Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations

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Summary

A central objective of utility grid modernization plans is to demonstrate that investments will provide net benefits to utility customers. The plans typically include some form of benefit-cost analysis (BCA) to determine whether projected benefits of grid modernization investments exceed estimated costs.

For jurisdictional utilities, grid modernization plans pose some new and complex challenges for state public utility commissions in determining whether projects will provide net benefits to customers. Plans typically include multiple grid modernization components that have interactive effects and are difficult to analyze or justify separately. Many benefits are hard to quantify or monetize, making it difficult to compare all benefits and costs. Part of the rationale for some grid modernization investments is to meet state energy goals, which can be difficult to quantify and account for in BCA. Equity issues arise when investments may benefit some types of customers more than others.

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 for supporting training for these audiences on this topic. It does not attempt to explain all the complexities and details of how to prepare BCA for grid modernization plans. Instead, it presents trends, challenges, and considerations for reviewing plans.

Trends in Recent Grid Modernization Plans

We reviewed 21 recent utility grid modernization plans and found a wide variety in assumptions, methodologies, justifications, and documentation for BCA. Many of the plans did not include all information or analysis needed for a thorough regulatory review of grid modernization projects. Following are some of the key items that were lacking in the plans:

- An overarching rationale for grid modernization investments and an explanation of how individual components will help meet overall goals
- Identification of cost-effectiveness test(s) used
- Identification of discount rate(s) used to determine present values
- Methodologies to account for interdependencies of grid modernization components
- Methodologies to account for unmonetized benefits of grid modernization components
- Robust definitions of grid modernization metrics and how they will be used to monitor grid modernization benefits over time
- Methodologies or discussions of how to address any customer equity issues

Challenges and Potential Approaches

Several aspects of planning for utility-facing investments in grid modernization make BCA more challenging than for other utility investments. The following table summarizes these challenges and potential approaches for addressing them.

Challenge	Potential Approaches
Identifying objectives	• Use long-term strategic planning to define objectives upfront • Identify the amount and type of cost-effective DERs
Documenting the purpose of each grid modernization component	• Specify a standard taxonomy for grid modernization • Define purpose and driver of each grid modernization component
Determining when to apply least-cost, best-fit approach	• Consider grid modernization objectives • Consider purpose and driver of the component • Consider whether component is core or application
Choosing BCA framework	• Articulate the BCA framework upfront • Focus on two tests: Utility Cost test and Regulatory test
Choosing discount rate(s)	• Choose a discount rate that reflects state regulatory goals • Conduct sensitivities using different discount rates
Accounting for interactive effects	• Use the least-cost, best-fit approach where warranted • Use scenario analysis with different combinations of components • Conduct BCA for grid modernization components in isolation
Accounting for benefits that are hard to quantify or monetize	• Use the least-cost, best-fit approach where warranted • Establish metrics to assess the extent of benefits • Apply methodologies to make unmonetized benefits transparent
Addressing uncertainty	• Use approaches that include contingency costs, scenario and sensitivity analyses, and probabilistic and expected value modeling
Putting BCA results in context	• Estimate long-term bill impacts
Prioritizing grid modernization investments	• Identify least-regrets investments that balance cost, risk, and functionality and value
Encouraging follow-through	• Establish metrics to monitor achievement of benefits

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Contents

Summary i
Acknowledgments iii
Disclaimer and Copyright Notice iii
Contents iv
1.0 Introduction 1
2.0 Utility-Facing Grid Modernization 3
3.0 Benefit-Cost Analysis Considerations 10
4.0 Trends in Recent Grid Modernization Plans 19
5.0 Options for Addressing Key BCA Challenges for Grid Modernization 23
6.0 Summary 32
7.0 References 35

Figures

Figure 1. Utility-Facing and Customer-Facing Grid Modernization Components 3
Figure 2. Advanced Distribution Management Systems (ADMS) Integrates and Enables Many Grid Modernization Components 7
Figure 3. Grid Modernization: Platform Components Versus Applications 9
Figure 4. Type and Frequency of Benefits Claimed in Grid Modernization Plans 20
Figure 5. Type and Frequency of Monetized Benefits Claimed in Grid Modernization Plans 21
Figure 6. Grid Modernization Benefit-Cost Ratios 22
Figure 7. Steps for Conducting a Grid Modernization BCA 32

Tables

Table 1. Examples of Costs for Utility-Facing Grid Modernization 4
Table 2. Examples of Benefits for Utility-Facing Grid Modernization 5
Table 3. Example of DOE Taxonomy Framework 8
Table 4. BCA Principles Proposed in Recent Initiatives 11
Table 5. Example Discount Rates for Utility BCA 17
Table 6. Grid Modernization Plans Reviewed 19
Table 7. Options for Addressing Key BCA Challenges 23
Table 8. Example of Scenarios to Test Interactive Effects 28
Table 9. Example of Scenarios to Account for Unmonetized Benefits 30

1.0 Introduction

In recent years, many electric utilities have prepared grid modernization plans for review by state public utility commissions.[1] A central objective of these plans is to demonstrate that grid modernization investments will provide net benefits to customers.[2] The plans typically include some form of benefit-cost analysis (BCA) to determine whether benefits of grid modernization projects will exceed costs.

Some of the key challenges for states determining whether investments will provide net benefits to customers include the following:

- Multiple grid modernization components with interactive effects are difficult to analyze or justify separately.
- Many benefits are hard to monetize, making it difficult to compare them with costs using a single metric.
- Equity issues may arise when all customers pay for grid modernization projects, but benefits of a particular project may accrue more to some customers than others.
- Utilities seek some form of approval for grid modernization projects before making investments.

Considerable progress has been made in recent years to support BCA of utility grid modernization plans. This work includes taxonomies for categorizing key aspects of grid modernization technologies and components and new evaluation approaches.[3] However, regulatory review practices have not kept pace.

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.

The report also builds on some of the key concepts in U.S. Department of Energy's forthcoming *Modern Distribution Grid Guidebook*, which synthesizes and updates elements of its Modern Distribution Grid Decision Guide.[4]

While this report emphasizes utility-facing grid modernization projects, the principles and concepts presented here generally apply to all types of grid modernization projects.

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[1] For most plans we reviewed, the grid modernization investments had not yet been made, and the utilities were seeking some form of guidance or approval from the state public utility commission. The issues discussed in this report are relevant even if the utility's filing with the commission is for cost recovery of grid modernization investments already made (no longer just a "plan").

[2] Other key objectives are meeting state energy goals and serving the public interest.

[3] See, for example, GMLC 2017; GMLC 2019; US DOE 2017; DOE Guidebook.

[4] DOE 2017, Volumes I, II, and III.

This report provides an overview of the challenges and some options for addressing them.

- Section 2 summarizes utility-facing grid modernization technologies and related issues.
- Section 3 presents BCA considerations and challenges related to grid modernization.
- Section 4 describes recent trends in BCA based on review of 21 grid modernization plans.
- Section 5 provides options for addressing some key challenges of these analyses.
- Section 6 summarizes the process that public utility commissions can use to provide utilities with guidance on grid modernization BCA, as well as the process that utilities can use to prepare BCA that address some of the challenges described in this report.

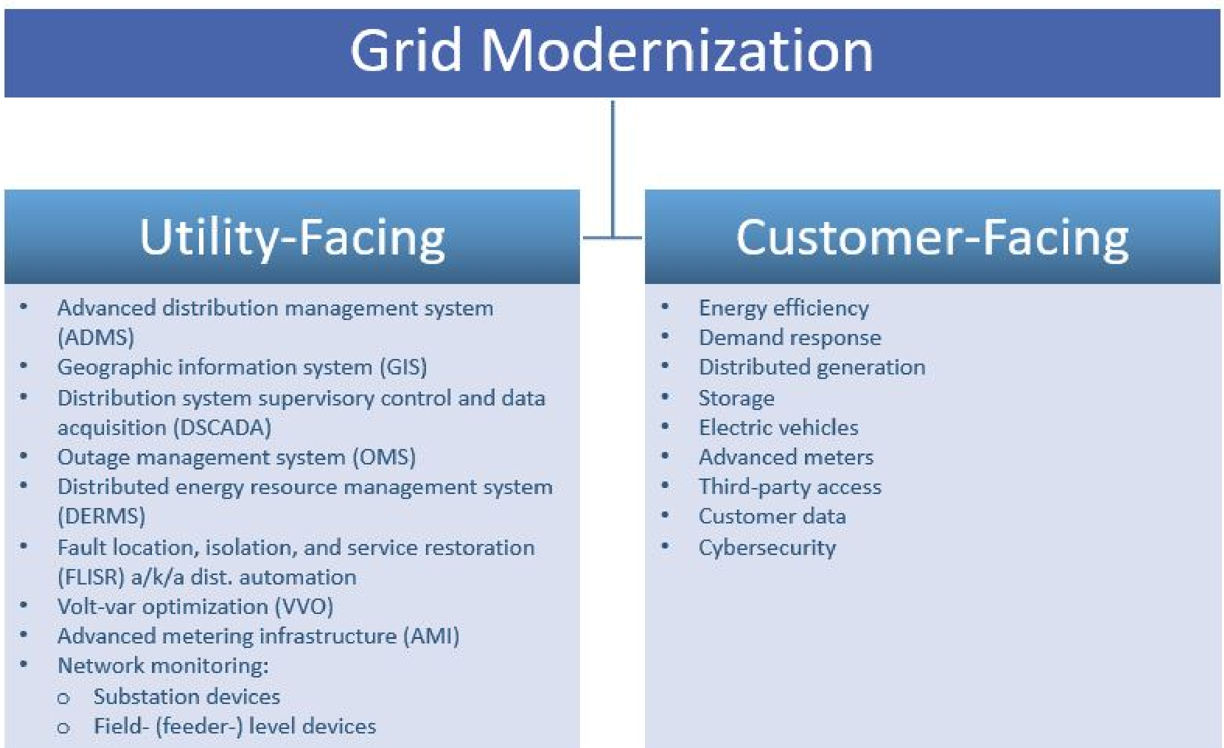
2.0 Utility-Facing Grid Modernization

Utility-Facing Versus Customer-Facing Grid Modernization

Utilities include many different components in their grid modernization plans and combine them in different ways. *Utility-facing* grid modernization initiatives include technologies and projects that help support more efficient and effective operation of distribution and transmission systems, including improved reliability and resilience. *Customer-facing* grid modernization initiatives include technologies that help support customer adoption of distributed energy resources (DERs) and customer access to third-party service providers and markets.

Figure 1 summarizes these two types of components.

Figure 1. Utility-Facing and Customer-Facing Grid Modernization Components[5]



This report focuses on conducting BCA for utility-facing projects. However, many of the principles and concepts described in this report are relevant to customer-facing grid modernization projects as well.

Key Costs and Benefits of Utility Grid Modernization

Table 1 and Table 2 provide examples of the types of costs and benefits associated with grid modernization plans. The list of costs and benefits comes from our review of utility-facing grid modernization plans, discussed in detail in Section 4.

[5] Some grid modernization components may be either utility- or customer-facing, depending on the context. Several categories of DERs, for example, may be owned by the customer (behind the meter) or by the utility (in front of the meter).

The tables categorize costs and benefits according to whether they apply to the utility system or to society in general.

- The costs and benefits for the "utility system" are those impacts on the entire utility system used to provide electricity services to retail electricity customers.[6] The utility system includes all elements of electricity services—generation, transmission, and distribution—regardless of whether the utility is vertically integrated or distribution only.

- The costs and benefits for "society" are those impacts experienced by society in general, not just customers of the electric utility.

Breaking out grid modernization costs and benefits in this way provides public utility commissions with useful information on implications of grid modernization for utility customers. Costs and benefits to the utility system indicate impacts on electric utility customers in terms of bills and services they receive, while costs and benefits to society indicate how well grid modernization projects are likely to meet additional state goals.

Table 1. Examples of Costs for Utility-Facing Grid Modernization

Cost	Utility System	Society
Incremental utility operations and maintenance (O&M) costs	✓	-
Incremental utility capital costs	✓	-
Incremental transmission and distribution (T&D) costs	✓	-

[6] NSPM 2017, Section 3.2

Table 2. Examples of Benefits for Utility-Facing Grid Modernization

Benefit	Utility System	Society
Reduced O&M costs	✓	✓
Reduced generation capacity costs	✓	✓
Reduced energy costs	✓	✓
Reduced T&D costs	✓	✓
Reduced T&D losses	✓	✓
Reduced ancillary services costs	✓	✓
Increased system reliability	✓	✓
Increased safety	✓	✓
Increased resilience	✓	✓
Increased DER integration	✓	✓
Improved power quality	✓	✓
Reduced customer outages	✓	✓
Increased customer satisfaction	✓	✓
Increased customer flexibility and choice	✓	✓
Reduced environmental compliance costs	✓	✓
Other environmental benefits	-	✓
Economic development benefits	-	✓

"Increased DER integration" is included in this table because it is frequently cited by utilities as a benefit of grid modernization. However, this benefit is distinctly different from the other benefits listed. Increased DER integration is more akin to an impact that will have its own costs and its own benefits, many of which already are listed in Table 1 and Table 2.[7]

Costs and benefits presented in these tables are not exhaustive. Examples of additional costs might include those for incremental metering, data management, and program administration. Examples of additional benefits are reduced ancillary service costs and wholesale market price suppression impacts.[8]

The lists of costs and benefits in these tables reveal important considerations for grid modernization BCA. First, the set of costs is generally narrower, simpler to define, and easier to calculate than the set of benefits. Consequently, many grid modernization plans include a relatively complete and detailed set of costs.

Second, grid modernization costs are typically incurred by all utility customers, while some benefits accrue only to society. In addition, in some cases benefits accrue to only specific customers. That makes it challenging to determine how much all utility customers should be expected to pay for those benefits.

[7] Some DERs also have participant costs and benefits, some of which can be quite large. Utility-facing grid modernization investments, on the other hand, typically do not have direct participant costs or benefits.

[8] See, for example, DOE Guidebook.

Third, many of the benefits are difficult to put into monetary terms. For example, utilities, state public utility commissions, and other stakeholders have had difficulty monetizing benefits such as resilience, safety, customer flexibility and choice, and improved power quality. While progress has been made in recent years to establish metrics and develop methodologies for quantifying and monetizing these benefits, most BCAs include some of these benefits in qualitative terms only.

Fourth, many costs and benefits cannot be easily identified separately for each grid modernization component. As described below, many components are interdependent, and in many cases benefits of one component cannot be experienced in the absence of others.

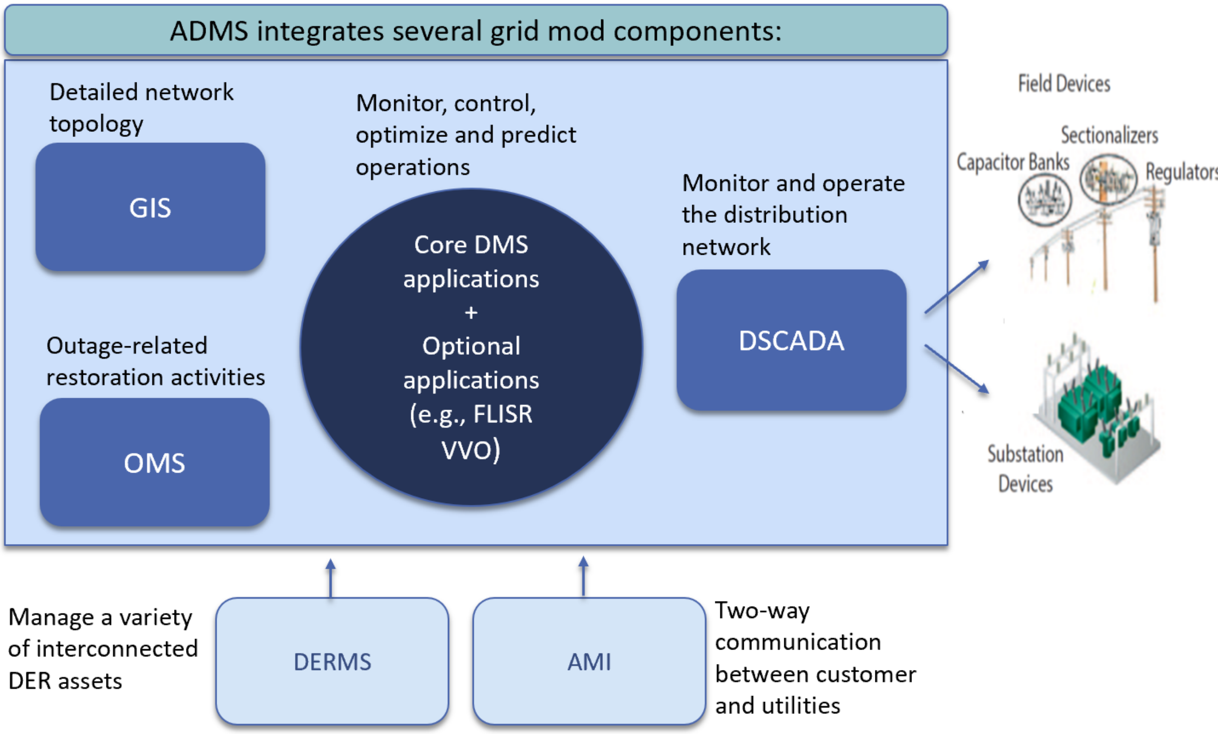
Fifth, some benefits are not well defined in utility grid modernization plans. For example, many plans list increased DER integration as one of the most important benefits of utility-facing grid modernization. However, the plans we reviewed did not provide quantitative information about increased DERs that are likely to be installed as a result of grid modernization. Further, this benefit was typically not put into monetary terms. Instead, it was addressed with qualitative statements, even though increased DER integration was one of the primary justifications for utility-facing grid modernization components. A fully transparent and comprehensive grid modernization BCA would provide more quantitative data on the likely increase in DERs. This is especially important if one of the key objectives of the proposed grid modernization components is to enable DERs. Such BCA would start with reasonable forecasts of the type and magnitude (units and capacity) of incremental DERs to be installed during the BCA study period. Ideally, it also would include the costs and benefits (e.g., resilience) associated with those incremental DERs, presented separately from costs and benefits of utility-facing grid modernization components.

Interdependency of Grid Modernization Components

One of the most difficult challenges of reviewing the cost-effectiveness of utility-facing grid modernization proposals is that many of the components are interdependent: The costs and benefits of one grid modernization component may be highly dependent upon the performance of other components. For example, Advanced Distribution Management Systems (ADMS) integrate and enable several other grid modernization components and cannot be easily separated from those other components for cost-effectiveness analysis. Figure 2 illustrates the interdependent relationship between ADMS and other grid modernization components.

Figure 2. Advanced Distribution Management Systems (ADMS) Integrates and Enables Many Grid Modernization Components

Source: Adapted from World Bank 2017, page 24.



Unmonetized Benefits

Unmonetized benefits create challenges for any type of BCA. That is especially the case for grid modernization BCA because many of the purported benefits are hard to monetize, but they are sometimes the primary justification for the grid modernization projects. For example, reliability, resilience, customer opportunities, and DER integration are often cited as benefits of grid modernization projects, but these benefits may be difficult to put into monetary terms.

In many instances utility-facing grid modernization investments are required either for safety, reliability, or policy requirements. In such cases, it may not be necessary or worth the effort to monetize the benefits. The investments could be justified on the grounds that they are needed to meet regulatory objectives, eliminating the need to show that monetized benefits exceed monetized costs. Similarly, there are many instances where utility-facing grid modernization investments are needed to support or enable other utility investments.

Taxonomy of Grid Modernization Terms

The DOE Guidebook includes a taxonomy of terms to define and clarify the many different components of grid modernization planning, as well as a taxonomy framework to connect the objectives of grid modernization with the proposed technologies.

Table 3 presents the DOE framework and an example application.[9] The framework includes four elements: objectives, capabilities, functionalities, and technologies. Drilling down to a specific technology, such as a Meter Data Management System (MDMS), the framework indicates how the capabilities and functions that the MDMS would support can be used to meet the objective of promoting customer choice.

In addition, this framework demonstrates how metrics can be used to help ensure that grid modernization investments deliver their purported benefits. In this example, a metric indicating "online customer access to relevant and timely information" would indicate how well the proposed technologies will meet that objective over time.

Table 3. Example of DOE Taxonomy Framework

Source: Reproduced from DOE Guidebook, page 42.

Objective	Capability	Function	Technology
Customer Choice through information access for small business & residential customers to support decision-making by 2020	Provide online customer access to relevant & timely information	Remote meter data collection & verification Customer data management Energy management & DER purchase analysis	Customer Portal Customer Analytic Tools Greenbutton Smart Meter Telecommunications Meter Data Management System Customer Info System Data Warehouse

Core Components Versus Applications

The DOE Guidebook also makes an important distinction between two types of grid modernization investments:

- *Core, or platform, components* represent foundational components that are necessary for providing the services required of modern grids.

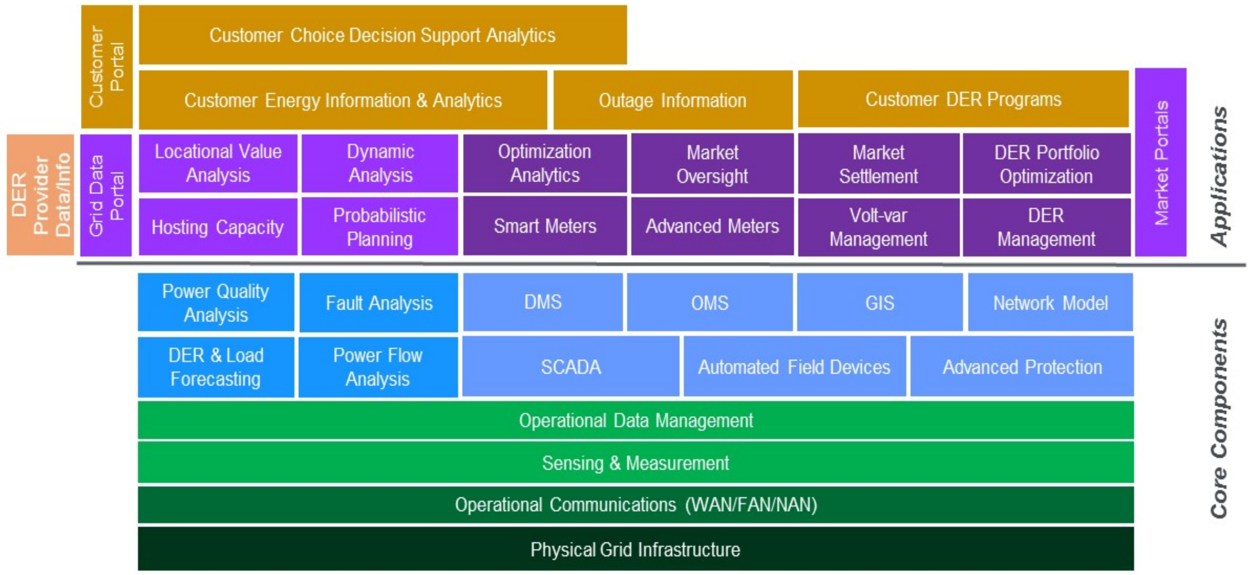
- *Applications, or modules,* represent additional, single-purpose components that can be layered on top of the platform components to provide additional functionality that is desired or needed.

Figure 3 illustrates types of grid modernization investments that are considered core (platform) components and those that are considered application (modular) components. This distinction is critical for grid modernization BCA because platform components can be evaluated using a different BCA approach than application components.

[9] DOE 2017, Volume I; US DOE 2019.

Figure 3. Grid Modernization: Platform Components Versus Applications

Source: DOE Guidebook, Figure 46, page 60.



Core components are similar to traditional distribution investments that utilities make to ensure reliability. For traditional utility investments, the need is typically established upfront based on reliability requirements and other objectives, and utilities conduct economic analyses to fulfill that need with the most appropriate infrastructure at the lowest cost. In the case of core grid modernization components, the analysis is more complex because there are often additional objectives for the investments, such as resilience and integration of DERs.

On the other hand, application components are more akin to supply-side and demand-side resource decisions where utilities use economic analyses to determine whether to make those investments. In the case of grid modernization applications, the analysis is made more complex because of objectives beyond simply meeting energy and capacity needs.

For most utilities, the core components make up the majority of the projects and the costs of grid modernization plans.[10]

Section 3.0 further addresses this important distinction between platform and application components.

[10] DOE Guidebook, page 90.

3.0 Benefit-Cost Analysis Considerations

Regulatory Contexts for Benefit-Cost Analyses

Public utility commissions have used BCA for many years to make decisions on a variety of utility investments. For the purpose of reviewing grid modernization investments, BCA is typically applied in two general types of regulatory contexts:

1. **A request for approval of grid modernization plans *prior* to incurring grid modernization costs**. Such a request typically occurs in a separate docket dedicated to the review of the grid modernization proposal, allowing regulators and stakeholders an opportunity to dig into the details of the proposal. Sometimes these proposals are requested by state legislatures or public utility commissions, and sometimes they are initiated by utilities. For states that allow an *ex ante* approach, utilities may be able to request some form of preapproval of the proposed investments. Preapproval is sometimes requested for large costs that are beyond those normally included in utility revenue requirements. The ability to request preapproval, and implications for utility cost recovery, varies by state. In general, if public utility commissions provide some form of preapproval of grid modernization investments, the utilities are still required to act prudently in the execution of the grid modernization plan.

2. **A request for approval of grid modernization investments *after* incurring the grid modernization costs**. This type of request is typically made in a rate case. In this context, regulators could review whether grid modernization investments are likely to be prudent, as with other major utility investments in a rate case. One advantage of this approach is that it allows regulators to review grid modernization investments in the context of other costs and cost savings included in utility revenue requirements in the rate case. One disadvantage of this approach is that regulators may not have a chance to provide input on grid modernization principles, objectives, or the BCA methodology until after the investments have been made.[11] Another disadvantage is that the investments are reviewed alongside all the other issues in a rate case. This limits the amount of time that can be spent examining grid modernization investments, which can be complex and time consuming.

Basic Principles of Benefit-Cost Analysis

Utilities use a variety of assumptions, methodologies, and frameworks in conducting BCA. In some cases, differences may be due to different direction provided by each state. In other cases, the state may not provide guidance at all, and utilities use their own approach.

Several recent efforts have made progress toward developing a consistent set of principles to ensure that BCAs are sound, consistent with fundamental economic concepts, and provide results that are reasonable, meaningful, and can be easily interpreted by state regulators and other stakeholders. Table 4 presents a summary of BCA principles proposed in three recent initiatives: the *National Standard Practice Manual* (NSPM), DOE's *Modern Distribution Grid* (DOE) and the New York Public Service Commission's *Order Establishing the Benefit Cost Analysis Framework* (NY PSC). While some of these principles were established in the context of energy efficiency BCA, they apply to utility BCA in general and provide a foundation for the grid modernization BCA discussion in this report.

[11] This challenge can be addressed by holding a generic proceeding upfront that outlines principles and objectives of grid modernization investments and how investments will be evaluated.

Table 4. BCA Principles Proposed in Recent Initiatives

Sources: NSPM 2017; DOE 2017, volume III; NY PSC 2016.

Principle	National Standard Practice Manual	DOE Modern Distribution Grid	New York Reforming the Energy Vision
Assess alternative projects comparably with traditional options	✓	✓	✓
Account for state regulatory and policy goals	✓	✓	-
Account for all relevant costs and benefits, including hard-to-monetize	✓	✓	-
Ensure symmetry across relevant costs and benefits	✓	-	-
Apply full life-cycle analysis	✓	✓	✓
Apply incremental, forward-looking analysis[12]	✓	-	-
Ensure transparency	✓	✓	✓
Avoid combining or conflating different costs and benefits	-	-	✓
Assess bundles and portfolios instead of separate measures	✓	✓	-
Address locational and temporal values	-	✓	✓

Benefit-Cost Analysis Frameworks

Utilities and public utility commissions typically establish a BCA *framework* to analyze costs and benefits of many types of utility investments. These frameworks generally address two questions: Which costs and benefits should be accounted for in the BCA? What are the implications of those costs and benefits from the perspectives of utility customers, meeting state energy goals, and society?

Once a BCA framework is established, it is used to compare all relevant costs to all relevant benefits forecast for the study period. The study period is generally at least as long as the operating life of the investment or resource that is the subject of the analysis. Costs and benefits are converted to present values, which are then cumulated for the entire study period. The two bottom-line metrics of the BCA framework are:

- *Net benefits*, which are equal to the cumulative present value of benefits minus the cumulative present value of costs. If net benefits are positive, the investment or resource is deemed to be cost-effective.

- *Benefit-cost ratio*, which is the ratio of cumulative present value of benefits to the cumulative present value of costs. If the benefit-cost ratio exceeds 1.0, the investment or resource is deemed to be cost-effective.

[12] Incremental forward-looking analysis refers to the practice of capturing the difference between costs that would occur over the life of the subject investment as compared to the costs that would occur absent the investments. According to the forward-looking aspect of this principle, sunk costs and lost revenues should not be included in a benefit-cost analysis.

Both metrics are important when assessing cost-effectiveness because they provide information in slightly different ways. Net benefits indicate the magnitude of benefits in terms of dollars. The benefit-cost ratio indicates whether benefits will exceed costs and by what proportion.

Traditional Cost-Effectiveness Frameworks for Energy Efficiency

For many years regulators and utilities have relied upon five frameworks (often referred to as "tests") for determining the cost-effectiveness of energy efficiency resources funded by utility customers:[13]

> The *Utility Cost test* represents the perspective of the utility system. In this context, the "utility system" refers to the entire utility system used to provide electricity services to retail electricity customers, including generation, transmission, and distribution of electricity services.
>
> The *Participant test* represents the perspective of energy efficiency program participants.
>
> The *Total Resource Cost (TRC) test* represents the perspective of the utility system and efficiency program participants.
>
> The *Societal Cost test* represents the perspective of society as a whole.
>
> The *Rate Impact Measure test* presents information about the impact on rates from the efficiency programs.

For energy efficiency BCA, most states use some form of the TRC test as the primary test, many states use the Utility Cost test, and several apply the Societal Cost test.[14] Many states also consider the results of multiple tests when reviewing energy efficiency programs. Regardless of which test is used, it is important to understand what information these different tests do—and do not—provide, because the choice of test has significant implications for what investments and resources are deemed cost-effective.

These BCA frameworks that have been applied to energy efficiency resources have important implications for grid modernization BCA. Many utilities and public utility commissions are using these tests, or variations of them, for grid modernization BCA.

The National Standard Practice Manual for Energy Efficiency

The National Standard Practice Manual (NSPM) updates and expands upon traditional energy efficiency cost-effectiveness frameworks. It provides the following new concepts and insights:

- A state's cost-effectiveness tests should adhere to fundamental BCA principles.[15] Table 4 (in Section 3) presents BCA principles recommended in the NSPM.

- A state does not need to be confined to the traditional BCA tests (e.g., Utility, TRC, and Societal tests) when assessing resource cost-effectiveness. States can develop alternative tests that adhere to fundamental BCA principles.

[13] CA PUC 2001. National Action Plan for Energy Efficiency 2008, Section 2.2.
[14] Some states calculate the results of the Participant and RIM tests as part of the cost-effectiveness analyses but do not use these tests as the primary test.
[15] NSPM 2017, pages 9-14.

- The NSPM introduces a new perspective for determining the costs and benefits to include in a BCA framework: the *regulatory perspective.* This perspective reflects the priorities and the responsibilities of regulators, where that term is applied broadly to include public utility commissioners and others.[16] The regulatory perspective should balance interests of customers and utilities and account for state energy goals. This perspective is typically broader than the utility system perspective but narrower than the societal perspective.

- While many states apply multiple cost-effectiveness tests, most states use a *primary* test to make the ultimate decision of which energy efficiency resources warrant ratepayer funding. The NSPM recommends that a state's primary cost-effectiveness test reflect the state's regulatory goals.[17] In this document we refer to a state's primary test as the *Regulatory test*.[18]

- The NSPM introduces a framework that offers a step-by-step approach for a state to establish or modify its primary energy efficiency BCA test.[19]

- Since the costs and benefits included in the Regulatory test are based on a state's energy goals, the impacts included in this test might vary from one state to another.

- States can also use *secondary* tests to inform energy efficiency cost-effectiveness decisions—for example, the Utility Cost or Societal Cost test.[20]

While the NSPM is focused on energy efficiency BCA, the principles and concepts in the NSPM are also directly relevant to BCA for grid modernization and DERs.[21] The National Efficiency Screening Project is currently developing the National Standard Practice Manual for Distributed Energy Resources, which will build on the principles and concepts of the NSPM and apply them to BCA issues that are unique to demand response, distributed generation, storage, electric vehicles, and non-wires alternatives.

Least-Cost, Best-Fit Analysis

The least-cost, best-fit approach is an economic evaluation technique that is sometimes used as an alternative to BCAs. The least-cost, best fit approach is applied when the need for a particular project or investment is already established. Once the need is established, the next step is to identify the technology option(s) that are likely to be the best fit to meet that need to achieve predetermined objectives. The final step is to identify the lowest cost way of implementing the technology chosen, typically using a competitive procurement process.

The least-cost, best-fit approach is distinctly different from a traditional BCA approach because it does not require a demonstration that monetized benefits exceed monetized costs. Instead, there is a presumption that the investment is needed, and the main goal of the economic analysis is to best meet that need at the lowest cost. This approach eliminates the need to monetize all the benefits associated with the investment in question. Instead, the least-cost, best-fit approach requires a demonstration that the investment will be needed to meet regulatory objectives.

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16 In other contexts, boards of publicly owned utilities, municipal utilities, and rural electric cooperatives.
17 NSPM 2017, page 16.
18 The NSPM refers to the primary BCA test developed using this framework as the *Resource Value* test. In this document we refer to the primary test that reflects the regulatory perspective as the *Regulatory test* because that term is more descriptive of the perspective and purpose of the test. NSPM 2017, page viii and page 11.
19 NSPM 2017, pages 18-38.
20 NSPM 2017, pages 44-46.
21 NSPM 2017, page xiii.

The least-cost, best-fit approach has been used for many years by utilities to help make decisions regarding traditional distribution investments, where the need for the distribution investments has been primarily driven by reliability and safety requirements. Grid modernization investments, however, are more challenging than traditional distribution investments because it is much less clear whether a particular grid modernization investment is needed. This makes it much less clear whether the least-cost, best-fit approach is appropriate to justify the investment.

DOE Guidebook

The DOE Guidebook provides guidance for assessing the economics of grid modernization investments from a broad, long-term perspective. It describes the importance of strategic planning, defining objectives, identifying the types and drivers of investments, prioritizing investments, using pilot programs, sequencing investments, and applying spending caps. Noting that "there is no single standard or method for determining the cost-effectiveness or prudence of grid modernization investments" in every jurisdiction,[22] the Guidebook offers a framework that can be tailored to each jurisdiction's objectives, priorities, spending limits, and industry structure.

The DOE Guidebook emphasizes ongoing, long-term utility planning processes. These can take many forms or incorporate many elements, including distribution planning, transmission planning, integrated resource planning (IRP), DER planning, and reliability and resilience planning.[23] The grid modernization planning process should be used to identify the mission and principles, develop objectives, identify grid capabilities and needed functionality, identify grid architecture, and develop strategies for the timing and coordination of grid modernization investments.[24]

Clearly identifying objectives is a critical aspect of the economic analysis of grid modernization investments. Grid modernization objectives provide the link between the investments and their expected benefits.[25] Identifying this link is especially important in the context of grid modernization, where many of the benefits are hard to monetize. Consider an example where utility regulators in a state decide that resilience is an important objective. In this instance, regulators might decide that the utility's proposed grid investments are necessary to achieve the resilience objective even if its grid modernization plan does not monetize the resilience benefits.

According to the DOE Guidebook, grid modernization investments can be broken down into two categories for economic analysis:

- Core components - Least-cost, best-fit approach for projects deemed to be necessary

- Application projects - BCA approach because these projects are optional and do not play as big a role in supporting other grid modernization projects[26]

Another approach is categorizing grid modernization investments by four main investment rationales, or drivers:[27]

1. *Joint benefits:* core platform investments that are needed to enable capabilities and functions;[28]

[22] DOE Guidebook, page 85.
[23] DOE Guidebook, page 83.
[24] DOE Guidebook, page 31.
[25] DOE Guidebook, page 82.
[26] DOE Guidebook, page 86.
[27] DOE Guidebook, page 84.
[28] Investments justified by joint benefits might include, for example, ADMS or DSCADA.

2. *Standards compliance and policy mandates:* utility investments that are needed to comply with safety and reliability standards or to meet policy mandates for proactive investments to integrate DER;
3. *Net customer benefits:* utility investments from which some or all customers receive net benefits in the form of bill savings; and
4. *Customer choice:* investments triggered by customer interconnection, opt-in utility programs, and customer-driven reliability improvements paid for by individual customers.

These investment drivers can be used to determine which analytical method should be applied to grid modernization investments—in particular:

- Investments driven by *joint benefits* or *compliance with standards or policy mandates* should be subject to a least-cost, best-fit approach.
- Investments driven by *net customer benefits* should be assessed using a standard BCA approach to demonstrate that the investment will provide net benefits.
- Investments driven by *customer choice* are considered "self-supporting," assumed to be cost-effective from the customer's perspective, and therefore do not need to be assessed by utilities or regulators.[29]

The extent to which the least-cost, best-fit approach or the BCA approach is used will vary across states, depending upon each state's objectives, priorities, and proposed investments. Core components typically account for the majority of grid modernization investments.[30]

Prioritization of grid modernization investments is an important aspect of the economic analysis. Grid modernization plans often propose large capital investments that might be burdensome to put into electricity rates all at once. This challenge is especially problematic if the plan does not provide a quantitative, monetized demonstration that customer benefits will exceed customer costs. According to the DOE Guidebook, "the goal of prioritization is to identify least-regrets investments that balance risk, cost, short-term functionality and value, and long-term functionality and value."[31] It recommends that prioritization be supported with risk-based techniques applied as part of the strategic planning and economic analysis.

The DOE Guidebook also discusses several other important aspects related to the economics of grid modernization investments. These include the roles of *ex ante* and *ex post* economic evaluations, coordinated planning, and clearly defined performance metrics.

California Public Utilities Commission Grid Modernization Proceeding

The California Public Utilities Commission (CPUC) recently issued an order addressing grid modernization planning and analysis, particularly regarding the interrelationship between grid modernization projects and DERs.[32] The order includes several findings and recommendations that might be helpful for other jurisdictions considering the economics of grid modernization investments.

[29] DOE Guidebook, page 84.
[30] DOE Guidebook, page 90.
[31] DOE Guidebook, page 98.
[32] CPUC 2018.

The CPUC notes that many grid modernization investments are intended to support the integration of DERs, as well as to achieve traditional distribution objectives, such as reliability and safety. The Commission found that grid modernization proposals must be considered holistically, accounting for reliability and safety objectives as well as the objective of integrating DERs. According to the CPUC, separate evaluation of the reliability and safety benefits from the benefits associated with DERs "would not be feasible."[33] The CPUC also found that the same threshold of review should be applied to investments made for reliability/safety objectives and for DER objectives.[34] For these reasons, the CPUC found that "the cost-effectiveness of grid modernization needs to be evaluated within the context of the overall cost-effectiveness of the DERs."[35]

The CPUC declined to require utilities to make a cost-effectiveness showing in order to justify grid modernization investments. Instead, utilities must demonstrate the *cost reasonableness* of grid modernization investments, which requires a demonstration that the investments meet distribution planning objectives at the lowest possible cost.[36]

The Commission finds that the "most appropriate approach to evaluate the cost reasonableness depends on what drives an investment: (1) to integrate and maximize the value of DERs, (2) to mitigate forecasted safety and reliability challenges based on either growth of DERs, or growth in demand, or (3) [a] combination of these drivers."[37] For this reason, in their requests for recovery of grid modernization costs, the CPUC requires utilities to explain what drives the need for each type of grid modernization investment.

The CPUC identifies three general approaches that can be used to determine the appropriate level of investment in DER integration:[38]

1. Use existing methods for evaluating cost-effectiveness of distribution investments, including the use of outage and safety metrics, particularly for meeting reliability and safety objectives.
2. Identify the lowest cost approach to meeting grid needs—least-cost, best-fit. This approach might be used for investments driven by either reliability/safety or DER integration.
3. Use the comprehensive, long-term IRP process to evaluate the cost-effectiveness of DERs, taking into account "naturally occurring" DERs as well as the potential for the utility to promote additional DER integration.

The Commission does not specify the extent to which any one of these approaches must be used for specific grid modernization proposals, and in practice they might all be used. For example, the IRP process can be used to determine a cost-effective level of DERs, and that level of DERs can be used to justify investments in grid modernization projects necessary to support them. The least-cost, best-fit approach can be used to demonstrate that the grid modernization projects meet the DER objectives at the lowest cost, and metrics can be established to demonstrate that those objectives are achieved over time.

The CPUC order includes a comprehensive template for grid modernization filing requirements.[39] It also includes a comprehensive classification of grid modernization investments.[40]

[33] CA PUC 2018, page 6 and page 24.
[34] CA PUC 2018, page 24.
[35] CA PUC 2018, page 24.
[36] CA PUC 2018, page 25.
[37] CA PUC 2018, page 26.
[38] CA PUC 2018, page 26.
[39] CA PUC 2018, Appendix A.
[40] CA PUC 2018, Appendices B and C.

Choice of Discount Rate

The discount rate is an important input to any BCA and has significant impacts on the results. Discount rates are often described as reflecting the cost of capital, the opportunity cost, or the risk associated with the future value of money. In regulatory settings, a discount rate reflects a particular "time preference," which is the relative importance of short- versus long-term costs and benefits.[41] A higher discount rate gives more weight to short-term impacts, while a lower discount rate gives more weight to long-term impacts.

Table 5 presents some example discount rates that could be used for utility grid modernization BCA. Many recent grid modernization plans and state BCA frameworks use the utility Weighted-Average Cost of Capital (WACC) as the discount rate.

Table 5. Example Discount Rates for Utility BCA

Note: Illustrative values are in real terms—i.e., net of inflation adjustments.

Type of Discount Rate	Illustrative Values
Investor-owned utility weighted average cost of capital	5%–8%
Publicly owned utility weighted average cost of capital	3%–5%
Utility customers	Varies widely
Low risk	0%–3%
Societal	<0%–3%

One of the challenges in choosing a discount rate for grid modernization BCA is that grid modernization sometimes includes projects driven by state energy goals and societal benefits. Consequently, the utility WACC might not be the appropriate discount rate to use. The utility WACC reflects the opportunity costs (i.e., time preference) of utility investors, but does not necessarily reflect a time preference consistent with regulatory goals. A discount rate based on the utility WACC is typically higher than one that reflects regulatory goals, which is closer to a low-risk or a societal discount rate.

The choice of discount rate has no bearing on whether the utility can recover its actual cost of capital. In any BCA, the cost of capital should be included in the undiscounted annual revenue requirement forecasts for each investment, and the utility should be allowed to recover any such prudently incurred costs. The choice of discount rate simply affects how much weight to give long-term impacts relative to short-term impacts, to help public utility commissions make decisions about whether the investment is consistent with regulatory goals.

Benefit-Cost Analysis Versus a Business Case Approach

Some grid modernization plans use a "business case" approach to evaluating investments, instead of a BCA approach.

- The term *benefit-cost analysis* is generally used to refer to an analytical approach that puts all costs and benefits into monetary values. The monetary values are often presented in terms of an annual stream of costs and benefits over the life of the investment, then discounted to determine

[41] NSPM 2017, Chapter 9.

the cumulative present value of costs and benefits. If benefits exceed costs, the investment is typically deemed to be cost-effective.

- The term *business case* is generally used to refer to an approach that is broader and more flexible than a BCA. In general, a business case differs from a BCA in that it accounts for impacts (costs and benefits, but typically benefits) that are difficult to define, isolate, quantify, or monetize. Some business case approaches include a traditional BCA, where many costs and benefits are put into monetary values, but then allow flexibility for deciding whether to pursue an investment after considering factors that have not been monetized. Other business case approaches include little monetization of costs and benefits, relying almost entirely on qualitative, non-monetary grounds for justifying the investment.

This distinction is more rhetorical than substantive. A BCA can account for non-monetary as well as monetary impacts, and a business case can serve the same fundamental objective as a BCA. Regardless of what the approach is called, costs and benefits should be monetized to the fullest extent possible, and unmonetized costs and benefits should be accounted for as much as is feasible.

4.0 Trends in Recent Grid Modernization Plans

General Trends

We reviewed 21 grid modernization plans prepared by electric utilities across the United States (Table 6). Five of these plans were submitted in the context of rate cases, while the others were filed for review and approval in a separate docket. Almost all these plans were submitted for public utility commission review prior to making the proposed grid modernization investments.

Table 6. Grid Modernization Plans Reviewed[42]

Utility	State	Year	Utility	State	Year
National Grid	NY	2016	DTE Energy	MI	2018
NYSEG & RGE	NY	2016	APS	AZ	2016
Unitil	MA	2015	PSE&G	NJ	2018
National Grid	MA	2016	LGE	KY	2018
Eversource	MA	2015	Consumers Energy	MT	2018
Public Service Company	CO	2016	Central Hudson Gas & Electric	NY	2018
SDGE	CA	2016	Hawaiian Electric Companies	HI	2017
Xcel	MN	2017	Southern California Edison	CA	2016
FirstEnergy	OH	2017	Connecticut Light and Power	CT	2010
Vectren	IN	2017	Entergy	AR	2016
National Grid	RI	2018			

We found wide variety in the assumptions, methodologies, justifications, and documentation across these plans. Many of the plans did not include all information or analysis needed for a thorough regulatory review of the grid modernization projects. Some of the key items that were lacking in the plans include:

- An overarching rationale for grid modernization investments and an explanation of how individual components will help meet overall goals.
- Identification of which cost-effectiveness test was used for the BCA. Based on our assessment of the cost and benefits included in the 15 plans in our review that included monetary costs or benefits, it appears as though nine used a Utility Cost test, three used a Societal Cost test, two used both types of tests, and one used a TRC test.
- Identification of which discount rate was used to determine present values. Based on our assessment of the discount rates used, roughly half of the plans used the utility WACC as the discount rate; the remaining plans did not specify the discount rate used.
- Methodologies to account for the interdependencies of grid modernization components. Some of the plans use the rationale that grid modernization investments are foundational, platform investments, and therefore do not need to have benefits monetized or assigned to each grid modernization component.

[42] DTE Energy and Consumers Energy filed plans in 2017 that were superseded in 2018.

- Methodologies to account for unmonetized benefits of grid modernization components because of the interdependencies of grid modernization components and the difficulty of monetizing some of the benefits.

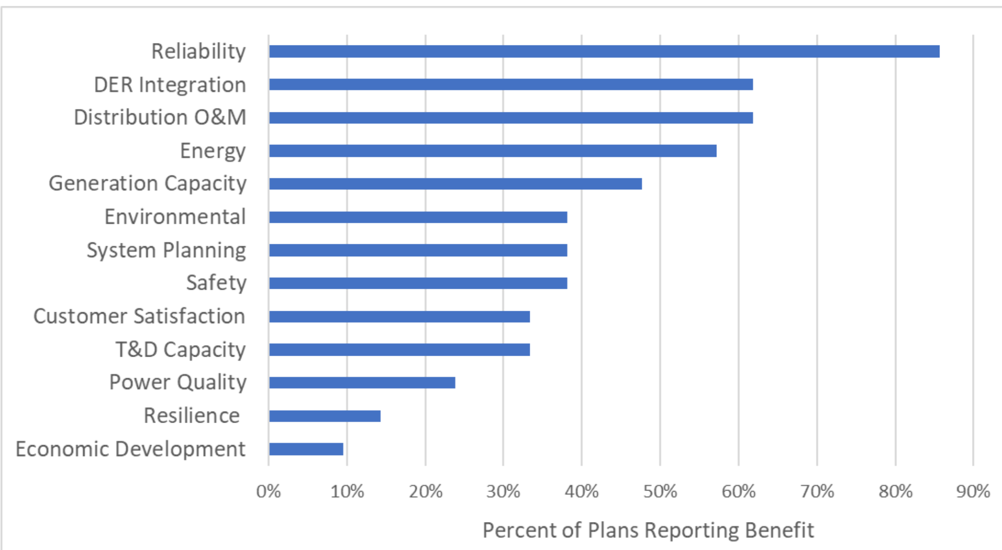
- Robust definitions of grid modernization metrics and how they will be used to monitor grid modernization costs and benefits over time.

- Methodologies or discussions of how to address customer equity issues.

Types of Benefits Claimed

Figure 4 shows the frequency with which utilities claimed certain benefits from grid modernization plans (including both monetized and unmonetized benefits). Nearly all plans claim reliability as a benefit; the majority of plans claim O&M, energy savings, and DER integration as benefits; and many plans include generation capacity. Few plans claim power quality, resilience, or economic development benefits.

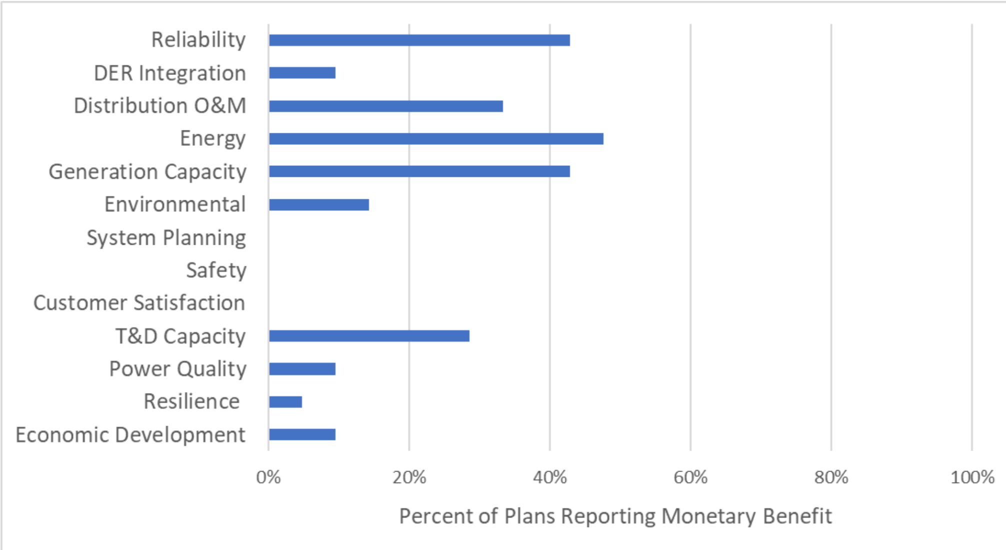
Figure 4. Type and Frequency of Benefits Claimed in Grid Modernization Plans



Use of Monetized Benefits

Figure 5 shows the frequency with which utilities present monetized benefits in their grid modernization plans. Most of the monetized benefits are claimed for energy, generation capacity, and O&M savings, as well as reliability benefits.

Figure 5. Type and Frequency of Monetized Benefits Claimed in Grid Modernization Plans



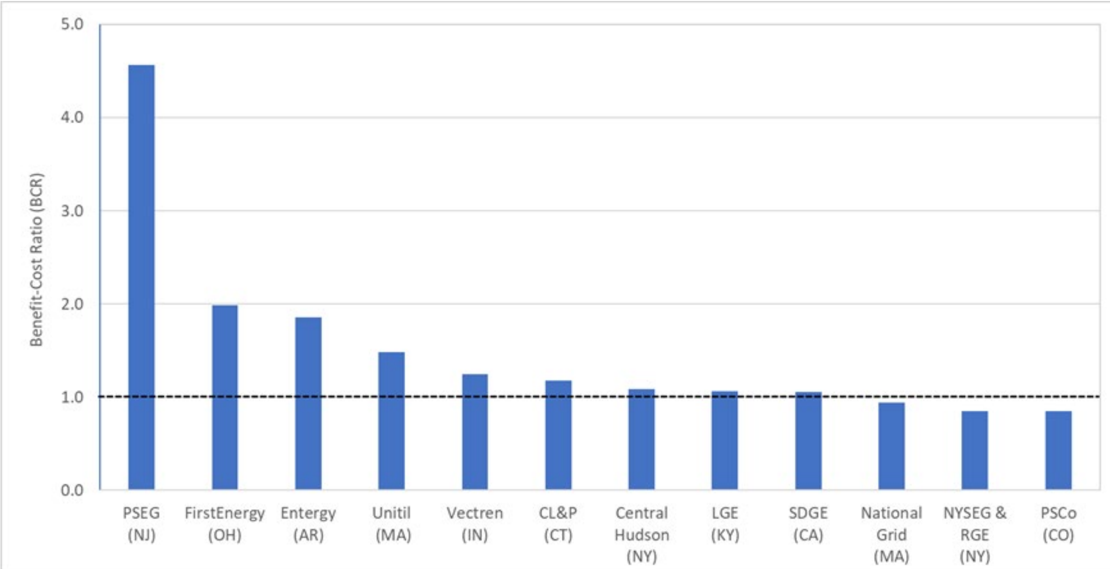
Examples of Monetized BCA Results

Figure 6 presents high-level results from the subset of grid modernization plans that include monetary values for costs and benefits. The figure presents benefit-cost ratios for the entire portfolio of grid modernization components. We present benefit-cost ratios because they are easy to compare across a range of utilities and grid modernization plans, and they are a conventional way to present bottom-line results from BCA.

Few of the grid modernization studies presented results in terms of a benefit-cost ratio. This situation may be because these ratios can mask some of the important challenges and considerations that affect the ultimate decision of whether benefits exceed costs for a grid modernization project. Notably, many of the benefit-cost ratios presented in Figure 6 are from studies that do not include monetary values for some of the benefits. Thus, these ratios only tell part of the story and could be misleading if not considered properly.[43] Nonetheless, we present the ratios here because they illustrate the extent to which unmonetized benefits will be needed to demonstrate that the portfolio benefits exceed the costs.

[43] While the plans that were reviewed commonly left some claimed benefits unmonetized, Figure 7 does not include cases in which monetization was demonstrably incomplete. National Grid NY, for example, monetized benefits for just the VVO/CVR components of its plan, representing only about $42 million out of a total proposed investment of $585 million. The utility's plan is therefore not included.

Figure 6. Grid Modernization Benefit-Cost Ratios[44]



44 Benefit-cost ratios were calculated from present value benefit and cost figures. We followed the cost-classifying conventions of individual reports, including all costs and benefits that were indicated to be associated with the grid modernization initiative. In some cases (e.g., PSCo), our figures include advanced metering infrastructure (AMI), while we omit AMI in others (e.g., PSE&G). If the utility provided both shorter- and longer-term values, we used longer-term values. The National Grid Massachusetts plan included several scenarios. We present here the Balanced scenario.

5.0 Options for Addressing Key BCA Challenges for Grid Modernization

This section provides options for addressing some of the more challenging aspects of BCA for grid modernization. Table 7 lists the key challenges and summarizes the discussion of potential approaches that follows.

Table 7. Options for Addressing Key BCA Challenges

Challenge	Potential Approaches
Identifying objectives	• Use long-term strategic planning to define objectives upfront • Identify the amount and type of cost-effective DERs
Documenting the purpose of each grid modernization component	• Specify a standard taxonomy for grid modernization • Define purpose and driver of each grid modernization component
Determining when to apply least-cost, best-fit approach	• Consider grid modernization objectives • Consider purpose and driver of the component • Consider whether component is core or application
Choosing BCA framework	• Articulate the BCA framework upfront • Focus on two tests: Utility Cost test and Regulatory test
Choosing discount rate(s)	• Choose a discount rate that reflects state regulatory goals • Conduct sensitivities using different discount rates
Accounting for interactive effects	• Use the least-cost, best-fit approach where warranted • Use scenario analysis with different combinations of components • Conduct BCA for grid modernization components in isolation
Accounting for benefits that are hard to quantify or monetize	• Use the least-cost, best-fit approach where warranted • Establish metrics to assess the extent of benefits • Apply methodologies to make unmonetized benefits transparent
Addressing uncertainty	• Use approaches that include contingency costs, scenario and sensitivity analyses, and probabilistic and expected value modeling
Putting BCA results in context	• Estimate long-term bill impacts
Prioritizing grid modernization investments	• Identify least-regrets investments that balance cost, risk, functionality and value
Encouraging follow-through	• Establish metrics to monitor achievement of benefits

Identify Objectives

Defining grid modernization objectives is critical to help guide utility decision-making and justify certain grid modernization investments. Ideally, these objectives would be identified, reviewed, and approved by the public utility commission prior to the development of a grid modernization plan.

Further, it would be best to develop these objectives through a long-term, strategic grid modernization planning process. Such a process would incorporate distribution, transmission, and generation resource planning as much as possible to identify the role of grid modernization investments in the context of the entire utility system.

Such a process also should analyze opportunities for implementing cost-effective DERs to meet future electricity needs. Given that many grid modernization investments are intended to support the implementation of DERs, it is important to assess the type and level of benefits DERs are likely to provide.

Documenting the Purpose of Each Proposed Grid Modernization Investment

Regulatory review of grid modernization plans will be greatly facilitated if utilities fully document the purpose of each grid modernization component, as well as the purpose of the total portfolio of these components. Section 2 of this report describes DOE's taxonomy for identifying principles, objectives, capabilities, functionalities, and technologies for grid modernization proposals. This taxonomy could be used to provide a justification for how certain components and technologies will meet regulatory objectives and comply with regulatory principles. This taxonomy also can be used to assist with decisions regarding the timing and the proportional deployment of grid modernization components.

In their grid modernization plans, utilities should distinguish between proposed investments that are core components and applications. Further, they should explain how each proposed investment in the context of stated objectives, whether proposed investments are needed to meet regulatory standards and requirements, and whether they are needed to enable other technologies or resources.

Articulating the purpose of each proposed grid modernization investment in these ways will aid state regulators in determining when to apply a least-cost, best-fit approach or a BCA approach.

Determining When to Apply the Least-Cost, Best-Fit Approach

The least-cost, best-fit approach may be warranted when there is a clearly defined need for a grid modernization investment and the purpose of the analysis is how to best meet regulatory requirements and objectives.

Compared to the BCA approach, this approach offers several advantages: It is relatively simple, accounts for interactive effects of grid modernization components, and does not require detailed, monetary estimates of benefits because they already have been deemed to be sufficient. However, the least-cost, best-fit approach does not quantify the net benefits to customers of meeting identified objectives. Consequently, regulators may wish to apply the least-cost, best-fit approach judiciously to those grid modernization components that are necessary to meet regulatory requirements and objectives.

As described above in Section 3.0, regulators can take into account several considerations to determine whether to apply least-cost, best-fit to proposed grid modernization investments. First is whether the proposed investment is a core component or an application. *Core*, or platform, components represent foundational elements that are necessary for providing the services required of modern grids. These components are therefore well-suited for the least-cost, best-fit approach. *Applications*, or modules, represent additional, single-purpose components that can be layered on top of the core components to provide additional functionality. Such components are therefore well-suited for the BCA approach.

Another consideration is the driver, or rationale, for the proposed grid modernization investment. The DOE Guidebook recommends that investments driven by *joint benefits* or *compliance with standards* or *policy mandates* should be subject to a least-cost, best-fit approach, whereas investments driven by *net customer benefits* should be assessed using a standard BCA approach to demonstrate that the investment will provide net benefits.

The utility's justification for using a least-cost, best-fit approach to economic evaluation of proposed grid investments should include a complete description of whether and how each proposed grid modernization component:

- is needed to meet objectives identified in a utility's long-term, strategic grid modernization plan;
- should be defined as a core component;
- is driven by compliance with standards or regulatory mandates; and
- is driven by the need to provide joint benefits or enable interrelated components.

Public utility commissions will review these justifications and consider the costs. For example, while the commission might agree to increased reliability as an objective, various grid modernization components might offer different degrees of increased reliability, at different costs to customers. As another example, a variety of options may be available for meeting regulatory mandates, and public utility commissions can compare those options using a BCA approach.

In some cases, a combination of least-cost, best-fit and BCA approaches may be appropriate. For example, if a utility proposes grid modernization components for the purpose of supporting increased integration of DERs, the utility should ideally conduct long-term strategic planning exercises to determine the objectives of grid modernization and assess the cost-effectiveness of DERs. If the utility finds the DERs to be cost-effective, the objective may to make grid modernization investments to enable their deployment. This objective then justifies the application of the least-cost, best-fit approach for assessing those grid modernization investments.

Choosing a Benefit-Cost Analysis Framework

Ideally, public utility commissions should articulate a BCA framework for grid modernization prior to the development and submission of grid modernization plans. This allows for stakeholder input and regulatory guidance in developing the framework, outside of the review of specific grid modernization proposals. Such a framework also allows the utility to conduct a more robust BCA for specific proposals so that commissions and stakeholders can focus on the analyses and results rather than the framework itself.

Public utility commissions may wish to require the use of multiple tests for grid modernization BCA, because a single test is unlikely to provide all the relevant information for deciding what projects are likely to provide net benefits and be consistent with regulatory goals.

The Utility Cost test provides extremely useful information for determining the likely costs and benefits for all electricity customers. This test provides an indication of how utility revenue requirements and average customer bills will be affected by grid modernization proposals. It is a conventional test that has been used for many years to assess whether utility investments are reasonable and in the public interest.

One limitation of the Utility Cost test is that it does not account for some regulatory goals, some of which are instrumental drivers behind grid modernization proposals. For example, the traditional Utility Cost test does not account for low-income customer benefits, but this may be an important regulatory goal. The typical response to this limitation of the Utility Cost test is to use the Societal Cost test because it better accounts for regulatory goals.[45]

[45] DOE 2017, Volume III; EPRI 2015; NY PSC 2016; RI PUC 2017.

As Section 3 explains, the National Standard Practice Manual articulates a more nuanced approach to determining a BCA test. Utilities and public utility commissions do not need to be confined to the traditional Utility Cost or Societal Cost tests. Instead, they can develop a Regulatory test that reflects the regulatory perspective and accounts for specific regulatory goals of their state. Such a test would likely be broader than the Utility Cost test and narrower than the Societal Cost test.

To gain a thorough understanding of the benefits and costs of grid modernization, it might be best to apply both the Utility Cost test and the Regulatory test. The former provides a relatively simple indication of costs and benefits to utility customers that are paying for grid modernization, and the latter indicates how grid modernization projects are likely to meet regulatory goals and objectives more broadly.

All the BCA tests are limited in that they do not provide much useful information on customer equity issues. They do not indicate whether some customers will experience very different costs or benefits than others, or whether some customers will experience enhanced electricity services more than others. Below we discuss options for state public utility commissions to address customer equity concerns.

Choosing a Discount Rate

In the context of utilities under the oversight of a state public utility commission, the choice of discount rate is essentially a regulatory decision. It does not influence the utility's cost of capital, nor does it influence the utility's ability to recover its cost of capital. The discount rate chosen for grid modernization BCA, or any BCA, should reflect the regulatory time preference—i.e., the priority that the public utility commission wishes to place on short-term versus long-term impacts of grid modernization.[46] This regulatory time preference should reflect the energy goals of the state and be informed by robust stakeholder discussion and input.

Further, the choice of a discount rate should recognize the objective of the BCA. In this case, the objective of the BCA is to determine whether proposed grid modernization investments will help meet the overall goals of safe, reliable, low-cost, equitable service to customers over the selected timeframe.

As noted above, many grid modernization plans use the utility WACC as the discount rate. The utility WACC reflects the time preference (i.e., the opportunity costs) of utility investors, but might not reflect a time preference that is consistent with regulatory goals. Consequently, the utility WACC might not be the appropriate discount rate to use for grid modernization BCA. A discount rate based on the utility WACC is typically higher than one that reflects regulatory goals.[47]

Estimates of utility costs for BCA analysis should use the cost of capital incurred by the utility for each investment, because this reflects actual costs incurred. The choice of discount rate, however, does not have to equal the utility's cost of capital. The utility's cost of capital is used to develop the best forecast available of likely costs incurred over the study period, while the discount rate is used to determine how much weight to give to short-term versus long-term costs when making decisions about utility investments.

The utility WACC offers the advantage of being a conventional approach familiar to utilities and public utility commissions. However, a discount rate that reflects regulatory goals has the advantage of being

[46] NSPM 2017, Chapter 9. This issue of short-term versus long-term priorities is separate from the decision about the length of the study period of the economic analysis. The length of the study period should always be sufficient to capture the anticipated lifetime costs and benefits of the proposed investments. The discount rate decision affects how much weight to give to the short-term versus long-term impacts throughout the study period.

[47] NSPM 2017, Chapter 9.

consistent with the objective of the BCA and better reflecting regulatory priorities. Public utility commissions could require utilities to analyze grid modernization scenarios with both the conventional utility WACC discount rate and a different discount rate that reflects regulatory goals. For example, a reference case could use the utility WACC, and a sensitivity case could use a lower discount rate to reflect the regulatory time preference.

Accounting for Interdependent Components

One of the most vexing challenges of grid modernization BCA is to properly understand and account for the interdependencies among different grid modernization components. The interdependence among some components raises the question of whether they should be reviewed in isolation, in combination with others, or as part of a single portfolio. None of the 21 grid modernization plans we reviewed evaluated every component in isolation. Most plans bundled components in logical configurations, and some plans simply reviewed all grid modernization components as a single portfolio.

Each public utility commission will need to answer this separation-versus-bundling question in a way that suits its needs, depending on the level of scrutiny it chooses to apply in reviewing grid modernization proposals.

One way to address interdependent components is to apply the least-cost, best-fit approach to grid modernization projects that are especially interdependent or fundamental. As described in Section 2, this approach can be used for platform components that play a foundational role in the grid modernization projects and are often needed to enable or support other grid modernization projects. If the least-cost, best-fit approach is used for some grid modernization components, then these components can be evaluated as a portfolio, and it is not necessary to evaluate each of them in isolation.

If public utility commissions are not satisfied with the justification for the least-cost, best-fit approach, or if they seek more information than is provided by that approach, they can direct the utility to conduct economic analyses to illustrate the implications of combining grid modernization components into logical bundles based on their interdependent natures and how they might support policy and timing objectives. Analyzing grid modernization components in logical bundles can provide useful information on their costs and benefits without conducting a BCA for each component in isolation.

A bundling analysis might include different combinations of grid modernization components that are considered foundational, or different combinations of foundational and optional grid modernization components. The example below illustrates how a bundling approach can be used to investigate interactive effects.

Example: Bundling Scenarios Can Be Used to Evaluate Interdependencies

In this example a utility is proposing the following components as part of its grid modernization plan: ADMS, GIS, DSCADA, OMS, FLISR, DERMS, AMI, and VVO. The utility conducts several scenarios to demonstrate the costs and benefits of different combinations of technologies. The first scenario includes all the components that are considered to be platform components: ADMS, GIS, DSCADA, and OMS. The second scenario adds two modular applications to the platform components: FLISR and VVO. The third scenario adds two more modular applications (AMI[48] and DERMs) to the second scenario.[49] Table 8 presents hypothetical results of these three scenarios.

Table 8. Example of Scenarios to Test Interactive Effects

	1. Platform Components Only	2. Platform Plus FLISR and VVO	3. Scenario 2 Plus AMI and DERMs
Costs (Mil PV$)	24	28	32
Benefits (Mil PV$)	22	36	38
Net Benefits (Mil PV$)	-2	8	6
Benefit-Cost Ratio	0.9	1.3	1.2
Findings:	not cost-effective	cost-effective	potentially cost-effective

In this hypothetical example:

- Scenario 1 is not cost-effective. Regulators should be reluctant to approve such a scenario that includes platform components only.
- Scenario 2 is cost-effective. This finding suggests that the platform components are a reasonable investment, as long as they are used to support cost-effective modular applications.
- Scenario 3 could be interpreted in two ways. One interpretation is to decide that AMI and DERMs are reasonable investments because they will result in net benefits to customers when combined with other grid modernization components. Another interpretation is that AMI and DERMs are not cost-effective because they reduce the net benefits offered by the other grid modernization components in Scenario 2. The choice of interpretation is up to each state.

The results for Scenario 3 suggest additional analysis may be warranted. One option is to prepare additional scenarios with AMI separated from DERMs to see how cost-effective they are on their own. Another option is to look deeper into the unmonetized benefits of this scenario. This option is addressed in the example presented in the following section.

Accounting for Unmonetized Benefits

Grid modernization benefits should not be ignored because they are not monetized. Assuming that these benefits do not exist or are not worth anything skews BCA against grid modernization projects. Conversely, providing only qualitative justification for benefits does not provide public utility commissions and others with sufficient evidence to determine if benefits exceed the costs.

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[48] This analysis might focus on just the smart meter component of AMI.

[49] A variety of other scenarios could be evaluated to test components in isolation or in other combinations.

Several approaches can be used to improve how grid modernization BCA accounts for unmonetized benefits:

1. *Put as many benefits as possible in monetary terms.* Methodologies are improving for monetizing some benefits that have been hard to monetize in the past—for example, for resilience.[50] Utilities can use the most up-to-date practices to monetize benefits wherever possible. Any monetization of hard-to-monetize benefits should be fully documented and justified.

2. *Define benefits in such a way that they can be monetized.* For example, in the 21 grid modernization plans we reviewed, many utilities cited increased DER adoption as a key benefit, but none of them provided a monetary value. If this benefit were instead defined in terms of the reduced generation, transmission, and distribution costs associated with the incremental DERs, the benefit could be monetized. If these benefits are already included in the monetized energy, capital, and O&M savings, then perhaps increased DER adoption should not be included among the benefits, to avoid double-counting and to reduce the number of benefits expressed only in qualitative terms.

3. *Provide as much quantitative data as possible*. Quantitative data can be useful, even if it is not put into monetary terms. For example, providing estimates of the type and magnitude (numbers, capacity, energy) of incremental DERs implemented as a result of grid modernization can be useful for assessing the value of that benefit.

4. *Use the least-cost, best-fit approach to mitigate the need to develop monetary estimates for all benefits.* This approach is focused entirely on costs, seeking to find the lowest-cost way to achieve the best fit and desired outcomes. However, the least-cost, best-fit approach should be applied only to those grid modernization components that are deemed to be necessary.

5. *Establish metrics to assess benefits, especially those that are not monetized.* Metrics are important to assess progress toward achieving benefits.[51] For example, if the utility does not monetize safety, resilience, or power quality benefits in its grid modernization plan, state regulators can establish metrics to indicate the extent to which these benefits will be experienced. Metrics can offer a quantitative way to assess the extent of the benefit, short of having monetary values for this purpose.

6. *Apply quantitative techniques that can provide helpful information regarding the impacts of unmonetized benefits on BCA results.* This quantification could include, for example, using a point system to assign value to unmonetized benefits; using a weighting system to assign priorities to unmonetized benefits; assigning proxy values for significant unmonetized benefits; and using multi-attribute decision-making techniques. The example below illustrates how a point system can be used to consider unmonetized effects.

[50] Converge 2019.
[51] GMLC 2017.

Example: A Point System Can Be Used to Consider Unmonetized Benefits

This example builds off the previous example. A utility is proposing the following components as part of its grid modernization plan: ADMS, GIS, DSCADA, OMS, FLISR, DERMS, AMI, and VVO. The utility conducts three scenarios, equivalent to the previous example: (a) including all the components that are considered to be platform components, (b) adding two modular applications to the platform components, and (c) adding two more modular applications to the second scenario.

Also, in this example, the utility has identified two benefits that are expected to be significant but were not monetized: increased resilience and increased customer choice and flexibility. The utility assigns points for these benefits to each of the scenarios: 0 = no benefits; 1 = low benefits; 2 = moderate benefits; and 3 = high benefits. Table 9 presents some hypothetical results using this approach.

Table 9. Example of Scenarios to Account for Unmonetized Benefits

	1. Platform Components Only	2. Platform Plus FLISR and VVO	3. Scenario 2 Plus AMI and DERMS
Monetary Impacts:	---	---	---
Costs (Mil PV$)	24	28	32
Benefits (Mil PV$)	22	36	38
Net Benefits (Mil PV$)	-2	8	6
Benefit-Cost Ratio	0.9	1.3	1.2
Unmonetized Impacts:	---	---	---
Resilience	1	1	3
Customer Choice & Flexibility	1	2	3
Findings:	not cost-effective	cost-effective	cost-effective

In this hypothetical example:

- Scenario 1 is not cost-effective based on monetary impacts, and the additional unmonetized points are not very high. This suggests that Scenario 1 might not be cost-effective.

- Scenario 2 is cost-effective based on monetary impacts alone and is even more cost-effective considering the additional unmonetized points.

- Scenario 3 is not most cost-effective based on monetary impacts alone, because it reduces the net benefits and the benefit-cost ratio relative to Scenario 2. However, this scenario is assumed to have significant resilience and customer choice and flexibility benefits, as indicated by the unmonetized points. Given this additional information, regulators might decide that this scenario is cost-effective.

Accounting for Uncertainty

All utility planning exercises involve a significant amount of uncertainty, and grid modernization BCAs are no exception. Grid modernization projects involve many uncertainties related to implementation costs, operating costs, technology performance, customer adoption of DERs, technological obsolescence, stranded assets, and evolution of new customer options such as community choice aggregation and third-party service providers.

Grid modernization BCA should take advantage of a variety of approaches that are currently used to account for uncertainty in long-term utility resource planning exercises.[52] Uncertainty considerations can be applied at the technology level. For example, proxy values can be applied to represent positive or negative risk by applying contingency costs or by using ranges of costs or benefits. Uncertainty considerations can be accounted for more broadly across the utility system using techniques such as probabilistic modeling or expected value assessments.[53] Systemic industry uncertainties, such as evolution of new customer options, can be accounted for using scenario and sensitivity analyses.

Bill Impact Analyses

BCA results are typically presented in terms of net present values of costs and benefits. But without more context, it is difficult to assess how these costs and benefits will directly affect customers and the costs they pay for electricity services.

Long-term bill impact analyses can complement BCA by providing information on how much typical customer bills are likely to increase or decrease as a result of the proposed grid modernization projects. While customer bills are not the only measure of net benefits, customer service, or customer satisfaction, they are an important metric nonetheless. Bill impact analyses are frequently performed in the context of rate cases, and the same technique can be applied to grid modernization BCA.

Bill impact analyses should use a study period that is as long as the BCA study period. While the costs of grid modernization projects tend to occur in the early years, benefits are experienced over the long term. Bill impact analyses should use the same costs and benefits that are included in the Utility Cost test because this test includes the revenue requirement impacts that affect customer rates and bills.

Generally, bill impact analyses should be based on the entire portfolio of grid modernization components, rather than separate components. However, if public utility commissions want to investigate certain marginal grid modernization components, it might be useful to conduct bill impact analyses on those components in isolation.

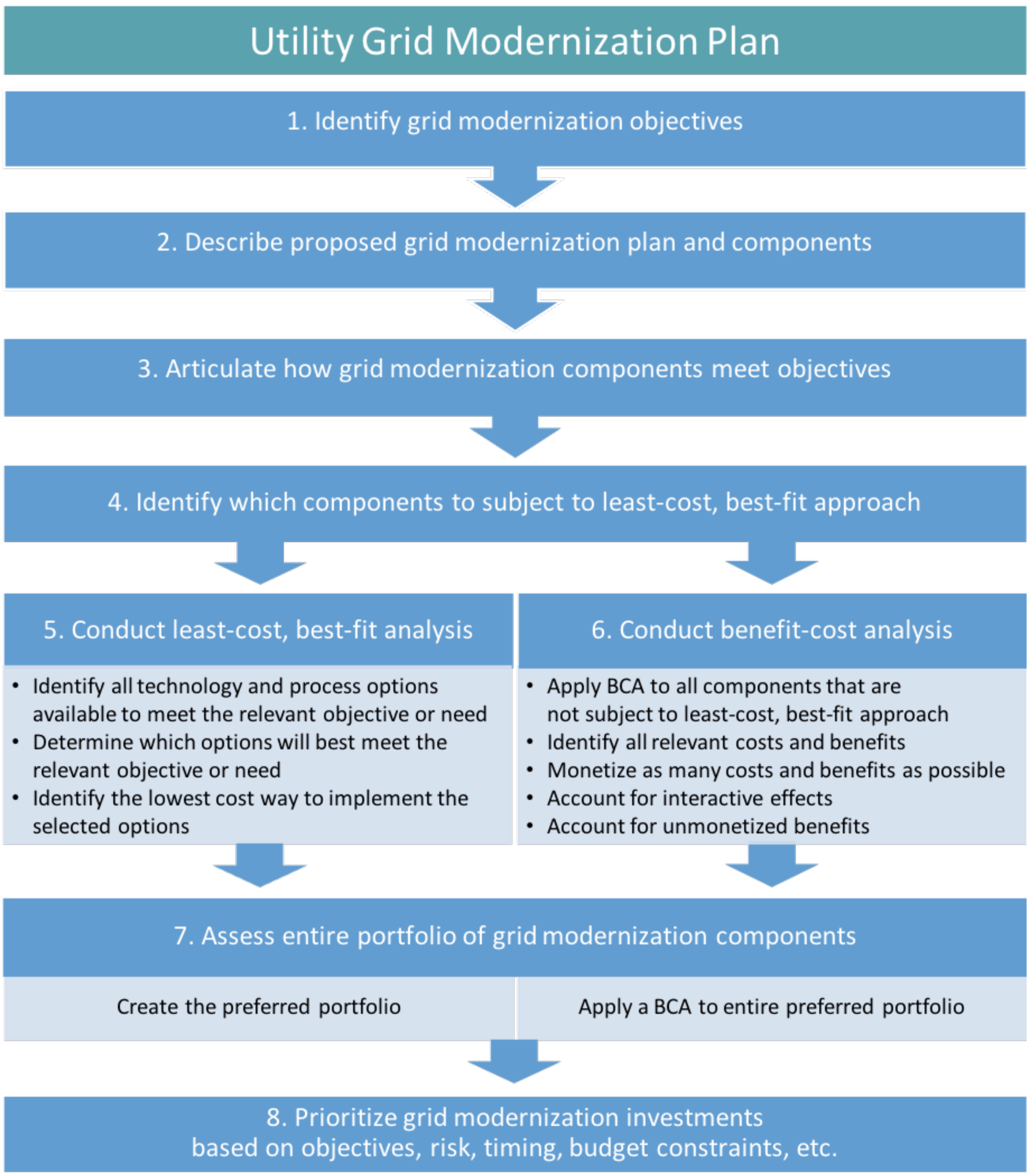
[52] See CERES 2012, especially chapter 4.
[53] For more information on risk assessment and management, see IEC 2019.

6.0 Summary

This section provides a summary of the process for developing BCA for grid modernization investments.

Figure 7 presents a chart showing steps a utility can take to develop a grid modernization BCA, based on the approaches described in this report and consistent with DOE's Guidebook. The chart depicts an aspirational or ideal process from the perspective of regulatory review. It provides as much transparency as possible for the benefit of public utility commissions, utility consumer representatives, and other stakeholders reviewing the BCA.

Figure 7. Steps for Conducting a Grid Modernization BCA



Following is a description of each of the steps in Figure 7.

1. **Identify grid modernization objectives**. Use a long-term strategic grid modernization plan to identify objectives, including reliability and safety objectives, regulatory mandates, and regulatory policy goals.

2. **Describe the proposed grid modernization plan and components**. This step includes a thorough description of each of the grid modernization components independently as well as how they interact with each other, and whether and how the components enable other components.

3. **Articulate how the grid modernization projects meet objectives**. Grid modernization investments are often justified on the basis of a variety of benefits that are beyond the minimum regulatory requirements of providing safe and reliable service at reasonable cost. If a utility seeks to justify grid modernization investments based on other regulatory objectives, these goals should be clearly articulated in the grid modernization proposal.

4. **Identify which components should be subject to a least-cost, best-fit approach**. Proper documentation for when to apply the least-cost, best-fit approach is critical to ensuring that the economic analysis provides sufficient justification of benefits to customers. There are several factors to consider when making this determination, including whether the component is a core component, whether the component is necessary to meet stated objectives, whether the component is needed to meet regulatory standards and requirements, whether the component is needed to enable other technologies or resources, and how much scrutiny the public utility commission wants to apply to specific components.

5. **Conduct the least-cost, best-fit analysis**. This step requires identifying all of the technology and process options available to meet the relevant objective or need, determining which options will best meet those objectives and needs, and identifying the lowest cost way to implement the selected options. These tasks can be supported by issuing requests for proposals for qualified vendors to meet the objectives and needs at the lowest cost.

6. **Conduct the BCA**. A standard BCA approach should be applied for all grid modernization components that are not subject to a least-cost, best-fit approach, or that public utility commissions decide warrant greater scrutiny than offered by that approach. Using a standard BCA approach, the utility makes a clear case that the benefits exceed the costs for each proposed investment.

   Identify all relevant costs and benefits. Begin with a full inventory of all relevant costs and benefits for each component under consideration. This inventory should be consistent with the primary and secondary BCA tests identified by the public utility commission.

   Monetize as many costs and benefits as possible. Monetizing as many of the costs and benefits as possible makes the BCA more transparent and reduces the need to account for unmonetized impacts using alternative approaches.

   Conduct a BCA for the component. This step should account for all monetary costs and benefits for each component in isolation.

   Account for interactive effects. One way to account for interactive effects of grid modernization components is to combine them in logical bundles to assess how they provide benefits when operating together (see Section 5).

Account for unmonetized benefits. In the absence of monetary values for some benefits, other quantitative techniques can provide helpful information regarding likely impacts of a grid modernization component (see Section 5). Such techniques could be applied at this stage for components expected to have significant benefits that are not monetized and a benefit-cost ratio less than 1.0.

7. **Assess entire portfolio of grid modernization components**. This step includes combining the results of the steps above to create a holistic picture of all the grid modernization components that the utility is proposing.

    Create the preferred portfolio. This step uses the combined results of the BCA and the least-cost, best-fit analyses to determine the combination of grid modernization components that best meets regulatory objectives and optimizes net benefits for utility customers.[54]

    Apply a BCA to the entire portfolio. This step includes analyzing all monetary costs and benefits of the preferred portfolio. This analysis serves as a double-check to the least-cost, best-fit analyses. If the preferred portfolio has a benefit-cost ratio exceeding 1.0, then public utility commissions can conclude that the portfolio will result in net benefits to customers. Otherwise, utilities may need to prioritize which investments to make and when.

8. **Prioritize grid modernization investments and objectives**. Utilities can prioritize grid modernization investments based on grid modernization objectives. Prioritization might lead to a longer implementation period with staggered investments, different sequencing of investments, downsizing of investments, or some other way to comply with regulatory constraints. In addition, public utility commissions might cap the level of grid modernization costs that go into retail rates at any one time.

[54] We refer to this portfolio as the "preferred portfolio."

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