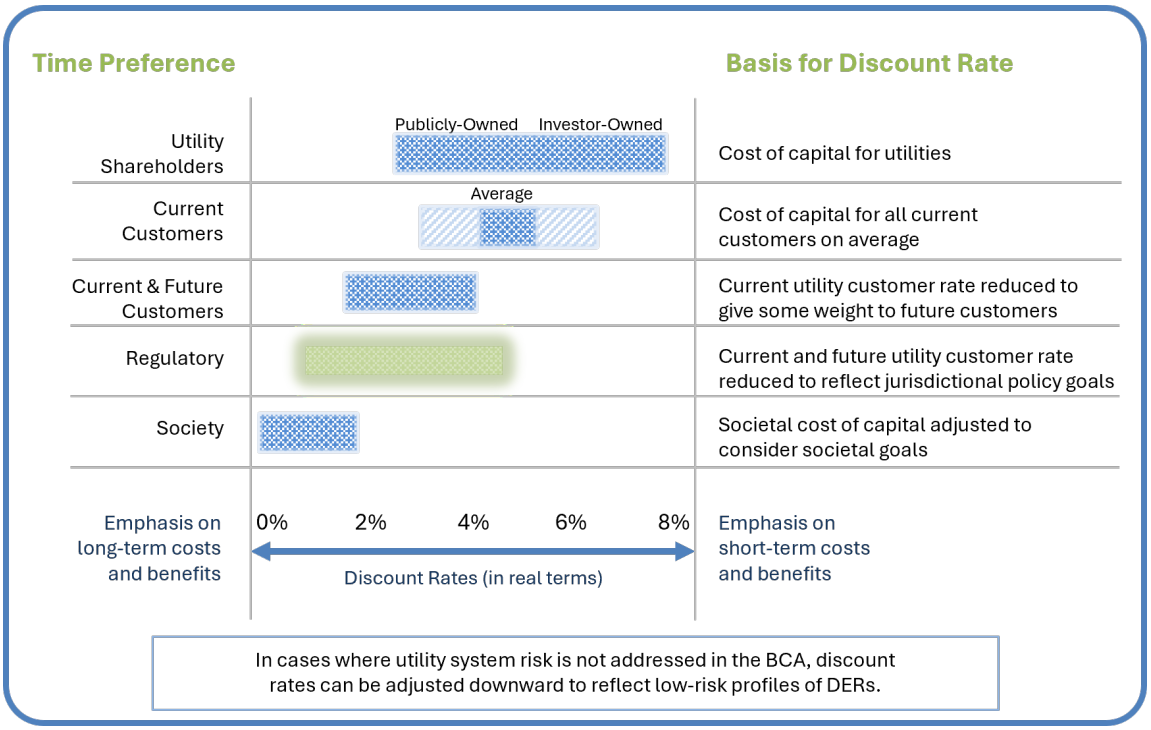
Some JSTs will include policy goals such as reducing environmental impacts, protecting public health, or improving the resilience of critical facilities that serve the public. The inclusion of these goals in the JST indicates a lower discount rate is appropriate, potentially comparable to a societal discount rate.

5. Consider whether other BCA assumptions have adequately accounted for risk.

The best place to account for risk is in the calculations of individual BCA impacts that have a high level of uncertainty. If these calculations do not sufficiently account for risk, regulators and other decision-makers may choose to adjust the discount rate to reflect the net risk benefits (or net risk costs) of the DERs under evaluation. A low-risk discount rate might be appropriate for those DERs assumed to have a net lower risk than the alternatives to the DER.

These considerations suggest that the regulatory time preference and associated *real* discount rate for a JST will often be in the range of 1 to 5 percent, depending on how much weight a jurisdiction places on future customers and any applicable policy goals. Figure H-2, along with the steps above, can guide the choice of discount rate for the JST.

Figure H-2. Factors Informing Choice of Real Discount Rate (Using Illustrative Values)



The examples in the following text box help illustrate how the steps above can inform the choice of a discount rate for a JST. The two examples and the discount rates provided are illustrative. They demonstrate the need for some professional judgment in weighing the questions outlined above and reaching decisions on the appropriate discount rate. Given the need to use professional judgment and reflect policy goals, it is important that decision-makers solicit robust stakeholder input, fully justify decisions, and transparently document the process.

Example 1: In developing a discount rate for a JST that includes only utility system impacts, a jurisdiction might start with the average cost of capital for customers of 5 percent and then adjust it downward to 4 percent to apply some weight to the goal of intergenerational equity.

In this example, the BCA test captures the risk associated with the DER investment (relative to alternative resources) and thus the discount rate does not reflect the risk.

Example 2: In developing a discount rate for a JST that includes reducing GHG emissions as a policy goal, the jurisdiction might start with the average cost of capital for customers of 5 percent, then adjust it downward to 4 percent to reflect the goal of intergeneration equity. It might then adjust it downward further to reflect the societal goal of reducing GHG emissions, resulting in a discount rate of 3 percent.

If risk is not adequately accounted for in the other aspects of the BCA, then the JST can use a reduced discount rate of 2 percent.

H.9 Additional Guidance

H.9.1 Discount Rate Choice for Secondary Tests

As described in Chapter 3, secondary tests can enhance regulators' and stakeholders' overall understanding of DER impacts. Secondary tests can serve as sensitivity tests by including or excluding impacts included in the JST or to address different questions than those answered by the JST.

The goal of the secondary test will determine whether to apply the same discount rate used in the JST to a secondary test(s), as follows:

The goal of the secondary test will determine whether to apply the same discount rate used in the JST to a secondary test(s).

- In cases where a secondary test seeks to *answer the same question* as the primary test but adds or removes impact categories (such as GHG impacts), it is advisable to use the same discount rate to isolate for differences in cost-effectiveness directly related to the change of impacts. Otherwise, it will not be clear whether the change in cost-effectiveness is due to the change in the range of impacts included in the test or the change in the discount rate. After completion of the secondary test using the same discount rate as the JST, a follow-up secondary test can use a different discount rate for an additional sensitivity.
- When the purpose of a secondary test is to *answer a different question* than the primary test, it becomes less important to have a consistent discount rate but there are still tradeoffs. For example, a jurisdiction's JST might include a broad set of societal impacts and therefore use a societal discount rate. After applying the JST, if a jurisdiction needs to further prioritize or compare the resulting cost-effective DERs, it could, for example, adopt a UCT as the secondary test to provide a narrower test focused on benefits and costs to the utility system. In this case a jurisdiction could use a discount rate representing the average customer discount rate for the UCT instead of a societal discount rate. This would not isolate for how the changes in impacts affect cost-effectiveness but, in this instance, that would not be important because the secondary test would serve a different purpose than assessment of overall cost-effectiveness.

H.9.2 Discount Rates Used in the Calculation of Individual BCA Impacts

Within a BCA test, the application of a discount rate converts future benefits and costs over the useful life of a DER into present value terms. Discount rates can also be useful in calculating key benefits or cost assumptions used as inputs to the BCA test.

For example, the determination of the social cost of carbon often uses a discount rate between 1.5 and 3.0 percent to reflect the fact that carbon dioxide emissions persist in the atmosphere for centuries and damage from climate change will impact future generations. However, if a jurisdiction calculates the social cost of carbon using a 2 percent discount rate, that does not mean the rest of the JST has to use the same discount rate. This is because the JST discount rate choices typically balance multiple policy objectives (and risk considerations) whereas some individual impact streams may reflect just one specific policy objective (and/or set of risks).

H.9.3 Discount Rates for Analyzing Different Types of Utility Investments

As described in Appendix A, the principles and concepts in this Manual apply to a variety of contexts, including regulatory review of utility-scale generation, grid modernization, distribution system planning, integrated resource planning, and more. This includes not only the NSPM Principles (Table 3-1) and the concepts behind the primary BCA test but also planning parameters such as the discount rate used in the BCA test. Ideally, all utility DER investment decisions would value DERs consistently, where valuations would use the same JST, the same underlying methods and assumptions (where relevant and material), and the same discount rates. This consistent application of BCA principles and concepts is likely to result in efficient economic analyses that identify all types of utility investments that can provide the greatest net benefits to customers while meeting regulatory policy goals. This means that all the discount rate concepts discussed above regarding BCA for DERs also apply to BCA for other utility resource investments.

In addition, as described above, it is important for the discount rate for DER BCAs to align with the regulatory perspective because (a) the discount rate should be consistent with the goal of BCA, (b) the goal of BCA is to identify those resources that will best serve customers and achieve relevant policies over the long term, and (c) the regulatory perspective reflects this same goal. This same logic applies to BCA for all types of utility resource investments, because for all types of utility investments the BCA goal is the same. Therefore, the regulatory perspective is just as relevant to BCA tests for all types of utility investments and the discount rates used in those BCA tests.

All the discount rate concepts discussed above regarding BCA for DERs also apply to BCA for other utility resource investments.

The one exception is the use of a risk-adjusted discount rate to reflect the different level of risk associated with the resource under evaluation in the BCA test (if risk has not been adequately addressed in the valuation of relevant impacts). For example, if a jurisdiction uses a low-risk discount rate in a BCA test for DERs because DERs are assumed to present lower risks than alternative supply-side resources, then that same low-risk discount rate would not be used in a BCA for other types of resources that have a different risk profile.

Appendix I. BCA Assessment Levels

This appendix provides guidance on options for different BCA assessment levels to inform DER investment decisions, and the pros and cons of the options.

The BCA test for DERs can be assessed at several levels of aggregation. Assessments can focus on individual measures, individual customer-specific projects, individual programs combining multiple measures and/or projects, sectors (such as all residential or all business programs), or portfolios of programs (across all sectors). This appendix discusses the advantages and disadvantages of conducting cost-effectiveness analyses at each of those levels. It also discusses how fixed costs fit into these assessment levels.

Assessment level options include the following and are each described in turn:

- **Measure-level:** Application of a BCA test to the average costs and savings across all utility customers for a particular technology or action that utility programs may promote
- **Project-level:** Application of a BCA test to a package of DERs offered to an individual customer
- **Program-level:** Application of cost-effectiveness analysis to an entire program[99] or initiative
- **Sector-level:** Application of a BCA test to a combination of programs targeted to a particular sector (i.e., small business, residential, industrial)
- **Portfolio-level:** Application of a BCA test to a combination of programs targeted at a range of different sectors

I.1 Measure-Level Assessment

Resource assessment at the measure level means that each individual measure promoted by an efficiency program must be cost-effective on its own. Screening at the measure level is the most restrictive application of the cost-effectiveness tests.

Measure-level application of BCA requirements will essentially guarantee that every measure included in a DER program will be cost-effective on its own. However, application of cost-effectiveness requirements at that level can have perverse implications. In some cases, it could reduce the overall net economic benefits of efficiency investments. That can occur for any of the following reasons:

- A customer's interest in a non-cost-effective measure may be key to persuading the customer to install a package of measures that are cost-effective in aggregate. In such cases, the flexibility to promote the non-cost-effective measure as part of a package will lead to greater overall net benefits.

[99] The term 'program' means an initiative (also a mechanism or an offering) that does not rely in a material way on synergies with other initiatives to effectively engage with the market and/or to drive investment in one or more DERs. While multiple initiatives can be combined and assessed together, there are merits to separately assessing cost-effectiveness of individual initiatives that do not rely on others to drive DER investment.

- A customer's interest in a non-cost-effective measure may be key to the development of a relationship with the customer that can lead to installation of cost-effective measures in the future. In other words, a portfolio can include some non-cost-effective DERs in which some customers may be interested as 'loss-leaders.' In that sense, promotion of the non-cost-effective measure can be analogous to a marketing investment.
- Installation of a non-cost-effective measure may be necessary to technically or safely enable the installation of other cost-effective measures. An example of this would be the installation of non-cost-effective mechanical ventilation to make indoor air quality acceptable when reducing building drafts.

Another disadvantage of requiring all measures to be cost-effective is that it can be difficult to account for NEIs, hard-to-monetize impacts, or additional considerations at the measure level. Some NEIs, such as improved health and safety, are obtained through a package of multiple measures, and it is impractical to apply such impacts to each measure.

I.2 Project-Level Assessment

Resource assessment at the project level means the combination of measures implemented together in a package for an individual customer must be cost-effective on its own. Utilities or program administrators typically reserve project-level assessments for projects undertaken by larger business customers due to the transaction cost of a site-specific assessment.

Project-level application of BCA requirements will essentially guarantee that every project included in a DER program will be cost-effective on its own. However, application of cost-effectiveness requirements at that level can have some (though fewer) perverse implications of measure-level cost-effectiveness requirements. Specifically, supporting the implementation of a non-cost-effective package of measures of interest to a customer can facilitate development of a relationship with customer that can produce a more cost-effective project later. Also, depending on whether and how jurisdictions include participant non-energy benefits in cost-effectiveness assessments, project-level assessments may not capture the full value of non-energy benefits of a project.[100]

I.3 Program-Level Assessment

Resource assessment at the program level means that the measures and/or projects within a program must be cost-effective collectively. Some individual measures and/or projects may not be cost-effective on their own but could still be included in the program if the overall program were cost-effective.

The primary advantage of this approach is that it best represents the benefits and costs of initiatives that combine a set of actions (e.g., marketing, education, technical support, financial

[100] The focus of this discussion is solely on the use of cost-effectiveness analysis to determine which investments merit acquisition from either utility system or broader perspectives. DER programs targeted to large business customers often present benefits and costs to individual customers from the customer's perspective (i.e., using retail energy prices rather than avoided system costs, as well as considering customer non-energy benefits that may or may not be part of a jurisdiction's cost-effectiveness test). Similarly, some low-income programs base the determination of which measures to install on the savings-to-investment ratio (i.e., benefit-to-cost ratio) derived using the customer's retail rate. The merits of such customer-focused analyses are fundamentally different from those discussed here regarding utility system resource analyses.

support, etc.) into a single package offered to customers. In addition, resource assessment at the program level avoids the problems noted above regarding missing the interrelationships between measures. These include technical connections and the ability to engage customers in ways that can lead to increasing net economic benefits, as well as the ability to properly capture customer non-energy benefits where warranted.

A disadvantage of this approach is that a program might include one or more measures that are not individually cost-effective and do not alleviate the concerns addressed above. This has the effect of decreasing to some extent the overall cost-effectiveness of the program. However, sound program design can mitigate this concern if DER program planners and designers include only those measures that effectively contribute to achieving the specific goals of the program.

One other potential concern with program-level screening is that it might preclude certain special programs that address important objectives at the sector or portfolio level. For example, pilot programs to test new and unproven program designs might not appear cost-effective but might provide future sector or portfolio benefits that cannot be identified in the present. For that reason, jurisdictions that apply program-level screening may want to allow assessment of these types of programs at the sector level.

I.4 Sector-Level Assessment

Resource assessment at the sector level means the programs within a sector (e.g., low-income, residential, commercial, and industrial)[101] must be cost-effective collectively. Some programs may not be cost-effective on their own but could still be implemented if the combined impact of all of the programs targeted to a given sector were cost-effective.

The primary advantage of this approach is that it indicates the benefits and costs of initiatives to provide a package of DER services to an entire sector. This may enable the provision of non-cost-effective programs to a sector for the purpose of providing a complete set of DER services to that sector—an objective often driven by concerns about equitable access to DER programs across a large range and number of customers.

The primary disadvantage of this approach is that it could result in the inclusion of measures or programs that are not individually cost-effective, thereby decreasing the economic value of the suite of programs for that sector.

I.5 Portfolio-Level Assessment

Evaluation at the portfolio level means the programs within a portfolio (i.e., combining all programs together) must be cost-effective collectively. Some programs may not be cost-effective on their own but could still be pursued if the combined impact of all of the programs was cost-effective.

[101] Some jurisdictions treat low-income programs as their own 'sector' because of the special consideration often given to such customers in program design and delivery. Others treat low-income programs as part of the residential sector. Alternatively, though commercial and industrial customers could be different 'sectors,' most DER programs targeted to business customers do not differentiate between those two groups of customers, creating what are called business, non-residential, or commercial & industrial (C&I) sector programs. For the purpose of this Manual, low-income, residential, and C&I are noted as three sectors of interest for illustrative purposes only. The conceptual discussion in this section applies regardless of whether low-income is treated as its own sector or as part of the residential sector and regardless of whether commercial and industrial are treated as their own sectors or combined.

This is a recommended approach when conducting a BCA test for multiple DERs (e.g., solar plus storage and EE). Conducting the BCA test at the portfolio level will allow for consideration of interactive effects between DERs (see Chapter 13).

The primary advantage of this approach is that it indicates the benefits and costs of the entire suite of DER programs.

The primary disadvantage of this approach is that it could result in implementing measures or programs that are not cost-effective, thereby decreasing the economic value of the overall portfolio.

I.6 Consistency in Assessment Level

It may not always be feasible to apply the same BCA assessment requirements for different types of DERs. For example, as indicated above, there are benefits to having a BCA assessment at the program level for EE projects to account for the use of non-cost-effective measures to serve as 'loss leaders' or to technically or safely enable the installation of other cost-effective measures. However, if a utility is proposing to install a large stand-alone solar PV system, a regulator may choose to conduct a BCA test at the measure level to assess the benefits and costs of that system on its own.

I.7 Properly Accounting for Fixed and Variable Costs

The acquisition of DERs incurs a variety of costs. It is important to include those costs at the proper analytical level—project, measure, program, sector, and/or portfolio—when analyzing the economics of DERs. In a nutshell, only DER impacts that are variable at a given analytical level should be included in a BCA test for that level because they are the only costs that will be avoided or increased due to the analysis. It is not appropriate to allocate or otherwise include DER costs that are largely fixed at a particular analytical level *at that level*. Doing so could lead to rejection of investments whose marginal benefits exceed their marginal costs, thereby lowering net economic benefits. That does not mean cost-effectiveness assessment should omit or ignore DER costs that are fixed at a given analytical level. Instead, those costs can and should be included at higher-level analyses at which they are variable and therefore are avoidable.

For example, when assessing the economics of DERs, it is important that a BCA test include only costs that largely increase or decrease in proportion to the number of measures installed. That will obviously include the cost of the measures themselves and could also include some program costs that are largely variable. Examples would include rebate processing costs, if the program administrator is paying a vendor a price for every rebate processed, and inspection costs if the program is committed to inspecting a certain percentage of all projects.[102] However, other DER program costs that are either largely fixed or do not change in proportion to program participation levels, such as the costs of marketing[103] or managing and evaluating the program, do not belong in

[102] Alternatively, if the program administrator is committed to inspecting enough projects to get a statistically valid sample, such that the number of inspections would not change significantly or at all between a level of 2000 and 10,000 participants, then such inspection costs should be treated as largely fixed and captured at the program level rather than at the measure level.

[103] Marketing costs can be somewhat variable in the sense that more marketing should lead to more participation. However, that relationship is rarely linear with the number of measures installed. In addition, and perhaps more importantly, program marketing budgets are often treated as largely fixed. That is, while marketing can play an

the economic analysis of individual measures. Rather, they should be included only in a program-level BCA.

Similarly, it is inappropriate to allocate portfolio costs that are either largely fixed (or do not change in proportion to the number of programs or participation levels in those programs) to programs for the purpose of analyzing the economics of individual programs. Rather, they should only be included in portfolio-level cost-effectiveness analysis. Such costs can include portfolio-level marketing, management, and evaluation costs.

The tables below illustrate the importance of accounting for largely fixed costs at the proper analytical level. Table I-1 shows that for each of five programs analyzed, the benefits exceed the variable costs of the programs. When largely fixed portfolio costs (equal to about 25 percent of the sum of the five program costs) are added to the sum of the variable impacts of the five programs, the portfolio itself proves to be cost-effective, providing total net benefits of $800,000.

Table I-1. Analysis with 25 Percent Fixed Portfolio Costs Included at Portfolio-Level Analysis

	Benefits ($000)	Costs ($000)	Net benefits ($000)	Positive net benefits?
Program 1	$500	$250	$250	Yes
Program 2	$300	$200	$100	Yes
Program 3	$1000	$400	$600	Yes
Program 4	$500	$300	$200	Yes
Program 5	$1000	$850	$150	Yes
Sum of all programs	$3300	$2000	$1300	Yes
Portfolio-level costs	$0	$500	-$500	
Total portfolio impacts	$3300	$2500	$800	Yes

Table I-2 shows that when the fixed portfolio-level costs are improperly allocated as 25 percent 'adders' to each of the programs, the fifth program no longer shows as cost-effective. Removal of that program from the portfolio, but with portfolio costs remaining unchanged, causes the portfolio net benefits decline by $150,000 (which is the marginal impact of the fifth program on the portfolio) to $650,000.[104] In short, including fixed costs at the improper level can reduce the economic benefits of DER acquisition.

important role in driving program participation, the costs of marketing do not go up and down as the number of participants goes up and down.

[104] Removing the fifth program would require a reallocation of the fixed portfolio cost to the remaining four programs (i.e. each of the remaining four programs would now be allocated a larger portion of the fixed portfolio costs). In this example, the four remaining programs would still all be cost-effective even after absorbing this larger allocation. However, under a different set of example programs, it is possible that the resulting larger allocation of fixed costs would render another program cost-ineffective.

Table I-2. Improper Analysis: 25 Percent Fixed Portfolio Costs Allocated to Individual Programs

	Benefits ($000)	Costs ($000)	Net benefits ($000)	Positive net benefits?
Program 1	$500	$313	$188	yes
Program 2	$300	$250	$50	yes
Program 3	$1000	$500	$500	yes
Program 4	$500	$375	$125	yes
Program 5	$1000	$1063	-$63	no
Sum of all programs	$3300	$2500	$800	yes
Portfolio-level costs		Included as adder for each program		
Total portfolio if non-cost-effective programs excluded	$2300	$1650	$650	yes

Appendix J. Template NSPM Tables

This appendix provides example template tables that jurisdictions can use to take inventory of their applicable policies, goals, and objectives and to help identify relevant benefits and costs to inform development of their primary Jurisdiction-Specific Test.

The template tables below can support jurisdictions in their efforts to articulate or document key information used in developing their primary cost-effectiveness test (or modification to an existing test) using the NSPM multi-step process (Steps 1–4). The template tables can help to guide stakeholder processes to (a) identify applicable priority energy policy goals and objectives and (b) determine how those goals and objectives translate into benefits and costs to account for in a primary BCA test: the JST.

The template tables are available for download (in Excel format) at: https://naseo.org/topics/nesp. The workbook contains the following tables that build on one another through the development of a JST:

1. **Take Policy Inventory Table:** Take inventory of the jurisdiction's applicable energy policies and prioritize policies
2. **Document Goals & Objectives:** Identify the goals and objectives articulated in priority policies (per relevant impacts)
3. **Summary of Relevant Impacts:** Summarize the relevant impacts to consider for inclusion in the primary BCA test
4. **Score Relevant Impacts:** Score the relevant impacts based on a set of agreed-to criteria
5. **Document Primary Jurisdiction Specific Test:** Document resulting JST, and for tests used to analyze more than one DER type, indicate relevance and materiality of impact to selected DERs (as this may vary)

1. Take Policy Inventory Table

The purpose of the *Policy Inventory* tab is to catalog the full range of a jurisdiction's energy policies as identified by stakeholders, provide a summary description of each policy, and indicate which DER types each policy covers. After identifying the full range of policies, stakeholders can identify the priority policies that will inform the JST.

Figure J-1. NSPM Template Table for Taking Policy Inventory

Jurisdiction's Applicable Energy Policies, Decisions, Plans		DER Type (EE, DR, DG, DS, EV)	Priority Policy, Decision, Plan?
Policy	Summary Purpose	Indicate the type of DER referenced	Yes/No
Energy Grid Modernization Act	Defines grid flexibility resources to enhance reliability, facilitate two-way energy flows, and create a resilient infrastructure that supports clean energy jobs and stabilizes long-term delivery costs.	All DERs	Yes
State Code, Public Utilities §55-555	This section of the State Code defines renewable energy and distributed resources with the purpose to facilitate the development of a balanced energy portfolio that supplies electricity to customers in a safe and reliable manner. The statute directs that energy policy should create clean energy jobs and provide measurable public health benefits to the state's citizens.	EE, DR, EV	Yes
State Climate Mitigation Plan	Defines decardbonization pathways to reduce GHG emissions, improve regional air quality, and provide measurable public health benefits by reducing criteria pollutants.	All DERs	Yes
Energy Storage Act	This Act defines energy storage resource with the purpose of facilitating the development of new storage capacity to support the integration of intermittent resources, balancing peak demand to stabilize energy prices, and engancing grid security for all citizens.	All DERs except EE	Yes

2. Document Goals & Objectives

This tab is for documenting and citing key language where policy goals and objectives align (or not) with a range of non-utility system impacts provided (which the user can modify). The cited language could require an action or a desired outcome of the non-utility system impact, state a non-utility system impact as an objective of the policy, or simply mention the impact.

Figure J-2. NSPM Template Table for Documenting Goals and Objectives

Jurisdiction's Priority Energy Policies	Non-Utility System Impacts Relevant to State Goals/Objectives			
	Societal Impacts			
	Other Fuels	Resilience	GHG Emissions	Other Environmental
Energy Grid Modernization Act	*No specific references. However, references to GHG goals could be interpreted to suggest all fuel impacts are of interest or concern.*	§ 77.7-7777.1 Paragraph A: "The State recognizes that effectively addressing climate change and **enhancing resilience** will advance the health, welfare and safety of the residents of the State. The State further recognizes that addressing climate change requires reducing greenhouse gas emissions across the State's economy sufficient to reach net-zero emission by 2050 in all sectors, including electric power, transportation, industrial, agricultural, building and infrastructure sectors. To achieve these objectives, it shall be the policy of the State to...5. Maximize energy efficiency programs as defined in § 88-888, to the extent determined to be in the public interest, that are the lowest-cost energy option to reduce greenhouse gas emissions, in order to produce electricity cost savings and to create jobs and economic opportunity from the energy efficiency sector."	§ 99-999. Integrated resource plan required. Paragraph (B): In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose...(11) Developing a long-term plan for energy efficiency measures to accomplish policy goals of reduction in customer bills, particularly for low-income, elderly, and disabled customers; reduction in emissions; and reduction in carbon intensity." 18. "That as part of its integrated resource plans filed between 2019 and 2028, any Phase II Utility, as that term is defined in subdivision A 1 of § 99-998.0 of the Code, shall incorporate into its long-term plan for energy efficiency measures policy goals of reduction in customer bills, particularly for low-income, elderly, veterans, and disabled customers; **reduction in emissions;** and reduction in the utility's carbon intensity. Considerations shall include analysis of the following: energy efficiency programs for low-income customers in alignment with billing and credit practices; energy efficiency programs that reflect policies and regulations related to customers with serious medical conditions; programs specifically focused on low-income customers, occupants of multifamily housing, veterans, elderly, and disabled customers; options for combining distributed generation, energy storage, and energy efficiency for residential and small business customers; the extent that electricity rates account for the amount of customer electricity bills including a comparison of the average retail electricity price per kWh by rate class among all 50 states and an analysis of each state's primary fuel sources for electricity generation, accounting for energy efficiency, heating source, cooling load, housing size, and other relative factors..."	transmission rates after capped rates terminate or expire. (A)(1)(z) regarding cost recovery for energy efficiency programs "In all relevent proceedings pursuant to this section, the Commission shall take into consideration the goals of economic development, energy efficiency and environmental protection of the state. § 88-899. Integrated resource plan required. Paragraph (B): In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose...(11) Developing a long-term plan for energy efficiency measures to accomplish policy goals of reduction in customer bills, particularly for low-income, elderly, and disabled customers; reduction in emissions; and reduction in carbon intensity." 18. "That as part of its integrated resource plans filed between 2019 and 2028, any Phase II Utility, as that term is defined in subdivision A 1 of § 88-885.1 of the Code of the State, shall incorporate into its long-term plan for energy efficiency measures policy goals of reduction in customer bills, particularly for low-income, elderly, veterans, and disabled customers; reduction in emissions; and reduction in the

3. Summary of Relevant Impacts

This tab serves to simply summarize the relevant impacts cited in the priority policies (Tab 3). Tab 4 uses a set of criteria to further address whether the JST ultimately includes these impacts.

Figure J-3. NSPM Template Table for Summarizing Relevant Impacts

Jurisdiction's Priority Policy Goals/Objectives	Relevance of Policy to DER type	Utility System Impacts	Non-Utility System Impacts Relevant to Jurisdiction's Goals/Objectives						
			Other Fuels	Societal Impacts				Host Customer	
		Generation, Capacity, T&D, General, etc.		Resilience	GHG Emissions	Other Environmental	Public Health	Host Customer (non-LMI)	Host Customer (LMI)
Energy Grid Modernization Act	All DERs								
State Code, Public Utilities §55-555	EE, DR, EV								
State Climate Mitigation Plan	All DERs								
Energy Storage Act	All DERs except EE								
Energy Efficiency Program Plan PUC Order No. 25-123	EE								
Distribution System Planning PUC Order No. 25-456	DG								
Governor's State Enery Plan	DS								
Include in Primary BCA Test (JST)?		*Always include in any BCA test*	Yes	Yes	Yes	Yes	No	No, but include in secondary test	

Always account for full range of Utility System Impacts in JST
Concensus that policy goals support inclusion in JST
Policy mentions the impact, may support inclusion in JST
Non-consensus on relevance of impact
Consensus that policy goal does not address impact and should not be in JST

4. Score Relevant Impacts

This tab illustrates one way that a stakeholder input process can 'score' impacts using a set of criteria to inform the relevance of non-utility system impacts for inclusion in the primary JST.

Figure J-4. NSPM Template Table for Scoring Relevant Impacts

Jurisdiction's Priority Energy Policies		Utility System Impacts	Non-Utility System Impacts Reflected in Policies						
			Other Fuels	Societal Impacts				Host Customer	
Policy	Purpose/Description	Generation, Capacity, T&D, General, etc.		Resilience	GHG Emissions	Other Environmental	Public Health	Host Customer (non-LMI)	Host Customer (LMI)
Energy Grid Modernization Act	Defines grid flexibility resources to enhance reliability, facilitate two-way energy flows, and create a resilient infrastructure that supports clean energy jobs and stabilizes long-term delivery costs.	*Always include in BCA test*		✓	✓	✓			
State Code, Public Utilities §55-555	This section of the State Code defines renewable energy and distributed resources with the purpose to facilitate the development of a balanced energy portfolio that supplies electricity to customers in a safe and reliable manner. The statute directs that energy policy should create clean energy jobs and provide measurable public health benefits to the state's citizens.				✓	✓			
State Climate Mitigation Plan	Defines decardbonization pathways to reduce GHG emissions, improve regional air quality, and provide measurable public health benefits through the reduction of criteria pollutants.		✓	✓	✓	✓	✓	✓	✓
Energy Storage Act	This Act defines energy storage resource with the purpose of facilitating the development of new storage capacity to support the integration of intermittent resources, balancing peak demand to stabilize energy prices, and engancing grid security for all citizens.			✓	✓	✓		✓	✓

5. Document Primary Jurisdiction-Specific Test

Using the results from Tab 4, users can populate all JST impact rows and indicate whether each impact is material, immaterial, currently not material or not applicable (NA). Users can also

compare JST impacts with current BCA practices to identify impacts not accounted for in current BCA practice.

Figure J-5. NSPM Template Table for Documenting the JST

Impact Category	Specific Impact	Is the impact relevant and material to the DER based on at least one of the policies in the Policy Inventory tab?				
		EE	DR	DG	DS	ELEC
Electric Utility System Impacts	Generation: Energy Generation					
	Generation: Capacity					
	Generation: Environmental Compliance	Yes				
	Generation: RPS/CES Compliance	NM				
	Generation: Market Price Effects	CNM				
	Generation: Ancillary Services	NA				
	Transmission: Capacity					
	Transmission: System Losses					
	Distribution: Capacity					
	Distribution: System Losses					
	Distribution: O&M					
	General: Financial Incentives					
	General: Utility Direct Investment					
	General: Program Administration Costs					
	General: Utility Performance Incentives					
	General: Credit and Collection Costs					
	General: Risk					
	General: Reliability					
	General: Resilience					

Appendix K. Presenting BCA Results

This appendix provides guidance on how to present results in ways that are most informative and most useful in making cost-effectiveness decisions. It also provides guidance on how to present results to support prioritization across different DER types.

K.1 Introduction

There are multiple ways of presenting the results of BCA tests, each with different strengths and limitations. The following subsections describe the primary options.

The examples below illustrate how to present some of the most useful information from cost-effectiveness analyses. The DERs and cost-effectiveness results presented in examples below are purely illustrative and not based on specific DERs in a specific jurisdiction. Actual cost-effectiveness results could be significantly different from those presented here. In addition, actual results will differ depending upon the cost-effectiveness test used. Further, some examples bundle several DER types together to keep the figures from being too complex. For information on how to present rate, bill, and participation impacts see Appendix B.

K.2 Present Values of Benefits and Costs

The present value of the benefits and costs serve as the foundation for BCA results. Below is a useful approach for presenting present values of impacts:

- Start by presenting the costs separately from the benefits before combining them into net benefits or BCRs.
- Present the stream of annual present value costs and the stream of annual present value benefits to provide a complete picture of how they play out over time.
- Show the accumulation of the two streams of annual present value benefits and costs over the study period to determine the cumulative present value of benefits and the cumulative present value of costs.
- Present the annual streams of *cumulative* present values of benefits and costs, to indicate which year, if ever, the cumulative benefits exceed the cumulative costs. (The number of years it takes for the cumulative benefits to exceed cumulative costs provides an indication of the 'payback' period. In general, resources with shorter payback periods are more cost-effective than those with longer payback periods.)

K.3 Net Benefits

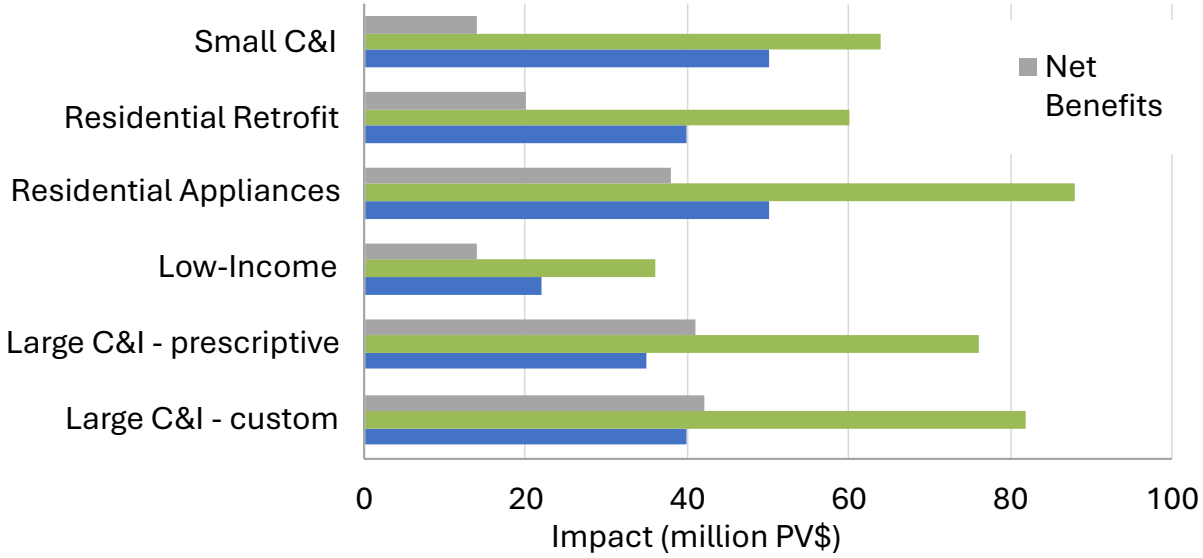
Net benefits are equal to the difference between the cumulative present value of benefits and the cumulative present value of costs, as per the formula below. This metric is useful as a benchmark for determining cost-effectiveness: If a DER's net benefits are greater than zero, its benefits exceed its costs, and it is considered cost-effective.

$$\textit{Net benefits (dollars)} = \textit{NPV} \sum \textit{benefits} - \textit{NPV} \sum \textit{costs}$$

Figure K-1 provides an example of a useful way to present costs, benefits, and net benefits of an illustrative set of EE programs. Similar graphs could also be developed for other DER programs,

other EE programs, and/or combinations of EE and other DER programs. In this hypothetical example, the Large C&I program offers the greatest net benefits, and the Deep Energy Retrofit program has negative net benefits and is therefore not cost-effective. Actual EE programs might have very different results than the examples presented here.

Figure K-1. Example Presentation of Costs, Benefits, and Net Benefits: Hypothetical EE Resources



The net benefits metric provides important information that is not provided by a BCR. It indicates the magnitude of the benefits to be gained by the efficiency resource. For example, a BCR of 2.2 does not indicate how much money will be saved by the resource. It might save $1 million, $10 million, or $100 million.

On the other hand, the net benefits of DERs metric does not lend itself to easy comparison of DERs across different utilities and jurisdictions. A large utility would naturally expect to have higher net benefits than a small utility for a comparable DER.

K.4 Benefit-Cost Ratio

A benefit-cost ratio is equal to the ratio of the cumulative present value of benefits to the cumulative present value of costs, as per the formula below. This metric is useful as a simple benchmark for determining cost-effectiveness: If a DER's BCR exceeds 1.0, its benefits exceed its costs, and it is considered cost-effective.

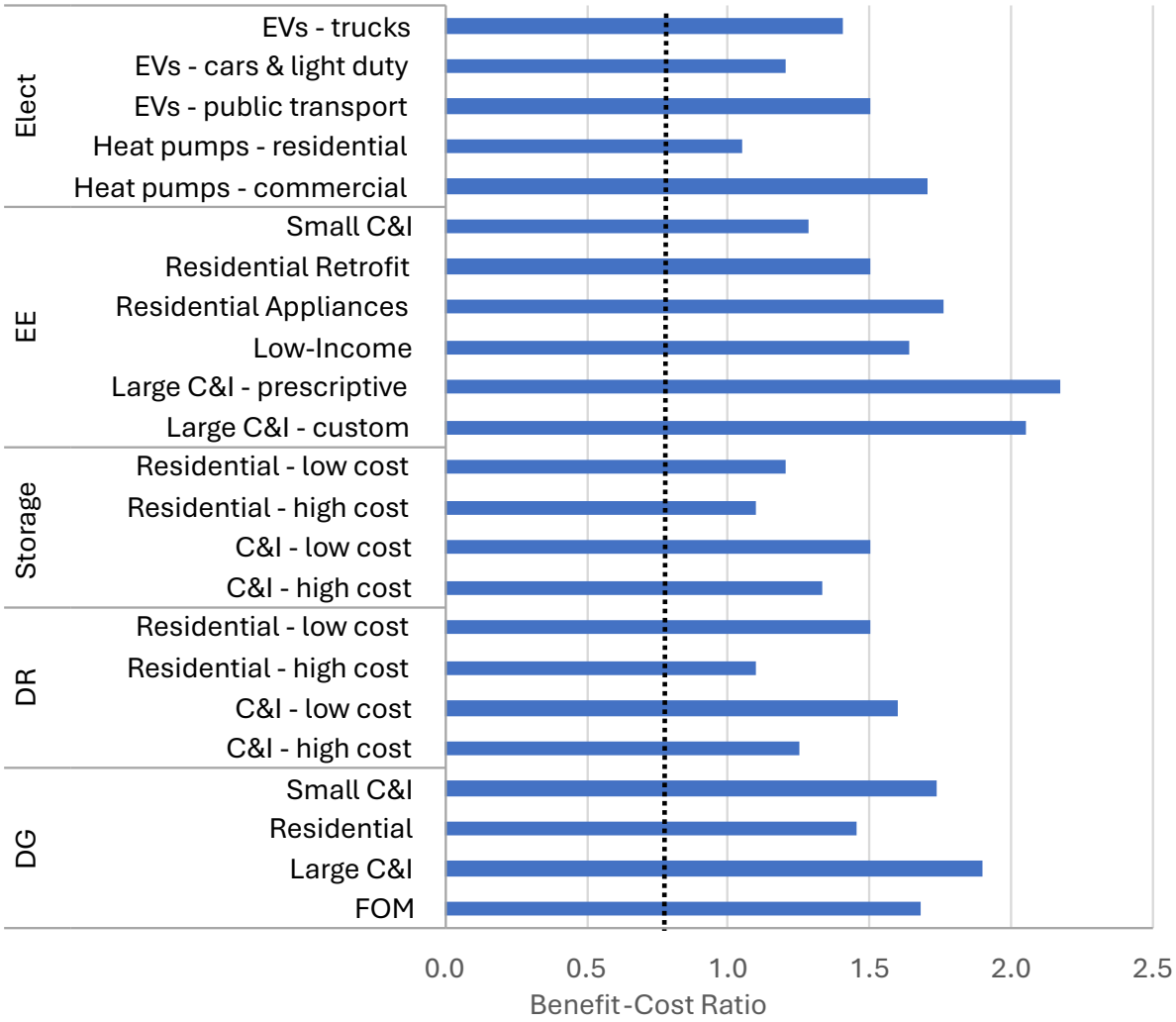
$$\textit{Benefit-Cost Ratio} = \frac{\textit{NPV} \sum \textit{benefits (dollars)}}{\textit{NPV} \sum \textit{costs (dollars)}}$$

The BCR metric can be useful for comparing DERs with each other (i.e., a higher BCR indicates one resource is 'more cost-effective' than another), because it effectively normalizes the results for DERs of different sizes. This metric is also useful for comparing DERs across utilities and

jurisdictions of different sizes, again because it effectively normalizes the results for any differences in size.[105]

Figure K-2 provides an example of a useful way to present benefit-cost ratios. This example includes a variety of hypothetical DER types. If combining multiple DERs in a single graph in this way, it is important that the cost-effectiveness test and the inputs for each DER are consistent. For example, if the host customer benefits and costs are included in the costs for one DER type, then they should be included for all DER types.

Figure K-2. Example Presentation of Benefit-Cost Ratios: Hypothetical Multiple DERs



The BCR metric provides important information that is not provided by a net benefits metric. It does this by indicating the relative effectiveness of the money spent on the resource—in other words, how many dollars of benefits are received per dollar spent. For example, a net benefit of $10 million in present value dollars (PV$) does not indicate how much money was needed to generate those

[105] However, in making such comparisons it is important to recognize that different utilities and jurisdictions might have different avoided costs, i.e., different benefits for the same amount of savings. Different jurisdictions might also include different impacts in their resource assessment test.

net benefits. It could have cost $90 million, with benefits of $100 million and a BCR of 1.1. Or it could have cost $4 million, with benefits of $14 million and a BCR of 3.5.

K.5 Levelized Costs

K.5.1 Net Levelized Cost Calculations

As discussed above, levelized cost calculations divide the levelized measure or program cost of a DER by *just one* of the many benefits of each DER—whether kWh reduction, peak kW reduction, gas thermal reduction, GHG emissions reduction, or any other metric of interest. That limits the value and applicability of levelized cost calculations. For example, a DER that provides both energy savings and system peak demand savings may be more cost-effective (either greater net economic benefits and/or higher BCR) but look more expensive on a levelized cost per kW of system peak reduction basis than a different DER that provides only system peak kW benefits.

That limitation can be addressed through one important modification: subtracting the value of the 'other benefits' (all benefits other than the one by which levelized costs are being divided) from the DER measure or program cost used in a standard levelized cost calculation. The result is a *net levelized cost*. As with levelized costs, the analysis can compute net levelized costs for any DER impact or benefit of interest—whether kWh saved, system peak kW reduction, distribution kW reduction, gas thermal reduction, GHG emissions reduction, or any other metric.

K.5.2 Levelized Cost Calculations

To allow for a relatively simple, direct comparison across different resources, one can convert the costs of electricity and gas resources, including DERs, into levelized costs. Levelized costs represent the average cost per unit of energy required to install and operate an electricity or gas resource. They include the costs of the resource over its economic operating life, amortized over the lifetime and discounted back to the first year divided by the total lifetime energy produced (Lazard 2025).

Levelized costs for electricity generation resources are commonly referred to as levelized cost of electricity (LCOE). Levelized costs for efficiency resources are commonly referred to as levelized cost of saved energy (LCSE) (LBNL 2018). They are calculated using the following formulas:

*LCOE = (capital recovery factor) * (resource lifetime costs) / (annual generation, in kWh)*

*LCSE = (capital recovery factor) * (resource lifetime costs) / (annual electricity savings, in kWh)*

Capital recovery factor = [r(1+r)n] / [(1+r)n-1]*

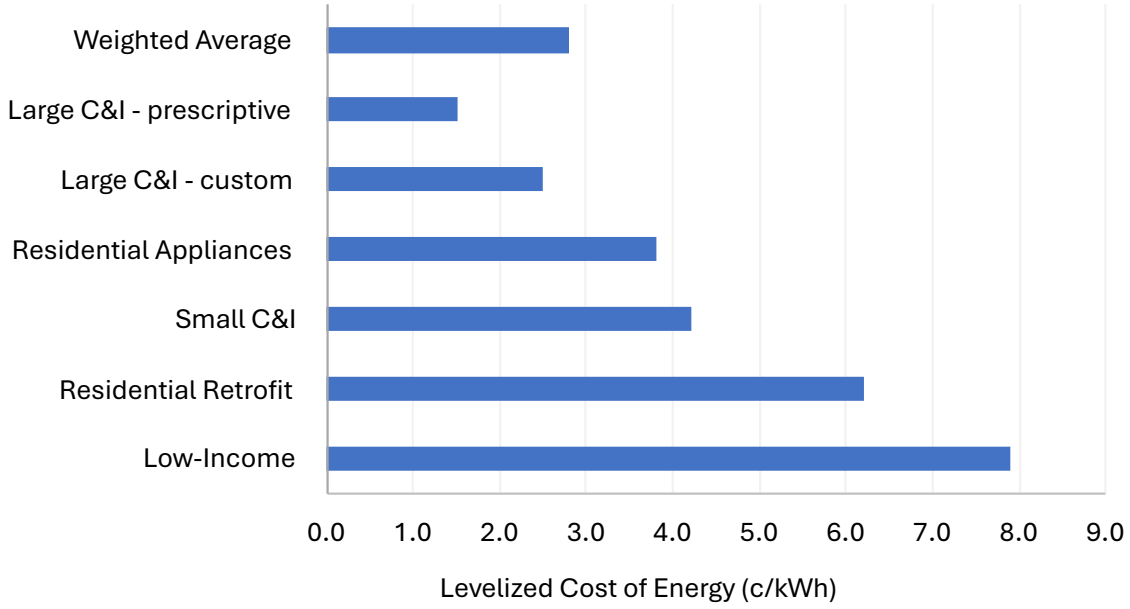
r = the discount rate

n = the resource lifetime

This Manual uses the term 'levelized cost of energy' to refer to both LCOE and LCSE interchangeably.

Figure K-3 provides an example of a useful way to present LCOE for EE resources.

Figure K-3. Example Presentation of Levelized Cost of Energy: Hypothetical EE Resources

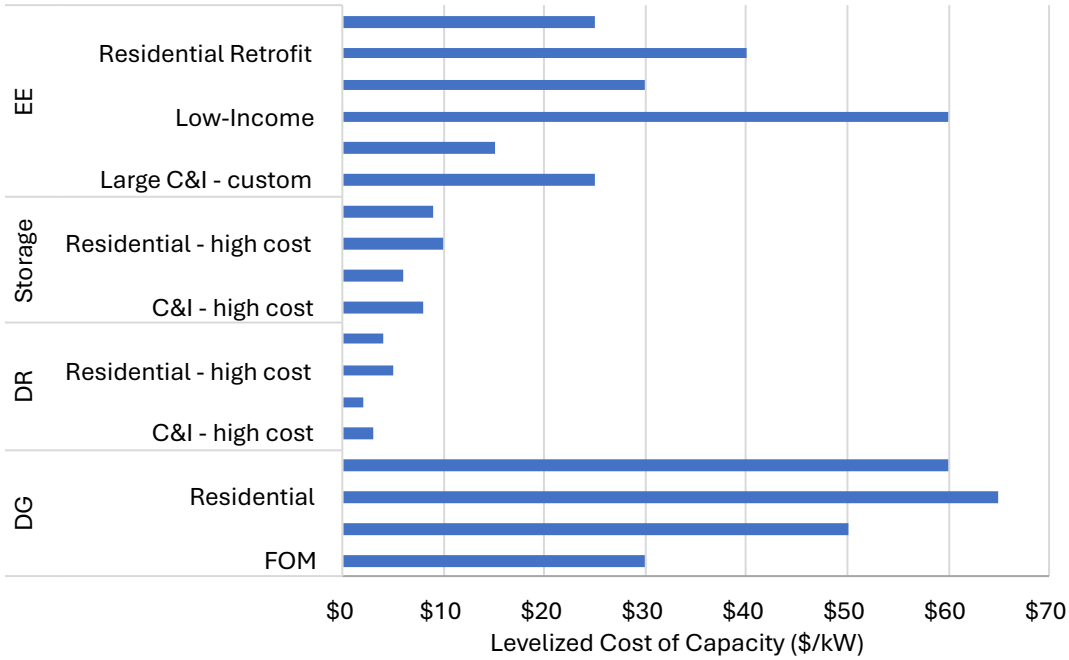


While the levelized cost of energy is a useful way to present the *costs* of electricity and gas resources, it only tells part of the story. It says little about the *benefits* of resources. It puts all the costs in terms of generation benefits (MWh) but says nothing about generation capacity (kW) benefits. It also says nothing about T&D benefits, risk, reliability, other fuel, host customer, or societal benefits.

Levelized costs can also indicate capacity impacts by calculating a levelized cost of capacity (in $/kW). This is especially useful for resources whose primary function is to provide capacity services. The calculation is the same as for the LCOE, except that annual generation is replaced with annual peak savings. Figure K-4 provides an example of a useful way to present levelized cost of capacity for several illustrative DERs.[106]

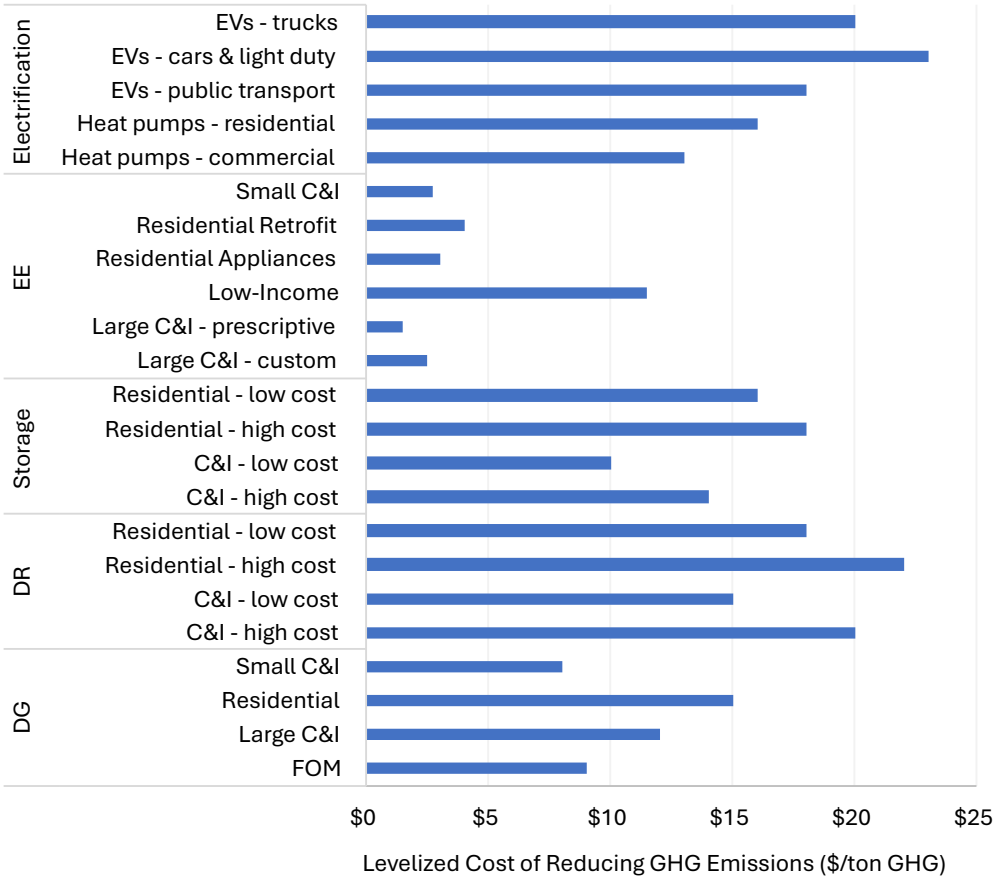
[106] This figure does not include levelized cost of capacity for electrification DERs because these resources typically do not save capacity.

Figure K-4. Example Presentation of Levelized Cost of Capacity: Multiple DERs



Similarly, levelized costs can also indicate carbon reduction impacts by calculating a levelized cost of carbon reduction (in $/ton of GHG reduced). This is especially useful for indicating which resources are most effective at reducing carbon emissions for the dollar spent. The calculation is the same as for levelized cost of energy, except that annual generation is replaced with annual GHG reductions (or increases). Figure K-5 provides an example of a useful way to present levelized cost of GHG reduction for several illustrative DERs.

Figure K-5. Levelized Cost of GHG Reduction: Multiple Hypothetical DERs



Levelized costs of energy, capacity, and GHG reduction all provide different information about the impacts of DERs. For those jurisdictions interested in avoiding capacity costs and reducing GHG emissions, in addition to avoiding energy costs, it would be most informative to calculate and consider all three of these metrics.

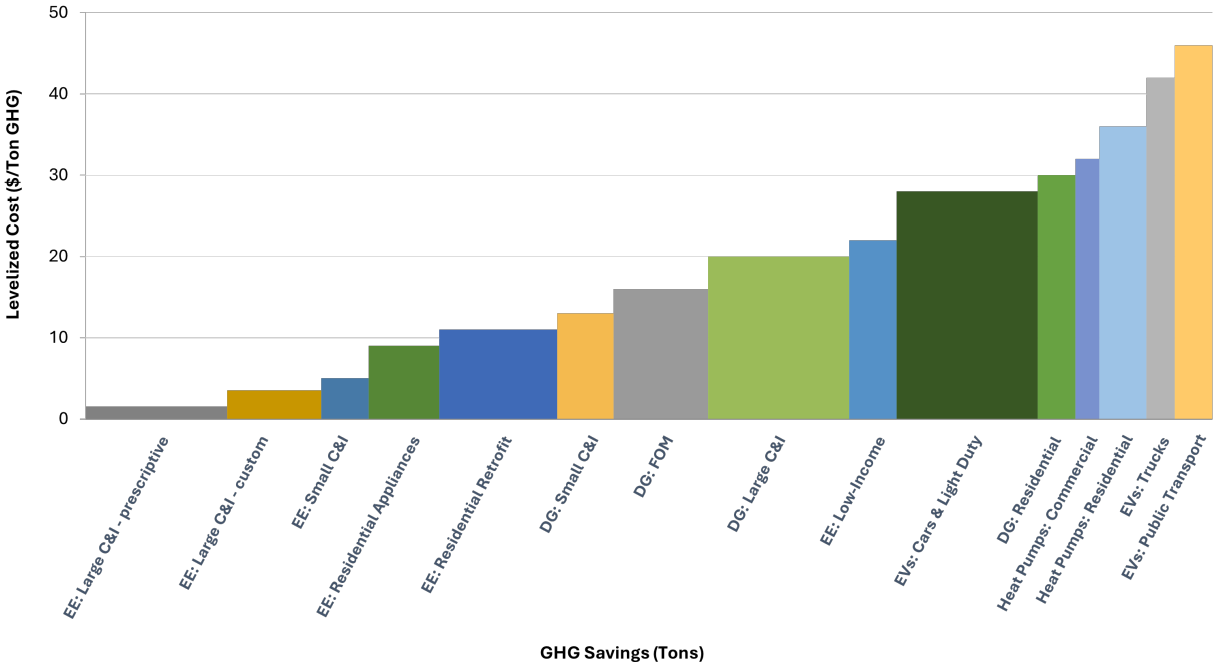
Finally, it is important to recognize the limitations of levelized costs of any type. They do not account for certain benefits that a jurisdiction's primary test might include, including risk, other fuel impacts, low-income benefits, host customer benefits, or societal benefits. Therefore, while levelized costs have some usefulness for comparing different DERs to each other, it is not appropriate to use them in isolation for determining whether a DER is cost-effective. Also, while levelized costs can help prioritization across DERs, it may be important to also consider comparisons that account for other differences in DER benefits.

K.5.3 Levelized Cost Curves

DER cost curves offer a useful way to compare DERs. Cost curves are a graphic depiction of levelized costs where a bar chart is used to depict (a) the DER levelized costs, sorted lowest to highest cost, and (b) the magnitude of the savings for each DER. Typically, the levelized costs are represented on the vertical axis, while the magnitude of savings is presented on the horizontal axis, where the width of each bar indicates the amount of savings.

There are many types of cost curves that can inform DER cost-effectiveness decision-making. Figure K-6 presents an example of a GHG cost curve.

Figure K-6. Example of GHG Cost Curve: Hypothetical Set of Multiple DER Types



Cost curves such as the one above are subject to the same limitations as levelized costs. They present only costs. They do not account for the full complement of DER benefits: they account for only the one benefit displayed along the horizontal axis, which in this case is GHG benefits. Therefore, while cost curves have some usefulness for comparing different DERs to each other, it is not appropriate to use them in isolation for determining whether a DER is cost-effective. And while they can help inform prioritization across DERs, it may be important to also consider comparisons that account for other differences in DER benefits.

K.6 Net Levelized Costs

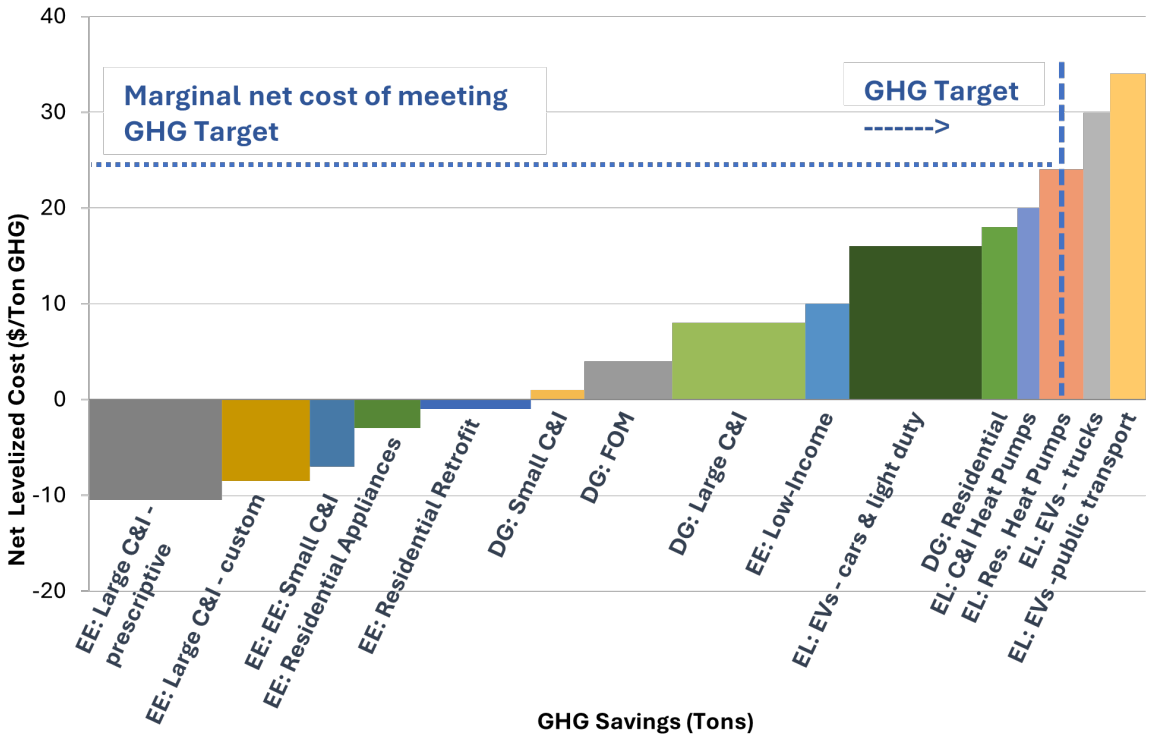
K.6.1 Net Levelized Cost Curves

Net levelized cost curves present all the relevant benefits and costs, where one of the benefits is displayed along the horizontal axis and the net levelized costs are presented along the vertical axis. These cost curves are like the levelized cost curves discussed above except the figures present net levelized costs.

Figure K-7 presents an example of a net levelized cost curve for GHG reductions. It uses all the same information as the example in Figure K-6 above, except that all the benefits but GHG emission benefits are subtracted from the DER costs before they are levelized. The DERs whose net costs are negative in the figure represent those DERs that are cost-effective even without accounting for the value of avoided GHG emissions. The DERs whose net costs are positive represent those that are not cost-effective without accounting for the value of avoided GHG

emissions but might be cost-effective once the BCA incorporates the value of such emission reductions.

Figure K-7. Example of GHG Net Cost Curve: Hypothetical Set of Multiple DER Types



Net cost curves such as this one are useful for several purposes:

- Net cost curves can help prioritize DERs according to those that will reduce GHG emissions at the lowest cost. The leftmost DERs can be prioritized over those on the right.
- Net cost curves can help determine which are the lowest-cost DERs available to meet a particular GHG target. Figure K-7 includes a dashed vertical line indicating the hypothetical GHG emission reduction target for this hypothetical jurisdiction. The DERs to the left of that line represent the lowest-cost options for meeting this GHG target.
- Net cost curves can help identify the marginal net cost of complying with a specific target. Figure K-7 includes a dotted horizontal line that indicates the marginal resource needed to meet the GHG target for this hypothetical jurisdiction. In this example, the marginal resource is EV initiatives for public transportation. As indicated in the previous figure, the cost of this DER is roughly 80 $/ton GHG. This marginal cost is a useful input to the BCA; where the value in $/tons is used as the cost of achieving the jurisdiction's GHG target.
- Net cost curves can also help estimate how much of a resource is cost-effective for a given avoided cost value. For example, at a GHG emission reduction value of $24/ton, all the resources to the left of the C&I heat pumps program in Figure K-7 are cost-effective. Jurisdictions can use similar assessments, for example, in comparing non-wires solutions (when their costs are expressed in net levelized cost per distribution kW) to the cost of a

substation or other traditional T&D capacity upgrade or to the value of deferring such an upgrade.

While levelized net cost curves facilitate the comparison and ranking of DERs and DER types, it is important to understand the limitations. Net cost curves do not necessarily account for interactions between DERs and represent a simplified presentation. There is also a possibility that assumptions for one DER type are of much worse quality than the other. Nonetheless, the information is useful for determining each DER's contribution towards meeting a jurisdiction's policy goals, relative to each other.

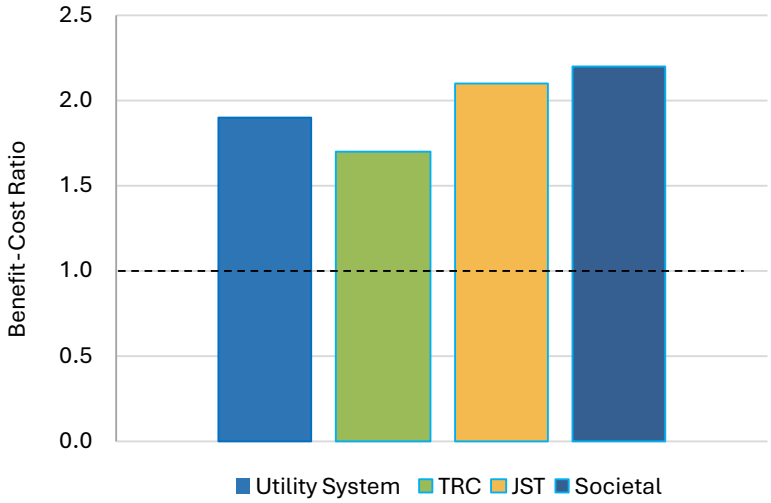
K.7 Multiple BCA Tests

K.7.1 Multiple Tests for One DER Type

Some jurisdictions might choose to use secondary tests, as described in Appendix G. In some cases, it might be helpful to present more than one secondary test. Different tests provide different information, and there may be situations where this additional information is helpful in analyzing and deciding among DER options.

Figure K-8 presents an example of how multiple test results can provide additional information about DER benefits and costs. It shows the BCA results for a hypothetical EE portfolio in terms of BCRs, for a hypothetical JST as well as the traditional UCT, TRC test, and SCT. Presenting the results this way allows for a quick assessment of how cost-effective this DER is according to different tests.

Figure K-8. Presentation of Multiple BCA Tests: Benefit-Cost Ratios—Hypothetical EE Portfolio



The primary test (JST) used in this example includes the following impacts: utility system, host customer, other fuel, low-income, and GHG emissions.

For this hypothetical EE portfolio:

- UCT results: The EE is very cost-effective, and the utility system benefits exceed the utility system costs by a factor of two.

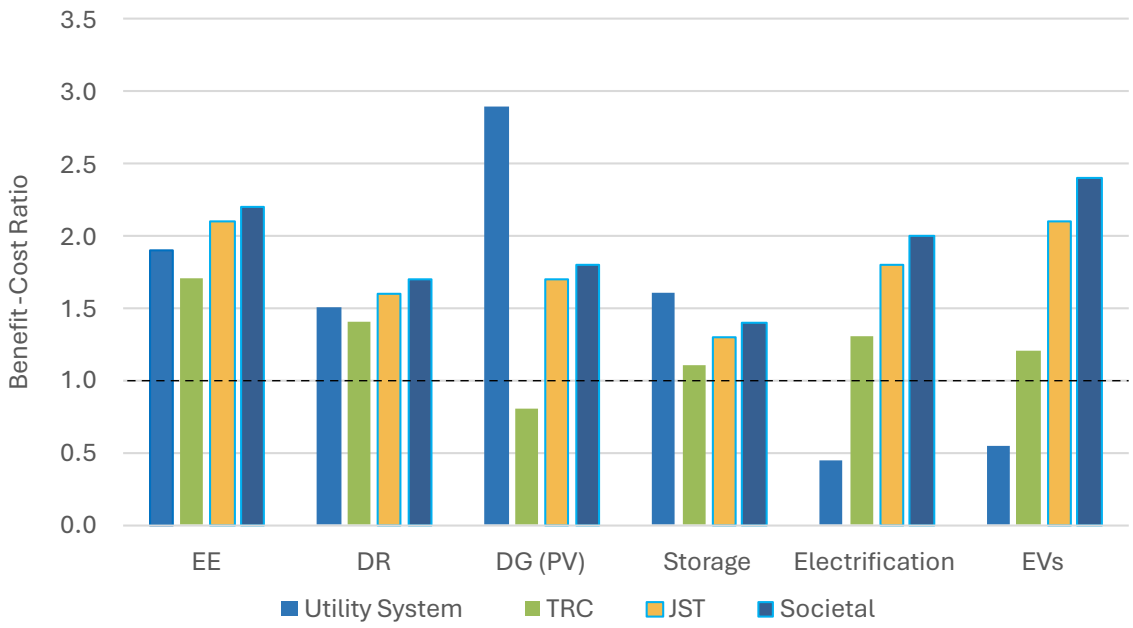
- TRC test results: The EE is less cost-effective than under the UCT because the TRC Test includes host customer impacts, which are predominantly costs in this example. The TRC test also includes low-income impacts and other fuel impacts.
- JST results: The EE is more cost-effective than under the UCT because the JST includes low-income benefits, other fuel impacts, and GHG benefits. The JST results show the EE is more cost-effective than the TRC test because it includes GHG benefits.
- SCT results: The EE is more cost-effective than under the JST because the SCT includes other environmental, public health and resilience benefits.

K.7.2 Multiple Tests and Multiple DER Types

Some BCA practitioners might choose to use secondary tests and apply them across multiple DER types. Again, different tests provide different information, and there may be situations where additional information is helpful in analyzing and deciding among DER options.

Figure K-9 presents the BCA results for hypothetical DERs in terms of benefit-cost ratios. Presenting the results this way allows for a quick assessment of how cost-effective the different DER types are according to different tests.

Figure K-9. Presentation of Multiple BCA Tests: Benefit-Cost Ratios—Multiple DER Types



This example uses the same primary test used in the previous sub-section. The primary test includes the following impacts: utility system, host customer, other fuel, low-income, and GHG emissions.

For this hypothetical EE scenario:

- The results are the same as those presented and explained in the previous section.

For this hypothetical DR scenario:

- UCT results: The DR is reasonably cost-effective. The utility system benefits exceed the utility system costs by a factor of 1.5.
- TRC test results: The DR is slightly less cost-effective than under the UCT because the TRC test results include some small net costs to the host customer.
- JST results: The DR is slightly more cost-effective than under the UCT because the JST includes low-income and GHG benefits.
- SCT results: The DR is slightly more cost-effective than under the JST because the SCT includes other environmental, public health and resilience benefits.

For this hypothetical PV scenario:

- UCT results: The PV is very cost-effective. The utility system benefits exceed the utility system costs by a factor of three. This is because the utility costs are relatively low since the host customer bears most of the PV costs.
- TRC test results: The PV is much less cost-effective than under the UCT because the TRC test includes host customer impacts that are predominantly costs and the host customer costs cover most PV costs.
- JST results: The PV is more cost-effective than under the TRC test because the JST includes GHG benefits.
- SCT results: The PV is less cost-effective than under the UCT because the SCT includes host customer costs. It is more cost-effective than under the JST test because the SCT includes other environmental, public health and resilience benefits.

For this hypothetical storage scenario:

- UCT results: The storage is reasonably cost-effective. The utility system benefits exceed the utility system costs by a factor of 1.6.
- TRC test results: The storage is much less cost-effective than under the UCT because the TRC test includes host customer impacts, which are predominantly costs in this case.
- JST results: The storage is less cost-effective than under the UCT because the JST includes host customer costs and the storage resource causes a slight increase in GHG emissions because it creates a net increase in electricity generation.
- SCT results: The storage is less cost-effective than under the UCT because the SCT includes host customer costs. It is more cost-effective than under the JST because the SCT includes other environmental, public health and resilience benefits.

For this hypothetical electrification scenario:

- UCT results: The electrification is not cost-effective—with a benefit-cost ratio of 0.9. This occurs because this test does not account for the other fuel savings, which are the primary rationale for electrification.
- TRC test results: The electrification is more cost-effective than the UCT because the TRC test accounts for the other fuel savings.
- JST results: The electrification is more cost-effective than under the TRC test because the JST includes GHG emission impacts.

- SCT results: The electrification is more cost-effective than under the JST because the SCT also includes other environmental, public health and resilience benefits.

For this hypothetical EV scenario:

- UCT results: The EV is not cost-effective—with a benefit-cost ratio of 0.8. This occurs because this test does not account for the other fuel savings.
- TRC test results: The EV is more cost-effective than the UCT because the TRC test accounts for the other fuel savings.
- JST results: The EV is more cost-effective than under the TRC test because the JST includes GHG emission impacts.
- SCT results: The EV is more cost-effective than under the JST because the SCT also includes other environmental, public health and resilience benefits.

Appendix L. Uncertainty and Risk

This appendix describes methods for accounting for uncertainty and/or risk in BCA tests for DERs. Uncertainty refers to situations where the correct or exact value of a BCA input is unknown. Risk refers to an adverse outcome that might result from uncertainty. A variety of methods can help address uncertainty and risk in BCA for DERs. The most useful methods in this context include sensitivity analyses, scenario analyses, expected value analysis, direct estimate, hedge value, and risk-adjusted discount rates.

L.1 Definitions

Defining risk and uncertainty

In the context of planning, *uncertainty* is defined as the situation where the 'correct' or 'exact' value of a parameter is unknown or cannot be known (EPRI 2015a).

In the context of planning, *risk* is defined as an adverse outcome that can result from uncertainty. In statistical terms, risk is the expected value of a potential loss (Ceres 2012). Risk is defined by the relationship:

*Risk = probability of the adverse outcome occurring * the consequence of the outcome*

Uncertainty in BCA

All analysis of future benefits and costs include some degree of uncertainty. One goal of BCA is to provide the information needed to make sound decisions regarding resource investments, despite the uncertainty inherent in resource planning. A variety of structured approaches are available for addressing uncertainty in the context of BCA for DERs.

Uncertainty Creates Risk

Uncertainty and risk are linked because uncertainty is what creates the potential for a variety of different outcomes, each with its own probability of occurring. There can also be uncertainty in the costs associated with each such outcome.

There is a long list of factors that introduce uncertainty into electric and gas utility planning processes. This includes uncertainties associated with power plant siting, cost, and availability; transmission and distribution facilities siting, cost, and availability; fuel prices; customer energy demand; regulatory requirements; costs and operating performance of DERs; customer response to DER programs; regulatory and policy shifts; environmental regulations; and more.

Resource Uncertainty and Risk

Resource risk[107] refers to risks caused by uncertainties associated with specific utility resources such as generation, transmission, distribution, and DERs. Examples of resource risk impacts associated with DERs relative to traditional supply-side alternatives include the following (ACEEE 2020b; RMI 2017):

- Reduced resource supply risk due to reduced reliance on fossil fuels that can be subject to limited availability and fluctuating prices; or increased resource supply risk due to those DERs that result in a net increase in fossil fuel use
- Reduced performance failure risk resulting from reliance on many smaller distributed resources (failure of one DER will have a much smaller impact on the system compared with one large generation or transmission failure)
- Reduced risk due to modular DERs' ability to reduce reliance on long lead-time GT&D investments (thereby creating 'option value' that reduces the risk that changing conditions over time may render such resources unnecessary)
- Reduced risk associated with DERs' ability to reduce emissions and lower costs of compliance with evolving climate or environmental policies; or increased risk associated with those DERs that result in a net increase in air emissions and hence a net increase in the cost of compliance with environmental requirements
- Reduced risk due to the demand flexibility provided by DERs, especially to address operational requirements of large-scale intermittent resources
- Either increased or decreased cybersecurity risk that DERs can provide to the utility system
- Increased risk associated with DERs not providing the benefits as planned (This could be caused, for example, by low customer response to DER program incentives, DER technologies not performing as expected, or vendors not installing or maintaining DERs as planned; any such increased risk needs to be determined relative to similar risks that might be associated with the resources displaced by the DER.)

All utility resource options can have both positive and negative resource risks. It is important, therefore, to account for both the increased and reduced risks of resources (in other words, the *net* resource risk impacts). The extent to which DERs increase or decrease risk to the utility system will depend on the DER type and the specific use case.

In addition, it is important to determine risks associated with any one utility resource relative to the risks associated with alternative resources. For example, when estimating the performance risk of a DER in a BCA test, it is appropriate to compare that risk with the performance risk of the resources avoided by the DER.

Planning Uncertainty and Risk

Planning risk[108] refers to the risks caused by the uncertainties inherent in any forecasting and planning exercise. Planning risk stems from the uncertainty around the estimated inputs and

[107] The term 'resource risk' commonly refers to both uncertainty and risk associated with resources.

[108] The term 'planning risk' is commonly used to refer to both uncertainty and risk associated with planning.

related forecasts in BCA. It can affect many aspects of a BCA test and many different resource types considered in the BCA test.

Examples of uncertainties that create planning risk include those related to electricity demand forecasts; gas demand forecasts; fossil fuel price forecasts; siting, and construction of energy facilities; uncertain environmental requirements; and more.

Notably, there is overlap between resource risk and planning risk. For example, the inherent uncertainty in fuel price forecasts creates a resource risk benefit for DERs that reduces exposure to fuel price uncertainty.

L.2 Methods for Addressing Uncertainty and/or Risk

The choice of method for addressing uncertainty and/or risk will depend upon the information available at the time the BCA happens, the type of uncertainty, the interest in applying monetary values, and more. Some inputs to a BCA test, such as the cost of a DER program in the first year, might be certain enough to forgo uncertainty or risk analysis. Some inputs, such as the expected cost of a new environmental regulation, might be deemed certain enough to use a quantifiable probability. Other inputs, such as the price of natural gas over the next 20 years, might be deemed especially uncertain and therefore warrant more sophisticated risk methods.

The methods described below fall into two general categories:

- The first category, including sensitivity and scenario analyses, includes methods that examine risk by running several BCA tests for individual inputs or groups of inputs to produce results for a variety of different futures. These results provide a range of potential outcomes that can inform the choice of a preferred investment.
- The second category includes methods that monetize or otherwise value risk for specific impacts and result in a single BCA test outcome that indicates the preferred investment.

The methods described below for addressing uncertainty and/or risk have different implications regarding the BCA test results, the potential costs to protect against risk, and the level of protection against risk. Section 7.2, Uncertainty Creates Risk, discusses these implications.

L.2.1 Sensitivity Analyses

Sensitivity analyses look at how different inputs regarding uncertain impacts affect benefits and costs. Sensitivity analyses work by changing one input assumption at a time to see how those input assumptions are likely to affect the benefits and costs. This typically involves changing key inputs by a given amount. A good example would be examining how an increase or decrease of 10 percent in a gas price forecast impacts the benefits and costs in the analysis.

This one-at-a-time approach to accounting for uncertainty is admittedly limited. It does not address questions about non-linearities, asymmetrical risks, and correlations across risks (where there are multiple uncertain outcomes that move in the same direction). If these issues are likely to have a significant effect on the outcome, then scenario analysis may be a better method than sensitivity analysis.

Sensitivity Analysis Example: EE Program Risk Benefits Regarding Gas Prices

A utility is evaluating eight EE programs. It conducts two sensitivities due to concerns about the uncertainties associated with natural gas prices: one with gas prices 10 percent lower than the reference case, and one with gas prices 15 percent higher than the reference case. The sensitivity analyses had the following results and outcomes:

- Six out of the eight EE programs pass the primary BCA test under the reference case and all sensitivities. The commission approves these six programs for utility funding.
- One EE program passes the primary BCA tests for the reference case and high gas sensitivity but has a benefit-cost ratio of 0.98 under the low gas price sensitivity. The utility proposes to fund the program because it passes the primary BCA test, is nearly cost-effective under all sensitivities, and serves an important customer segment.
- One EE program fails the primary BCA tests for the reference case with a benefit-cost ratio of 0.95 and low gas sensitivity with a ratio of 0.90, but it has a benefit-cost ratio of 1.25 under the high gas price forecast. The utility proposes to fund this EE program despite not passing the primary BCA test because there is a reasonable probability of high gas prices and value to customers of avoiding the risk of exposure to much higher prices.

L.2.2 Scenario Analyses

Scenario analyses can build on sensitivity analyses. They involve building scenarios that account for changes across multiple inputs based upon a specific outlook or forecasting perspective.

For robust scenario analyses, each scenario uses a coherent and internally consistent set of assumptions about key relationships and driving forces (Spaniol and Rowland 2018). Alternative scenarios can serve as alternative model formulations, as alternative sets of input data, or as both (Walker et al. 2003).

There are a variety of scenarios that might be useful in BCA tests for DERs. Examples include:

- A high (or low) fuel price scenario, where all fuel prices are higher (or lower) than the base case; this would affect not only avoided costs of DERs, but also electricity and gas demand, and electricity and gas prices.
- An advanced technology scenario, which assumes many technologies evolve more rapidly than the base case; this would affect not only the cost of DERs but also the performance assumptions, the availability, and the customer adoption of DERs.
- A high load growth scenario, where energy and peak demand forecasts exceed the reference forecasts due to data centers, EVs, or building electrification; this would affect the need for new resources and thus the marginal resources likely to be avoided by DERs.
- A decarbonization scenario, which assumes more stringent climate change regulations than the base case; this would affect many elements in a BCA test (such as fuel prices,

electricity and gas prices, electricity and gas demand, the advancement of energy technologies, retirement of fossil-fuel resources, and more).

The key issue in designing scenarios such as these is to account for all the different inputs that the scenario assumptions might affect, not just how they might affect a single input as is done with sensitivity analyses.

Scenario Analysis Example: Battery Distributed Storage Risk Benefits Regarding Gas Prices

A utility is evaluating three battery DS programs: one for residential, one for commercial, and one for industrial customers. The purpose of the programs is to reduce the cost of distribution system peak demands. Due to concerns about the uncertainties associated with natural gas prices and their impacts on distribution system peak demands, the utility analyzes three scenarios: (1) the reference scenario, (2) a high-peak scenario based on low gas prices and low electricity prices that lead to high distribution system peak demands, and (3) a low-peak scenario based on high gas prices and high electricity prices that lead to low distribution system peak demands. The scenario analyses had the following results and outcomes:

- The industrial DS program passed the primary BCA test under all three scenarios. The utility decided to provide this DS program to all eligible customers because it expected the program to be cost-effective even after accounting for the uncertainties analyzed.
- The commercial DS program passed the primary BCA test under the reference case scenario and the high peak scenario but failed the primary BCA test under the low peak scenario. The utility decided to fund this DS program because it passed the primary BCA test. The utility also decided to focus the initial implementation of the program for customers who live in parts of the service territory with the greatest distribution system peak to increase the chances of it being cost-effective under the low peak scenario.
- The residential DS program passed the primary BCA test under the high peak scenario but failed under the low peak and reference scenarios. The utility decided to limit this program to two regions where the residential batteries could be combined with the commercial and industrial batteries to act as non-wires solutions to avoid specific new distribution system investments.

L.2.3 Expected Value Analyses

Expected value analyses can help prioritize and refine sensitivity and scenario analyses. Expected value analyses consider the probability that different sensitivity assumptions and scenarios are to occur. This involves using as much information as is available to assign probabilities to each sensitivity or scenario. Those sensitivities or scenarios with higher probabilities receive greater weight in the BCA test results.

If the BCA test includes an analysis of multiple scenarios, then the test assigns each scenario a probability where the sum of all probabilities (i.e., all scenarios) is 100 percent. To determine the 'expected value' of the costs, the calculation is to multiply the probabilities by the costs of each scenario and add them together.[109]

[109] In statistics, the expected value of a random variable with a finite number of outcomes is a weighted average of all possible outcomes.

One exception to this concept is for outcomes that might be extremely unlikely but have a very high cost associated with it, such as severe weather events or aggressive cybersecurity attacks. In these cases, it might be best to account for risk by using the direct estimate of risk value method.

Expected Value Analyses Example: EE Program Risk Benefits Regarding Gas Prices (Part 2)

This example builds off the example above for sensitivity analysis. A utility is evaluating eight EE programs. Due to concerns about the uncertainties associated with natural gas prices, the utility conducts two sensitivities: one with gas prices 10 percent lower than the reference case, and one with gas prices 15 percent higher than the reference case.

The utility assigns a probability to each sensitivity as follows: the reference case has a 50 percent probability, the low gas prices case has a 20 percent probability, and the high gas prices case has a 30 percent probability. The utility applies these probabilities to the three gas price cases to determine a single expected value forecast of gas prices. The expected value gas price forecast is higher than the reference case because the probability of high gas prices is higher than the probability of low gas prices and the high gas price difference from the reference case is higher than that for low gas prices.

The results of the primary BCA test indicate that all eight EE programs are cost-effective, due to the higher gas prices in the avoided costs. Using expected value analysis this way is different from simply using sensitivity analysis in that it requires estimates of the probabilities of each sensitivity. Further, sensitivity analysis might require judgment when the results of one sensitivity show the DER is economic and the results of another show that it is not, whereas expected value analysis automatically indicates the economic outcome based on the probabilities assumed.

L.2.4 Direct Estimate

The risk formula described below is useful for quantifying a direct estimate of the risk value:

Risk ($) = probability of the outcome occurring (%) * the consequences of the outcome ($)

The resulting risk cost (in dollars) can be added to the other costs of the resources that create the risk. This approach is a simplified version of an expected value analysis. The direct estimate approach typically focuses on one input deemed to be especially uncertain, whereas expected value analyses can consider a range of uncertain inputs and can consider a range of probabilities for each input.

This approach gives very little weight to outcomes that have a low probability of occurring, unless the cost of that outcome is very high. Similarly, it gives little weight to outcomes with expected low costs.

The main disadvantage of this approach is that it requires an assumption regarding the probability of the outcome occurring, which can be challenging to ascertain. In these cases, the hedge value method might be more appropriate.

Direct Estimate Example: Distributed PV Risk Benefits Regarding Gas Prices

A jurisdiction recognizes that distributed PV programs can help reduce the risk of volatile natural gas prices and seeks to account for this benefit in the BCA test for net billing programs. The utility assumes a 20 percent probability that natural gas prices will be 30 percent higher than those in the reference case. This means that the value of this risk is 6 percent of the price of natural gas. The utility increases the avoided cost of natural gas by 6 percent to account for this risk. Consequently, BCA results showed the distributed PV programs to be more cost-effective than without the direct estimate of risk.

L.2.5 Hedge Value

A hedge value approach can help estimate the cost of avoiding a risk by determining the cost of an alternative investment or product that reduces or eliminates the risk of the investment in question. The cost of the alternative can indicate the risk associated with the investment in question. In other words, the cost of the hedge serves as a proxy for the risk benefit. Using a hedge value is comparable to buying insurance to protect against risk.

For some impacts, such as fossil fuel prices, there are financial hedging instruments available on the market to help provide insurance against risk. For example, a 10-year natural gas swap instrument would essentially lock in a price for natural gas for 10 years. That hedge instrument would have the same effect as procuring a fix-price DER that avoids natural gas generation. When added to the avoided natural gas costs, the incremental value of such a hedge (in dollars) reflects the DER's ability to reduce the risk of natural gas price increases.

Hedge Value Example: Distributed PV Risk Benefits Regarding Gas Prices

A jurisdiction recognizes that distributed PV programs can help reduce the risk of volatile natural gas prices and seeks to account for this benefit in the BCA test for net billing programs. The market offers a 10-year natural gas price swap instrument that costs roughly 9 percent of the current and projected future price for natural gas. Increasing the avoided natural gas prices in the BCA test by 9 percent accounts for the fact that the distributed PV programs have fixed costs whereas the avoided gas does not. Consequently, the jurisdiction finds the distributed PV programs to be more cost-effective than without the hedge value.

L.2.6 Risk Adder

When it is impractical to analytically assess and monetize all the ways in which a DER is less or more risky than alternatives, expert judgment is useful for establishing a risk 'adder' as a proxy for the economic value of expected increases or decreases in risk associated with a DER investment. Proxy values are often presented in volumetric terms (e.g., dollars per MWh) or as a percentage of other benefits or costs, and they can be informed by both quantitative and qualitative analysis. Proxies might differ from one type of DER to another, or for unique applications of a given DER.

Risk Adder Example: Risk Benefits of Energy Efficiency Programs

The Vermont Public Service Board's 1990 order in Docket 5270 concluded that well designed DSM programs "are generally of lower risk than supply procurement" and therefore required that future analyses of cost-effectiveness of energy efficiency programs apply a 10 percent downward adjustment to the cost of such programs to account for their risk-mitigating benefits (VT PSB 1990). That adjustment remains in effect today.

L.2.7 Risk-Adjusted Discount Rates

One method is to adjust the discount rate used in the BCA to reflect the lower or higher risk associated with the resources under evaluation. For example, several states use a low-risk discount rate when conducting BCAs for EE programs to reflect the notion that EE programs on average create less risk than the resources that they avoid. Appendix H. *Selecting Discount Rates for BCAs* describes this method in more detail.

The advantage of this method to addressing risk is that it is simpler than the methods described above. Conversely, the disadvantage of this method is that it is relatively blunt; it requires bundling all risk types together and cannot specifically address certain types of resource or planning risk.

L.3 Implications of Different Methods

The methods described above have different implications regarding the information and assumptions required, the treatment of uncertainty and/or risk, the results of the BCA tests, and the interpretation of those results. These implications are summarized below and in Table L-1.

- *Sensitivity and scenario analysis* require assumptions regarding alternative forecasts of uncertain BCA test inputs. The results of these analyses indicate how the BCA test conclusions might vary after accounting for uncertainty. The sensitivity and scenario analysis results can inform decisions that deviate from the results of the primary BCA test under the reference case. These decisions could rely on qualitative assessments of the probability of different outcomes and the value of risk aversion.
- *Expected value analysis* also requires assumptions regarding alternative forecasts of uncertain BCA inputs. In addition, it requires assumptions regarding the probabilities of those forecasts. The probabilities allow the BCA analyst to develop an alternative forecast that accounts for the uncertainty of the input. The expected value analysis will enable the primary BCA test results to reflect the potential for both desirable and adverse outcomes in monetary terms. However, it would not assign value to risk aversion.

- *Direct estimates* require assumptions regarding the probability of an uncertain outcome and the cost of that outcome. This method determines a monetary value of risk based on assumptions of cost and probabilities. That monetary value is then used to modify the benefits or costs of the DER, which become part of the primary BCA test results.
- *Hedge values* are similar to direct estimates except that markets are available to provide hedge commodities to help determine the monetary value of risk aversion. That monetary value is then used to modify the benefits or costs of the DER, which become part of the primary BCA test results.
- *Risk Adders* require expert judgment (ideally informed by qualitative and/or quantitative assessment) to approximately account for a variety of risk impacts of DERs. This method may be most applicable when there are a variety of risk impacts, and/or when it is impractical to apply other analytical methods because of resource or time constraints.
- *Risk-adjusted discount rates* differ from the other methods in that they do not require assumptions regarding uncertain BCA inputs or the probabilities of uncertain outcomes. Instead, they are based on the general premise that the DER in question has a lower (or higher) risk profile over time than the alternative resources assumed in the avoided costs. Risk-adjusted discount rates also do not attempt to quantify any specific risk for any specific impact. Instead, these rates place greater value on future impacts (in the case of low-risk discount rates) under the presumption that there is less uncertainty about those impacts occurring as estimated. This method changes the monetary values of benefits and costs (in present value dollar terms), which then become part of the primary BCA test results.

Table L-1. Implications of Different Methods of Accounting for Uncertainty and/or Risks

Method	Assumptions Required	Implications for BCA
Sensitivity analysis	Alternative estimates of an uncertain BCA input or inputs	Provides information regarding the range of potential outcomes. Results can inform decisions that deviate from the results of the primary BCA test under the reference case.
Scenario analysis	Alternative estimates of multiple related uncertain BCA inputs	Provides information regarding the range of potential outcomes. Results can inform decisions that deviate from the results of the primary BCA test under the reference case.
Expected value analysis	Alternative estimates and probabilities of uncertain BCA inputs	Provides a probabilistic, and thus likely more accurate, estimate of uncertain BCA impacts by accounting for the expected value of uncertain outcomes.
Direct estimate	The probability and cost of an undesirable outcome associated with a BCA input	Provides a single monetary value of risk for an uncertain BCA impact, based on the probability of the uncertain outcome times the cost of that outcome.
Hedge value	The value of a market hedge equivalent to the risk benefit of the BCA input	Provides a single monetary value of risk for an uncertain BCA impact, based on market instruments.
Risk adder	A proxy value approximating the degree to which a DER increases or decreases a risk	Provides a single monetary value of risk associated with a range of BCA impacts, based on stakeholder input and expert judgment.
Risk-adjusted discount rates	A market proxy for a low-risk (or high-risk) investment	Low-risk discount rates put greater weight on future BCA impacts under the presumption that there is less uncertainty about those impacts occurring as estimated.

Some of these methods can work in combination. For example, evaluation of a program promoting distributed PV combined with storage might use a hedge value to account for the risk benefit of avoiding fossil fuels and a direct estimate method to account for the resilience benefit. In this example, the evaluation uses the most suitable method for each type of risk.

However, combining some of these risk methods would be inappropriate because doing so would result in double-counting. For example, it would not be appropriate to use the hedge value method to account for the risk benefit of avoiding the volatility of fossil fuel prices and reduce the discount rate to reflect the risk benefit of avoiding fossil fuel price volatility.

Appendix M. Identifying and Accounting for Transfers

This appendix explains how BCAs for DERs can involve accounting for transfers—where one party incurs a cost that is equal to a benefit experienced by another party—and treatment of such transfers, which depends on whether both parties are within the scope of the BCA or not.

M.1 Introduction

Some impacts from DERs represent transfers from one party to another.[110] In the context of BCAs, an offsetting transfer occurs when one party incurs a cost that is equal to a benefit experienced by another party, and both parties are within the scope of the BCA test.

If the cost and corresponding benefit are an offsetting transfer, they will net each other out of the net benefits of the BCA. If the cost and corresponding benefit are not an offsetting transfer, it is appropriate to include one of them in the BCA and exclude the other depending upon which party is within the scope of the test. Consequently, the treatment of transfers can have significant impacts on BCA results.

In some cases, it is not obvious whether an impact is an offsetting transfer. The purpose of this appendix is to provide practical guidance for how to identify and treat offsetting transfers when conducting a BCA.[111]

In the context of BCAs, an offsetting transfer occurs when one party incurs a cost that is equal to a benefit experienced by another party, and both parties are within the scope of the BCA test.

M.2 Terminology: Transfers and Offsetting Transfers

In the context of BCAs, a 'transfer' occurs when one party incurs a cost that is equal to a benefit experienced by another party.

An 'offsetting transfer' occurs when one party incurs a cost that is equal to a benefit experienced by another party, and both parties are within the scope of the BCA test. In this case, the cost to one party exactly offsets the cost to another party in the BCA results, i.e., the benefits and costs net each other out.

The *California Standard Practice Manual* uses the term 'transfer payment' as it relates to cost-effectiveness tests for EE programs (CPUC 2001). However, the theoretical definition of transfer payment (referring to government programs to support those in need) does not apply to utility BCA.[112] Therefore, this appendix does not use the term transfer payment any further.

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[110] Throughout this paper, the term 'impact' refers to either a cost or a benefit that might be included in a BCA test.

[111] This guidance was informed by an NESP white paper: Identifying and Accounting for Transfers in Benefit-Cost Analysis of Distributed Energy Resources (NESP 2025).

[112] Economists use the term *transfer payment* to refer to efforts by local, state, and federal governments to redistribute money to those in need. Common examples of transfer payments include government programs such as Social Security, Medicare, student grants, and unemployment compensation. The concept of transfer payments has been used for decades in public finance theory, particularly by economists studying the implications of wealth

M.3 Identifying Transfers

M.3.1 Identify the Parties That Experience the Relevant Benefit and Cost

The first step to identifying an offsetting transfer is to determine the parties that experience the relevant benefit and cost. The potential parties include utility customers, host customers, and various members of society.

Identifying the parties that experience the relevant benefits and costs often requires further delineations beyond these categories. The utility system might include several different parties, such as utility customers, utility management, utility shareholders, independent power producers, and parties that provide other goods and services to utilities. Identifying the specific party might be necessary to determine whether it is within the scope of the BCA test, as described further below.

Similarly, society includes many different parties and can theoretically include all parties potentially affected by DERs or the resources to which they are compared in a BCA test. Identifying the specific party within the broad scope of society is sometimes necessary to determine whether it is within the scope of the BCA test. Again, the section below provides examples of this.

M.3.2 Check Whether Both Parties Are Within the Scope of the BCA Test

BCA Tests with Different Scopes

A JST serves as a jurisdiction's primary test,[113] while other traditional cost tests may serve as secondary BCA tests, as described in Chapter 4.2. The scope, i.e., boundary, of each test determines which parties to include and which to omit. If the BCA test includes one party but not another party, then the cost (or benefit) does not offset the relevant benefit (or cost). Thus, whether an impact is an offsetting transfer depends on the test used.

- *The Utility Cost Test (UCT)*: An offsetting transfer would occur only if the relevant benefits and costs are experienced by parties within the utility system.
- *The Total Resource Cost (TRC) Test*: An offsetting transfer would occur only if the relevant benefits and costs are experienced by parties within the utility system and host customers.
- *A Jurisdiction-Specific Test (JST)*: An offsetting transfer would occur only if the relevant benefits and costs are experienced by parties within the scope of the JST, which will depend on the energy policy goals of the jurisdiction.
- *The Societal Cost Test (SCT)*: An offsetting transfer would occur if the relevant benefits and costs are experienced by parties within society. Theoretically, the SCT includes all parties in society, which suggests that all parties are within the scope of the BCA test. However, it is conventional practice to exclude certain parties from even the SCT, as described below.

redistribution through taxes and government welfare programs (Pigou 1932). Sometimes the term 'transfers' is used synonymously with 'transfer payments' (OMB 2023, 57).

[113] Though a jurisdiction's JST may align with a traditional cost test, as described in Chapter 4.

The Scope of the Societal Cost Test

While the societal perspective implies the SCT would include all parties because society could theoretically include any party, this is not necessarily the case. In many cases, certain parties fall outside the boundaries of an SCT.

Excluding certain parties from the scope of the SCT is necessary to make the BCA meaningful. If an SCT includes all parties within society, and therefore all sets of benefits and costs are offsetting transfers when applying an SCT, then all benefits and costs would net each other out and thus render the BCA meaningless. The analysis must omit some parties so the remaining benefits and costs can be used to answer the question the BCA is designed to answer.

If an SCT includes all parties within society, and therefore all sets of benefits and costs are offsetting transfers when applying an SCT, then all benefits and costs would net each other out and thus render the BCA meaningless.

For example, consider some of the key costs that utilities incur to provide electric services: fuel costs, costs to procure generation, transmission, or distribution equipment, costs to procure DER technologies, costs to pay vendors to help install DERs, and others. In all cases, there is a counterparty within society that receives payment for those products and services. That payment represents a benefit equal to the cost incurred by the utility. If the SCT's scope includes all parties that sell fuels, equipment, and other materials to utilities, then all the costs that the utility incurs to pay those parties will net out to zero, rendering the BCA useless. Therefore, it is conventional practice to exclude these parties from a BCA, even when applying the SCT.

As another example, the profits that utilities pay to vendors when procuring goods and services of any type are theoretically a transfer from the utilities to the vendors' shareholders. If these were treated as an offsetting transfer, then the profits that utilities pay for goods and services would be netted out of the BCA. This would understate the total cost of the goods and services incurred by the utility and would therefore make it difficult for regulators and others to assess the true costs incurred by the utility and passed on to customers. Thus, the profits that utilities pay vendors for goods and services are not considered offsetting transfers by convention, even when applying the SCT.

M.4 Accounting for Offsetting Transfers

A key NSPM principle is to treat benefits and costs symmetrically for any given type of impact. This means the BCA test will either include both the benefits and the costs or exclude both the benefits and the costs for each type of impact. This principle applies to offsetting transfers as well. If a particular impact is deemed to be an offsetting transfer, then the test would include both the benefits and the costs or exclude both the benefits and costs (OMB 2023, 57–60).

The choice of whether to include or exclude both offsetting transfer benefits and costs can affect the BCA results:

- *The net benefits* will be the same regardless of whether the BCA test includes both offsetting transfer benefits and costs or excludes both, because when they are both included the subtraction nets them out.
- *The benefit-cost ratio*, however, will depend on whether offsetting transfer benefits and costs are both included or excluded, because when the ratio includes them in both the numerator and denominator, they do not exactly net out.

Table M-1 presents an example of BCA results showing the effects of including versus excluding offsetting transfers in a hypothetical BCA. It shows how the net benefits do not differ, but the BCR does differ.

Table M-1. Example Presentation of Including Versus Excluding Offsetting Transfers

Impacts	Include Both Benefits and costs	Exclude Both Benefits and costs
Transfer cost	10	0
Other costs	55	55
Total costs	**65**	**55**
Transfer benefits	10	0
Other benefits	95	95
Total benefits	**105**	**95**
Net benefits	**40**	**40**
Benefit-cost ratio	**1.6**	**1.7**

Note: These values are hypothetical, for illustrative purposes.

Including both the benefits and costs of an offsetting transfer is more transparent because it reveals the parties affected by the transfer as well as the magnitude and the direction of the transfer. This information might not be apparent if the benefits and costs are both excluded from the BCA test. Further, including both the benefits and costs of an offsetting transfer provides a more accurate BCR, as indicated in Table M-1. Therefore, including both the benefits and costs of an offsetting transfer is preferable to excluding them both.

M.5 Potential Offsetting Transfers in DER BCAs

M.5.1 DER Tax Incentives

Description

Federal, state, or local governments sometimes provide tax incentives to DER host customers to defray some of the costs of adopting DERs. In recent years, the federal government has established a wide range of tax incentives to encourage the adoption of DERs, including the *Inflation Reduction Act* and the *Infrastructure Investment and Jobs Act* (Analysis Group 2023). The scope and magnitude of these tax incentives can be large, so it is important that BCA tests properly characterize and account for these tax incentives.

This Manual uses the term 'tax incentives' broadly to refer to all forms of subsidies or support provided by federal, state, and local governments. These might include tax credits, tax deductions, research and development grants, mineral, fuel mining, and drilling rights, property tax breaks, and more.

It is important to think broadly about where and how tax incentives might be relevant in a BCA, as discussed further below. DERs are not the only energy resources offered tax incentives. There are numerous tax incentives for various types of energy technologies and resources. Examples include fossil fuels, nuclear power, fuel renewable resources, biofuels, and more. Further, tax incentives

are available at various points in the energy supply chain, including mineral rights, mining and drilling rights, research and development grants, investment credits, production credits, and accelerated depreciation accounting methods. When conducting a BCA of DERs, some of these other tax incentives might be relevant because they are likely to affect the energy resources avoided by the DERs.

The questions below help determine whether tax incentives are an offsetting transfer.

Which Party Experiences the Cost?

Taxpayers pay the costs of tax incentives. This might include local taxpayers for tax incentives such as reduced property taxes, state taxpayers for tax incentives provided by state government, and federal taxpayers for the variety of tax incentives offered by the federal government.

Which Party Experiences the Benefit?

Which party benefits from a tax incentive will depend upon the type of tax incentive. For example, fuel mining and drilling rights will benefit the coal, gas, or oil companies that conduct the mining and drilling. Research and development grants will benefit the companies researching and manufacturing energy technologies. Property tax breaks will benefit the power plant owner. Investment and production tax credits will benefit the power plant owner.

Regarding DER tax incentives, most incentives go to the owner of the DER, which might depend on the type of DER. For example, some DERs might be owned by the host customer, the DER developer, or the host customer's landlord.[114]

Are Both Parties Within the Scope of the BCA Test?

Utility Cost Test

Host customers are not within the scope of the UCT. Taxpayers are not within the scope of the UCT. Therefore, DER tax incentives are not an offsetting transfer under this test.

While it is true that utility customers are also taxpayers, it is not appropriate to consider them to be the same 'party' for this purpose. Regulators have a responsibility to protect utility customers, but no similar responsibility to taxpayers. This is consistent with the fact that many utility customers are also utility shareholders, but they are treated as different parties for regulatory purposes.

Total Resource Cost Test

Host customers are within the scope of the TRC test. Taxpayers are not within the scope of the TRC test. Therefore, DER tax incentives are not an offsetting transfer under this test.

[114] In some situations, the utility providing a DER program might choose to reduce the host customer incentive provided by a DER program because of the DER tax incentive. Nonetheless, the host customer is the party experiencing the benefit of the DER tax incentive.

Societal Cost Test

Host customers are within the scope of the SCT. Taxpayers (federal, state, and local) are also within the scope of the SCT test. Therefore, DER tax incentives are an offsetting transfer under the SCT.

Jurisdiction-Specific Test

If the JST does not include host customers, then the party benefiting from DER tax incentives is not within the scope of the test, and therefore DER tax incentives are not an offsetting transfer.

Under a JST, regulators might decide that taxpayers should be outside the scope of the test, meaning that costs to taxpayers should not be included in the test.

If the JST does include host customers, then *regulators need to decide whether to include taxpayers within the scope of the JST*, depending upon their jurisdiction's policy goals. Regulators might decide that taxpayers should be *outside* the scope of the JST, meaning the test should not include costs to taxpayers. Alternatively, regulators might decide that taxpayers should be *inside* the scope of the JST, meaning the test should include the costs to taxpayers. Further, this choice of whether to include taxpayers within the scope of the JST needs to be made for federal, state, and local taxpayers, depending on the source of the tax incentive.

As explained in this Manual, decisions about which impacts to include in the JST should be based on transparent and robust stakeholder input. Similarly, stakeholder input should inform the decision of whether the JST will include federal, state, or local taxpayers.

How to Treat the Relevant Benefits and Costs

How to treat the relevant benefits and costs depends on the test applied:

1. The UCT should include neither the benefits nor the costs of the DER tax incentive.[115]
2. The TRC test should include the benefits to host customers and exclude the costs to taxpayers.
3. The SCT should include the benefits to host customers. Theoretically, it should also include costs to taxpayers. However, for consistency purposes it is better to omit the costs to taxpayers, as discussed below.
4. For the JST:
    - If it does not include host customers, then this test should include neither the benefits nor the costs of DER tax incentives.
    - If it includes host customers and not taxpayers, then this test should include the benefits of the DER tax incentives but exclude the costs.
    - If it includes both host customers and taxpayers, then this test should include the benefits of DER tax incentives. Theoretically, the test should also include costs to taxpayers in this situation. However, for consistency purposes it is better to omit the costs to taxpayers, as discussed below.

[115] If the utility that implements the DER program chooses to reduce the incentive/rebate provided to host customers because of the DER tax incentive, then the BCA test should account for the reduced incentive/rebate to the host customer.

Consistency With Other Types of Tax Incentives

As noted above, there are numerous types of tax incentives for a variety of energy resources, at multiple points in the supply chain, from federal, state, and local governments. The box below presents a partial list of several federal tax incentives.

Examples of Federal Tax Incentives for Various Energy Technologies

- Expensing of intangible drilling costs (26 U.S. Code § 263)
- Deduction for percentage depletion for oil and gas wells of 15 percent of gross income from the property (26 U.S. Code § 613)
- Two-year amortization of geological and geophysical expenditures (26 U.S. Code § 167(h))
- Expensing of tertiary injectants for crude oil production (26 U.S. Code § 193)
- Exception from passive loss limitation for any working interest in oil or gas property (26 U.S. Code § 469)
- Corporate income tax exemption for publicly traded oil and gas partnerships (26 U.S. Code § 469)
- Credit for clean coal investments (26 U.S. Code § 48A)
- Credit for enhanced oil recovery (26 U.S. Code § 43)
- Credit for producing oil and gas from marginal wells (26 U.S. Code § 45 I)
- Credit for nuclear power (26 U.S. Code § 45J and 26 U.S. Code § 45U)
- Credit for biodiesel and renewable diesel (26 U.S. Code § 40A, 26 U.S. Code § 6426(c), 26 U.S. Code § 6427)
- Incentives for biofuel (26 U.S. Code § 40)
- Credit for renewable energy investment or generation (26 U.S. Code § 45, 26 U.S. Code § 48)

Source: *("Earth Track," n.d.)*

BCA typically (perhaps always) accounts for these tax incentives by including the benefit to the mining or drilling company, the power plant owner, the utility, or the customer but not including the cost to taxpayers. In other words, by convention tax incentives are not offsetting transfers. This convention applies to the SCT, despite the fact that tax incentives are theoretically a transfer under the SCT.

Best practice is to treat all tax incentives consistently in BCA tests. Otherwise, the analysis will skew the BCA test results in favor of those utility resources where only the tax incentive benefits are included and against those where both benefits and costs are included. Specifically, if a DER BCA test treats the tax incentives for the DER in question as an offsetting transfer and nets the incentives out of the analysis but does not treat the tax incentives for the resources avoided by the DER as an offsetting transfer (and thus does not net them out of the analysis) then the test will skew the results against the DER.

Further, analysis of DERs should be consistent with all other types of resources. This is a fundamental principle from the NSPM (see *Principle 1: Align with Applicable Energy Policy Goals*). This means analyzing tax incentives for DERs consistently with the tax incentive analysis for other types of utility resources.

Best practice is to treat all tax incentives consistently in BCA tests. Otherwise, the analysis will skew the BCA tests results.

However, identifying and calculating all the benefits and costs associated with all the tax incentives that affect all the resources in a BCA is infeasible because they are so extensive and affect many different parts of the electricity and gas supply chains.

When applying an SCT, if the test does not identify all the tax incentives for all the resources in the analysis and treat them as offsetting transfers, then there are two options for how to treat the DER tax incentives:

- **Treat the DER tax incentives as if they are an offsetting transfer.** This means *including* the cost to taxpayers and *including* the benefits to DER host customers, effectively netting out the benefit of the DER tax incentive. This option results in a bias against the DER because the other resources in the BCA test do not have their tax incentives netted out.
- **Treat DER tax incentives as if they are not an offsetting transfer.** This means *excluding* the cost to taxpayers and *including* the benefits to DER host customers, effectively including the benefit of the DER tax incentive. This option also results in a bias, but it is not certain whether that bias is in favor of the DER or against the DER because the direction and the extent of the bias will depend on the magnitude of the tax incentives embedded in the DER costs and the avoided costs.

In sum, when applying an SCT, analysts face a dilemma: either violate the principle of treating DERs consistently with other resource types (option 1) or deviate from the theoretically appropriate treatment of offsetting transfers (option 2).

In this situation, this guide recommends treating DER tax incentives as if they are not an offsetting transfer (option 2). This will result in a bias that might be for or against the DER, which is likely to be more accurate than using a BCA test that will certainly result in a bias against the DER (option 1). Further, if the tax incentives for the DER are comparable to those for the avoided resources, then the combined tax incentives will work in opposite directions, thereby reducing the bias. In sum, it is conventional practice to treat tax incentives for energy resources as if they are not offsetting transfers, and therefore it is appropriate to do the same for DER tax incentives.

Note that this dilemma occurs only in the context of the SCT. For the UCT and the TRC test, tax incentives are not offsetting transfers. For the JST, regulators can resolve this dilemma by deciding that taxpayers are outside the scope of the BCA test and therefore tax incentives are not offsetting transfers.

Summary

Table M-2 presents a summary of how to account for DER tax incentives.

- *For the UCT,* the host customer is not part of the test, so the DER tax incentive does not affect it.

- *For the TRC tests*, the taxpayers that incur the cost are not part the test, thus DER tax incentives are not an offsetting transfer. The test should include the benefit to host customers.
- *For the SCT*, the test includes both the taxpayers that experience the cost and the host customer that experience the benefit, thus DER tax incentives are an offsetting transfer. However, to be consistent with the treatment of tax incentives for other resources, the test should not treat DER tax incentives as an offsetting transfer.
- *For the JST*, regulators can choose whether to include taxpayers as a part of the test, which will determine whether DER tax incentives are an offsetting transfer. Either way, however, to be consistent with treatment of tax incentives for other resources, the test should not treat DER tax incentives as an offsetting transfer.

Table M-2. Treatment of Offsetting Transfers: DER Tax Incentives

Impact	Cost: Increased Taxes	Benefit: Reduced DER Cost	Both Parties in Test	Treatment
Affected party	*Federal, state, or local taxpayers*	*Host customers*	--	--
Utility Cost Test	No	No	No	Exclude benefit and cost
Total Resource Cost test	No	Yes	No	Include benefit only
Societal Cost Test	Yes	Yes	Yes	Include benefit only, for consistency
Jurisdiction-Specific Test	Depends on whether taxpayers are deemed to be within scope of test	Yes	Depends	Include benefit only, for consistency

M.5.2 Utility Performance Incentives

Description

Many jurisdictions provide utilities and other programs administrators with performance incentives for successfully implementing EE programs (ACEEE 2015) and other DER types. Some jurisdictions provide similar incentives for successful implementation of other DER types.

These performance incentives can take many forms. For instance, utilities might receive rewards for achieving targets for energy or capacity savings. Or, they might receive rewards for maximizing the savings of a DER program, where the utility receives a portion of the DER cost savings.

The questions below help determine whether utility performance incentives are an offsetting transfer.

Which Party Experiences the Costs?

The utility customers experience the costs of utility performance incentives. These are typically included as part of the cost of implementing the relevant DER program.

Which Party Experiences the Benefits?

The utility shareholders experience the benefits of utility performance incentives because utility performance rewards are typically used to increase utility earnings.[116]

Are Both Parties Within the Scope of the BCA Test?

Utility customers are within the scope of every BCA test (see Section M.3). They are the central party to the utility system.

Utility shareholders, however, are not within the scope of any BCA test. While utility shareholders are a part of society, and therefore it might seem like the SCT scope would include them, this is an example of a party that BCA tests exclude by convention to make the BCA meaningful.

As described in Section M.3, SCTs omit some parties so the remaining benefits and costs can help answer the primary question for which the BCA is designed. A good example is counterparties to the materials, fuels, and labor that utilities procure to provide their services: If the SCT or other BCA test includes these counterparties within their scope, then many critical utility costs would be netted out of the analyses, rendering it meaningless.

This same concept applies to utility shareholders: if the SCT or other BCA test includes utility shareholders as within the scope of the test, meaning that profits are offsetting transfers and will be netted out, then one of the costs necessary for producing the DER will be excluded from the analysis. Utility performance incentives represent profits to utility shareholders; utility shareholders are not within the scope of the test, and therefore utility performance incentives are not an offsetting impact and should not be netted out.

This treatment of utility shareholders is consistent with how shareholders of other services are treated in BCAs. When a utility (or any actor) purchases a product from a retail supplier, e.g., fuel, equipment, energy, the cost of the product includes the cost of profits earned by the supplier. Even under an SCT, those profits are not considered an offsetting impact that should be netted out of the BCA. Similarly, utility profits should not be netted out either.

How to Treat the Relevant Benefits and Costs

Under the BCA Framework, all BCA tests should include the cost of utility performance incentives as a utility system cost. None of them should include the benefit of utility performance incentives.

Summary

Table M-3 presents a summary of how to account for utility performance incentives. For all tests, the utility shareholders are not within the scope of the test and therefore this set of benefits and costs is not an offsetting transfer. All BCA tests should include the utility performance incentives costs but exclude the benefits.

[116] In some cases, utilities might choose to provide rewards, i.e., bonuses, for the utility employees responsible for implementing the DER program and earning the reward. In these cases, the rationale for identifying whether the performance incentive is a transfer is the same as for cases where the performance incentive goes to utility shareholders.

Table M-3. Treatment of Offsetting Transfers: Utility Performance Incentives

Impact	Cost: Increased Program Cost	Benefit: Increased Earnings	Both Parties in Test	Treatment
Affected party	*Utility customers*	*Utility shareholders*	--	--
Utility Cost Test	✓	--	No	Include cost Exclude benefit
Total Resource Cost test	✓	--	No	Include cost Exclude benefit
Societal Cost Test	✓	--	No	Include cost Exclude benefit
Jurisdiction-Specific Test	✓	--	No	Include cost Exclude benefit

M.5.3 Incentives to Host Customers

Description

Many DER programs provide host customers with rebates, loans, or other forms of financial incentives to participate in the program and adopt the DER measure.

The questions below help determine whether incentives to host customers are an offsetting transfer.

Which Party Experiences the Costs?

The utility customers experience the costs of host customer incentives. BCA tests typically include these costs as part of the cost of implementing the relevant DER program.

Which Party Experiences the Benefits?

The host customer experiences the benefits of host customer incentives. The incentives help the host customer offset the costs of the DER measure.

Are Both Parties Within the Scope of the BCA Test?

For the UCT, host customers are not within the scope of the test. Therefore, host customer incentives are not an offsetting transfer under the UCT. The UCT should include the cost to utility customers but exclude the benefits to host customers.

For the TRC test and the SCT, the host customers are within the scope of the test. Therefore, host customer incentives are an offsetting transfer under these tests. The TRC test and the SCT should include both the costs to utility customers and the offsetting benefits to host customers.

For a JST that *does not include* host customers, the incentives to host customers are not an offsetting transfer, and the test should include only the costs. For a JST that *does include* host customers, the incentives to host customers are an offsetting transfer and the test should include both the costs and offsetting benefits.

How to treat the relevant benefits and costs

Under the BCA Framework, all BCA tests should include the cost of host customer incentives as a utility system cost.

Further, all BCA tests that include the host customer should include the benefit of host customer incentives.

Even though the host customer incentive is an offsetting transfer under some tests, this does not mean that the host customer portion of the cost of the DER measure is netted out of the BCA test. This is because after the offsetting transfer from the utility to the host customer, the host customer uses that incentive to pay for the incremental cost of the DER measure.

> Even though the host customer incentive is a transfer under some tests, this does not mean that the host customer portion of the cost of the DER measure is netted out of the BCA.

Table M-4 illustrates this point. It presents a hypothetical scenario where the incremental cost to purchase an efficiency measure is $80 and the host customer receives a rebate of $20 to offset a portion of that cost.[117]

The effect of this host customer incentive on the two parties is a net cost to the utility system of $20 and a net cost to the host customer of $60, as indicated in the two middle columns. These parties experience these effects, regardless of the BCA test used.

The UCT only includes the utility incentive, and therefore the net cost in the BCA is $20. Under the TRC test, SCT, and a JST that includes host customer impacts, the host customer pays the $80 for the efficiency measure, and there is an offsetting transfer of $20 from the utility system to the host customer. Therefore, while the offsetting transfer of $20 is netted out, the BCA test includes the full incremental measure cost paid by the host customer. In this case, the $20 host customer incentive is assigned to the utility system and the remaining $60 is assigned to the host customer.

Table M-4. Example of Offsetting Transfers and Host Customer Incentives

	Affected Party		Total Effect on BCA	
	Utility system	*Host customer*	*UCT*	*TRC, SCT, or JST**
Incremental measure cost paid by host customer	---	-$80	---	-$80
Utility incentive	-$20	$20	-$20	Offsetting transfer: Utility -$20 Host customer $20
Net cost	-$20	-$60	-$20	-$80

Note: This example assumes the JST includes host customer impacts.

[117] The incremental cost of an efficiency measure represents the cost beyond the cost of a comparable non-efficient measure. For example, assume that the total cost of an efficient motor is $500 and the total cost of a baseline, inefficient motor is $420. The incremental cost of the efficiency measure would be $80.

Summary

Table M-5 presents a summary of how to account for host customer incentives. In all tests that include host customers, this incentive is an offsetting transfer. In these cases, the BCA test would include both the benefits and costs.

Table M-5. Treatment of Offsetting Transfers: Host Customer Incentives

Impact	Cost: Increased Program Costs	Benefit: Reduced DER Cost	Both Parties in Test	Treatment
Affected party	*Utility customers*	*Host customers*	--	--
Utility Cost Test	✓	--	No	Include cost only
Total Resource Cost test	✓	✓	Yes	Include cost & benefit
Societal Cost Test	✓	✓	Yes	Include cost & benefit
Jurisdiction-Specific Test	✓	Depends	Depends	Depends

M.5.4 Wholesale Market Price Effects

Description

When DERs reduce electricity load and/or peak demand, they can cause a reduction in wholesale electricity market energy and capacity clearing prices.[118] When the market price reduction is multiplied by the entire quantity of energy or capacity purchased from the market, it can result in potentially significant cost savings to all customers purchasing from the wholesale market.[119]

The opposite effect occurs when DERs, such as heat pumps or EVs, increase electricity load and peak demand. In these cases, marginal increases in wholesale market prices may increase generation and distribution company profits and impose higher costs on retail customers purchasing from the market.

The questions below help determine whether wholesale MPEs are an offsetting transfer.

[118] In the theoretical economic supply and demand curves, a reduction in load shifts the demand curve inward (i.e., to the left), resulting in the demand curve intersecting the supply curve at a lower price point. In the energy markets, all energy or capacity is purchased at the market clearing price, so the price reduction applies to all purchases, not just the marginal unit.

[119] This same effect applies to wholesale gas markets. The discussion here refers only to wholesale electricity markets for simplicity.

Which Parties Experience the Costs and the Benefits?

The two parties affected by this impact are the wholesale generation companies and the customers that purchase power from the wholesale market. Whether those parties experience a benefit or a cost depends on whether the effect is a decrease in prices or an increase.

- When DERs reduce electricity consumption, they can cause a reduction in wholesale market prices. In this case, the wholesale generation companies experience the costs in the form of reduced revenues, and the wholesale market customers experience the benefits.
- When DERs increase electricity consumption, they can cause an increase in wholesale market prices. In this case, the benefits are experienced by the wholesale generation companies in the form of increased revenues, and the costs are experienced by the wholesale market customers.

Are Both Parties Within the Scope of the BCA Test?

Wholesale market customers are within the scope of every BCA test. Even if some of these wholesale market customers are not utilities, the power they procure is eventually sold to retail customers, who are central to the utility system.

Wholesale generators, however, are not within the scope of any BCA test. While wholesale generators are a part of society, and therefore it seems like the scope of at least the SCT test would include them, this is an example of a party excluded from BCA tests by convention to make the BCA meaningful.

As described in Section M.3.2, an SCT must leave out some parties so the remaining benefits and costs can be used to answer the question for which the BCA test is designed. Examples include counterparties to the materials, fuels, and labor that utilities procure to provide their services. If the SCT or other BCA test includes these counterparties, then many critical utility costs would be netted out of the analysis, thus rendering it meaningless.

The same is true for wholesale generators. It is necessary to exclude them from the analysis to isolate the benefits and costs associated with the DER in question.

A simple thought experiment illustrates the importance of excluding wholesale generation companies from any BCA test. If a BCA test included wholesale generators, then that would make all the electricity purchased from the market an offsetting transfer. This would mean that the primary benefit of implementing DERs (avoided energy and capacity) would be netted out of the BCA and make the BCA meaningless. Another way to put this thought experiment is: If *wholesale market price effects* are an offsetting transfer, why are *wholesale market costs* not also an offsetting transfer?

Wholesale generators are an example of a party that is excluded from BCA tests by convention to make the BCA meaningful.

Therefore, wholesale MPEs are not an offsetting transfer. This is true for all BCA tests.

How to Treat the Relevant Benefits and Costs

Under the BCA Framework, all BCA tests should exclude the costs (or benefits) of wholesale MPEs on wholesale generators and include the benefit (or cost) of wholesale MPEs on wholesale customers.

Geographic Scope

There is one important nuance to wholesale MPEs. Wholesale markets often span multiple states. Thus, wholesale price effects created in one state might be experienced across multiple states. This raises the question of which wholesale market customers to include in the BCA test: those within the state where the DER is installed, or those within the entire wholesale market region. The recommended treatment for each test is as follows:

- A strict interpretation of the UCT suggests that wholesale market customers outside of the state in which the DER is implemented are not a part of the utility system, and therefore the UCT should not include them. A similar conclusion applies to the TRC test.
- Under an SCT, the wholesale customers in other states could be considered to be within the scope of the test. In this case, the SCT should include the full wholesale MPEs.
- Under a JST, regulators can choose whether to include in the test the full wholesale price effects or only the effects experienced in the state in which the DER is implemented. This is a policy decision for each jurisdiction to make, with input from relevant stakeholders.

Summary

Table M-6 presents a summary of how to account for wholesale MPEs. For all tests, the wholesale generation companies are not within the scope of the test and therefore this set of benefits and costs is not an offsetting transfer. Under the BCA Framework, all BCA tests should include the wholesale MPEs on customers but exclude the effects on wholesale generation companies.

Table M-6. Treatment of Offsetting Transfers: Wholesale Market Price Effects

Impact	Reduced or Increased Price	Increased or Reduced Price	Both Parties in Test	Treatment
Affected party	*Wholesale customers*	*Wholesale generators*	--	--
Utility Cost Test	✓	--	No	Include customer impact only
Total Resource Cost test	✓	--	No	Include customer impact only
Societal Cost Test	✓	--	No	Include customer impact only
Jurisdiction-Specific Test	✓	--	No	Include customer impact only

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