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REGULATORY ASSISTANCE PROJECT

Using Benefit-Cost Analysis to Improve Distribution System Investment Decisions

Reference Report

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I. Introduction

This reference report explores the many opportunities for electric utilities and public utility regulators to use benefit-cost analysis techniques to evaluate potential investments. The foundational premise of the reference report is that these techniques can contribute to decisions that better serve the public interest than decisions made solely based on traditional least cost methods. Benefit-cost analysis is, to put it simply, a superior tool to other analytical methods in many (but not all) cases. Increasing its use in utility regulation can result in better outcomes for ratepayers and society.

A. Background

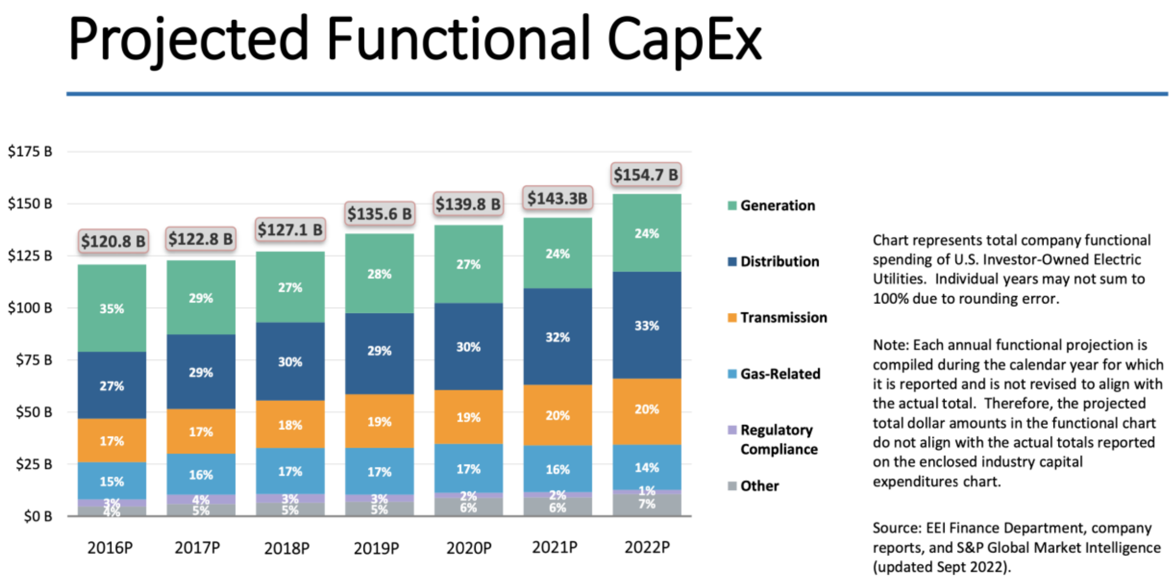
Historically, utility regulators have exercised relatively limited oversight with respect to the maintenance and operation of the electric distribution system. For the most part, regulators have relied on utility experts to make prudent decisions about investments in the distribution system that are necessary to accommodate growth, replace failing assets and ensure power quality. Limited oversight does not, however, mean no oversight. During rate cases, past utility investments may be reviewed for prudence and future distribution system spending budgets may be determined as part of establishing the revenue requirement, but individual distribution system investment options are rarely scrutinized. In contrast, regulators in many jurisdictions have required utilities to transparently develop detailed, long-term plans for bulk power system generation and transmission investments. Planners evaluate a wide range of potential solutions to identify the optimal portfolio of investments, they document their findings, and stakeholders have opportunities to comment on the plans.

For a variety of reasons, regulators in recent years have increasingly turned their attention toward the distribution system:

- Some utilities, particularly those in restructured states, do not own generation assets and might not own transmission assets, yet their operation of the distribution system is still regulated by a state public utility commission (PUC) or public service commission (PSC).
- The vast majority of service outages occur due to problems on the distribution system, not because of problems on the high-voltage transmission system or inadequate generation resources.

- Among investor-owned electric utilities throughout the United States, distribution system spending is increasing as a share of total utility capital investment (as shown in Figure 1)[2] and operational expenses (Figure 2 on the next page).[3]
- Investment in distributed energy resources (DERs)[4] has grown rapidly.
- In addition to building out the system to accommodate load growth, and replacing aging or failing assets, new utility investments are needed to modernize the grid — especially at the distribution system level.

Figure 1. Distribution system spending increasing as share of total capital expenses



Source: Edison Electric Institute. (2022). *Projected Functional CapEx*

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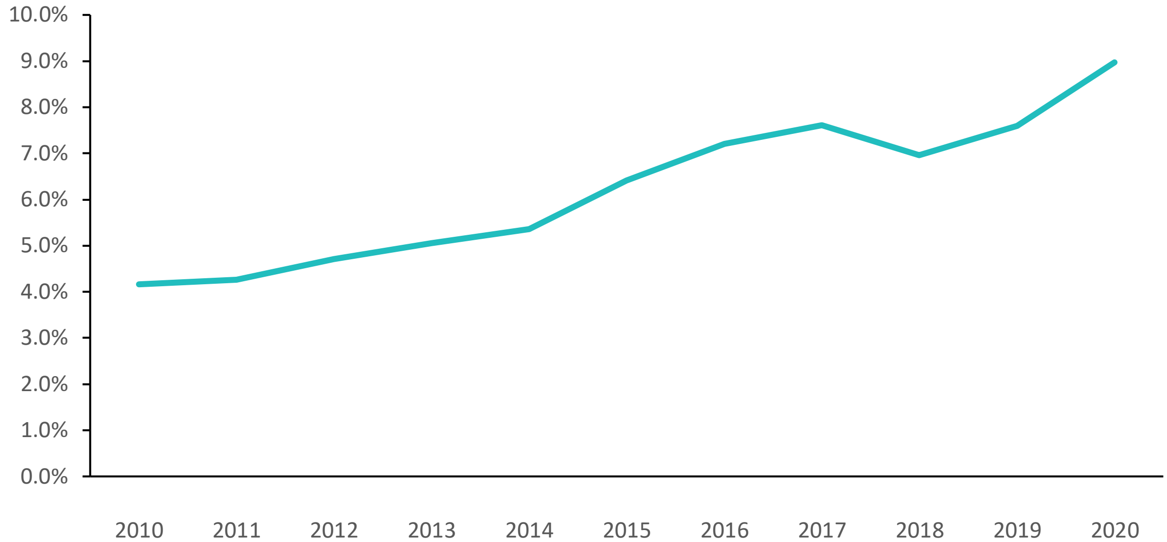
[2] Edison Electric Institute. (2022). *Projected functional capex.* https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Finance-And-Tax/bar_cap_ex.pdf?la=en&hash=3D08D74D12F1CCA51EE89256F53EBABEEAAF4673

[3] Based on Federal Energy Regulatory Commission Form 1 data from major U.S. investor-owned utilities, as compiled by the U.S. Energy Information Administration. https://www.ferc.gov/general-information-0/electric-industry-forms/form-1-1-f-3-q-electric-historical-vfp-data

[4] States vary in how they define DERs. Most states limit this term to resources interconnected to the distribution system or operating behind the customer's meter. In terms of resource types, most DER definitions encompass a subset of energy efficiency, demand response or "flexible loads," distributed generation, distributed energy storage, microgrids and electric vehicles.

Figure 2. Distribution system spending increasing as share of total operating expenses



Source: Federal Energy Regulatory Commission Form 1 data from major U.S. investor-owned utilities

Regulators today are paying closer attention than ever to individual distribution system investment decisions, more frequently requiring utilities to transparently evaluate alternatives to meet customer needs, and increasingly requiring utilities to file long-term distribution system plans (DSPs). This increased scrutiny is sometimes applied to traditional distribution system assets like substations and transformers but is even more likely to be used to evaluate "grid modernization" investments.

Because some new technologies and applications available to utilities are very expensive, smart investment decisions are necessary to derive maximum system value from their capabilities.

As Table 1 on the next page suggests, a wide range of new technologies and applications are available to utilities that can integrate DERs, lower costs or otherwise improve service. But because some of the new technologies and applications are very expensive, smart investment decisions are necessary to install them when and where they are beneficial and derive maximum system value from their capabilities.

Table 1. Examples of grid modernization technologies and applications

Function	Technologies/applications
Communications	Wide area network
	Optical fiber
Monitoring and sensing	Advanced metering infrastructure
	Line sensors
Reliability management	Fault location, isolation and restoration
	Outage management system
Distribution grid control	Supervisory control and data acquisition
	Energy storage
Power quality management	Advanced inverters
	Integrated volt-var control
Optimization	Advanced distribution management system
	Volt-var optimization

B. Two Common Approaches to Evaluating Utility Investments

This report compares two analytical approaches that can be used to evaluate utility investments in DERs and the distribution system and ensure that investments in grid modernization are smart: least cost/best fit (LCBF) techniques and benefit-cost analysis (BCA) techniques.

1. Definitions and Differences

Least cost/best fit: We categorize analytical methods as LCBF if decisions are made by comparing the total costs of investment alternatives over a defined period of time, including capital costs as well as operations and maintenance costs, and identifying the options that minimize the net present value of the revenue requirement associated with the entire power system, or in some cases just a portion of the power system (e.g., just the transmission system).

Occasionally, an option may be chosen that isn't technically the least cost solution (doesn't minimize the revenue requirement) but is considered the best fit — for example, because it reduces uncertainty about future operations and maintenance costs. The benefits associated with each investment alternative do not need to be identified or quantified. LCBF methods are typically used when action is needed, or presumed to be needed, and the goal is simply to minimize the cost.

Historically, utilities have relied on LCBF techniques to make decisions about investments in utility-owned infrastructure like power plants, transmission lines, substations or systems monitoring equipment or to evaluate power purchase agreements and other utility contracts with vendors. After the utility identifies something that is needed to maintain safe and reliable electric service or extend service to a new area, it then seeks the least costly way to meet the identified need in a manner that complies with all applicable legal requirements.[5]

Benefit-cost analysis: In contrast, we apply the term BCA to methods that compare the costs and benefits of investment alternatives to assess and *maximize the net benefits* (i.e., benefits minus costs) when viewed from an agreed perspective.[6] This can include situations where the options being considered include the status quo or a "take no action" alternative.

For decades, utilities, PUCs and independent evaluators have used BCA methods to assess whether certain types of utility expenditures will be (or in retrospective evaluations, were) cost-effective. The most common and widespread use of BCA has been for evaluating utility programs offered to customers, such as incentive programs that support energy efficiency or other DERs. BCA has also been used in many cases to evaluate utility investments in new technologies, such as advanced metering infrastructure, or other assets.

Before going any further, we must acknowledge that the lines separating LCBF methods from BCA methods can be blurry. There are at least two reasons for this:

1. Some of the benefits of almost any utility program or investment come in the form of reducing the revenue requirement — for example, by reducing total systemwide demand or peak demand through an energy efficiency program. When benefits come in the form of reducing the revenue requirement, they are considered in both LCBF and BCA methods. But benefits that don't reduce the revenue requirement, such as increases in homeowner comfort or employee productivity that might result from some energy efficiency measures, are usually not considered in an LCBF approach.

2. In some cases the "best fit" part of an LCBF-based decision may take into consideration costs and benefits that have nothing to do with the revenue requirement, such as reductions in greenhouse gas emissions beyond any existing legal requirements.

Regardless of any differences over terminology or the way we've characterized LCBF and BCA, we hope readers will agree there are differences between these two methods and opportunities to use BCA in new and better ways to improve decisions.

2. Outline of This Report

In Section II of this reference report, we review how LCBF techniques are used to make long-term planning decisions. Although utilities routinely make decisions about the least costly solutions to identified short-term needs, long-term planning processes offer the best

[5] Options that do not satisfy all applicable legal requirements are not considered "solutions" to an identified need. This distinction is important but easily overlooked. For example, if a utility is subject to a renewable portfolio standard, it will seek to minimize the costs of meeting customer demand *while complying with that standard*. This is consistent with minimizing the revenue requirement because utilities include the costs of complying with legal obligations in the revenue requirement.

[6] The perspectives that might be considered are explained in more detail in Section III of this report.

opportunities to identify long-term needs and evaluate portfolios of solutions to meet those needs. These planning processes also occur, typically, with a measure of stakeholder engagement and regulatory oversight and are thus of greater interest to regulators than smaller-dollar, short-term, one-off investment decisions.

In Section III, we look at the key steps of a BCA and how different cost tests can be used to examine cost-effectiveness from different perspectives.

In Section IV, we offer our views on how LCBF and BCA methods are similar, how they differ and why they often yield different answers to questions about optimal utility investment.

Although we see opportunities to improve LCBF techniques, we are not seeing any trends or increased interest in the regulatory community toward using LCBF in fundamentally new ways. In contrast, there are noteworthy trends and significant regulatory interest around using BCA in new ways. Thus, the remainder of this reference report focuses on opportunities to explore new uses of BCA as a supplement or alternative to LCBF for evaluating utility investments. Accordingly, Section V considers the question of *when* BCA techniques might be used (i.e., in what types of regulated proceedings and under what circumstances or conditions), while Section VI reviews key reference documents explaining *how* BCA can be used to make investment decisions and looks at crucial decisions that regulators will have to make. Throughout these two sections, we emphasize novel and emerging applications of BCA to improve distribution system investment decisions. Where appropriate, the reference report cites noteworthy examples and useful lessons.

II. Use of LCBF Techniques in Utility Planning

Many utilities are required by state laws, state rules or PUC orders to prepare and file detailed long-term investment plans for satisfying their customers' demand for electricity. Other utilities not subject to these requirements may develop similar plans for internal use. Long-term planning processes have historically focused on only one part of the electric power system at a time, as explained in this section. In each case, LCBF techniques are normally used to make most planning decisions, though there are many examples (as we will see later in this report) of using BCA methods in concert with LCBF.[7]

A. Integrated Resource Plans

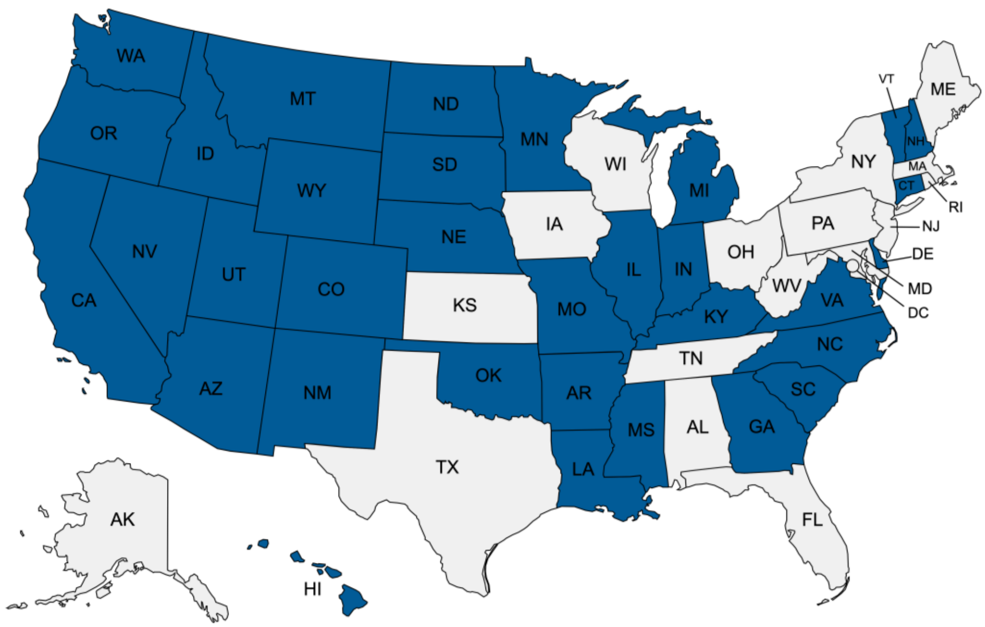
More than half of state PUCs require some or all of the electric utilities they regulate to file integrated resource plans (IRPs) (see Figure 3 on the next page).[8] These plans typically focus on generation resource adequacy, though they sometimes also address transmission capacity needs associated with acquiring new generation resources. The emphasis in an

[7] And, as previously noted, non-utility-system costs and benefits may sometimes be evaluated in these plans to arrive at the "best fit" solution.

[8] The filing requirements, scope and terminology differ — sometimes significantly — by state. Figure 3 offers RAP's interpretation of states that require IRPs, based on available literature and state statutes and orders. The question is not a black-and-white one.

IRP is on identifying the utility-scale resources needed to ensure resource adequacy (i.e., adequate generating capacity to meet anticipated energy demand at all hours, with an adequate reserve margin) while meeting all other mandatory criteria.[9] In recent years, it has become commonplace for these plans to take into consideration the expected contributions of DERs toward resource adequacy, but IRPs do not otherwise examine the need for or benefits of new investments in the distribution system. In other words, IRPs tend to focus only on minimizing the revenue requirement for attaining generation resource adequacy, or generation plus transmission, rather than minimizing the revenue requirement for the entire power system.

Figure 3. States with integrated resource plan requirements for electric utilities



In the course of developing an IRP, utilities use capacity expansion models[10] and dispatch models[11] to simulate the construction and operation of a variety of resource portfolios that are likely to provide resource adequacy over the long term while also complying with other mandatory criteria (e.g., local renewable portfolio standard requirements or air pollutant

[9] Technically, resource adequacy means having enough generation capacity to meet established reliability standards, which are normally based on a maximum loss of load expectation of one day in 10 years. It is perhaps worth noting that the reliability standard is not based on a BCA. There is no guarantee that a loss of load expectation of one day in 10 years is the level that maximizes net benefits and no examination of whether a higher or lower level would be more beneficial than the standard. Rather, the planning exercise seeks an LCBF solution to meeting the standard of one day in 10 years.

[10] Capacity expansion models are used to identify the portfolio of power system resources that will meet annual energy and peak demand projections at least cost, based on a specified load forecast, assumptions about the costs and capabilities of various technologies and fuels, and binding regulations (e.g., renewable portfolio standards). Planners can run these models multiple times with different combinations of load forecasts, assumptions and regulatory criteria to identify different candidate resource portfolios for more detailed comparison.

[11] Dispatch models, also called production cost models, take the candidate resource portfolio from a single capacity expansion model run and simulate how the system operator would dispatch the available resources to meet reliability standards at every location on an hourly or subhourly basis at least cost. Planners can run these models multiple times, too, using different candidate resource portfolios.

emission limitations).[12] Generally speaking, the goal of the planning process is to identify the portfolio of resources that costs the least under a set of baseline assumptions. In some cases, however, a portfolio that is not strictly the least cost portfolio may be considered a better fit because it performs well across a wider range of realistic assumptions and scenarios than the least cost portfolio or because it performs much better on a wide range of noncost criteria.[13] That is why in this reference report we describe these decision-making approaches as least cost/best fit techniques or methods rather than simply least cost.

B. Transmission Plans

Transmission plans may be developed by transmission-owning utilities to satisfy state regulators or by regional transmission organizations (RTOs) and independent system operators (ISOs) to satisfy regulators at the Federal Energy Regulatory Commission (FERC). The emphasis in transmission planning is on ensuring adequate transmission capacity to serve peak demands and, in some cases, relieving congestion between low-cost generation resources and load centers. Transmission plans typically do not examine the need for or benefits of distribution system investments. They may, however, consider the impact of transmission solutions on generation costs, especially if the solution will relieve a congestion problem that has prevented the delivery of lower-cost electricity to customers. With transmission plans, models may be used to compare the costs of potential transmission solutions, but "engineering judgment" is often used to select the preferred solution. In some ways, engineering judgment is like an informal version of LCBF, because the technical experts choose the solution they believe is the best fit, considering costs.

C. Distribution System Plans

Distribution system planning proceedings are a new development, with a small number of states instituting a regulated DSP process in just the past few years (Figure 4 on the next page)[14] and additional states now developing rules or investigating distribution system planning. Prior to these recent developments, DSP activities in virtually all jurisdictions were conducted by utilities in-house with little or no regulatory oversight or transparency. A regulated DSP proceeding is specifically designed to create a measure of PUC oversight over utility investments in the distribution system.

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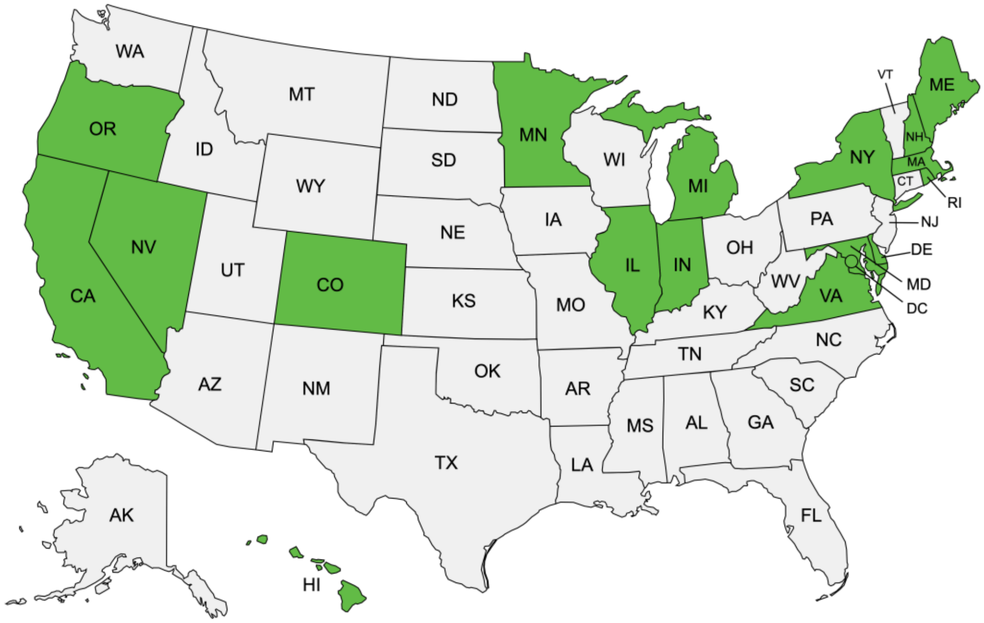
12 Modelers often refer to mandatory criteria that must be satisfied as "constraints."

13 This point can be understood by considering two hypothetical cases. First, consider a case where two candidate resource portfolios were identified by a capacity expansion model as "least cost" based on different assumptions about future gas prices, which can't be predicted with certainty. The "baseline" model run assumed lower future gas prices than the second model run. Consequently, the candidate resource portfolio constructed under the baseline assumptions (Portfolio A) included more gas-fired generation than the second candidate portfolio (Portfolio B). But imagine now that Portfolio A is only slightly less costly than Portfolio B under baseline assumptions about future gas prices but vastly more expensive if future prices are higher than baseline assumptions. Planners may consider Portfolio B less risky and a better fit for customer needs. Second, imagine a case where a portfolio of resources that costs $1 more than the least cost portfolio uses half as much water in a drought-stricken area. The water-saving benefits for the region are undoubtedly worth more than $1, and thus the higher-cost portfolio might be considered a better fit for customer needs.

14 Schwartz, L. (2022, March 3). *Integrated distribution planning overview* [Presentation]. U.S. Department of Energy. https://eta-publications.lbl.gov/sites/default/files/schwartz-integrated-distribution-planning-overview-20220303-fin.pptx.pdf

Figure 4. States with distribution system plan requirements for electric utilities



Source: Schwartz, L. (2022, March 3). *Integrated Distribution Planning Overview*

DSP processes vary from state to state in terms of which types of investments fall under the scope of the planning process. For example, like-for-like replacement of broken or aging infrastructure assets might not be reviewed as part of the process in some states.

Distribution plan processes, like transmission plan processes, typically rely on some combination of LCBF techniques and engineering judgment to make decisions about utility infrastructure investments. In this case, the focus is on minimizing distribution system costs, but generation and transmission costs may sometimes be considered as well.

DSP processes are more likely than integrated resource planning or transmission planning to also incorporate some form of benefit-cost analysis — for example, as a way of testing whether DERs can cost-effectively substitute for some infrastructure investments. Examples of current state DSP requirements are provided in the next section, including detailed explanations of which types of traditional and grid modernization investments are subject to BCA.

III. Use of BCA Techniques

Benefit-cost analyses are used to assess whether an expenditure a utility is considering (or has already made) is cost-effective. An expenditure is cost-effective if its lifetime benefits exceed its lifetime costs, as examined through an agreed perspective and cost test. BCA techniques are routinely used to evaluate utility demand-side management programs in most states and are sometimes used to evaluate other types of utility programs or expenditures.

A. Key Steps of a BCA

BCA methods are used to evaluate proposed or hypothetical changes to an assumed reference case.[15] The essence of BCA is thus a comparison of two or more potential courses of action. The analyst first looks at the marginal impacts (ideally, long-run marginal impacts) of a proposed expenditure on grid capacity needs and how the power system is operated, when compared to the reference case. The analyst then looks at the costs or avoided costs associated with those marginal impacts. Depending on the cost test used, additional non-utility-system costs and benefits (or avoided costs) may also be assessed. If the benefits of an expenditure are greater than the costs, it is considered cost-effective and ideally will be implemented as a supplement or alternative to the reference case.

B. Cost-Effectiveness Tests

Perhaps the most crucial decision before conducting any BCA is the selection of a perspective from which to evaluate costs and benefits. This is because some of the costs and benefits of an expenditure can look different when viewed from different perspectives.

For decades, state PUCs have borrowed ideas from a BCA manual published by the California Public Utilities Commission and adapted them to meet their own needs. The *California Standard Practice Manual for Economic Analysis of Demand-Side Programs and Projects* (CSPM) was originally published in 1983 and then updated multiple times in subsequent years.[16] The CSPM defines five cost-effectiveness tests and offers a standard methodology for conducting each. Each test considers the question of cost-effectiveness from a different perspective. The five tests described in the manual are the participant cost test (PCT), ratepayer impact measure (RIM), program administrator cost test (PACT),[17] total resource cost test (TRC) and societal cost test (SCT).

The *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (NSPM) is the most up-to-date reference available on BCA principles.[18] It builds on ideas from the California manual, updates them for the modern era and offers guidance on how to apply BCA to different types of DERs. A key contribution of the NSPM is that it offers a structured framework and set of guiding principles for states to develop their own jurisdiction-specific test (JST) that starts with all the costs and benefits included in a PACT but also explicitly considers costs and benefits associated with achieving established policies for the jurisdiction in question.

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[15] The reference case could in some cases be to maintain the status quo or take no action.

[16] California Public Utilities Commission. (2001). *California standard practice manual: Economic analysis of demand-side programs and projects*. https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy_-_electricity_and_natural_gas/cpuc-standard-practice-manual.pdf

[17] The term "utility cost test" is frequently used as a substitute or synonym for PACT in recognition of the fact that most customer-facing programs are in fact administered by utilities. There is no methodological difference.

[18] National Energy Screening Project. (2020). *National standard practice manual for benefit-cost analysis of distributed energy resources*. https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/

Table 2 compares the JST with traditional cost tests.[19]

Table 2. Cost-effectiveness tests

Test	Perspective	Key question answered	Impacts accounted for
Participant cost test[20]	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
Ratepayer impact measure[21]	Impacts 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
Program administrator cost test/ 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
Jurisdiction-specific test	Regulators or decision-makers	Will the cost of meeting utility system needs while achieving applicable policy goals decrease?	Includes utility system costs and benefits and any additional costs and benefits associated with achieving applicable policy goals

Sources: Adapted from Woolf, T., Malone, E., Schwartz, L., & Shenot, J. (2013). *A Framework for Evaluating the Cost-Effectiveness of Demand Response*; and National Energy Screening Project. (2020). *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*

[19] Adapted from Woolf, T., Malone, E., Schwartz, L., & Shenot, J. (2013). *A framework for evaluating the cost-effectiveness of demand response*. U.S. Department of Energy and Federal Energy Regulatory Commission. https://www.ferc.gov/sites/default/files/2020-04/napdr-cost-effectiveness.pdf; and National Energy Screening Project, 2020.

[20] The PCT provides useful information about whether participating customers will save money and thus the likelihood that customers will participate in the program, but it is not helpful for deciding whether the utility should offer the program and is never used as a primary test.

[21] The RIM test is identical to the PACT, except that the RIM test also treats utility lost revenues as a cost. As explained in the NSPM, evaluating the potential impacts of a DER program on retail rates is subtly different from a true benefit-cost analysis and should be conducted only as an adjunct to other cost tests, never as a primary test.

Every state that mandates energy efficiency programs currently uses one or more of the tests identified in Table 2 to evaluate programs and projects, albeit in some cases with state-specific modifications. Most states designate one of the tests as their primary test for making decisions. Current state practices for evaluating energy efficiency programs can be compared by reviewing the *Database of State Practices* maintained by the sponsors of the NSPM.[22] It details which cost tests are used and how they are applied in each state.

IV. Comparing LCBF and BCA as Investment Decision-Making Tools

LCBF methods begin with an attempt to find the least cost solution to identified resource or grid needs from the utility perspective. The least cost solution is then modified in some cases to select a best fit solution that is not strictly least cost under assumed baseline conditions. But for now, consider a case where the least cost solution is in fact also the best fit solution. What would we expect to happen if alternative or additional expenditures are proposed and subject to BCA?

If the LCBF exercise considered every potential solution to grid needs, if the BCA used the PACT/utility cost test (UCT), and if the two types of analysis used the same data assumptions, then in theory none of the proposed alternative or additional expenditures would pass the test. In other words, if LCBF yields a least cost solution for the utility system, then the proposed expenditures subject to BCA won't reduce utility system costs (i.e., the revenue requirement). One might then argue that BCA is unnecessary at best and a waste of time and resources at worst. But this is where theory runs into the reality of LCBF and BCA techniques. The two techniques can lead to divergent conclusions for the following reasons, which we explain in more detail in this section:

- Use of costs tests other than the UCT.
- Practical limitations of power sector modeling.
- Timing of different evaluations.
- Level of detail in analysis/modeling.
- Differences in whether the evaluation looks holistically across the generation, transmission and distribution portions of the power system.

[22] National Energy Screening Project. (2021, April 1). *Database of screening practices*. https://www.nationalenergyscreeningproject.org/state-database-dsp/.

First, one must acknowledge that as of August 2022, only six jurisdictions used the UCT as their primary test, according to the *Database of State Practices*. The moment one considers using a test other than the UCT, the biggest differences between BCA and LCBF become readily apparent. BCA quantifies all costs and benefits relevant under the chosen cost test, while LCBF (as we use the term in this reference report) quantifies avoided utility system costs but no other categories of relevant benefits.[23] BCA allows for decisions that maximize net benefits, while LCBF allows only for decisions that minimize costs.[24] If an action will have significant non-utility-system benefits that are included in the cost test chosen by a jurisdiction, the action could easily maximize net benefits while not minimizing costs.

Even in states that use the UCT as their primary test, there are still several reasons why BCA and LCBF may lead to different conclusions. In practice, it is virtually impossible to construct workable models for planning processes that consider every potential solution to every potential need. This problem is addressed through two common shortcuts:

Assuming that existing grid assets will remain on the system. Resource planning processes almost always seek LCBF solutions to identified *incremental* system needs. They focus almost exclusively on finding ways to satisfy load growth, though they do also seek to replace any capacity that is scheduled for retirement. But until recent years, planners have generally assumed as a shortcut that existing grid assets are part of the LCBF solution and will remain part of the system unless and until they are scheduled for retirement as a result of some separate evaluation. Because of this simplified approach, the possibility that existing assets could be replaced *before* their scheduled end of life by lower-cost solutions is not always examined as part of the utility's planning process. Wherever this kind of shortcut persists, BCA methods can readily be used to evaluate whether early retirement of specific power plants would reduce the revenue requirement (or, under a different cost test, increase net benefits).

Treating DERs differently from utility-scale assets. This is done in large part because it is easier to model utility-scale assets. For example, modeling the impact of adding a 1,000 MW utility-owned power plant at a specific location on the grid requires far less computational power than modeling hundreds of thousands of individual customer-owned solar photovoltaic systems rated at less than 10 kW each that are scattered all over the system. To make matters worse, some DERs pose their own modeling challenges because their impact on the system depends on day-to-day operational decisions made by customers, not by the utility. This is especially true for distributed energy storage solutions and electric vehicle charging but also true for demand response. Out of necessity, power system modelers make simplified assumptions about

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[23] Again, we acknowledge that others may define LCBF differently. For example, some jurisdictions may impute a cost per ton of greenhouse gas emissions, which is not actually part of the utility system revenue requirement, and include the imputed costs in what they call a least cost or LCBF decision-making framework. However, this is not an LCBF as we define the term in this reference report, but rather an example of using BCA concepts to supplement LCBF results, which we encourage. In any event, it is an example of how the lines between LCBF and BCA can be blurry.

[24] While it is possible that the best fit adjustment to a least cost evaluation might replicate some aspects of a TRC, SCT or JST framework, the non-utility-system impacts included in those tests can be more accurately and more transparently accounted for using BCA techniques, because one only needs to quantify the marginal impacts from specific proposed expenditures rather than trying to quantify the non-utility-system impacts of all potential expenditures.

how those DERs will operate. They can model different scenarios with different assumptions, but the models cannot possibly compute every theoretical combination of assets and how they are operated to arrive at a true least cost solution. Instead, the most common approach is to assess likely scenarios for DER growth outside of the resource planning models, and then use the results of the exogenous DER assessments to modify the load forecast that goes into the planning process. This approach has a serious limitation, however, because there is no guarantee that utility-scale resources selected via the planning process will actually cost less than adding even more DERs than was determined exogenously. A detailed BCA of a specific DER proposal may find that the proposal reduces the revenue requirement below what the simplified modeling identified as the LCBF solution.

Timing differences can also cause these two techniques to lead to different answers even if BCAs are conducted using the UCT. Utility IRPs are huge undertakings; for that reason, most states require utilities to update them only every two or three years. Transmission plans and DSPs may be updated more or less frequently (usually more frequently) but are rarely completed on the same schedule as IRPs. In the intervals between different types of plans (for example, between the issuance of an IRP and the start of a DSP process) or the periods in between updates of a single type of plan, utilities or others may have reason to propose expenditures that were not included in the most recently issued plan. In those cases, it makes little sense to evaluate the proposed expenditures using the exact same data assumptions as the recent plan, if different and more accurate data are available today. For example, because energy storage costs have plummeted faster than expected, it would be unwise to assess a utility energy storage proposal today using data assumptions about storage costs from an IRP completed three years ago. A BCA might reveal that a storage project that was not included in the LCBF portfolio three years ago is cost-effective today even under a UCT.

Because BCA is used to evaluate specific proposed expenditures, rather than every possible solution to meeting a grid need, it is possible to look at costs and benefits associated with those proposed expenditures in much greater detail than is normally done with LCBF. This, by itself, can generate different answers from an LCBF evaluation even if the UCT is used. For example, the models used for IRP purposes might make little or no attempt to minimize costs for ancillary services, but with BCA the costs and benefits of a demand response program or energy storage system that is designed specifically to provide needed ancillary services can be assessed in exacting detail, perhaps revealing that those DERs can reduce the revenue requirement.

Because BCA is used to evaluate specific proposed expenditures, rather than every possible solution to meeting a grid need, it is possible to look at costs and benefits in much greater detail than is normally done with LCBF.

And that brings us to the final reason why BCA can lead to different (and better) decisions than total reliance on LCBF methods, even in jurisdictions that rely on the UCT. As we've already noted, most planning processes focus on only one portion of the electric power system: generation, transmission or distribution. To keep the analysis manageable, the LCBF approach described above identifies the least costly way of meeting identified needs *for that portion of the system*. But because BCA is only used to evaluate specific options, rather than all options, a more detailed examination of costs and benefits across all parts of the electric power system is possible. So, for example, one can imagine a hypothetical case where an IRP process finds that a new power plant is the least costly way to meet future needs for power generation. But a BCA might reveal that a distributed energy storage solution which costs more than the power plant (while providing equivalent contributions to resource adequacy) will reduce distribution system costs and, considering all parts of the power system, be cost-effective under a UCT.

For all these reasons, it is entirely possible that BCA techniques will reveal utility expenditures (for utility assets or for DER programs) that reduce the revenue requirement (i.e., pass the UCT) compared to the portfolio of assets identified in an IRP, transmission plan or DSP. If a different cost-effectiveness test is used, there is an even greater likelihood that some expenditures will be cost-effective because additional potential benefits will be quantified. This conclusion does not diminish the value of LCBF techniques; rather it underscores the usefulness of both methods in certain circumstances.

V. When Might BCA Be Used?

Utility regulators have historically used BCA techniques primarily to assess DER programs, especially energy efficiency and demand response programs.[25] Almost every state is familiar with this practice. In the past decade, however, utilities and regulators have increasingly used BCA methods in other contexts to inform a broader set of regulatory decisions. Table 3 on the next page offers examples of the types of regulatory proceedings where utility commissions have used BCA techniques to evaluate the costs and benefits of distribution system investments.[26]

[25] To be more precise, in nearly all cases a utility or another party conducts the BCA and then enters the results into the record of a utility commission proceeding.

[26] Adapted from Woolf, T. (2021, November 3). *The role of benefit-cost analysis in distribution planning* [Presentation to a Michigan Public Service Commission workshop]. Synapse Energy Economics. https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/elec-dist-planning/bca_report.pdf#page=98

Table 3. Regulatory proceedings where BCA techniques have been used

Type of regulatory proceeding	Application	Goal of BCA	Role of costs and benefits
Customer-facing programs	DERs	Determine whether to implement a program and/or how to design the program	Compare program benefits to costs
Distribution system infrastructure investments	Advanced metering infrastructure, EV charging infra-structure, grid modernization, etc.	Determine whether to make the investment	Compare investment benefits to investment costs
Long-term planning	IRP, transmission plan, DSP	Determine optimal DER investment levels and contributions to preferred resource portfolio	Compare DER portfolio benefits to costs
	Greenhouse gas plans	Achieve greenhouse gas reduction goals at lowest societal cost	Compare greenhouse gas plan benefits to costs
	State energy plans	Identify resources to meet state goals	Compare state plan benefits to costs
Procurement	DERs, nonwires alternatives, power purchase agreements	Compare resource offerings to maximize net benefits or determine the ceiling price for procurement	Ceiling price should equal the benefits of the procurement
Rate cases/rate design	DER compensation rates	Determine the value of DER as basis or justification for compensation	Value of DER is the sum of benefits
	Retrospective review of past investments for prudence	Determine whether investment costs should be recovered from ratepayers	Compare benefits and costs using test in place when the decision was made
Performance-based regulation	Performance incentive review	Determine value of utility incentives	Incentives are sometimes set at a percentage of net benefits

Source: Adapted from Woolf, T. (2021, November 3). *The Role of Benefit-Cost Analysis in Distribution Planning*

In the remainder of this section, we'll consider in greater detail the types of regulatory proceedings where BCA methods are most commonly used or are increasingly being used compared to past practices:

- Customer-facing DER programs.
- Distribution system infrastructure investments.
- Long-term planning (IRP, transmission planning or DSP), including the evaluation of nonwires alternatives (NWAs) within a planning process.
- Rate cases/rate design.[27]

Our aim is to provide insights into the circumstances or conditions under which BCA might be used to improve regulatory outcomes. Armed with this information, regulators can decide whether they wish to expand the use of BCA methods in their own jurisdictions.

A. Customer-Facing DER Programs

BCA methods have been used for decades by program administrators, PUCs and sometimes other government agencies to do three distinct but closely related types of DER program assessments:

- Potential studies.
- Program plans.
- Program evaluations.

Using BCAs to develop program plans creates an opportunity to maximize net benefits, while using BCA to evaluate programs ensures accountability for results and an opportunity for continual improvement.

These assessments can be done for any kind of DER, but by far the most experience to date comes from their use with energy efficiency programs. Program plans and program evaluations have also been commonly used with demand response programs, but demand response potential studies are less common. And we find far fewer examples where regulators used BCA to evaluate other DER programs, such as those for distributed generation, distributed energy storage, electric vehicles (EVs), building electrification or customer-owned microgrids. Most of those examples were produced in just the past five years.

1. Potential Studies

Potential studies typically start with a review of available DER technologies and how many customers theoretically could use each technology. This is called technical potential. After that initial review, BCA methods are used to determine how much of the technical potential would be cost-effective. This is called economic potential. Finally, most potential

[27] In some cases we categorize the cited examples somewhat arbitrarily, since an investment that might be evaluated as a stand-alone proceeding in one case or one jurisdiction might be evaluated as part of a different type of proceeding in another case or another jurisdiction. For example, customer-facing programs are sometimes evaluated as part of a rate case, and NWAs may be reviewed in the context of a stand-alone infrastructure investment decision or as part of a long-term planning process.

studies also attempt to determine how much of the economic potential might realistically be deployed. This last value is called achievable potential.

Because potential studies tend to be comprehensive, complex, costly and time-consuming, there are very real trade-offs to consider in deciding when or how often to do them. The value of having updated information on potential must be greater than the cost of acquiring that updated information.

In some cases, state legislation has dictated that potential studies be completed for specific DERs as a one-time investigation or on a recurring basis. Such is the case in Michigan, where 2016 Public Act 341 directed the PSC to conduct energy efficiency and demand response potential studies every five years, "based on what is economically and technologically feasible, as well as what is reasonably achievable."[28] More commonly, potential studies are produced in response to a PUC order or in response to a governor's executive order. Given that most states have experience with energy efficiency potential studies, we note below some interesting examples of potential studies that address other DERs:

- In 2017, Lawrence Berkeley National Laboratory produced a demand response potential study in response to an order by the California PUC. The study examined a broad suite of potential uses for flexible loads, whereas most demand response potential studies and most demand response programs focus exclusively on load shedding. The California study also considered using flexible loads to shape load curves, shift loads in time and provide ancillary services.[29]
- The Colorado Energy Office produced a building electrification market potential study in 2020 as a one-time research project on its own general authority (i.e., without a specific legislative mandate).[30]
- Wisconsin's Focus on Energy program produced a potential study focused specifically on rooftop solar in 2021.[31]
- The Pennsylvania PUC commissioned a potential study in 2015 that looked at combined heat and power installations as well as distributed solar.[32]

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[28] Note that in Michigan statutes and regulatory proceedings, the term "energy waste reduction" is used instead of "energy efficiency." The terms are synonymous. The most recent Michigan potential studies were finalized in separate reports in 2021. Guidehouse Inc. (2021). *Michigan energy waste reduction statewide potential study (2021-2040)*. Michigan Public Service Commission. https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/potential_studies_2021/MI-EWR-Statewide-Potential-Study-Report---Final.pdf. Guidehouse Inc. (2021). *Michigan demand response statewide potential study (2021-2040)*. Michigan Public Service Commission. https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/potential_studies_2021/MI_DR_Statewide_Potential_Study_Report_-_Final.pdf

[29] Lawrence Berkeley National Laboratory, Energy and Environmental Economics, Inc., & Nexant, Inc. (2017). *2025 California demand response potential study — Charting California's demand response future: Final report on phase 2 results*. California Public Utilities Commission. https://eta-publications.lbl.gov/sites/default/files/lbnl-2001113.pdf

[30] GDS Associates, Inc. (2020). *Beneficial electrification in Colorado: Market potential 2021-2030*. Colorado Energy Office. https://drive.google.com/file/d/17bMnJv-5YgIeW3y6NERyqYBRhtYm7BR6/view

[31] Cadmus. (2021). *Focus on energy: 2021 rooftop solar potential study report*. Public Service Commission of Wisconsin. https://focusonenergy.com/sites/default/files/inline-files/Potential_Study_Report-FoE_Rooftop_Solar_2021.pdf

[32] GDS Associates, Inc., Nexant, Research Into Action & Apex Analytics. (2015). *Distributed generation potential study for Pennsylvania*. Pennsylvania Public Utility Commission. https://www.puc.pa.gov/pcdocs/1355000.pdf

- In 2015, the governor of Massachusetts launched an energy storage initiative to evaluate and demonstrate the benefits of deploying energy storage technologies. As part of that initiative, the Massachusetts Department of Energy Resources led a multiparty study team that produced an energy storage potential study with detailed BCA results.[33]

In those cases where PUCs opted on their own initiative to require a potential study, they have usually done so based on a belief (or testimony from parties) that significant cost-effective and achievable DER potential exists but is not being captured via existing customer-facing programs.

2. Program Plans

In states where energy efficiency programs are mandated as a continuing obligation of utilities (or a third party), program administrators are generally required to periodically file a plan for PUC approval that explains what services will be offered to customers and details the costs and benefits of each. These program plans are frequently filed as multiyear plans covering two to four years. The PUC can then review the plan and reject it, approve it or request modifications.

BCA results help energy efficiency program administrators decide which programs to offer and regulators decide whether to approve those program plans. The purpose of the BCA is to ensure that the planned portfolio is cost-effective in aggregate or, in some jurisdictions, that each individual measure in the portfolio is cost-effective. Many states make exceptions to cost-effectiveness requirements for low-income programs, pilot/experimental programs and market transformation programs. If a jurisdiction has recently completed a market potential study, data from that study may be used to justify the program plan. But if a potential study has not been recently completed, the program plan typically includes a fresh assessment of the BCA results for each component of the plan.

BCA is also used, albeit less commonly, to assess customer-facing program plans for other DERs. In jurisdictions where demand response programs are paired with energy efficiency programs into a combined demand-side management plan, BCA analysis of demand response programs is routine. For example, the demand-side management plans that Xcel Energy files with Colorado regulators include a BCA for demand response offerings as well as energy efficiency.[34]

BCA results may also be filed in proceedings where utilities are seeking approval for new pilot or experimental programs or where interveners are requesting such programs. In 2021, the Michigan PSC encouraged utilities to propose pilot energy storage programs in upcoming rate cases and specified that proposals should detail the "Anticipated cost-effectiveness and net benefits when deployed at scale described," including "Quantification

[33] Customized Energy Solutions, Sustainable Energy Advantage, Daymark & Alevo Analytics. (2019). *State of charge: Massachusetts energy storage initiative*. Massachusetts Department of Energy Resources and Massachusetts Clean Energy Center. https://www.mass.gov/doc/state-of-charge-report/download

[34] Xcel Energy. (2021). *2021/2022 Demand-side management plan: Electric and natural gas*. https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/CO-DSM/CO_2021-22_DSM_Plan_Final.pdf

of expected benefits of the pilot and the evaluation criteria/methods used."[35] BCAs have already been filed in other states for customer-facing energy storage programs. For example, in 2020, the Connecticut Green Bank along with several partner organizations filed a proposal for a new customer-sited energy storage program with the Connecticut Public Utilities Regulatory Authority that included a thorough BCA.[36]

3. Program Evaluations

Energy efficiency programs are typically evaluated a second time, after they are implemented, based on actual achieved results. The focus tends to be on summarizing the energy and demand savings achieved by programs and demonstrating that the programs were in fact cost-effective. This requires a BCA. In addition, the results of these evaluations are often tied to financial incentives or penalties and in some cases the amount of incentive awarded to the program administrator is expressed as a percentage of the net benefits achieved by the program.[37] Examples of using net benefits to determine performance incentives can be found in Arizona, Arkansas, Minnesota, Missouri and several other states.[38]

Virtually all states that require utilities or third parties to offer energy efficiency programs require the program administrator or an independent evaluator to file an evaluation report after each program cycle (or, in some cases, midcycle as well).

Demand response programs may be evaluated on the same frequency and with the same level of regulatory oversight as energy efficiency programs. Again, this is especially true in states where demand response is lumped with energy efficiency into a combined demand-side management portfolio. For example, BCAs are included in the following evaluations:

- Pennsylvania utilities file annual reports evaluating their demand response programs.[39]
- Utah's only large investor-owned electric utility, Rocky Mountain Power, produces annual evaluation reports for its combined demand-side management programs.[40]

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35 Michigan Public Service Commission, Case No. U-21032, Order on August 11, 2021. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000RlWgpAAF

36 Connecticut Green Bank. (2020, July 31). *RE: Solarize storage — A proposal of the Connecticut Green Bank under Docket No. 17-12-03(RE03) — Electric storage*. https://www.ctgreenbank.com/wp-content/uploads/2020/08/PURA-Docket-No.-17-12-03RE03-%E2%80%93-Solarize-Storage-Proposal-from-the-Green-Bank.pdf

37 This represents the most common application of performance-based regulation in the United States today. Table 3 listed performance-based regulation as a distinct type of proceeding in which BCA methods may be used because most of the performance-based regulation proceedings opened by PUCs in recent years have been broad in scope, whereas here we are referring narrowly to incentives for energy efficiency program performance.

38 Cleveland, M., Dunning, L,. & Heibel, J. (2019). *State policies for utility investment in energy efficiency*. National Conference of State Legislatures. https://www.ncsl.org/Portals/1/Documents/energy/Utility_Incentives_4_2019_33375.pdf?ver=2019-04-04-154310-703

39 For a recent example, see The Cadmus Group. (2018). *Demand response program annual evaluation*. PPL Electric Utilities. https://www.pplelectric.com/-/media/PPLElectric/Save-Energy-and-Money/Docs/Act129_Phase3/PPLPY9ChapterDRProgram20180115.ashx?sc_lang=en&hash=82F633BE210BC4DFA83DA2CDFEDAB1D6

40 For the latest of these, see Rocky Mountain Power. (2021). *2020 Utah energy efficiency and peak reduction annual report.* https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/environment/dsm/utah/Energy_Efficiency_and_Peak_Reduction_Report_2020.pdf

- Commonwealth Edison in Illinois produces annual reports on the results of its peak-time rebate program.[41]

But more typically, demand response programs are not evaluated as frequently as energy efficiency programs, if at all. Other DER programs tend not to be routinely evaluated, either, but may be evaluated for cost-effectiveness in a proceeding to determine whether the programs should be continued or expanded. In any event, there are fewer examples where BCA was used to evaluate a distributed generation, storage or other DER program after implementation.

B. Distribution System Infrastructure Investments

Prior to the emergence of new grid modernization technologies in the past two decades, utility investments in the distribution system were virtually never assessed using BCA methods. Utilities would instead use LCBF methods to make decisions and then, perhaps, justify the most expensive investments in a rate case. Or they would seek preapproval of the most expensive investments in a separate proceeding, but again using LCBF methods to justify their proposals. This approach has been slowly changing. Today, BCA methods are increasingly used in investment preapproval cases or rate cases, for at least two reasons.

First, some grid modernization technologies and applications require large expenditures but create substantial new opportunities — for example, opportunities to improve customer service, reliability, resilience and DER integration. These investments may not be absolutely necessary if the only objective is the traditional one of "keeping the lights on" at least cost. Rather, the potential benefits are the primary reason for making these investments. Consequently, some utilities and regulators have gravitated toward using BCA methods instead of (or in addition to) LCBF methods to demonstrate that those benefits justify the costs and reveal whether ratepayers are paying more than is necessary to obtain the benefits. We will take a closer look at three such technologies that have sometimes been justified using BCA methods: advanced metering infrastructure (AMI), EV charging infrastructure and energy storage assets.

One reason behind the trend toward greater use of BCA is that utilities and regulators are increasingly thinking about grid modernization in a comprehensive way.

A second and related reason behind the trend toward greater use of BCA is that utilities and regulators are increasingly thinking about grid modernization in a comprehensive way and evaluating expensive plans to invest in multiple interrelated components.[42] As we will see, BCA can help justify those plans because, unlike LCBF methods, it allows decision-

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[41] For a recent example, see Nexant. (2020). *Commonwealth Edison Company's peak time savings program annual report.* Commonwealth Edison Co. https://www.icc.illinois.gov/docket/P2019-0858/documents/302498/files/527335.pdf

[42] Although AMI is unquestionably a grid modernization technology, in this reference report we review AMI examples separately from grid modernization examples because AMI has often been proposed by utilities in a narrow, stand-alone preapproval proceeding or reviewed as a distinct issue in a rate case, separate from any broader or comprehensive grid modernization strategy that the utility might have.

makers to see how investments in one component can enable new benefits to be gained from another component and test whether the total benefits of a comprehensive approach exceed the total costs.

Finally, we will also note in this section how BCA methods could be used in jurisdictions where regulations require utilities to seek preapproval of some types of investments, including more traditional distribution system assets.

1. Advanced Metering Infrastructure

Electric utilities in the United States are in a decades-long transition toward universal deployment of AMI, as evidenced by annual reports produced by FERC. In 2007, FERC surveys indicated that AMI penetration nationally was at less than 5% of all electric meters. By 2019, that number had risen above 60%.[43] Along the way, utilities have sought preapproval from regulators for these relatively large investments, either in a stand-alone regulatory proceeding or as part of a general rate case. These preapproval requests have sometimes motivated the utility to conduct a BCA to justify their proposed investments in new metering technologies. In a few other cases, regulators have proactively asked utilities to analyze benefits and costs of full AMI deployment prior to receiving preapproval requests.

In 2017, Northeast Energy Efficiency Partnerships (NEEP) published a review of BCAs that accompanied eight utility AMI proposals across six different states.[44] The report includes a short case study describing each example. Though some of the key details about methods and results are not included in every case study, the report includes links to all the relevant PUC proceedings. Table 4 on the next page lists the BCAs reviewed in the report, with some of the key results.[45]

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[43] Federal Energy Regulatory Commission staff. (2021). *2021 assessment of demand response and advanced metering*. https://www.ferc.gov/media/2021-assessment-demand-response-and-advanced-metering

[44] Northeast Energy Efficiency Partnerships. (2017). *Advanced metering infrastructure: Utility trends and cost-benefit analyses in the NEEP region*. https://neep.org/advanced-metering-infrastructure-utility-trends-and-cost-benefit-analyses-neep-region

[45] Northeast Energy Efficiency Partnerships, 2017.

Table 4. AMI BCA studies reviewed by Northeast Energy Efficiency Partnerships

Utility	Year Proposed	Meters	Costs		Benefits			
			Physical Hardware	O&M	O&M	Peak reduction (DR/TVR)	CVR	Lifecycle
CMP (ME)	2007	622,000 (Deployed)	$78.4M	$48.8M	$67.8 M	Included, but unquantified		20
GMP (VT)	2010	260,600 (Deployed)	104.8M	19.64M	19.32 M	No	vvo	20
CL&P (CT)	2007	3,000[17] (Deployed)	294M	197M	211M	Included, but unquantified		20
NGrid (MA)	2015	1.3M (Proposed)	300.65 M	x	x	Included, but unquantified	x	15
Con Edison (NY)	2015	4.7M[18] (Approved)	777M/ 1,026M	634M	1,383 M	Included, but unquantified	cvo	20
BG&E (MD)	2010	1.23M (Deployed)	$653.6M		436M	$123M	cvr	15
Unitil (MA)	2015	103,000 (Deployed, to be upgraded)	x	x	x	Included, but unquantified	x	15
Eversource (MA)	2015	5 percent (Proposed)	140-450 $/unit[19]	$21 ($/unit/yr)	x	33.4M	vvo	15

Source: Northeast Energy Efficiency Partnerships. (2017). *Advanced Metering Infrastructure: Utility Trends and Cost-Benefit Analyses in the NEEP Region*

Examples of BCAs for AMI proposals are of course not limited to one region. For example, in 2016, the utility Entergy sought approval from the Arkansas Public Service Commission to replace analog meters in its service territory with AMI. Entergy filed a BCA with its application for preapproval, not because the commission required it but rather as evidence in support of a claim that the investment was "in the public interest."[46] In this case, the utility presented BCA information only for its proposed investment and not for any alternatives to the investment. Details of the BCA were a core issue in the proceeding and factored into the commission's eventual decision to approve the AMI investment with modifications from the original proposal.

Transparency can be critically important in evaluating a BCA for AMI investments. The suite of technologies we call AMI, which can include not only "smart" digital meters but also some of the digital communications and software investments that typically accompany those meters, can facilitate new opportunities for utilities and customers, such as conservation voltage reduction, time-varying rate designs and next-generation demand response programs. A transparent BCA should reveal which of these new opportunities the utility is assuming will happen and which benefits it is quantifying. Reviewers of the BCA

[46] Lewis, J. A. (2016, September 19). Direct testimony on behalf of Entergy Arkansas Inc. Arkansas Public Service Commission Docket No. 16-060-U. http://www.apscservices.info/pdf/16/16-060-U_22_1.pdf

can then consider whether these opportunities and benefits are certain to occur or, in the worst case, if they might be used to justify the AMI investment but never be implemented. Reviewers can also judge whether the specific suite of proposed AMI components is sufficient to enable the presumed benefits or if those benefits will not be possible without additional investments not included in the BCA.

2. EV Charging Infrastructure

Many organizations, including some state government bodies, have used BCA to assess the costs and benefits to drivers and society of increasing EV deployment without looking comprehensively at the benefits and costs for electric utilities or at specific utility investments related to EV deployment. These kinds of studies are not of interest for this reference report. Instead, we are interested in cases where BCA is used to evaluate specific proposed utility investments in public charging infrastructure or other electric vehicle supply equipment. As with the AMI examples above, this can happen as a stand-alone proceeding or as part of a general rate case. There are relatively few examples of a comprehensive transparent BCA to examine, but they do exist.

In April 2017, the Michigan PSC opened a docket with the goal of collaboratively addressing EV-related issues on a statewide basis. In August 2017, the commission sought comments "on whether utilities should initiate a series of targeted pilot programs designed to further explore issues related to the deployment of [plug-in EV] charging stations and associated infrastructure. If targeted pilot programs are appropriate to guide future commission and utility decision making, the commission also seeks input on the focus of such pilots so that they could strategically identify and reduce barriers and inform future investment and regulatory strategies." Several parties focused on BCA issues in their comments. In response, in a December 2017 order, the commission established the use of BCA as a guiding principle for EV-related utility investments: "... with these potential pilot programs, and those the Commission foresees will actually be submitted by regulated utilities for Commission approval in the near future, if ratepayer funding is proposed as a funding source, the Commission expects a detailed cost-benefit analysis to be included, with any benefits specifically concentrated on those to ratepayers as utility customers, not as a part of society in general."[47] Several pilot and larger-scale utility investments have been proposed since the December 2017 order, with BCA information included in each case.

The impetus for using BCA to assess EV-related investments has been different in some other states. In Colorado, Senate Bill 19-077 required each Colorado electric public utility to file "an application for a program for regulated activities to support widespread transportation electrification" within their service territories. The parent company of the larger of the state's two affected utilities, Xcel Energy, filed its transportation electrification plan for approval in 2020.[48] To support its proposed plan, Xcel

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[47] Michigan Public Service Commission, Case No. U-18368, Order on December 20, 2017, adopting guiding principles and commencing a second collaborative technical conference. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001X2MFAA0

[48] Public Service Company of Colorado. (2020, May 15). *Application for approval of 2021-2023 transportation electrification plan*. Colorado Public Utilities Commission Proceeding No. 20A-XXXXE. https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=926517&p_session_id=

commissioned a BCA that looked at the net benefits of expected EV deployment in Colorado through 2030.[49] More importantly, the analysis also examined the incremental costs and benefits of several scenarios that reflected aspects of EV adoption and EV charging behavior that the utility could control or influence, including:

- Managing charging through time-of-use energy rates, plus additional charge management performed by Xcel to mitigate the impact of rebound peaks when off-peak periods resume.
- Doubling the number of public direct-current fast charging stations deployed across the utility's territory.
- Contributing 50% toward all charging infrastructure costs behind the customer meter.[50]

Looking at one other example where the impetus for a BCA was slightly different, the New York utility National Grid proposed a suite of EV offerings on its own initiative as part of its 2020 rate case. As in the Xcel Energy example, National Grid's proposal consisted of a mix of customer-facing programs, utility investments in EV "make ready" infrastructure and new rate offerings. The utility filed BCA results with the New York commission to justify the proposal and gain approval for recovering costs from ratepayers.[51]

3. Energy Storage Assets

Utilities and regulators are occasionally using BCA methods to evaluate investments in energy storage. As was the case with AMI and EV supply equipment investments, these analyses may appear in a utility preapproval request or in a rate case or they may be filed in response to an order or request by regulators. Storage options may also be reviewed as part of a long-term IRP or DSP process or a nonwires alternatives solicitation.

Energy storage resources present a particularly promising area for use of BCA methods because of the multitude of energy, capacity and ancillary services that are possible, as well as customer benefits and societal resilience benefits. As a reminder, LCBF methods sometimes only quantify benefits for a portion of the utility system (e.g., the bulk power system) and normally don't quantify non-utility-system benefits; they only find the lowest-cost solution, from the utility's perspective, to a particular identified problem. But storage resources often can contribute to solving multiple problems with one investment and can even produce net benefits for customers and society where reliability and capacity problems don't currently exist.

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[49] Energy and Environmental Economics, Inc. (2020). *Benefit-cost analysis of transportation electrification in the Xcel Energy Colorado service territory.* https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=926529&p_session_id=

[50] The first scenario from the Xcel Energy filing could have been presented later in this reference report as an example of using BCA to design retail rates, while the third scenario could have been presented earlier as an example of evaluating a customer-facing EV incentive program. We chose to present all three scenarios in this section because the second scenario involved utility investment in EV supply equipment.

[51] Flynn-Kasuba, R., & Sondhi, R. (July 31, 2020). Direct testimony on behalf of Niagara Mohawk Power Corporation d/b/a National Grid. New York Public Service Commission Case Number 20-E-0380. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={9628378F-D083-440C-AEAA-521503F5E86A}

In Maryland, utility interest in energy storage projects was driven by a state law (2019 Senate Bill 573, the Energy Storage Pilot Project Act) that required the PSC to establish an energy storage pilot program. In August 2019, the PSC directed the state's regulated utilities to solicit offers to develop energy storage projects and file them to the commission for approval.[52] In response, Maryland's utilities filed eight proposed storage projects for the commission's consideration and approval. The utilities' proposals were not supported by BCAs, but as part of the proceeding, PSC staff submitted its own BCA on the record, finding some of the projects to be cost-effective and some not.[53] This example serves to underscore the fact that BCAs do not always have to originate with utilities, even when the utility is requesting preapproval for an investment.

4. Grid Modernization

"Grid modernization" has become a catchall phrase that is used to describe different initiatives in different places. Broadly, it refers to developing, deploying and using methods and devices for reliably and efficiently operating a modern grid. This modern grid is defined by several of its key characteristics, including:

- A mix of utility-scale and distributed generation and storage resources provides capacity, energy and ancillary services.
- A portion of customer demand is flexible and capable of responding to price signals or dispatch commands from a utility or system operator.
- Many analog devices have been replaced with digital substitutes.
- Digital information about system and resource conditions is communicated freely, rapidly and routinely between system operators, utilities, customers and third parties.

Electric utilities in the U.S. are investing in a wide range of technologies that fit this description, at a cost that already totals many billions of dollars. This includes AMI, advanced distribution management systems, digital communication systems, sensing and measurement equipment and much more. In some cases, proposals to invest more than a billion dollars in grid modernization investments have been filed by a single utility. The need for grid modernization investments is huge and will persist for decades to come. This is why the U.S. Department of Energy launched a grid modernization initiative years ago and established the Grid Modernization Laboratory Consortium with the national energy labs.[54]

Although some types of grid modernization investments might be reviewed in a DSP proceeding or a general rate case (to be discussed in later sections of this reference report), it is often the case that a utility will seek preapproval from regulators for certain types of

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[52] Maryland Public Service Commission, Case No. 9619, Order No. 89240 on August 23, 2019, establishing an energy storage pilot program. https://www.psc.state.md.us/7463-2/

[53] Maryland Public Service Commission staff. (June 19, 2020). *Comments on the applications submitted for the Maryland energy storage pilot program.* Case No. 9619. https://webapp.psc.state.md.us/newIntranet/Casenum/NewIndex3_VOpenFile.cfm?filepath=//Coldfusion/Casenum/9600-9699/9619/Item_25\9619-StaffCommentsStorageProjectProposalsPUBLIC-061920.pdf

[54] U.S. Department of Energy. (n.d.) *Grid modernization initiative*. https://www.energy.gov/gmi/grid-modernization-initiative

grid modernization investments in a separate, stand-alone proceeding. This happens because many types of grid modernization investments have nothing to do with the resource adequacy needs that are typically the focus of DSP and other long-term planning exercises. Modern sensing and measurement equipment, for example, may not be needed to ensure resource adequacy but will probably be essential for safe, reliable and efficient operation of the modern grid. Utilities may seek preapproval of investments because regulators require it or seek preapproval voluntarily to minimize the possibility that costs will be disallowed in their next rate case. The larger the investment, the more likely it is that a utility will seek assurances that it can recover costs from ratepayers.

In cases where a utility seeks preapproval for a grid modernization investment, there may be opportunities to reach better decisions by using BCA techniques. Preapproval proceedings often resemble scaled-down versions of a planning process, with the utility first demonstrating with data there is a grid need that must be met (or a new opportunity to improve service) and then comparing the feasibility and costs of a few potential solutions of their choosing. The grid need (or opportunity) is sometimes very narrowly defined, and the range of solutions considered may be small. Using BCA techniques as part of these preapproval proceedings may allow for a more rigorous exploration of the benefits and costs of a wider range of potential solutions, including solutions proposed by interveners. This probably makes the most sense in cases where a few important conditions can be met, such as:

- Interveners can identify feasible alternatives to the investment for which the utility has requested preapproval.
- The dollars at stake in the utility request and the potential savings from finding a "better solution" are enough to warrant the time and effort needed to complete a BCA.
- The schedule for making a decision allows for enough time to solicit alternatives and conduct a BCA of those alternatives.

In 2013, Pacific Gas and Electric applied to the California PUC for approval of a multimillion-dollar package of smart grid (i.e., grid modernization) pilot projects. The utility quantified costs and benefits of each project and filed those BCA results, even though the PUC at the time was not requiring smart grid pilot projects to be cost-effective as a prerequisite for approval. The BCA results ultimately influenced the PUC's decision, as some of the least cost-effective requested pilot projects were not approved. However, the commission eventually approved three components of the original proposal: a line sensor pilot, a voltage and reactive power optimization pilot, and a pilot for detecting and locating outages and circuit faults. Interestingly, the BCA results showed that the voltage and reactive power optimization pilot was expected to be highly cost-effective while the line sensor and outage detection pilots were not cost-effective — but all three were approved as a package, and the package was, in aggregate, cost-effective.[55]

[55] California Public Utilities Commission, Application No. 11-11-017, Decision 13-03-032 on March 21, 2013. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M063/K535/63535551.PDF

The question of when to use BCA methods to evaluate grid modernization investments is a complicated one. As part of its grid modernization initiative, the Department of Energy produced a four-volume Modern Distribution Grid series of publications. The latest of those publications, which is still labeled "draft" but is nonetheless available from the department's website, is the *Strategy and Implementation Planning Guidebook*.[56] The guidebook includes a lengthy section on methods for evaluating the cost-effectiveness of grid modernization investments. Notably, the guidebook does not recommend using BCA for all potential investments. Rather, it suggests a framework for evaluation in which some investments are subject to LCBF techniques, while others are subject to BCA. The choice of evaluation method depends on the driver or purpose of the investment, as described in Table 5 and Figure 5, both from the handbook.[57]

Table 5. Cost-effectiveness framework

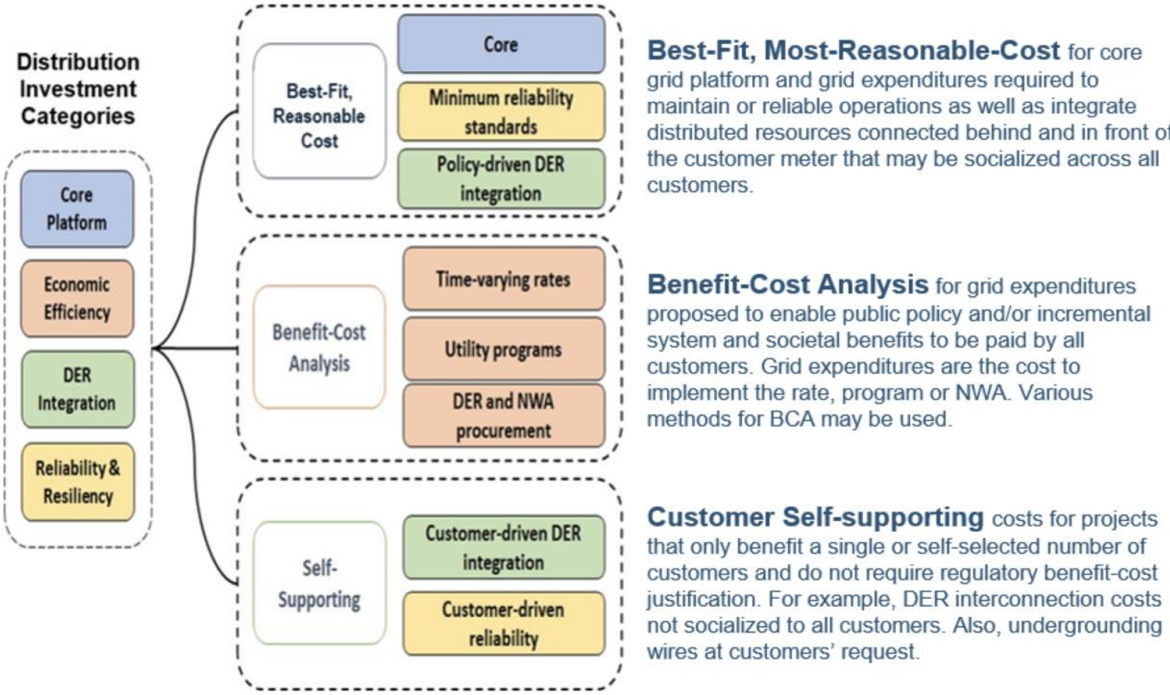
No.	Expenditure Purpose	Methodology
1	Grid expenditures to replace aging infrastructure, new customer service connections, relocation of infrastructures for roadwork or the like, and storm damage repairs.	Least-cost, best-fit or other traditional method recognizing the opportunity to avoid replacing like-for-like and instead incorporate new technology
2	Grid expenditures required to maintain reliable operations in a grid with much higher levels of distributed resources connected behind and in front of the customer meter that may be socialized across all customers.	Least-cost, best-fit for core platform, or Traditional Utility Cost-Customer Benefit based on improvement derived from technology.
3	Grid expenditures proposed to enable public policy and/or incremental system and societal benefits to be paid by all customers.	Integrated Power System & Societal Benefit-Cost (e.g., EPRI and NY REV BCA)
4	Grid expenditures that will be paid for directly by customers participating in DER programs via a self-supporting margin neutral opt-in DER tariff, or as part of project specific incremental interconnection costs, for example.	These are "opt-in" or self-supporting costs, or costs that only benefit a customer's project and do not require regulatory benefit-cost justification.

Source: U.S. Department of Energy. (2020). *Modern Distribution Grid: Strategy and Implementation Planning Guidebook (Volume IV)*

56 U.S. Department of Energy. (2020). *Modern distribution grid: Strategy and implementation planning guidebook (Volume IV)*. Version 1.0 Final Draft. https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume_IV_v1_0_draft.pdf

57 U.S. Department of Energy, 2020.

Figure 5. Evaluation methods for distribution system investments



Source: U.S. Department of Energy. (2020). *Modern Distribution Grid: Strategy and Implementation Planning Guidebook (Volume IV)*

The approach the department describes in its guidebook is informed by actions in some leading states and has gained traction in others. For example, the guidebook cites a decision by the California PUC (subsequent to the pilot project example cited earlier) as part of the rationale for proposing LCBF rather than BCA for "core platform" investments:

> "To determine the cost effectiveness of each grid modernization investment, the [investor-owned utilities] would need to identify the driver of the investment and isolate the value of its contribution to enabling DER growth. We find this infeasible, given the multiple, interrelated functions of grid modernization investments."[58]

The Hawaii PUC apparently accepted the U.S. Department of Energy framework when it approved a broad grid modernization strategy (GMS) proposed by Hawaiian electric companies in 2017.[59] As part of their strategy, the utilities proposed to use different evaluation techniques for grid modernization investments depending on the purpose of each investment. LCBF techniques would be used for investments necessary to satisfy service quality and safety requirements or to comply with state policy goals, while BCA

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[58] California Public Utilities Commission, Rulemaking 14-08-013 and related matters, Decision 18-03-023 on March 22, 2018. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M212/K432/212432689.PDF. California was one of several states that collaborated with the U.S. Department of Energy in producing the Modern Distribution Grid series of publications.

[59] Hawaiian Electric Co., Hawai'i Electric Light Co. & Maui Electric Co. (2017). *Modernizing Hawai'i's grid for our customers.* https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A17I05B52711G00112

would be used for grid modernization investments that were otherwise not required but would yield net benefits to customers.[60]

The PUC conditionally approved the utilities' GMS in February 2018.[61] In the order, the PUC did not specifically comment on the proposed cost-effectiveness framework but directed the utilities to file one or more applications to implement the GMS and to provide more details about costs and benefits in those applications.

In 2019, the utilities applied for preapproval to invest in and recover costs for an advanced distribution management system. The application included quantitative information about the total costs of the proposal but only qualitative descriptions of the benefits. By way of explanation, the utilities referred to the cost-effectiveness framework from their GMS and made an assertion reminiscent of the California PUC's:

> "It is impracticable to aggregate GMS implementation benefits for use in a traditional benefit-cost analysis. Indeed, the GMS investments in general, and the [advanced distribution management system] in particular, are foundational to and enable other programs. GMS investments have interrelated and naturally synergistic functions that make it infeasible to determine the cost-effectiveness of each GMS component independently."[62]

In 2021, the Grid Modernization Laboratory Consortium published a separate report, *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations*, that is intended to be used in conjunction with the Modern Distribution Grid publications and that specifically builds on the Department of Energy guidebook.[63] The authors explain its purpose as follows:

> "This report provides state public utility commissions, energy offices, utility consumer representatives, and other stakeholders with a framework for navigating BCA for utility grid modernization plans, and it supports training for these audiences on this topic. It does not attempt to explain all of the complexities and details of how to prepare BCA for grid modernization plans. Instead, it presents trends, challenges, and considerations for reviewing plans. It includes a brief review of 21 recent utility grid modernization plans and identifies how to address several of the most challenging issues when reviewing them."

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[60] Hawaiian Electric Co. et al., 2017, Section 4.2.

[61] Hawaii Public Utilities Commission, Docket No. 2017-0226, Decision and Order No. 35268 on February 7, 2018. https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A18B08B13014I00232

[62] Hawaiian Electric Co., Hawaiʻi Electric Light Co. & Maui Electric Co. (2019, September 30). *Application to commit funds*. Hawaii Public Utilities Commission Docket No. 2019-0327. https://www.hawaiianelectric.com/documents/clean_energy_hawaii/grid_modernization/2019_0327_20190930_cos_ADMS_application.pdf

[63] Woolf, T., Havumaki, B., Bhandari, D., Whited, M., & Schwartz, L. (2021). *Benefit-cost analysis for utility-facing grid modernization investments: Trends, challenges, and considerations*. U.S. Department of Energy. https://emp.lbl.gov/publications/benefit-cost-analysis-utility-facing

Although the examples cited above demonstrate that the evaluation framework presented in the Energy Department guidebook is workable and pragmatic, it is not necessarily the final word on when or how to use BCA to evaluate grid modernization investments. In Michigan, the state's two largest utilities appear to have diverged somewhat on this question in 2021. DTE's grid modernization study explicitly adopted the approach suggested in the Energy Department guidebook,[64] while Consumers Energy proposed the Grid Modernization Roadmap BCA, which offers a framework for how the company plans to assess the net benefits of its investments prospectively and retrospectively.[65]

We feel that BCA methods can be practically applied in a wider set of circumstances than those outlined in the framework. Failing to do so will result in lost opportunities to maximize the net benefits of grid modernization efforts for ratepayers and society. In particular, while appreciating that practical considerations must always factor into the decision of which evaluation method to use, we believe that BCA may be a practical option for evaluating some "core platform" investments and some investments necessary to meet "minimum reliability standards" (see Figure 5). In those cases, BCA would, in fact, be a superior tool to LCBF.

5. Preapproval Processes for Other Distribution System Investments

In some jurisdictions, laws and regulations already on the books require utilities to seek preapproval of infrastructure investments that meet certain criteria. Formal approval often comes in the form of a PUC finding that the investment is in the public interest or a certificate of some kind, such as a certificate of public convenience and necessity or certificate of authority. We note in passing that this creates an opportunity for regulators to routinely use BCA methods to ensure smart investment decisions are made for all types of distribution system infrastructure, including traditional assets like substations and transformers. Unfortunately, to the best of our knowledge, this opportunity is unrealized in any of the jurisdictions we examined:

- California requires preapproval for some investments based on voltage levels, but does not require a BCA as part of preapproval requests: "No electric public utility shall begin construction in this state of any electric power line facilities or substations which are designed for immediate or eventual operation at any voltage between 50 kV or 200 kV or new or upgraded substations with high side voltage exceeding 50 kV without this Commission's having first authorized the construction of said facilities by issuance of a permit to construct in accordance with the provisions of Sections IX.B, X, and X1.B of this General Order."[66]

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[64] ICF and EnerNex. (2021). *DTEE grid modernization study 2021-2035: Final draft*. [Appendix VIII to *DTE Electric Company 2021 distribution grid plan: Draft report*]. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000RUqKjAAL

[65] Consumers Energy. (2021). *Electric distribution infrastructure investment plan (2021-25)*. https://www.consumersenergy.com/-/media/CE/Documents/company/electric-generation/ediip-report.ashx. Note that the proposed BCA framework was not comprehensively applied to the 2021 plan. Instead, the document offers an illustrative example of applying the framework to just one portion of the utility's current plan.

[66] California Public Utilities Commission, General Order 131-D.

- Wisconsin requires preconstruction approval of utility investments generally, without a BCA, but projects that fall below specified cost thresholds are entirely exempt from preapproval: "A public utility is exempt from the requirement to obtain a certification or approval of the commission … before beginning a proposed project if …:

  > 1m. The estimated gross cost of the proposed project is not more than one of the following cost thresholds:
  >
  > > a. For an electric public utility whose electric operating revenues in the prior year were less than $5,000,000, the cost threshold is $250,000.
  > >
  > > b. For an electric public utility whose electric operating revenues in the prior year were $5,000,000 or more and less than $250,000,000, the cost threshold is 4 percent of those operating revenues.
  > >
  > > c. For an electric public utility whose electric operating revenues in the prior year were $250,000,000 or more, the cost threshold is $10,000,000."[67]

- Like Wisconsin, Colorado also requires preconstruction review of utility investments, without a BCA, but specifically exempts all traditional distribution system investments: "(a) Expansion of distribution facilities, as authorized in § 40-5-101, C.R.S., is deemed to occur in the ordinary course of business and shall not require a certificate of public convenience and necessity."[68]

C. Long-Term Planning

LCBF methods have been the predominant evaluation tool used for long-term planning processes, including IRP, transmission planning and now also DSP processes, and are likely to remain in that position. However, there is still room within these processes and within an overall LCBF framework for using BCA methods and results to evaluate non-utility-system costs and benefits and improve planning outcomes. It's worth reviewing some of the opportunities and examples seen to date, but first we'll examine in a generic way what these three types of planning processes have in common.

In recent years, some states have begun working toward aligning or integrating their various long-term planning processes. Working toward that goal, the National Association of Regulatory Utility Commissioners and the National Association of State Energy Officials convened the Task Force on Comprehensive Electricity Planning from 2018 to 2021, which identified a standard set of building blocks that can be used to describe a typical DSP, transmission plan or IRP process, as shown in Figure 6 on the next page.[69] Describing

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[67] Wis. Stats. § 196.49(5g)(ar). The statutes further require the commission to adjust these cost thresholds every other year based on an index of public utility industry construction costs.

[68] 4 CCR 723-3-3207.

[69] NARUC-NASEO Task Force on Comprehensive Electricity Planning. (n.d.). *Aligning integrated resource planning and distribution planning — Standard building blocks of electricity system planning processes*. https://pubs.naruc.org/pub/27D273D6-9583-2B07-E555-38B1DB450279

planning processes with these standard building blocks can help states to better align or integrate processes that have historically been disconnected.[70]

Figure 6. Standard building blocks for long-term planning processes

Source: NARUC-NASEO Task Force on Comprehensive Electricity Planning. (n.d.). *Aligning Integrated Resource Planning and Distribution Planning — Standard Building Blocks of Electricity System Planning Processes*

Even if we assume that LCBF tools will anchor this generic planning process, there are several steps (i.e., building blocks) where BCA methods can potentially provide helpful information and shape the outcome. Planning does not have to be solely about minimizing the revenue requirement; decisions can also consider ways to maximize net benefits that may differ from strictly least cost solutions. The most likely steps where BCA can play a role are the following.

Develop forecasts: Forecasts of future load must account for the deployment of DERs and the impacts they have on capacity and energy needs as well as load shapes. This should include the impacts of previously installed DERs that will still be operational in future years, as well as the impacts of DERs that are expected to be deployed in coming years through "natural uptake," already-approved DER programs and future mandatory requirements.[71] However, when we examine these practices more closely, we sometimes find that the load forecast only accounts for levels of DER deployment that result from approved programs and mandatory requirements. This approach will almost always underestimate future DER deployment. Planners can instead use BCA methods to develop exogenous forecasts of DER deployment based on an expectation that DERs will be deployed by customers at levels over and above those resulting from approved programs and mandatory requirements, if and when and where doing so is cost-effective for the customer.[72]

System needs: In a traditional long-term planning process, this step focuses on identifying all the ways in which the current grid will not be sufficient to serve future load — usually because of inadequate generation, transmission or distribution capacity. A more modern approach to planning can expand the focus of this step, using BCA to identify opportunities to increase net benefits, even where there are no forecasted capacity shortfalls. To understand the difference between these two approaches, consider the case of a distribution circuit that has no available hosting capacity for additional distributed generation. In the traditional approach, planners might simply use a load forecast that assumes there will be no additional distributed generation on that circuit. But using BCA

[70] For complete information on the task force and its work products, see National Association of Regulatory Utility Commissioners. (n.d.). *Task force on comprehensive electricity planning*. https://www.naruc.org/taskforce/

[71] By "future mandatory requirements," we mean those cases where utilities are subject to mandatory DER procurement requirements, such as an energy efficiency portfolio standard or a renewable energy portfolio standard with a minimum distributed generation target, even if the programs that the utility will use to meet that standard in future years are unknown today.

[72] In fact, in some states there are laws or regulations *requiring* utilities to procure "all cost-effective energy efficiency." These are the most obvious examples of places or cases where some form of BCA would be necessary for developing the load forecast.

methods, they could instead evaluate whether the benefits of increasing hosting capacity outweigh the costs. In this case, increasing hosting capacity is not a system need but rather an opportunity to increase net benefits. Section V.C.1 below describes an example from California where BCA was used this way.

Identify solutions: BCA can play a big role in assessing potential solutions to identified system needs and opportunities, as well. For starters, planners can use BCA methods to determine if there is any cost-effective DER potential that is not already built into the load forecast and allow that additional potential to compete with other generation resources on an LCBF basis.[73] Section V.C.2 offers an example of this practice from a utility operating in six states. In addition, DERs that are not included in the load forecast can be evaluated as potential NWAs. The most common approach to NWAs is for planners to first identify a default LCBF solution to the identified system need (i.e., a utility investment in transmission or distribution system infrastructure). Then, they identify portfolios of DERs that could potentially alleviate the need for wires investment. And finally, they compare the default solution to the potential NWAs on either an LCBF basis or using BCAs to compare net benefits. Section V.C.3 offers examples from five states of how BCA is being used in NWA proceedings.

Evaluate solutions: This step is the heart of the LCBF approach to long-term planning. Historically, the preferred solution to system needs was normally the least costly solution, based on minimizing the net present value of the revenue requirement, or in exceptional cases a best fit solution that was not technically the least costly. But there may be cases where it is entirely feasible for planners to assess the net benefits of various options that can potentially meet specific needs, based on BCA results, and use that information as part of the criteria for selecting a preferred portfolio of solutions. In essence, this would be akin to using BCA to do the “best fit” part of LCBF.

Implement: Some long-term plans rely on competitive procurement processes for implementing the preferred solutions. The solicitation and review of competitive bids provides yet another opportunity to use BCA to get better results. Once again, the opportunity comes in using net benefits to select winning bids rather than making decisions solely based on least cost criteria.

BCA methods have, in fact, been used in interesting ways in a variety of long-term planning processes, as illustrated by the examples that follow.

[73] In most jurisdictions, utilities are not required to procure all cost-effective DERs, and the load forecast will not be based on an assumption that all cost-effective DERs have been deployed. Rather, the forecast will include assumed amounts such as the amount of energy efficiency needed to comply with an energy efficiency resource standard or the amount of distributed generation that is implied by recent deployment trends or market forecasts. This means it is entirely possible, and in most cases likely, that some level of additional cost-effective DER deployment is potentially available as a resource to meet identified system needs.

1. DSP: Identifying Locational Net Benefit Opportunities

Some of the earliest examples of DSPs arose from proceedings in California. A state law enacted in 2013 required regulated utilities to file distribution resource plans (i.e., DSPs) that identify optimal locations for the deployment of distributed energy resources. To implement this requirement, the California PUC adopted a locational net benefits analysis (LNBA) methodology in 2016, ordered utilities to use the methodology to assess pilot projects in their initial DSPs and formed a working group to advise the PUC on refinements to locational net benefits analysis methods. This is one of the few examples to date of using BCA methods to identify investments that can yield net benefits even where there are no forecasted capacity shortfalls. However, in its final report to the PUC, the working group concluded: "The current LNBA methodology is not yet ready for a system-wide rollout. LNBA methodology ... may be used on a provisional basis in the [DSP] pilots in two defined use cases (i.e., for information purposes, and as a tool to support identification of project deferral)."[74]

2. IRP: Treating Demand-Side Management as a Resource

The utility PacifiCorp, which serves customers in six western U.S. states, uses potential study data to develop supply curves for energy efficiency and demand response resources. The result is a table that shows how much demand-side management is potentially available at various prices, as shown in Table 6 on the next page.[75] This approach acknowledges that there will be more of these resources available if customers are compensated at $100 per MWh than if they are compensated at $50 per MWh, for example. In other words, the amount of demand-side management that is potentially available in each state depends in large part on thinking about how much of the resource would be cost-effective (based on the prevailing test used in each state) at various assumed values of avoided energy costs. So, instead of assuming a fixed amount of demand-side management is cost-effective and including that in the load forecast or assuming a fixed additional amount would be available at a specific fixed cost, the amount that is included in PacifiCorp's preferred resource portfolio can be optimized by allowing demand-side management to compete with other resources to meet future energy and capacity needs.

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[74] Locational Net Benefit Analysis Working Group. (2017). *Locational Net Benefit Analysis Working Group final report*. California Public Utilities Commission Rulemaking 14-08-013 and related matters. https://drpwg.org/wp-content/uploads/2016/07/R1408013-et-al-SCE-LNBA-Working-Group-Final-Report.pdf

[75] PacifiCorp. (2017, April). *2017 integrated resource plan, Volume I*. https://edocs.puc.state.or.us/efdocs/HAA/lc67haa102643.pdf. Note that the first row shows available demand-side management potential at a cost to the utility of $10 per MWh or less. Each subsequent row shows the *additional* potential available as prices rise in $10 increments.

Table 6. Demand-side management supply curve (potential in MWh by cost bundle)

Bundle	California	Idaho	Oregon	Utah	Washington	Wyoming
<= 10	27,146	91,695	610,445	972,850	118,725	211,694
10 - 20	8,772	37,868	186,280	869,625	43,968	91,745
20 - 30	10,126	45,728	688,346	588,821	79,553	131,056
30 – 40	14,956	38,417	334,064	411,008	52,584	342,310
40 – 50	9,775	52,426	229,316	483,287	65,569	193,275
50 - 60	4,341	36,941	77,508	530,396	87,588	151,994
60 – 70	17,388	15,456	5,469	455,608	61,885	64,025
70 – 80	9,417	25,123	134,301	220,392	42,658	107,615
80 – 90	5,154	10,915	100,947	108,222	26,837	49,829
90 – 100	10,254	16,337	326,823	73,579	34,445	23,983
100 – 110	11,845	15,402	123,499	73,895	40,142	83,812
110 – 120	5,672	5,813	84,733	81,351	25,457	20,135
120 – 130	2,185	1,895	31,830	135,611	13,624	8,299
130 – 140	1,180	2,936	243	96,048	12,904	7,132
140 – 150	3,650	9,583	8,074	102,483	20,565	19,236
150 - 160	5,327	13,075	5,370	171,330	1,751	12,537
160 – 170	2,948	2,079	11,767	79,327	11,433	31,246

Source: PacifiCorp. (2017). *2017 Integrated Resource Plan, Volume I*

3. DSP: Evaluating NWAs

Because few states have adopted DSP requirements to date, it is a stretch to suggest that best practices exist. We simply note that it is common where such requirements currently exist for BCA methods to play a role in evaluating NWAs. We examine several examples below, paying attention to what the triggers are for when NWAs must be evaluated in the DSP process and how benefits and costs are to be assessed. The examples illustrate a variety of approaches.

a) Rhode Island

Rhode Island was one of the first states to require a utility to consider NWAs. In 2006, regulators adopted a system reliability procurement policy that requires the only major investor-owned utility in the state to file plans every three years that have most of the elements of a DSP. The plans must consider NWAs — including energy efficiency, specifically — whenever an identified system need meets all the following criteria:

- Is not based on an asset condition.
- Would cost more than $1 million.
- Would require no more than a 20% reduction in load to defer.
- Would not require investment in a “wires solution” for at least three years.

Based on these guidelines, the utility National Grid first proposed an NWA pilot project as early as 2011 to defer the upgrading of a substation through a combination of energy efficiency and demand response. Related policies for NWAs, and the use of BCA to evaluate NWAs, have continued to evolve ever since.

In 2017, a stakeholder report laid out a BCA framework identifying categories and drivers of benefits and costs in an effort to help the commission identify the costs and benefits that can be evaluated across any and all programs or policies, where physically on the system these costs and benefits can be quantified, how to measure costs and benefits and the visibility required to measure them.[76] The report also describes several purposes and contexts in which the framework can be used:

- **DER programs and technologies, such as energy efficiency programs, demand response programs, distributed generation resources, storage and net metering programs.** In this case, a single program or resource is compared in isolation with a reference future scenario. This type of analysis would be applied in the context of approving utility investments for a particular type of DER or technology, which is how energy efficiency programs are assessed.
- **Conventional distribution projects.** The framework can be used to analyze conventional investments, including those to maintain, upgrade or expand the distribution system. This type of analysis might happen in the context of a rate case, where the utility is proposing to recover costs from investments in conventional distribution technologies.
- **Grid modernization projects, including advanced metering functionality, other customer-facing grid modernization technologies and grid-facing technologies.** This type of analysis might be applied when a utility is seeking guidance on whether to make proposed grid investments or in a rate case where the utility is seeking cost recovery.
- **Rate designs.** The framework can be used to evaluate different rate design proposals.
- **Comparison across resources, technologies or policies.** The framework can be used to compare different resources — such as different types of DERs — to each other, to compare conventional distribution projects with DERs in the form of an NWA (this is the approach currently used in system reliability procurement), or to compare multiple resource options in a system optimization analysis.

The PUC subsequently adopted the BCA framework proposed in the 2017 stakeholder report and directed the utility to reference each category within the framework in any future rate design proposals. In addition, the commission said that any new proposed programs or capital investment that will impact distribution rates should also reference the BCA framework.

In September 2018, the commission adopted revised system reliability procurement standards (Docket 4684) requiring the company to integrate the analysis of NWAs into its planning functions by using analytical tools to evaluate the costs and benefits of traditional and NWA solutions. In August 2020, the commission revised its “least cost procurement standards” (Docket 5015). Section 4.4.A of these standards requires the utility to identify

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[76] Docket 4600 Stakeholder Working Group. (2017). *Report to the Rhode Island Public Utilities Commission*. http://www.ripuc.ri.gov/eventsactions/docket/4600-WGReport_4-5-17.pdf

distribution projects that meet certain screening criteria for potential NWAs that reduce, avoid or defer distribution wires investments. The standards also require the company to submit, every three years in November, a three-year plan that includes:

- A proposed performance incentive mechanism.
- Proposed screening criteria for system reliability procurement investments.
- Strategies that enhance procurement of these investments.
- A procurement process.
- An evaluation process and criteria for system reliability procurement investments.
- A proposed annual reporting plan for implementation updates.

b) New York

As part of its comprehensive Reforming the Energy Vision (REV) initiative, regulators at the New York Public Service Commission decided that the five-year capital investment plans that utilities had been filing prior to 2015 were not sufficient for achieving the state's energy goals. The commission, in its order in Case 14-M-0101, decided that requiring utilities to file distributed system implementation plans (DSIPs) with transparent assumptions and methodologies would be "a central component of REV implementation."[77]

The PSC recognized from the outset that NWAs would play a role in the planning process. The 2015 order stated:

> "Staff recommended as a near-term implementation item that utilities should publish information regarding portions of their system that need upgrades but are amenable to non-wires alternatives. As an interim filing prior to the initial DSIP, each utility should identify at least one such potential project, including the nature, scale, and timing of the need and the geographic area affected, with enough specificity for potential market participants to develop proposals. These filings will be made not later than May 1, 2015 …"

In the ensuing years, New York utilities have collaborated in many ways to implement DSIP requirements. One key development was the idea of using suitability criteria to make decisions about when to solicit NWAs. Developing NWAs for every utility investment was thought by all stakeholders to be impractical and far too costly. So, New York's utilities jointly proposed suitability criteria in 2016 that can be used to identify the investments where there is realistic potential for NWAs to yield significant net benefits. The suitability criteria jointly proposed by the utilities, which screen opportunities based on the type of utility investment needed, the timeline and the cost, are summarized in Table 7.[78]

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[77] New York Public Service Commission, Case 14-M-0101, Order on February 26, 2015, adopting regulatory policy framework and implementation plan. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B0B599D87-445B-4197-9815-24C27623A6A0%7D.

[78] Joint Utilities. (2016). *Supplemental distributed system implementation plan*. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B3A80BFC9-CBD4-4DFD-AE62-831271013816%7D

An example from one New York utility is shown in Table 8.[79]

Table 7. NWA suitability criteria proposed by Joint Utilities of New York

Criteria	Potential Elements Addressed
Project Type Suitability	• Project categories and their relative applicability for NWA • Guidelines or procedures for the application of suitability based on project type
Timeline Suitability	• Minimum lead times to need date for projects based on project size and/or other criteria • Guidelines or procedures for the application of lead time criteria
Cost Suitability	• Cost floors for projects based on project size and/or other criteria • Guidelines or procedures for the application of cost criteria

Source: Joint Utilities. (2016). *Supplemental Distributed System Implementation Plan, Table IV-4*

Table 8. Consolidated Edison suitability criteria

Criteria	Potential Elements Addressed	
Project Type Suitability	Project types include Load Relief or Load Relief in combination with Reliability.	
Timeline Suitability	**Large Project** (Projects that are on a major circuit or substation and above)	• 36 to 60 months
	Small Project (Projects that are feeder level and below)	• 18 to 24 months
Cost Suitability	**Large Project** (Projects that are on a major circuit or substation and above)	• No cost floor
	Small Project (Projects that are feeder level and below)	• Greater than or equal to $450,000

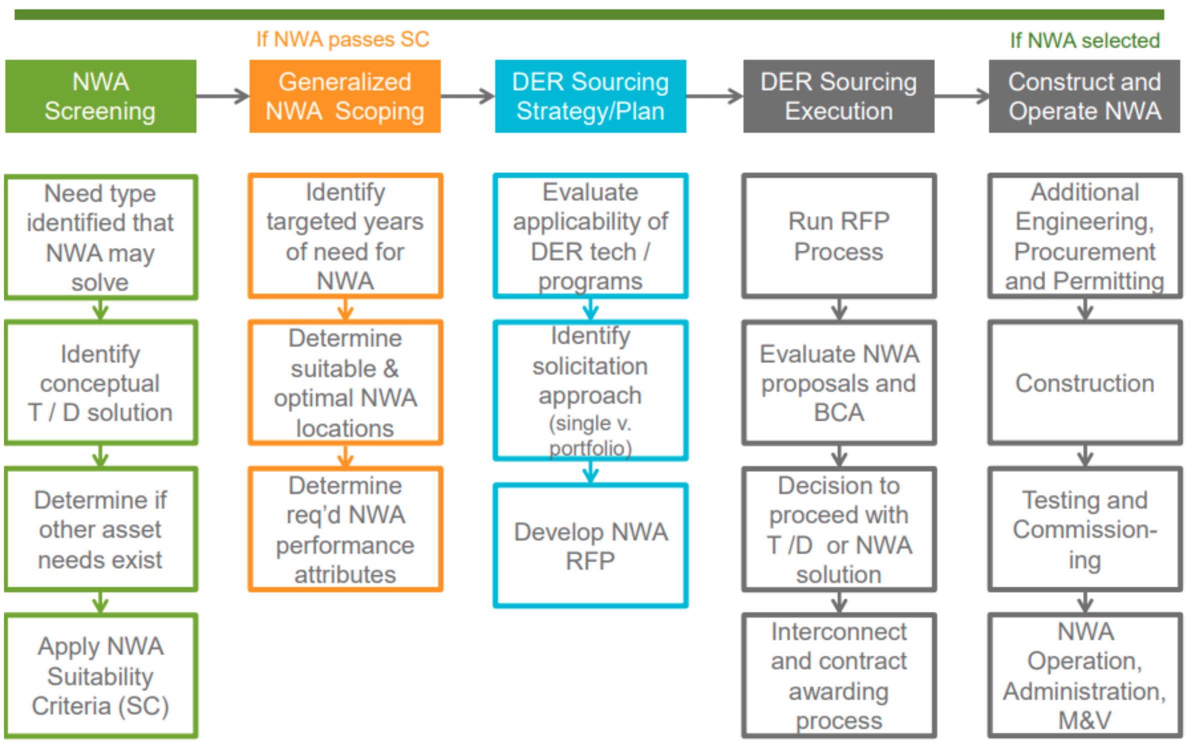
Source: Consolidated Edison. (2020). *Distributed System Implementation Plan*

[79] Consolidated Edison. (2020). *Distributed system implementation plan*.
https://documents.dps.ny.gov/search/Home/ViewDoc/Find?id=%7B8ED58C88-FB25-4E7E-BB66-A9DA9FCDEEDD%7D&ext=pdf

While the concept of suitability criteria was under development, related work on BCA methods was proceeding on a parallel path. In its initial REV order in 2015, the New York PSC acknowledged the value of using BCAs as an evaluation tool and ordered staff to propose a BCA framework that could be used for evaluating NWAs and other proposals made within the scope of REV-related proceedings. The commission eventually adopted a BCA framework, based on staff recommendations, in a 2016 order.[80]

Figure 7 shows how Avangrid (which owns two New York utilities, NYSEG and RG&E) integrates NWAs into its distributed system implementation plan processes and indicates where in the process suitability criteria and BCA methods are used.[81]

Figure 7. Avangrid's NWA process, identifying role of suitability criteria and BCA



DeAngelo, M. (2019, May 29). *Stakeholder Engagement Webinar: DER Sourcing / Non-Wires RFP Process*

[80] New York Public Service Commission, Case 14-M-0101, Order on January 21, 2016, establishing the benefit cost analysis framework. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF8C835E1-EDB5-47FF-BD78-73EB5B3B177A%7D

[81] DeAngelo, M. (2019, May 29). *Stakeholder engagement webinar: DER sourcing / non-wires RFP process* [Presentation], slide 33. New York State Electric & Gas, Rochester Gas and Electric Corp. https://jointutilitiesofny.org/sites/default/files/Joint-Utilities-of-New-York-DER-Sourcing-Stakeholder-Webinar-5.29.19.pdf

c) Minnesota

The Minnesota PUC requires the state's largest electric utility, Xcel Energy, to file integrated distribution plans, which is simply another name for a DSP. The commission adopted filing requirements in August 2018.

The scope of integrated distribution plans in Minnesota is broad: Xcel is required to plan for, report and discuss distribution system spending in the following categories:

- Age-related replacements and asset renewal.
- System expansion or upgrades for capacity.
- System expansion or upgrades for reliability and power quality.
- New customer projects and new revenue.
- Grid modernization and pilot projects.
- Projects related to local (or other) government requirements.
- Metering.
- Other.

In its 2019 integrated distribution plan, Xcel reported:

> "To help rank projects and perform cost-benefit analyses, we use an internally-developed Microsoft Access Database tool called WorkBook. This tool allows us to input our distribution system risks along with the proposed mitigations and their indicative costs that are intended to solve those risks. Algorithms in the tool result in a ranking score that helps to incorporate these projects in the budgeting process. The primary risk inputs that planning engineers develop for entry into WorkBook includes N-0 and N-1 risks for feeders and substation transformers. However, other inputs such as asset age and historical failures are also considered, which further aids prioritization of the projects as part of the budget process."[82]

Xcel's 2019 integrated distribution plan includes the results of cost-benefit analyses for several proposed investments: (1) an advanced planning tool (software); (2) a grid modernization investment proposal, called Advanced Grid Intelligence and Security; and within that proposal, an analysis specifically for AMI.

With respect to NWAs, Xcel was also required to provide information on the following:

- Project types that lend themselves to NWAs (i.e., load relief or reliability).
- A timeline that is needed to consider NWAs.
- Cost threshold of any project type that should trigger an NWA review.
- A proposed screening process to determine when NWAs are considered.

Xcel used an NWA screening process that focused on capacity projects scheduled for years three through five of the integrated distribution plan. Xcel reported that capacity projects

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[82] Xcel Energy. (2019). *Integrated distribution plan (2020-2029)*. https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={90E1276E-0000-C617-9E33-75094BC2422E}&documentTitle=201911-157133-01

needed in the first two years of the plan, mandated projects and asset health and reliability projects were less suitable for NWAs or not suitable at all.

The cost threshold was established in an earlier PUC order: For all distribution system projects in the filing year and the subsequent five years that are anticipated to have a total cost of greater than $2 million, Xcel is required to provide a detailed discussion of the project and an analysis of how NWAs compare in terms of viability, price and long-term value. Using this screening process and cost threshold, Xcel identified nine projects that were evaluated for NWAs in the integrated distribution plan. The analysis of these potential NWAs was not a comprehensive benefit-cost analysis, considering the fact that Minnesota normally used multiple cost-effectiveness tests for BCAs. Rather, in the Xcel integrated distribution plan, the cost of each potential NWA was compared to the cost of the project for which it was a potential alternative — which yields similar results to a UCT but no information for other cost tests.

d) Nevada

In Nevada, the PUC implements a state law that requires the state's two investor-owned utilities (which are owned by the same holding company and do business as NV Energy) to file distributed resources plans, yet another variation on a DSP. The regulations governing distributed resources plans (Nevada Administrative Code §704.9237) prescribe a central role for BCA, including requirements to:

- Identify and evaluate the locational benefits and costs of DERs.
- Propose and evaluate procurement mechanisms that maximize locational benefits and minimize the incremental cost of DERs.
- Use a locational net benefit analysis to compare utility infrastructure upgrade solutions and DER solutions to forecasted transmission and distribution system constraints.
- Recommend new cost-effective DERs, sourcing of DER solutions and utility infrastructure upgrade solutions that have been determined to be the preferred solution to grid constraints based on the locational net benefit analysis.

Within the distributed resources plans that NV Energy filed in 2019, the utility describes "suitability criteria" (summarized in Table 9 on the next page) that were used to determine when NWAs would be evaluated as potential solutions to identified grid needs.[83] The suitability criteria reflect NV Energy's judgment that NWAs were most promising as alternatives to traditional utility infrastructure investments in cases where a reduction or shift in load could eliminate a near-term thermal, voltage or reliability constraint.

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[83] NV Energy. (2019). *NV Energy's distributed resource plan*. https://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2019-4/37375.pdf

Table 9. NWA suitability/screening criteria used by NV Energy

Non-Wires Alternative Suitability/Screening

		Yes	No	Comment
Critical Suitability Criteria				
A.	Is the constraint anticipated to occur between January 1, 2020 and December 31, 2025?			
B.	Is the constraint based upon thermal loading, voltage, or reliability reasons where a reduction in peak demand loading or energy consumption, or load shifting, on the transmission or distribution facilities involved would eliminate or defer the constraint?			
Red Flag Suitability Criteria				
C.	Is the wired solution still within the planning or design stage, with no major equipment on order, received, or installed?			
D.	Is it reasonable to assume at this time that a Distributed Energy Resources solution will be reliable and safe (i.e., non-critical customers) in this location on the grid?			
E.	Is it reasonable to assume at this time that local residents would accept a Distributed Energy Resources solution in this area?			
F.	Is it reasonable to assume at this time that local governmental agencies would accept a Distributed Energy Resources solution in this area?			
G.	Is it reasonable to assume at this time that there are no environmental concerns which would preclude a Distributed Energy Resources solution in this area?			
H.	Is it reasonable to assume at this time that a Distributed Energy Resources solution would be able to be physically sited in this area?			

1. ***If all of the responses above are Yes, then proceed with the Non-Wires Alternative analysis.***

2. ***If either of the responses in A or B are No, then provide appropriate comment(s) and do not proceed with the Non-Wires Alternative analysis.***

3. ***For the questions in C through H, No responses should only be initially entered if the user has good reason supported by personal knowledge or experience. If any of the responses for C through H are initially entered as No, initiate a discussion with appropriate NV Energy personnel to discuss the specifics of the situation and verify the response. Following this discussion, if it is appropriate for all the responses for C through H to be Yes, proceed with the Non-Wires Alternative analysis, documenting in the Comments area where any responses were changed and why. Do not proceed with the Non-Wires Alternative analysis if any one of the initial No responses presents a supportable reason to not continue. Document the discussions in the Comments area and via a separate attachment if necessary.***

Source: NV Energy. (2019). *NV Energy's Distributed Resource Plan*

e) Michigan

In 2018, the Michigan PSC ordered the state's three largest electric utilities to file DSPs. The order did not specify how utilities should use BCA methods to evaluate NWAs. In its most recently filed DSP, the utility DTE explains at length how it used BCA methods to score and prioritize potential capital programs for its distribution system.[84] DTE combined quantitative cost and benefit data with qualitative assessments of "safety, load relief, regulatory compliance and major event risk benefits." The various quantitative and qualitative benefits of each program were combined into an index. In addition, DTE's DSP indicates that the utility used cost-effectiveness screening to assess NWA pilots "to ensure that the NWA would be less costly than traditional grid solutions, such as a substation upgrade."

The 2022 *Energy Storage Roadmap for Michigan* recommends that the commission establish an appropriate benefit-cost analysis framework for NWAs, including storage resources, such that storage is considered on an equal footing with other investments.[85]

[84] DTE Electric Company. (2021). *2021 distribution grid plan draft report*. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000RUqKjAAL

[85] Institute for Energy Innovation. (2022). *Energy storage roadmap for Michigan.* Michigan Department of Environment, Great Lakes and Energy. https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Programs/MMD/Energy/roadmap/IEI_EnergyStorageReport_FINAL-web.pdf?rev=07068712a96741e7bd18bbdef2935657

f) Oregon

Oregon is a newcomer to DSP, with rules adopted by the utility commission for the first time in December 2020. The first utility DSPs were filed in 2021. Oregon is taking a staged approach to implementing DSP requirements. For the plans filed in 2021, utilities were not required to systematically evaluate NWAs as alternatives to solve every grid need or even those needs that meet "suitability criteria." Instead, the Oregon commission directed utilities in their initial DSPs to:

> "Evaluate at least two pilot concept proposals in which non-wire solutions would be used in the place of traditional utility infrastructure investment. The purpose of these pilots is to gain experience and insight into the evaluation of non-wire solutions to address priority issues such as the need for new capacity to serve local load growth, power quality improvements in underserved communities ...
>
> "In its pilot concept proposals, a utility should discuss the grid need(s) addressed, various alternative solutions considered, and provide detailed accounting of the relative costs and benefits of the chosen and alternative solutions. The pilot concept proposals should be reasonable and meet the Guidelines, even if the individual proposal may not be cost-effective ...
>
> "As non-wires solutions are constructed and their performance in serving grid needs and deferring grid upgrades is better understood, valuation methods may be needed to compare non-wires solutions to traditional utility hardware (for example, substation upgrades, additional transformer deployment)."[86]

4. Transmission Plans: Evaluating Nontransmission Alternatives

Finally, we consider the potential use of BCA methods in transmission plans. Long-term planning for the transmission system occurs at both the state and federal levels. States do indeed regulate the transmission investments of transmission-owning utilities, but none that we are aware of require the filing of transparent, utility-specific, long-term transmission plans. In contrast, at the regional level, RTOs and ISOs, like PJM and MISO, develop mostly transparent, long-term transmission plans that aggregate the plans of multiple transmission-owning utilities. These regional transmission plans are subject to FERC regulation.

FERC Order 1000 requires RTOs and ISOs, as part of their regional transmission planning processes, to consider any alternatives to transmission that are proposed by a party to the process. Nontransmission alternatives (NTAs) can potentially include DERs or other

[86] Oregon Public Utility Commission, Docket No. UM 2005, Order No. 20-485 on December 23, 2020, Appendix A, Attachment 1. https://apps.puc.state.or.us/orders/2020ords/20-485.pdf

distribution system investments. In the same way that BCA can be used to evaluate nonwires alternatives in an IRP or a DSP, it could be used to evaluate NTAs in a regional transmission plan. However, in practice, this is a hypothetical possibility. To begin with, Order 1000 makes clear that if no NTAs are proposed by any party, the RTOs and ISOs are not required to proactively examine any such alternatives. Next, almost no NTAs have been proposed to date in any of those processes. And perhaps most importantly, it must be understood that Order 1000 does not require RTOs and ISOs to evaluate the benefits of NTAs, so the evaluation of any proposed NTAs is likely to focus only on minimizing utility system costs rather than maximizing net benefits. In summary, we have yet to see an example where BCA methods were used to assess net benefits of a proposed NTA and are not expecting to see any under the current FERC policy.

D. Rate Cases/Rate Design

Over the past decade, BCA has increasingly been used in rate cases or other proceedings where regulators establish or approve retail rates. We've already noted in earlier sections of this reference report how BCA is sometimes used in rate cases when utilities want assurances that they will be allowed to recover in rates the costs of specific, planned utility investments in infrastructure assets like AMI. Those examples will not be repeated here. But BCA can also be used to determine appropriate rates for customers with DERs or it can be used to determine whether past utility investment decisions were prudent.

1. DER Compensation

BCAs have been used in many states to design or evaluate the compensation provided to customers with DERs via retail tariffs. These analyses are typically introduced into proceedings when a utility or intervener proposes a new rate design or a brand-new tariffed DER program offering. The impetus for these analyses is often an assertion by utilities or other parties that cross-subsidies are occurring (as would be the case if the compensation provided to the DER customer exceeds the value to the utility). Or, in other cases, the BCA is triggered by a desire to design a tariff where compensation for energy from customer DERs is based explicitly on the value of that energy. The most common examples of using BCA for rate design have evaluated net energy metering tariffs, "value of solar" tariffs or other compensation mechanisms for customers with distributed generation resources.

In 2018, the consultancy ICF prepared a report that reviewed and summarized BCA studies from 15 states that focused on distributed generation tariffs.[87] ICF divided the studies into three categories, as shown in Table 10 on the next page,[88] depending on the trigger or purpose of the study. Six studies were initiated to determine whether existing net metering tariffs were cost-effective or whether they created a cost shift to customers not on the tariff. Seven studies sought to determine the value (i.e., the monetary benefits) of distributed generation as part of an effort to design a value of solar tariff or a successor

[87] ICF. (2018). *Review of recent cost-benefit studies related to net metering and distributed solar*. U.S. Department of Energy. https://www.energy.gov/sites/default/files/2020/06/f75/ICF%20NEM%20Meta%20Analysis_Formatted%20FINAL_Revised%208-27-18.pdf

[88] ICF, 2018.

to the existing net metering tariff. And two of the studies sought to quantify the value of all DERs (not just distributed generation) using a consistent framework, again to support the design of a universal retail tariff for customers with DERs.

Table 10. Types of BCA studies reviewed by ICF

Type of Study	Number Reviewed	Description of Study Type	States/Prepared by
NEM Cost-Benefit Analysis	6	Evaluate costs and benefits of a NEM program; study whether NEM is creating a cost-shift to non-participating ratepayers.	▪ Arkansas (Crossborder) ▪ Louisiana (Acadian) ▪ Mississippi (Synapse) ▪ Nevada (E3) ▪ South Carolina (E3) ▪ Vermont (VT PSD)
VOS/NEM Successor	7	Discuss the impacts of NEM and consider options for reforming or realigning rates with the net impacts of distributed solar in ways that go beyond net metering.	▪ District of Columbia (Synapse) ▪ Georgia (Southern Company) ▪ Hawaii (CPR) ▪ Maine (CPR) ▪ Minnesota (CPR) ▪ Oregon (CPR) ▪ Utah (CPR)
DER Value Frameworks	2	Reflect the elements of regulatory activities that look at VOS as part of a more precise approach within a framework that can be applied to other DERs.	▪ California LNBA (CPUC) ▪ New York BCA (Department of Public Service Staff)

Source: ICF. (2018). *Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar*

As Table 11 on the next page shows, some of the studies reviewed by ICF used one or more of the traditional cost-effectiveness tests.[89] Other studies did not use a traditional test but still utilized BCA methods. Details on the approach taken in each study, including the categories of benefits and costs assessed, can be found in the ICF report.

[89] ICF, 2018.

Table 11. Cost tests used in BCA studies reviewed by ICF

			Cost-Effectiveness Test				
State	**Year**	**Prepared by**	**PCT**	**UCT**	**RIM**	**TRC**	**SCT**
Arkansas	2017	Crossborder	√	√	√	√	√
District of Columbia	2017	Synapse		√			√
Georgia	2017	Southern Company					
California	2016	CPUC	√		√		
Nevada	2016	E3	√	√	√	√	√
New York	2016	NY DPS		√	√		√
Hawaii	2015	CPR					
Louisiana	2015	Acadian					
Maine	2015	CPR					
Oregon	2015	CPR					
South Carolina	2015	E3			√		
Minnesota	2014	CPR					
Mississippi	2014	Synapse	√			√	
Utah	2014	CPR					
Vermont	2014	PSD					

Source: ICF. (2018). *Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar*

2. Retrospective Review of Prudence

Utility investments in distribution system infrastructure may occasionally be reviewed for prudence as part of a rate case. Prudence reviews do not typically involve a formal BCA, nor are all the potential alternatives to the investment reviewed to ensure that the least cost/best fit option was selected — especially if the utility investment is not challenged by any parties to the rate case. Disallowances for imprudent investments are always possible, but at best they change how costs are or are not recovered; after-the-fact review of prudence will not change investment decisions.

VI. How Might BCA Be Used to Optimize Investment?

Having demonstrated that there are many types of proceedings in which a BCA might prove useful, we turn now to the question of how to conduct a BCA. Fortunately, there is a long and rich tradition of papers, reference reports and regulatory decisions addressing this question. Rather than summarizing the accumulated knowledge of all that work, we will instead cite key reference reports that cover the essential ground, and then focus on some of the crucial decision points and challenges regulators may face as they shape BCA policies for their jurisdictions.

A. Key Reference Reports

As we noted in Section III of this reference report, the *California Standard Practice Manual for Economic Analysis of Demand-Side Programs and Projects* built a foundation for BCA practices that has been adapted and used virtually everywhere in the United States for decades. The CSPM is our first key reference report for using BCA methods.

The Regulatory Assistance Project published a report in 2013, *Recognizing the Full Value of Energy Efficiency*, that might be useful as a second key reference report.[90] This report offers details not found in the CSPM on how energy efficiency programs can generate many types of benefits that are often overlooked or excluded from BCA studies.

Although several reports and utility commission decisions over the past decades attempted to expand CSPM concepts and apply them to other DERs — most commonly, demand response programs — the publication in 2020 of the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* was a watershed moment. We view the NSPM as the essential document for anyone interested in understanding how to apply BCA methods to DERs. More than that, it points the way toward using BCA to assess almost any kind of utility investment. In addition, the same team that created the NSPM published a companion document in 2022 that provides more details on methods, tools and resources for conducting BCA studies.[91] We will rely heavily on these two documents in the next section of this reference report, where we examine crucial decision points for regulators.

B. Crucial Decisions

We will now examine in more detail some of the decisions that can strongly influence the extent to which a BCA furthers the public interest and leads to better investment decisions. This reference report cannot tell regulators the “right” answers to these questions, but we will suggest some factors for regulators to consider as they develop their own answers and, where possible, note some examples of commissions that are trying to tackle these issues. The crucial questions are:

- In what proceedings will we use BCA methods?
- Who will conduct BCAs?
- How will we engage stakeholders?
- Which cost-effectiveness test(s) will we use?
- How will we use BCA results to make decisions?

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[90] Lazar, J., & Colburn, K. (2013). *Recognizing the full value of energy efficiency*. Regulatory Assistance Project. https://www.raponline.org/knowledge-center/recognizing-the-full-value-of-energy-efficiency/

[91] National Energy Screening Project. (2022). *Methods, tools and resources: A handbook for quantifying distributed energy resource impacts for benefit-cost analysis*. https://www.nationalenergyscreeningproject.org/resources/quantifying-impacts/

1. In What Proceedings Will We Use BCA Methods?

BCA methods can point the way to smarter utility investment decisions, but a BCA can also be complex, costly and time consuming. State regulators can protect the public interest and the interests of ratepayers by encouraging or requiring parties to use state-of-the-art BCA methods when and where doing so is appropriate. The fundamental question for regulators will always be, perhaps ironically, whether the benefits of doing a BCA will exceed the costs. This will always be a judgment call, since the two variables in that equation can never be known until the BCA itself is completed. In summary, this reference report cannot tell regulators when they “should” require BCAs. Instead, we suggest that regulators consider opening a proceeding or hosting a workshop to consider this specific question in the broadest sense — that is, to consider what types of proceedings are suitable for using BCAs. Or regulators can pose the question in specific dockets where BCA methods might be used and solicit responses from the parties.

Regulators in some states have hosted workshops with presentations from invited subject matter experts to explore the question of when and how to use BCAs in specific regulatory proceedings — for example, a DSP investigation in Illinois, a transportation electrification docket in Oregon, a distribution planning workgroup in Michigan and a grid modernization initiative in New Mexico.

2. Who Will Conduct BCAs?

As many of the examples cited above indicate, utilities will sometimes present regulators with a BCA they completed or a contractor completed on their behalf. But in other cases, the regulators themselves may come to appreciate that a BCA would be helpful in making decisions, and a key question then becomes, whom should they direct to do the work and who will oversee it? The answers could involve a utility, a contractor, commission staff or another state agency. Furthermore, the PSC might consider ordering a utility to provide data and otherwise cooperate with a party to a proceeding that wishes to complete its own BCA and submit it into the record.

On this question, the bulk of the experience around the country originates with evaluations of energy efficiency program BCAs. A 2020 review of energy efficiency evaluation practices in 44 U.S. jurisdictions found that contractors most often conducted BCAs, as shown in Table 12 on the next page,[92] and most often under the supervision of utilities, as shown in Figure 8.[93]

[92] York, D., Cohn, C., & Kushler, M. (2020). *National survey of state policies and practices for energy efficiency program evaluation*. American Council for an Energy-Efficient Economy. www.aceee.org/research-report/u2009

[93] York et al., 2020.

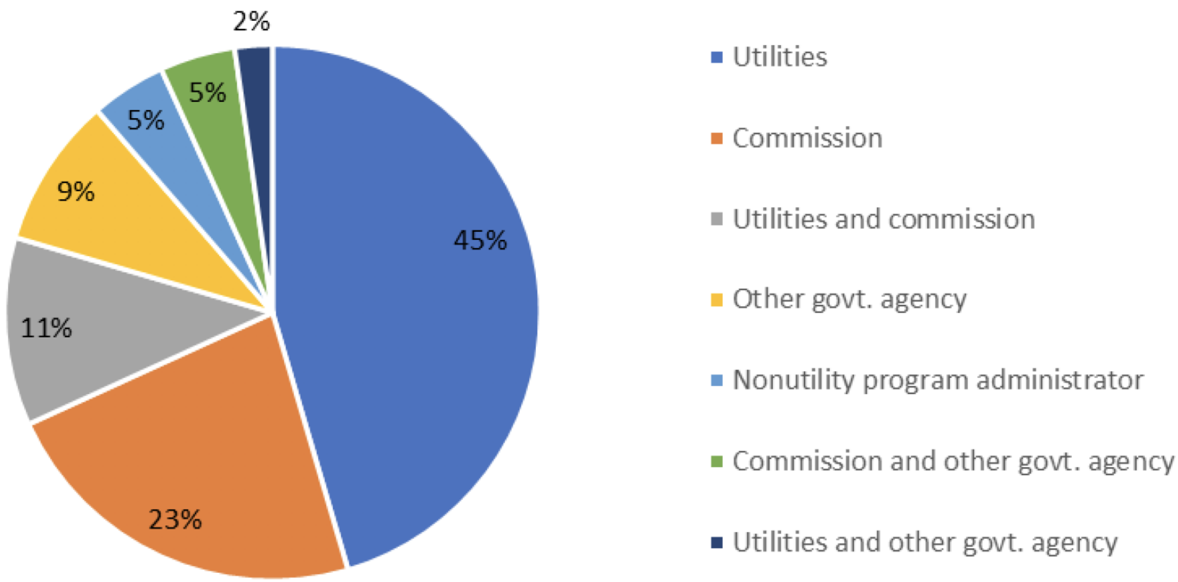
Table 12. Who conducts energy efficiency program evaluation BCAs?

Who conducts the actual evaluation studies?		
Utility staff	14%	6
State agency staff	9%	4
Independent contractors	80%	35
		n=44

Some states provided multiple responses.

Source: York, D., Cohn, C., & Kushler, M. (2020). *National Survey of State Policies and Practices for Energy Efficiency Program Evaluation*

Figure 8. Who oversees energy efficiency program evaluation BCAs?



Source: York, D., Cohn, C., & Kushler, M. (2020). *National Survey of State Policies and Practices for Energy Efficiency Program Evaluation*

3. How Will We Engage Stakeholders?

There is considerable variability among the states in how stakeholders have been allowed to participate in developing, contributing to or reviewing BCAs. In some states, the answer to this question has even varied across different types of proceedings.

Our research finds that it is standard practice to allow stakeholders to review and comment on filed BCA results before regulators make a final decision, but regulators need to also think about whether BCA results will be presented in a sufficiently detailed and transparent manner for stakeholders to meaningfully review them.

Without belaboring the many details, some of the other key aspects of this decision revolve around whether stakeholders will be participants or spectators in or completely excluded from the following key steps that occur before a BCA is completed and results are filed at the PSC:

- Designing or deciding on the cost-effectiveness test(s) that will be used.
- Choosing scenarios, portfolios or test cases that will be evaluated.
- Selecting BCA input data sources or assumptions.

In several jurisdictions, task forces or working groups have been established that allow many parties to play an active role, as full participants, in energy efficiency potential studies, program plans and evaluations. To name just two examples, the Northwest Power and Conservation Council established the multiparty Regional Technical Forum (https://rtf.nwcouncil.org/) to help quantify the costs and benefits of energy efficiency measures. The results are used by utilities and regulators across a four-state region. And in 2013, the Arkansas PSC ordered the creation of an ongoing multistakeholder group that eventually came to be called the PWC, or Parties Working Collaboratively:

> "The Commission therefore proposes that, under the leadership of Staff, the Utilities and the stakeholders should select and engage a facilitator with extensive experience in the development of utility EE programs to manage collaborative resolution of the issues described below. The CPI Collaborative would aim to reach consensus on each issue addressed, make a record of its decisions for reporting to the Commission, and provide for minority/dissenting reports to the Commission on issues not resolved by the parties."[94]

Although these two examples apply only to energy efficiency programs, there is no reason why stakeholders could not or should not be proactively involved in decisions about how to conduct BCAs for other investment decisions.

4. Which Cost-Effectiveness Test(s) Will We Use?

As we explained in Section III, the question of whether an investment is cost-effective depends on the perspective from which costs and benefits are tallied. Different tests evaluate cost-effectiveness from different perspectives. For the purposes of reviewing energy efficiency programs, most states have chosen to use one test as their primary test for making decisions, even though they often review BCA results from more than one perspective. However, many states have not decided on a primary cost test that applies to other DERs, let alone all DERs or all types of distribution system investments.

[94] Arkansas Public Service Commission, Docket No. 13-002-U, Order No. 1 on January 4, 2013. http://www.apscservices.info/pdf/13/13-002-u_1_1.pdf

One of the most consequential decisions regulators must make for any proceeding in which they will request BCA results is to decide on a primary cost test. Table 13 shows the BCA results using different cost tests for a hypothetical EV program. In this example, the hypothetical jurisdiction has enacted an economywide greenhouse gas reduction goal but no other policies relevant to EVs. As the table indicates, the question of whether this EV program is cost-effective depends on the test used. It is highly cost-effective under an SCT, slightly cost-effective under the JST, not quite cost-effective under a TRC and not at all cost-effective under a UCT.

Table 13. Net costs of a hypothetical EV program under different cost tests

Impacted Party	Impact Category	Cost Impact	UCT	TRC	SCT	JST
Electric Utility System	Generation	$ 1,150,000	$1,150,000	$ 1,150,000	$ 1,150,000	$ 1,150,000
	Transmission	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000
	Distribution	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000
	Other	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000
Host Customer	Host Contribution	$ 200,000		$ 200,000	$ 200,000	$ 200,000
	Other Fuels	$(1,500,000)		$(1,500,000)	$(1,500,000)	$(1,500,000)
Other Fuel Systems	Capacity	$ (50,000)			$ (50,000)	
	Other	$ (25,000)			$ (25,000)	
Society	Climate/GHG	$ (50,000)			$ (50,000)	$ (50,000)
	Other	$ (25,000)			$ (25,000)	
		NET COST	$1,325,000	$ 25,000	$ (125,000)	$ (25,000)

We believe that regulators will find no better source of guidance in making decisions about BCA policies than the NSPM. The manual offers regulators a set of principles, shown in Table 14 on the next page, that can guide their selection of a cost test and their decisions on many detailed questions about how to apply BCA methods.[95]

95 National Energy Screening Project, 2020.

Table 14. Fundamental BCA principles

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

Source: National Energy Screening Project. (2020). *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*

The NSPM also describes a clear five-step process regulators can use to design their own tailor-made jurisdiction-specific cost test, as shown in Table 15.[96]

Table 15. Steps in developing a jurisdiction-specific cost test

STEP 1	**Articulate Applicable Policy Goals** Articulate the jurisdiction's applicable policy goals related to DERs.
STEP 2	**Include All Utility System Impacts** Identify and include the full range of utility system impacts in the primary test, and all BCA tests.
STEP 3	**Decide Which Non-Utility System Impacts to Include** Identify those non-utility system impacts to include in the primary test based on applicable policy goals identified in Step 1: • Determine whether to include host customer impacts, low-income impacts, other fuel and water impacts, and/or societal impacts.
STEP 4	**Ensure that Benefits and Costs are Properly Addressed** Ensure that the impacts identified in Steps 2 and 3 are properly addressed, where: • Benefits and costs are treated symmetrically. • Relevant and material impacts are included, even if hard to quantify. • Benefits and costs are not double-counted. • Benefits and costs are treated consistently across DER types.
STEP 5	**Establish Comprehensive, Transparent Documentation** Establish comprehensive, transparent documentation and reporting, whereby: • The process used to determine the primary test is fully documented. • Reporting requirements and/or use of templates for presenting assumptions and results are developed.

Note: The 5-step process is not necessarily chronological in order and often requires iteration.

Source: National Energy Screening Project. (2020). *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*

Reviewing the cost tests currently in use in any jurisdiction can be a significant undertaking, even more so if that is but the first step in changing the tests to be used or developing a JST. It is not something regulators should undertake casually. However, jurisdictions that are inconsistent in the tests they use for different DERs run the risk of allocating resources in suboptimal ways, spending too much on one type of DER and too little on another. The larger the scale and the faster the pace of investment, the greater the risk. Jurisdictions may also be evaluating resources in ways that are inconsistent with established environmental or social policies, which can interfere with or increase the cost of meeting those policy goals. Getting the cost tests "right" can help to address this

[96] National Energy Screening Project, 2020.

problem. We suggest that each jurisdiction weigh the risks of making bad investment decisions against the cost of reviewing and updating the BCA tests they use.

Several states, in fact, have already embarked on designing their own JST for energy efficiency programs, following the recommended steps in the NSPM. The sponsors of the NSPM have published case studies describing efforts in Arkansas, Minnesota, New Hampshire and Rhode Island.[97] These case studies provide a good preview of what regulators in other states pursuing a JST might expect to happen.

Returning to the NSPM principles in Table 14, perhaps the biggest implementation challenge regulators will face is conforming to Principle 1; namely, comparing DERs "with other energy resources, including other DERs, using consistent methods and assumptions." Because few jurisdictions have taken on this challenge, we will cite examples from just two states that have established a uniform BCA framework for all DERs and two more examples of states that have open proceedings on this topic as of April 2022:

- New York: Another aspect of the groundbreaking New York REV initiative was that the PSC directed staff to develop a paper on how to use BCA for evaluating utility proposals for distribution system "platform" investments, DER procurement, DER tariffs and energy efficiency programs. In 2016, the PSC issued an order establishing a comprehensive BCA framework.[98]
- California: As an offshoot of the distributed resource planning docket that it initiated in 2014 to respond to state legislation, the California PUC opened a rulemaking docket to "create a consistent regulatory framework for the guidance, planning, and evaluation of integrated distributed energy resources." After many delays and restarts, the PUC established a uniform BCA framework by order in 2019 without actually promulgating administrative rules.[99]
- Maryland: In December 2021, the PSC opened a new proceeding to explore the process for developing a proposed unified BCA framework for DERs in Maryland. An initial hearing in the case was held on February 23, 2022, and several parties have filed comments.[100]

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[97] National Efficiency Screening Project. (n.d.). *Application of NSPM — case studies*. https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/nspm-application-by-state/

[98] New York Public Service Commission, January 21, 2016.

[99] California PUC, Rulemaking 14-10-003, Decision 19-05-019 on May 16, 2019, adopting cost-effectiveness analysis framework policies for all distributed energy resources. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M293/K833/293833387.PDF

[100] Maryland Public Service Commission, Case No. 9674. https://www.psc.state.md.us/search-results/?q=9674&x.x=8&x.y=14&search=all&search=case

- Washington: Also in 2021, the Washington Utilities and Transportation Commission opened a similar proceeding for developing a commission jurisdiction-specific cost-effectiveness test for distributed energy resources incorporating the state's 2019 Clean Energy Transformation Act. Parties had an opportunity to file initial comments and a first workshop was held on May 10, 2022.[101]

We note that there are many challenging aspects of applying BCA methods beyond merely choosing (or designing) a cost test. These include questions about how to quantify and monetize DER impacts, especially difficult-to-quantify impacts like safety, resilience, energy security, equity and risk impacts. Selecting a discount rate to apply to future year benefits and costs is another difficult, controversial topic. Fortunately, the newly published companion document to the NSPM (*Methods, Tools and Resources: A Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis)* offers fairly detailed guidance on how to address some of these questions.

Although it is helpful to use consistent BCA tests and methods for all types of resources, some states may find it impossible or impractical to revamp all their evaluation practices all at once. In some states, legislation might have to be changed to allow for true consistency. For example, Illinois law specifies that the cost-effectiveness of energy efficiency and demand response programs shall be determined using the TRC test. Illinois regulators could choose to apply the TRC consistently to the evaluation of all resources, but if they determined some other test would best satisfy the NSPM principles, they couldn't use that test for energy efficiency and demand response without a change to state legislation. There will also be cases where utilities or third-party DER program administrators are in the midst of implementing programs they designed in accordance with past PUC decisions about BCA tests or methods. Performance incentives or noncompliance penalties that are tied to estimates of net benefits could be at stake. In these cases, PUCs shouldn't change the rules in the middle of the game. Nevertheless, if a comprehensive revamp of state policies is not possible, incremental steps toward a consistent approach can be taken each time a relevant proceeding is adjudicated.

5. How Will We Use BCA Results to Make Decisions?

Although this reference report encourages regulators to make greater use of BCA methods, we do not intend to suggest that the quantitative results of a BCA should bind the hands of decision-makers. Regulators have discretion in how they exercise their authority, including discretion over whether and how they will use BCA results to inform their decisions.

A variety of practices can be observed as one pores over the many examples of BCAs used by state regulators. We see cases where regulators have chosen to use BCA results in the following ways.

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[101] Washington Utilities and Transportation Commission, Filing UE – 210804. https://www.utc.wa.gov/casedocket/2021/210804/docsets

- As the determinative factor in preapproving investment decisions or allowing cost recovery for past decisions — for example, in approving a proposed utility investment in energy storage or AMI.
- To establish investment budgets or ceiling prices for procurement — for example, energy efficiency program budgets.
- To design programs or retail rates — for example, in choosing an incentive level for demand response program participation or a compensation rate for energy exported by customers with solar photovoltaics.
- To set investment priorities — for example, in deciding which utility grid modernization investments to do first.
- To determine monetary incentives for a utility or program administrator operating under a performance-based regulatory regime.
- As supplemental information — for example, as one of many quantitative and qualitative factors considered when comparing potential utility investments or deciding if a particular utility investment is in the public interest.

VII. Conclusion

Least cost/best fit methods still have a significant role to play in making decisions about electric utility investments and probably always will. However, benefit-cost analysis methods can play a much bigger role in the power sector transformation we see happening today and can contribute to better decisions about distribution system investment.

Opportunities abound for using BCA in a wide variety of proceedings to improve investment outcomes, thereby maximizing net benefits (from an agreed perspective) rather than simply minimizing costs. In addition to their traditional use in planning and evaluating energy efficiency programs, we've noted a growing number of examples where BCA methods are used to evaluate other customer-facing DER programs, such as incentive programs for demand response, behind-the-meter energy storage and electric vehicles. BCA methods can also be applied to decisions about utility investments in infrastructure, either as a stand-alone proceeding, in a rate case or as part of a long-term planning process. And finally, for those DERs that can inject energy into the distribution system, we've also documented many examples of state utility commissions that have reviewed BCA results to inform decisions about net metering tariffs and other retail rate designs.

Public utility commissions will play a large role in determining whether and when BCA methods will be used to evaluate investment options. They can also dictate whether utilities, commission staff or other parties will conduct the BCAs, whether stakeholders will be active or passive participants in the analysis, what costs tests and methods will be used and how the BCA results will be used when it is time to make investment decisions. None of this is easy, but in many cases the level of effort that is required to do a BCA can easily be justified because it supports and validates decisions that optimize benefits, avoid expensive mistakes and protect ratepayers and utility shareholders.

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