

The Economics of Customer and Grid Connectivity and Grid Interoperability

*Evaluation of the Potential Impacts of Interoperability in Utility Economic
Analyses and Program Design*

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The Economics of Customer and Grid Connectivity and Grid Interoperability

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Technical Update, December 2018

EPRI Project Managers

B. Ealey
C. Holmes

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Principal Investigators and Authors

G. Ghatikar

C. Holmes

B. Ealey

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ABSTRACT

Government and utility grid modernization initiatives are deploying grid-connected and communicating distributed energy resources in a fast-changing technology landscape. In the United States, a new challenge is emerging. Energy policies were enacted that favor renewable generation and distributed energy resource technologies such as energy efficiency, demand response, energy storage, and electric vehicles. These disparate and multi-vendor technologies require device- and system-level connectivity and interoperability. The integration of these technologies into utility programs and systems prompts utilities to make a number of communications related decisions, each potentially impacts the initial and on-going costs of programs. These requirements are therefore of paramount importance for both grid operators and customers to maximize benefits and minimize risk in utility programs.

The research value of interoperability is well understood based on previous studies. For example, the U.S. Department of Energy (DoE) research has shown that interoperability lowers the integration cost and improves grid efficiency. However, there lacks much needed support for utilities and customers on the economic benefits of connectivity and interoperability. Specifically, the questions that emerge are:

- How connectivity and interoperability supports the utility business needs?
- What interoperable communications considerations must be made to lower capital and operational expenses and reduce the grid-asset risks?

In support of utility requests to better understand the value behind the requirements of communications to integrate grid- and customer-systems, this study focuses on a high-level overview of economic benefits of interoperable connectivity between distributed energy resources and associated systems.

Keywords

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Grid Architecture
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PRIMARY AUDIENCE: Electric Utility, Grid Operators, and Regulators

SECONDARY AUDIENCE: The Vendor Community and Electricity Customers

KEY RESEARCH QUESTION

To support scaled deployments of distributed and grid-connected energy resources, the following questions are answered:

- *How connectivity and interoperability supports the utility business needs?*
- *What interoperable communications considerations must be made to lower capital and operational expenses and reduce the grid-asset risks?*

RESEARCH OVERVIEW

The study first creates a list of high-level grid interoperability requirements to understand connectivity and interoperability use cases. Then the methods for capturing interoperability in utility economic analyses are studied. Finally, each of the interoperability use cases are paired with high-level economic impacts that utility program designers can use to more accurately capture the benefits of interoperable communications.

Note that the lessons from deployments can lead to further need for interoperability benefits assessment where a similar methodology can be applied for continuous and evolving grid modernization and to upgrade efforts and research needs.

KEY FINDINGS

- Interoperability is not a single technology or product. Interoperability is a concept that may include new processes, protocols, application of standards, or technologies. It is often an applied concept – technologies and products may support these processes, protocols, application of standards, or technologies making interoperability easier to achieve.
- Interoperability considerations for connected devices and systems may reduce costs, improve grid reliability, or result in a better customer experience.
- The quantifiable benefits of interoperable connectivity often impacts service quality or customer satisfaction which can be more difficult to quantify in economic analyses. This paper identifies some mechanisms which can be used to quantify benefits of interoperable connectivity.
- Project evaluators must use their judgement when evaluating a capital investment that has interoperability characteristics that are difficult to estimate.
- Utilities may seek expert legal advice on contract terms and contract structures that are designed to reduce utility performance risk and shift risks to the vendor.

WHY THIS MATTERS

Utilities are connecting customer-owned devices in increasing numbers to help provide flexibility to manage grid beyond traditional distribution system assets. The integration of these technologies into utilities programs prompts utilities to make a number of communications related decisions, each potentially impacts the initial and on-going costs of programs. This project will provide an analysis of which communications decisions have the largest impact on program costs. It will then evaluate how to account for them in cost tests to improve program analysis.

HOW TO APPLY RESULTS

In support of utility requests to better understand the value behind the requirements of communications to integrate grid- and customer-systems, this study focuses on a high-level overview of economic benefits of interoperable connectivity between distributed energy resources and utilities or other similar grid operators. Utility program evaluators can use the results of this study to learn potential mechanisms to quantify benefits of interoperable connectivity.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- *Mounting Importance of Communications to Monitor and Control Distributed Energy Resources*. EPRI, Palo Alto, CA: 2018. 3002013480.
- *The Value of Direct Access to Connected Devices*. EPRI, Palo Alto, CA: 2017. 3002007825
- *IEEE Standard 1547™ — Communications and Interoperability: New Requirements Mandate Open Communications Interface and Interoperability for Distributed Energy Resources*. EPRI, Palo Alto, CA: 2017. 3002011591.
- *Protocol Reference Guide: Understanding the Characteristics of Communications with Distributed Energy Resources*. EPRI, Palo Alto, CA: 2018. 3002013621.
- *Supplemental Project – Distributed Energy Resources Communication Standards and Protocols Harmonization Project*. EPRI, Palo Alto, CA: 2018. 3002014601

EPRI CONTACTS: Rish Ghatikar, Senior Program Manager, rghatikar@epri.com, Chris Holmes, Principal Technical Leader, cholmes@epri.com, Ben Ealey, Senior Project Manager, bealey@epri.com

PROGRAMS:**Program 161: Information and Communication Technology**

PS161D: Applied Information and Communication Technology for Distributed Energy Resources and Demand Response. Program 170: End-Use Energy Efficiency and Demand Response

PS170A: Energy Analytics & Market Insights

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3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA

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1

INTRODUCTION AND BACKGROUND

Government and utility grid modernization initiatives are deploying grid-connected and communicating distributed energy resources in a fast-changing technology landscape.^{1,2} In the United States (U.S), a new challenge is emerging. In 2017, over 78 million smart meters were deployed.³ Energy policies were enacted that favor renewable generation and distributed energy resource (DER) technologies such as energy efficiency, demand response (DR), energy storage, and electric vehicles. These disparate and multi-vendor technologies require device- and system-level connectivity and interoperability. The National Institute of Standards and Technology defines interoperability within the context of standards-based communications, as the “process of achieving technical equivalency and enabling interchangeability between different standards with overlapping functionality.”⁴ Connectivity and interoperability in the context of this study is described, as the integration of information among grid networks, systems, and electricity markets through data and transport mechanisms, and co-existence with synergistic standards.⁵ These requirements are of paramount importance for both grid operators and customers since they reduce the deployment costs and risks of technology lock-ins.

The research value of interoperability is well understood based on the previous studies. For example, the U.S. Department of Energy (DoE) research has shown that interoperability lowers the integration cost and improves grid efficiency.^{6,7} However, there lacks much needed support to the utilities and customers on the economic benefits of connectivity and interoperability. Specifically, the questions that emerge are—*How connectivity and interoperability supports the utility business needs? What interoperable communications considerations must be made to lower capital and operational expenses and reduce the grid-asset risks?*

In support of utility requests to better understand the value behind the requirements of communications to integrate grid- and customer-systems, this study focuses on a high-level overview of economic benefits of interoperable connectivity between distributed energy resources and utilities or other similar grid operators.

¹ The U.S. Department of Energy (DOE), “Grid Modernization Multi-Year Program Plan.” November 2017.

² Hawaiian Electric, Maui Electric, and Hawaii Electric Light, “Modernizing Hawai’i’s Grid for our Customers,” August 2017.

³ The U.S. Energy Information Administration (EIA), “How many smart meters are installed in the United States, and who has them?” <https://www.eia.gov/tools/faqs/faq.php?id=108&t=3> (Accessed on November 21, 2018)

⁴ National Institute of Standards and Technology (NIST) Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0 2010.

⁵ *Supplemental Project - Distributed Energy Resources Communication Standards and Protocols Harmonization Project*. EPRI, Palo Alto, CA: 2018. 3002014601

⁶ The U.S. Department of Energy (DOE) Grid Modernization Lab Consortium (GMLC), “Interoperability Strategic Vision: A GMLC White Paper.” March 2018. PNNL-27320.

⁷ The U.S. Department of Energy (DOE), “The SunShot Initiative’s 2030 Goal: 3¢ per Kilowatt Hour for Solar Electricity.” 2016.

The study objectives are:

- Define the key connectivity requirements to integrate grid- and customer-systems.
- Develop high-level interoperability use cases for connected devices and systems.
- Highlight the economic assessment criteria to articulate the interoperability benefits.

A Utility Context

Connectivity and interoperability investments, from an electric utility perspective, create value to customers through reduced cost or increased comfort, convenience, control, and certainty/confidence. Interoperability can be used to integrate devices and grid systems across vendors and ease the maintenance of these interfaces over the life of the system and associated connected devices. These utility investments create value to stakeholders including customers, shareholders, suppliers, and employees.

In the early 1990s a set of economic evaluations allowed regulators to compare alternative value when making investments for both the supply and the demand side of a utility's business. Up to that point some claim that utilities were biased in favor of supply-side only investments. The regulators embraced this integrated resource planning approach as a way to meet help policy objectives. This paradigm shift will be key in considering interoperability in economic analyses.

This study focuses on the interoperability aspects of energy efficiency and demand response (DR) programs. Connectivity and interoperability requirements have a significant impact on the cost effectiveness of these devices and their grid connectivity. This will require careful analysis of incurred costs. Utilities use cost tests to determine the economic performance of customer facing programs. There is a need for cost tests to quantify the impact of all aspects of DER programs because of the rising application of DER (including energy efficiency and demand response technologies). This study focuses on the interoperability aspects of *energy efficiency and demand response*. Interoperability ultimately has a significant impact on the cost effectiveness of these devices and grid interconnections and careful analysis of the risks and benefits from their application.

It is important to note that interoperability is not a single technology or product. Interoperability is a concept that may include new processes, protocols, application of standards, or technologies. It is often an applied concept – technologies and products may support these processes, protocols, application of standards, or technologies making interoperability easier to achieve.

Study Methodology

Figure 1-1 shows the study methodology. First a list of high-level grid interoperability requirements is generated to understand the connectivity and interoperability use cases. These extrapolate the use cases for with connectivity objectives

through a qualitative review of utility and customer benefits. These use cases are used to conduct economic assessments, and to derive conclusions on the value of interoperability for integrated utility deployments of DER technologies. Note that the lessons from deployments can lead to further need for interoperability benefits assessment where a similar methodology can be applied for continuous and evolving grid modernization and upgrade efforts and research needs.

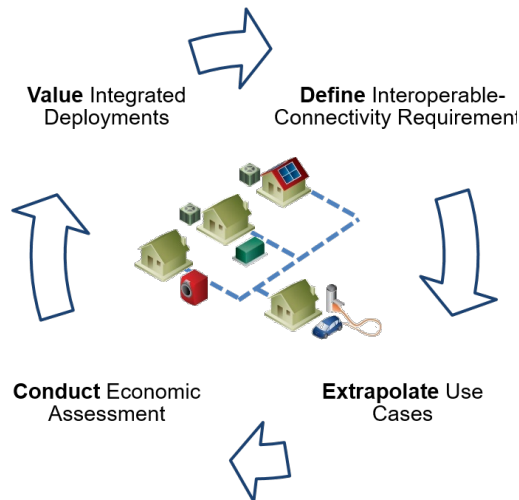


Figure 1-1
Study Methodology

2

DEFINING THE INTEROPERABLE-CONNECTIVITY REQUIREMENTS

Is it important to consider the ownership models and the degree of disparity of connected grid and customer systems to define interoperability requirements and articulate economic value. While connectivity is imperative in the integrated grid context, interoperability may not be. Consider the example of interoperability of smart thermostats with utility demand response (DR) program(s). The value of interoperable-connectivity can be derived from the inevitable disparity of DER technologies and ownership models within the grid and customer domains. If a single vendor is used, then the value of interoperability is less because only a single interface must be supported. However, if a utility uses a mixture of “bring your own thermostat” programs and third-party service providers then the value of interoperability would be high because these disparate technologies may be more difficult to integrate.

This spectrum is shown in Figure 2-1. The DER technologies can have different system and ownership boundaries for utility and customer systems. This can lead to many approaches required to enable their connectivity. Such disparate DER technologies and communications can exist within the transmission and/or distribution grid. It should be noted that the value from the deployments of DER technologies can also be the function of electricity market design and the services offered. However, such functions are not focused in the study.

The following are the descriptions of key terms used in defining the interoperable-connectivity requirements:

- **Disparate vs Uniform Technologies:** Many different information and communication technologies may be required to support the devices and systems that provide benefits to utilities through energy efficiency or demand response programs. In Figure 2-1(left and right), disparate technologies are closer to the origin, moving up or down the Y-axis. Moving away from the origin means that technologies are less disparate and therefore more uniform in how they behave, what they can provide, and their interfaces.
- **System Similarity (Customer and Grid):** This references smart grid domains—customer or the distribution grid—where the communication technology is in a single domain. In Figure 2-1(left) systems are at the far left and right of the x-axis are considered solely providing benefits to either the customer or the grid. At the origin, systems are mixed with the technology(ies) providing benefits to both customers and the grid. Moving away from the origin means that the benefits lean more towards customers or the grid.
- **Ownership:** Ownership describes the number of owners for a particular system. In Figure 2-1(right) a single-owner system falls on the far left and right of the x-axis. This may include the owner/operator of a home or a distribution grid managed by a utility. Moving closer to the origin means that the technology has multi-ownership. This refers to technologies that are owned by multiple entities. This may include the owner/operator of a multi-tenant building or a distribution grid managed by utilities.

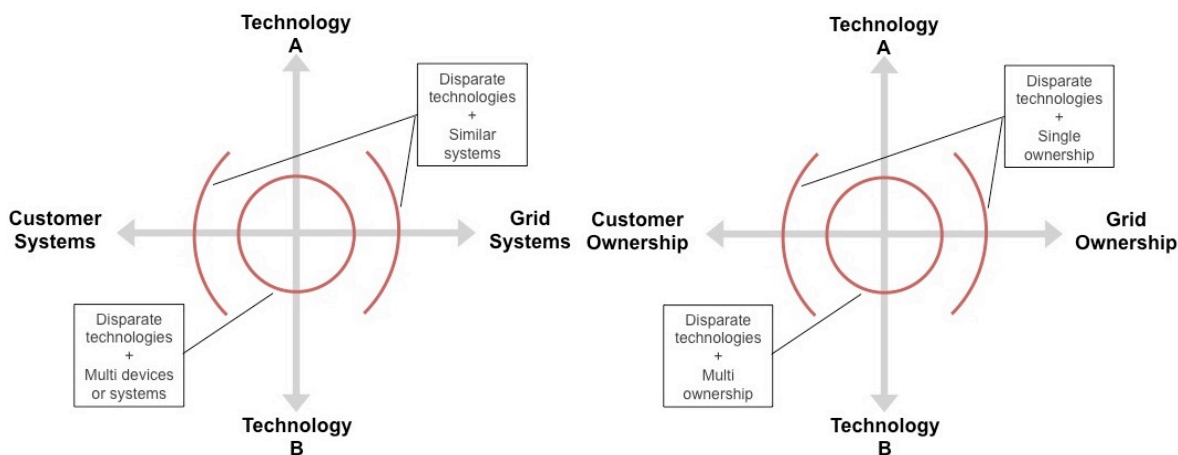


Figure 2-1
Interoperable-Connectivity for Systems (left) and Ownership Models (right)

The key takeaway from Figure 2-1 is that the technologies, systems, and ownership can vary. This is important to understand in this study because the more varied the technologies, systems, and ownership; the more valuable interoperability can be. This is because interoperability helps to reduce challenges with integrating disparate technologies, systems, and ownership models. The impacts of utility decisions, including interoperability, can either relate to higher or lower costs to execute and manage a project, and ultimately the avoidable costs could get transferred to the ratepayers and society.

While there could be other scenarios where the value of interoperability can exist among and between different smart grid devices, systems, and domains,⁸ the study focuses on this framework and interoperability of communications within the distribution grid context—where the electric grid systems interface with the customer devices and systems – however customer benefits are considered tangentially because they can impact customer satisfaction and therefore program metrics like attrition and the number of customers enrolled.

Drivers for Utility Communications Interoperability

Earlier studies have reviewed the communication interoperability benefits for demand response and electric vehicle technologies, and how this precedent was applied for the smart grid, and its domain interfaces.^{9,10,11} These studies have described the innovation system of an open standard before it can become a value to the utility for widespread deployments. Most recent studies¹²

⁸ The National Institute of Standards and Technology (NIST) Special Publication 1108r3, “NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 3.0.” September 2014

⁹ Ghatikar G. and E. Koch, Deploying Systems Interoperability and Customer Choice within Smart Grid, Grid-Interop Conference, December 2012. LBNL-6016E. DOI 10.13140/2.1.5162.8320.

¹⁰ Ghatikar G., J. Zuber, E. Koch, and R. Bienert, Smart Grid and Customer Transactions: The Unrealized Benefits of Conformance, Green Energy and Systems Conference (IGESC), 2014 IEEE, November 2014. DOI 10.1109/IGESC.2014.7018633.

¹¹ *The Value of Direct Access to Connected Devices*. EPRI, Palo Alto, CA: 2017. 3002007825

¹² *Protocol Reference Guide: Understanding the Characteristics of Communications with Distributed Energy Resources*. EPRI, Palo Alto, CA: 2018. 3002013621.

have looked at providing the grid operators and vendors with objective program reference guides to implement open standards or, interchangeably referred to, as protocols, for DER connectivity.¹³ Such open standards have the communication models and its use publicly available where the intellectual-property terms and non-discriminatory use are well described.^{14,15}

From the distribution grid's perspective, interoperable connectivity is driven by three interlinked factors:

1. Distribution grid and customer domains.
2. Devices or systems and automation within these domains.
3. The ownerships of these devices and systems, as alluded in the introduction earlier.

It should be noted that within the distribution grid and customer domains, there is a diversity in ownership models. For example, multiple utilities and/or service providers operating a distribution grid that is servicing a customer, and customers with different service level agreements in a multi-tenant facility. In each of these factors, interoperability for connectivity of devices and systems becomes a critical requirement.

Some of the key benefits of interoperability – such as the facilitator for innovation, competitive markets, public benefits, lowering the barrier for the adoption of technology by easing the integration, automation, etc. – become the drivers for regulators to mandate regulated utilities to adopt open standards that lowers the barriers. Such benefits are typically overlooked by the industry. For this reason, the regulatory entities – such as public utility commissions, regulatory commissions, etc. – play an important role in mandating the use of standards-based communications for connectivity to ensure customers and grid operators' benefit. While in past the technology effectiveness led to the policy changes that encouraged their adoption, in recent years, the clean energy, and grid reliability and resiliency policies are driving accelerated development and adoption of an interoperable framework as a precursor to the field deployments. Hence, this assessment forms a lens of economics to help utilities reduce the risk and uncertainty in the evaluation of interoperable technologies and its incorporation in programs. Table 2-1 shows the links between the policy and technology drivers, and their interoperability benefits for a distribution grid. The drivers for renewable generation, energy efficiency, and DR are provided to highlight the benefit from interoperability. Energy efficiency and demand response are the focus of this study however the benefits may apply to other DER domains like renewable energy, energy storage, or electric vehicles.

¹³ *Protocol Reference Guide: Overview of Application Layer Protocols for DER and DR*. EPRI, Palo Alto, CA: 2017. 3002009850.

¹⁴ The Organization for Advancement of Structured Information Standards (OASIS), "Intellectual Property Rights (IPR) Policy," <https://www.oasis-open.org/policies-guidelines/ipr> (accessed on December 7, 2018).

¹⁵ The Institute of Electrical and Electronics Engineers (IEEE), "IEEE Intellectual Property Rights," <https://www.ieee.org/publications/rights/> (Accessed on December 7, 2018).

**Table 2-1
Policy and Technology Drivers, and their Cumulative Interoperability Benefits**

Policy Drivers	Technology Drivers	Interoperability Benefits
Renewable Portfolio Standards	<ul style="list-style-type: none"> • Solar photovoltaic (PV) distributed generation • Smart inverters for monitoring and control of interconnection. • Data models to forecast and measure generation. • Tools for predictive and real-time grid balancing. 	<ul style="list-style-type: none"> • Automated data integration of PV, facility, and synergistic DER systems. • PV communication and control standards ease monitoring and generation actuation. • PV systems can integrate with disparate customer- and grid-systems.
Energy Efficiency	<ul style="list-style-type: none"> • Diverse heating, cooling, lighting, and miscellaneous loads become intelligent and connected. • Energy information systems provide tangible efficiency and fault metrics. • Energy management systems becoming increasingly grid-aware 	<ul style="list-style-type: none"> • Automated integration with fragmented end-systems maximizes the value of efficiency and cost savings. • Real-time data analytics for building energy and power management. • Leverage building- and grid-level system integration for grid services.
Demand Response	<ul style="list-style-type: none"> • Advancement in connectivity of in-facility end-use devices/systems for comfort, cost, and convenience. • Transition of traditional DR into anytime DR for demand flexibility • DER technologies can provide demand flexibility. • Electricity market innovation favor customer economics. 	<ul style="list-style-type: none"> • Leverage advanced technologies and device/systems connectivity to ease and scale participation. • Leverage traditional loads to provide flexible demand services. • DER technologies integration with systems and electricity markets. • Multiple value streams from flexible demand for electricity markets.

The economic value of device/system connectivity and interoperability can be well understood by highlighting some of the important use cases that utilities can benefit from. These use cases also form the basis for consideration of connectivity and interoperability in the utility DER deployment program design and their supporting business models.

3

EXAMINING USE CASES INTEROPERABLE COMMUNICATIONS

The first step in this study is to capture the use cases that electric utilities and distribution system grid operators can benefit from interoperability. This provides a foundation for analyzing how each use case may impact utility economic analysis. The following use cases were identified and are listed in no particular order.

- Reliable backhaul communications
- Integration of new devices and systems
- Integrate disparate systems and architecture
- Lower risk of vendor lock-in or stranded assets (or asset re-use)
- Device and/or system installation and commissioning
- Assess and access device/system functionalities
- Two-Way Data Communication for Grid Management
- Customer enrollment and service selection
- Data harmonization from devices and systems

Each of these use cases are analyzed further in this chapter. Each section captures the specific use case objectives and a description of how this may impact a utility. It is important to note that, typically, the use cases capture the processes, pre- and post-conditions, dependencies, and other factors that help define the use case and help the reader understand the content. However due to the high-level objectives of the study they have been excluded from the scope. In addition to these use case details cyber-security has also been omitted in this study though the researchers understand the importance of cyber-security in connectivity and interoperability.

Each of these nine use cases are further described in the sections below with focus on their objective and descriptions, as they relate to the goals and objectives of the study.

Reliable Backhaul Communications

The communications reliability between the utility and customer (within the distribution system, residential, commercial, and industrial) is a prerequisite for a smart grid. This is often referred to the backhaul because it describes the network required to connect the core of the

network to each of individual networks at the edge. In a utility demand response example, the backhaul could be an AMI network, cellular network, or a homeowner's internet service provider¹⁶. This network connects devices or systems that may be operating on a homeowner or site network.

Failures in the backhaul communication between DER and managing entities (utility, aggregator, or owner) is a large factor in attrition of available devices. Technologies to improve reliability of these connections can increase the confidence that the smart grid and its operators' have persistent connectivity connected devices.

One of the most popular communications used by the energy technologies is the customer-owned Internet. Utilities use a mix of AMI networks, cellular, and radio communications to communicate with devices/systems and activate their value. Two cases are important to consider. 1) Intermittency related reliability. This includes occasional loss of communications to a device or system. 2) Permanent issues. This is the loss of devices because of a failure in the connection between the device/system and the core system. The reasons for this are numerous but may include customers changing network settings, changing equipment, or internet service providers. The key difference between intermittent issues and permanent issues is that permanent issues often require some action by the utility/aggregator/retail service provider, the customer, or both.

Intermittency related reliability. Each communication use case has different reliability requirements depending on the services they are used for. For example, day-ahead DR programs do not have the strict telemetry and low-latency requirements that real-time require. The varied reliability requirements for the services offered could lead to different infrastructure and operational costs to the utility that should be integrated (and interoperated) with customer and utility systems, as part of the program design. The requirements are relevant for interoperation with other value-added service providers, such as the aggregators of DR services. This can assist in interoperability of different services to offer multiple benefits to the customers. For example, energy efficiency strategy can be expanded to support DR services.

Permanent issues. Devices and systems can drop off utility programs for a variety of reasons but one significant contributor is some technical issue or failure in the connection of the device to the core system managing the program. These issues often require that utilities or customers notice the issue and take an action to correct it. For example, if the cause is that the homeowner replaced their networking hardware that a connected thermostat was on and didn't reconnect their thermostat to the network then a program administrator may not be able to deliver price signals or demand response signals to that thermostat. A customer may notice and correct the issue themselves or it may take action from the program administrator to correct it. This may include notifying the customer and/or sending a technician to the site to reenroll the device.

Improvement of reliability can also be an important part of utility roadmaps. Utilities may choose to consider requirements and associated performance metrics of these backhaul networks so that they can strategically deploy communications technologies to support future milestones on their roadmaps.

¹⁶ *Internet service providers (ISPs)* are companies that provides subscribers with access to the Internet. This includes companies like AT&T, Comcast Xfinity, Time Warner Cable, Verizon, Charter, and others.

Integration of New Devices and Systems

The proliferation of smart-devices such as smart thermostats that offer value-added features for utility customers (e.g., control using a smart phone), utility benefits (reduction of energy usage), and potentially mutual benefits like energy efficiency had led to utilities using programs like “bring your own thermostat” programs where utility customers can integrate thermostats from a list of supported devices to participate in DR programs. As the number of devices and services come on the market that can offer services to the grid and therefore utility benefits it will be increasingly important that utilities have the capability to integrate these devices/systems into their control architectures.

Enabling efficient integration requires interoperability on the grid- and customer- side to support a variety of communication interfaces (standardized or proprietary). As the numbers rise it may become difficult to integrate a potentially infinite number of proprietary systems so utilities may choose to require standardize interfaces in lieu of allowing vendor proprietary systems.¹⁷ Without interoperability standards, the utility systems need modifications and access to vendor technologies to be able to integrate existing systems. This approach allows a utility to integrate existing devices into DR programs without having to bear all the cost of installing a new model of thermostat specifically deployed for the program.

Integrate Disparate Systems Architecture

The customer choice of devices and systems are based on the individual needs of the customer. This may include decreased energy bills through energy efficiency, comfort, convenience, or others. This is contrasted to the utility which is based on business drivers such as operational efficiency, grid reliability, operational costs, and others. It may be advantageous for utilities to embrace the systems customers choose to accelerate program enrollment by enrolling systems customers have already adopted or are adopting. It can also help to increase program appearance to customers by providing them with choices that may better align with their needs. For this to happen, the existing devices should be integrated into utility systems to expand their capabilities, and to meet utility-supported services. This means that interoperability requirements must be considered to ease the integration of likely disparate customer and field systems and architecture into utility enterprise systems.

Depending on the type of technology and the customer segment, the system architecture varies. For example, some DR programs or dispatches use manual methods like scheduling events over email or phone calls. Other methods use integration at an enterprise system level through a mix of proprietary techniques and standardized techniques. If the customer- and grid-systems must integrate to enable the grid facing benefits and services then the integration requirements and costs to utilities, third-parties, and customers must be considered. An example of this includes potential benefits of automation from an integrated system as opposed to a manual approach.

¹⁷ *Mounting Importance of Communications to Monitor and Control Distributed Energy Resources*. EPRI, Palo Alto, CA: 2018. 3002013480.

While this use case focuses on utilities with integration challenges of existing systems, the aforementioned use case, *Integration of New Devices and Systems*, focuses on the new devices and systems.

Lower Risk of Vendor Lock-In or Stranded Assets (or Asset Re-Use)

Use of closed protocols, as opposed to either open proprietary standards or open standards, often requires utilities to continue to use specific management equipment or aggregators to manage devices. There may be cases where a utility wants to change management equipment or aggregators but cannot do so because the protocol choice has locked them into that specific vendors. While a much of it depends on the probability of an event occurring that may lead a utility to no longer want to use that specific equipment or vendor, the risk of lock-in may lead to stranded assets or reduced capability to negotiate. An example of this is a manufacturer or aggregator going out of business and the utility having no other way to manage those assets.

The consideration of communication interoperability is akin to insurance where the assets and business risks are future-proofed. Leveraging the interoperability and open standards communications, where appropriate, can allow utilities to continue to use existing devices for connectivity while having flexibility to change management equipment, avoid vendor lock-in, encourage competitive innovation, and reduce the possibility of stranded assets (also used interchangeably with asset re-use). This was primary driver for the open protocol requirements in IEEE 1547-2018 which mandates the use of at least one open-protocol in smart inverters.¹⁸ There are some industry stakeholders in favor of following similar requirements for demand response technologies like connected water heaters.¹⁹

Device and/or System Installation and Commissioning/Provisioning

There are significant variations of utility requirements for integration of DERs with the grid, enterprise systems, and utility programs. These variations across utilities and programs create quite a few challenges because there is often information that must be exchanged such as URLs, security credentials, others that may be program specific and custom tailored to a specific program. Very few standardized methods of program enrollment (a prerequisite to device registration) exist. This creates the need for interoperability of communication for installation and commissioning of new devices/systems. The increase in the complexity in commissioning impacts the convenience and adds to the overall cost—scaled exponentially across a diversity of devices that considers customer and utility interests.

The features that enable efficient installation and commissioning of devices saves significant time for utilities. One of the key challenges for the utilities to scale device installation is to automate provisioning of the devices. The understanding of the device functionalities and interoperable data and communications can enable efficient integration of grid and customer devices with utility systems.

¹⁸ 1547-2018 - IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces.” IEEE Xplore – Digital Library, The IEEE Standards Association, 6 Apr. 2018, ieeexplore.ieee.org/servlet/opac?punumber=8332110.

¹⁹ *Mounting Importance of Communications to Monitor and Control Distributed Energy Resources*. EPRI, Palo Alto, CA: 2018. 3002013480.

Assess and Access Device or System Functionalities

The industry is developing methods to quantify the functional interface for utility facing device/system capabilities. For the solar PV these functions are specific where the command is directly linked to a specific electrical impact on the grid and forecasting of generation for reliability reasons. For DR, the functions tend to be more of a request or an “inform and motivate” type of command along with reporting metrics as a receipt of response and performance. Because demand response technologies may not have strictly defined electrical responses the functionality offered by a specific device or system must be characterized. New standards like CTA-2045 support advanced two-way communications where devices can advertise their capabilities before the request to reduce demand allowing the utilities to know capabilities before they happen. Similarly, standards such as OpenADR 2.0 and IEEE 2030.5 have well-established specifications that show the features offered. For standards-based communication interoperability, the conformance assessment and certification is critical to establish certainty of supported functions and establish a market eco-system that can support utility programs.²⁰

The technical and operational understanding of device functionality offered by a device or a system provides the utility with the potential to simplify the assessment of its capabilities and access data from the device. The quantification of device functionality and its interoperable access provides the utility with the ability to monitor and report key grid operational needs.

Two-Way Data Communication for Grid Management

In addition to quantification of device functionality the data management through advanced data analytical methods provide additional uses that supports monitoring and efficient operations of grid-supporting assets. Interoperable two-way with reliable communications enable utilities to manage the data and extract value such as, determining the load shapes, forecasting loads and generation, and monitoring grid and weather conditions. The data management also can help the customers to understand potential issues with their devices and systems to thus diagnose and enable energy services to improve their efficiency. Such data-driven services can provide non-tangible benefits such as customer control in energy management. The data provide another significant value where its use can show savings to utility programs and increase the benefits in the cost-benefit analysis.

The utility’s access to device and system data from grid and customer assets may be valuable to validate a request for real-time dispatch and for increasing accuracy of future program design. Access to data is also critical from developing local intelligence and competitiveness for new business services.

²⁰ Ghatikar G and R. Bienert, Smart Grid Standards and Systems Interoperability: A Precedent with OpenADR, Grid-Interop Conference. December 2011. LBNL-5273E. DOI 10.13140/2.1.4163.4081.

Customer Enrollment and Service Selection

Ease of customer enrollment and service selection of utility offerings is based on the ability of device discovery and enrollment (also termed registration). As a result, interoperability can impact the increase in the enrollment of the devices in the utility programs and their success by making drivers like proactive customer engagement possible.

The traditional enrollment of customers in utility programs had been at the meter-level. The increased deployment of smart meters, and their automated enrollment using AMI and other communication technologies has led to efficient management of customer's energy. While the ease of enrollment is dependent on earlier use cases (e.g., ease of identification of device functionalities), customers' devices can be leveraged to offer value-added services and improve their performance and compliance to program rules.

Data Harmonization from Devices and Systems

Data generated from multiple disparate devices and systems can help utilities operate an integrated and coordinated grid. However, it requires the harmonization of data. Harmonization is the “ability of one or more standards and protocols to interoperate with a diversity of grid standards and protocols to meet integrated grid objective(s).²¹” Focusing on the communication standards, NIST defines it, as the “process of achieving technical equivalency and enabling interchangeability between different standards with overlapping functionality.”²² In summary, utilities are often required to harmonize the meaning and syntax of data streams for that data to be useable in their systems and analytics.

Whatever the utility business or program business objectives may be, data is often collected, aggregated, and harmonized from disparate devices and systems, and structured appropriately for validation and use. Interoperable and standardized data models can make this process more efficient and accurate by helping to harmonize data returned from diverse systems. The improvements in efficiency and accuracy are realized through reductions in data processing time, improvements in understanding data taxonomy, and increases utility confidence on the data integrity and suitability.

²¹ *Supplemental Project - Distributed Energy Resources Communication Standards and Protocols Harmonization Project*. EPRI, Palo Alto, CA: 2018. 3002014601

²² National Institute of Standards and Technology (NIST) Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0 2010

4

CONNECTIVITY AND INTEROPERABILITY: AN ECONOMIC LENS

This chapter focuses on reviewing the traditional utility business models and regulatory structures to understand how they fit within the context of the interoperable connectivity use cases identified in the previous chapter.

To facilitate the relationship between society and the special purpose entity or utility, the regulatory contract, compact, or bargain has been employed to characterize the set of mutual rights, obligations, and benefits that exist between the utility and society. This is key in ensuring that the benefits of interoperable connectivity benefits both the utility, customers, and society. To induce a utility to commit private capital in the service of society it is reasonable to expect that it would seek to clarify the terms and conditions under which a service is rendered. As under any normal contractual relationship where utilities and regulator(s) – which acts on behalf of the customer or the ratepayer – make tradeoffs in establishing their rights and responsibilities, the purpose of a contract is to establish terms and conditions to allocate investment risks.

Here, the utilities receive:

- A defined service territory, no competition
- Assurances of the recovery of capital investments (used and useful)
- Access to capital markets

In exchange, the regulated utilities are expected to:

- Operate their system in a cost-effective manner (technically efficient)
- Have an obligation to serve (allocative efficiency) which requires adequate planning and construction
- Maintain reliable service

Here, utilities earn a rate of return on their capital investments and recover their operating and maintenance costs.

In return, the regulators want:

- A utility business model that emulates the outcomes from competition without the redundant assets
- Electricity rates to customers as low as technically feasible
- Customer satisfaction and high reliability, as the rate limitations will allow

And are, in most cases, a utility is willing to promote socially desirable goals:

- Providing reliability improvements
- Undergrounding or protecting the distribution facilities
- Deploying energy efficiency and demand response programs
- Supporting environmental objectives

The desire by regulators to emulate competition is based on maximizing societal welfare that competition produces. There are several conditions that, in the real world, will never be achieved but a transition in the direction creates value.

Appendix A provides examples of these conditions that include: (1) competitive electricity markets, (2) willingness to pay vs. cost of service, (3) risk assumption and rate of return, (4) revenue requirements, (5) competitive and deregulated markets, (6) program design and economic cost tests, (7) calculation of cost tests, (8) total resource cost test (TRC), (9) utility cost test (UCT), (10) ratepayer impact measure test (RIM), and (11) participant cost test (PCT).

Recommended Adjustments for Interoperable Connectivity

Interoperability for connected devices and systems are not part of benefit-cost assessments. For interoperable connections of grid devices and systems, an adjustment to the benefit portion of the cost test could be fashioned to reflect the shortened life or likelihood of a stranded asset due to lack of interoperability. This effectively reduces the benefits thus shortening the benefit cost ratio. If sufficient in magnitude, it may push the benefit-cost ratio from a pass to a fail.

Alternatively, a risk adder could be constructed that could be added to the discount rate used to determine the present worth of the cost streams for the capital investment. The discount rate would then be applied to the benefits effectively reducing the benefits in the benefit-cost ratio. This would effectively reduce the benefit to reflect the risks they may produce.

Much of program design is artful and the determination of adjustment to reflect interoperability of connected technologies is no exception. On a standalone basis, it may be difficult to construct these adders or discount rate adjustments. However, it is often easier to develop ordinal rankings of the interoperability across manufacturers equipment or across alternative program designs that allow for more systematic and consistent ranking of the differences interoperability may cause.

Assessing the Costs and Risks of Open vs. Closed Architectures – An Example

It is not always the case that open designs are more cost effective in the short and long run. In many cases closed architecture are designed in that way to increase or improve the functionality of the system thus reducing cost. For new markets this is often the case. As competitors enter the market and the number of closed systems increases, the issue of interoperability becomes more critical as product developers will see the inelasticity of their customer base and possibly adjust contract terms accordingly.

An example of this is what recently happened to utility who used a third-party service to manage their fleet of devices. Both will remain unnamed in this paper. In this case a utility who had been paying a third-party to manage a fleet of the third-party's devices returned at the end of their contract to renegotiate the next phase of their contract. In this phase the third-party changed their

pricing model to now include a per device charge. The utility had the choice to negotiate on these terms or walk away. The outcome of these negotiations was not shared with EPRI however it highlights that the terms in closed architecture may prevent use of that system in the future if new terms are not determined economically logical. However, it also puts the utility in a difficult negotiation position because often the benefit of using closed architectures is that the vendor can quickly ramp up the number of devices. If the portfolio is large then the utility may need to find an alternative to replace the program if negotiations fail – something third-parties are likely aware of. However, if the device/systems use an open architecture then competition could exist between third-parties who could manage the devices and systems. This can promote innovation and cost-competitiveness between these service providers because the devices could be managed by an entity that supports the open architecture.

Many utilities are currently using closed architectures because devices/systems that support closed architectures are more prevalent. This is because customers may have chosen these devices/systems for customer facing benefits and utility enrollment is a secondary feature. Open architectures are increasing in support and some major manufacturers are including them in their products however utilities may have to incentivize customers to installed compatible products until natural adoption reaches critical mass.

Therefore, for applications that are long term, such as regulated utilities systems which have planning horizons in the decades, open system architectures that provide for high levels of interoperability should produce the largest cost savings to the utility and hence to customers.

Upstream and Downstream Costs and Benefits

Project evaluators should consider both upstream and downstream costs and benefits when assessing impacts from interoperable communications.

Upstream refers to stages of product delivery that occurs prior to the use by the ultimate consumer. So architectural design for new residential construction would be considered an upstream activity. Connected products that are interoperable in the upstream can produce large cost savings when the product is mass-produced. For products, which are customized or have limited marketability, interoperability can be less of a benefit.

A downstream application would include activities that affect the after-installation operations by the ultimate consumer. An example of a downstream system could be the communication method for end-use electric appliance such as CTA-2045 for residential appliances or BACnet for commercial control systems to engage in energy efficiency and/or DR program management. An enabling communication technology that when connected and used in an installed device, such as electric water heater, may monitor the status of the device to determine the value cost ratio. The upstream facility to communicate with the device when its cost is much less than its value produces benefits to the utility and ultimately though the participating customer and presumably to all customers.

These product services have the effect of reducing uncertainty and therefore reducing the risk to a utility by providing energy services through capital investments.

5

ECONOMIC CONSIDERATIONS OF INTEROPERABILITY

Our previous sections focus on how interoperable connectivity may have impacts on capital decisions depending on the objective functions – be it reducing costs, increasing customer satisfaction or reducing operational or capital investment risk, or some combination of all three. Each of these functions vary depending upon the utility business structure under which their investments are being made—i.e., *is it a regulated business with cost recovery generally guaranteed but restricted in its use or a competitive market where investments are made to provide a competitive edge with no guarantee of recovery or success?*

The ultimate objective is crucial in determining the economics of grid connections and their supporting interoperability. For regulated investments that produce cost savings the main strategies are energy efficiency and DR programs. Benefit cost ratios that exceed one (1.00) reflect investments that are less expensive than conventional supply-side alternatives and therefore reduce costs and provide benefits to both grid and the electricity customer.

For investments that are made for service quality or new product development the metrics are less obvious. Improved service quality may not reduce overall cost and therefore rates. Instead they may produce more satisfied customers, higher reliability on the grid, or shorter wait times for service connections. These create value but each must be evaluated differently as these non-energy benefits are not recoverable for investor owned utilities. Likewise, interoperability considerations for connected devices and systems within grid- and customer-systems may also reduce costs, improve grid reliability, or result in a better customer experience that results in increased customer satisfaction.

In competitive markets, these forces become even more important in the form of lower acquisition costs, lower service cancellations, and higher renewal rates. These can all increase profits, reduce business risk, and assist in attracting shareholder investments. Each capital investment must be evaluated in the way that is relevant to the objectives it is intended to achieve and the business model under which it operates is expected to operate

In summary, regardless of the business model under which the investment is made – competitive or regulated – there are limited ways to capture the impacts of interoperability. The main methods are fundamental methods that provide exact risk or cost numbers. In contrast, the nine (9) interoperability characteristics described in *Examining Use Cases Interoperable Communications* are not easily quantifiable. If interoperability is inherently important to a utility, then a system may be applied to rank the level that each of the nine interoperability characteristics may be present in the options assessed. However, the impact and magnitude is still difficult to capture particularly when several characteristics are in the analysis.

Table 5-1 provides some examples of potential benefits from interoperability. This list is designed to provide some basis for fundamental ranking of interoperability benefits. This is just a sample of benefits as an example of compounding and contradicting characteristics of any capital project.

**Table 5-1
Utility Business Objectives and Relation to Interoperability**

Value and Cost Metrics	Customer Satisfaction	Business Risk Mitigation
Rate Levels	Cost	Load certainty
Shareholder return	Comfort	Reliability
Lower Levelized Cost	Control and Convenience	Resilience
Benefit/ Cost ratios (EE&DR)	Certainty and Connectivity	Portfolio risk and "mark to market" accounting
Increased Fixed Cost Contribution (Load Growth)	Health, safety, environment and productivity	Contract terms - supplier and customers

Similar to non-energy benefits that accrue to utility marketing programs, the ability to quantify the precise financial impacts may be difficult to measure. The project evaluator must use their judgement when evaluating a capital investment that has interoperability characteristics that are difficult to estimate. This is also an area where expert legal advice on contract terms and contract structures that are designed to reduce utility performance risk and shift it to the vendor.

For instance, a vendor system that provides reliable and consistent back office data hauling may be a good choice for a utility to consider when assessing demand impacts and incentive payments to the customer and regulatory reporting requirements. But if the ease of enrollment for the customer is difficult, the former characteristics are of little benefit. This may be even more pronounced if the utility assumed a level of market participation that was not achieved and was not addressed in the vendor contract.

To assess potential economic benefits for each of the aforementioned use cases in *Examining Use Cases Interoperable Communications*, the following sections outline the summary of qualitative assessment of the benefits. It should be noted that these are initial and high-level expert-based qualitative assessments. Each case is different for utility-specific implementations and should be assessed accordingly for accuracy before any business decisions are made.

Reliable Backhaul Communications

When designing programs utilities must consider the attrition rate of participants in a program. This can be caused by a variety of reasons but the persistence of the network connection to enrolled participants can be a significant contributor to attrition. Technologies like Wi-Fi are known for reliability issues caused by customers changing network equipment, settings in existing equipment, or changing internet service providers. If improvements can be made to these network connections to improve reliability, then this attrition rate may be improved. This can impact utility program economics. High confidence in attrition rates can help avoid misestimate the demand reduction yield that the measure is providing. These misestimates can lead to miscalculation of customer incentives awarded. Ultimately this may create errors in calculations of avoided costs and potentially even rates. This may also impact the results of utility cost tests.

Another potential impact is customer satisfaction. Customers may be unsatisfied by the performance of the program especially if the value they receive depends on their participation in individual events. If connection is lost, they may not be able to participate even though they would like to. More reliable connections may improve customer satisfaction because customers may not have to interact with reenrolling or other program mechanisms to regain network connection to the utility.

Integration of New Devices and Systems

The cost of integration of new distributed energy resources and aggregators into utility programs can be largely impacted by technical costs. These costs are associated with developing new interfaces or processes to communicate program dispatch commands to individual DER or aggregator services but also the economic analyses to analyze the benefits available from those services. As the number of DER on the grid increase it becomes more difficult to integrate custom or proprietary communications with the control architectures. Today where the number of DER are low it is more feasible to design and maintain a few custom interfaces however when that number climbs into the hundreds or thousands it becomes more important that we use standards to make this happen to help reduce integration and maintenance costs but also to preserve those assets for future use. This can impact utility program economics through potentially previously unexpected costs. Unexpected costs can potentially lead to disallowance which may lead to lower earnings because costs can't be recovered through rates or higher rates if recovery is allowed through rate increases.

Integrate Disparate Systems Architecture

Utilities can benefit from choosing existing systems that may be available today. Aggregators or third-party service providers can provide utilities with aggregated services at some negotiated cost. In addition, these systems can help promote customer choice because utilities can choose to contract with third-party service providers that represent popular products on the market today. Similar to *Integration of New Devices and Systems*, this can reduce the number of interfaces the utility must directly manage however utilities must still consider both the cost of potentially maintaining multiple interfaces to interact with third-party service providers and the technical and business processes required to do that. It is important to consider that at any given time, DER integration is looking at the accumulation of products that have been interconnected over a period of time.

Customer choice creates customer value by getting the customer to become invested in the device and therefore the program. This may reduce attrition rate because they can choose what they want to purchase. This can help keep customers enrolled in the program. If then number of customers enrolled in a program is more stable, then it can be more predictable. This makes it easier (and therefore less expensive) for a utility to manage the program and makes it easier for program designers to predict the ultimate outcome of the program.

Lower Risk of Vendor Lock-In or Stranded Assets (or Asset Re-Use)

The primary motivation for recent regulations, mandates, or requirements documents is preserving the longevity of the communications interfaces to distributed energy resources.²³ As the number of DER on the grid increase, it is likely that the grid's stability will depend on reliable control of DER. Investments to install these resources must be protected from risks that could lead to stranded assets like companies going out of business and losing support for those systems. This can limit the utility from improving or augmenting these devices/systems and their associated programs.

This relates to utility programs because as utilities become more dependent on DER utilities may need to consider the loss of services – like load shape changes, cost savings, reducing operational risk, or providing customer services. For example, if a service is lost then it may cause some sort of rippling cost. If load shapes are altered by a service, then load shapes may return to their previous state which could presumably be a higher cost state. If risks are addressed, then those risks return. If customer services are lost, customer satisfaction may drop. Therefore, utilities will need to consider how and whether to replace these services. This may be addressed in contract terms however beyond the established timeline for those terms will need to be considered. The economic impact will depend on which of the services are lost. Utilities may also consider services technologies that offer open architectures for managing DER so that the interfaces can be preserved even if manufacturers or services providers go out of business or otherwise unavailable.

Device and/or System Installation and Commissioning/Provisioning

Interoperability can allow for easier and less expensive device and/or system installation and provisioning with utility programs through defining standardized and streamlined procedures for installation, provisioning, and enrollment. This may reduce the cost and time needed for utilities to enroll new devices. This means that utilities will get the benefits – load shape changes, cost savings, reducing operational risk, or providing customer services – of these programs faster and more reliably.

If utility personal or contractors must go out to the site this can also create more cost for utilities. Interoperability can help to make commissioning and provisioning automated which can lead to expedited enrollment in programs.

If the right information is not collected or enrollment is not successful (technical issues) this may lead to repeat site visits. Interoperability can define processes to ensure that the right information is collected in the right form.

Assess and Access Device or System Functionalities

If a utility can assess or access device or system functionality it provides them with the ability to validate the capabilities of a system to provide benefits that system can provide at a given time. For example, a utility may be able to query a customer's water heater to confirm it is running and therefore can be shed to reduce load on that feeder. Understanding the capability of devices and

²³ *Mounting Importance of Communications to Monitor and Control Distributed Energy Resources*. EPRI, Palo Alto, CA: 2018. 3002013480.

systems can allow utilities to operate the system more effectively both financially and operationally. This is because it can allow a utility to understand the total capabilities of a program portfolio to meet obligations. If total portfolio capabilities are not sufficient it may give utilities time to acquire the most cost-effective resources to meet those needs. This may also lead to higher confidence in the capabilities of the portfolio so utility can only secure replacement options for what is needed. The alternative is to use probability assessments to determine likely response and possibly over purchase replacement options to ensure obligations are met.

Two-Way Data Communication for Grid Management

If utilities have access to data from individual DER this provides them with a wealth of personalized load shape data that can provide a utility with the ability to more accurately estimate loads and generation in their service territory. This can impact all cost tests through improving the accuracy of pre- and post-program analysis.

Data management can also impact societal welfare. It can allow utilities to directly pair participation – and amount of – to the benefit and costs to run the program. This means that participants can be directly rewarded with the benefits they provide which avoids cross-subsidies between over and under producers of benefits. Societal welfare may impact customer satisfaction and attrition in both positive or negative ways depending on the customer and their value requirements for participation in the program. It is often difficult to know why a customer participates so this can be difficult to understand. For example, one customer may need a strong financial incentive to participate while another wants to participate for the benefit of society and would participate with a lower financial incentive.

Customer satisfaction can also be impacted through utilities providing information to the customers regarding the performance of their facility/devices through energy advisement programs. It can also provide utilities with additional metering points that can allow them to identify potential issues – like low voltage or poor power factor – and address them proactively.

Customer Enrollment and Service Selection

Interoperability allows utilities to support multiple third-party service providers that offer aggregated DER services to utilities. In these cases, this can provide utility customers will more choice in the how they can provide benefits to the grid through having a choice of third-party service providers that customers may engage with. So in contrast to device selection, this gives customers a choice in services that they provide and the benefit they receive. This impacts utility economics because it may lead to higher participation in programs, lower attrition, and improved societal welfare through natural competition between third-party service providers within a service territory.

Data Harmonization from Devices and Systems

Information models help systems standardize on the syntax and meaning of data. When utilities are integrating data from a large number of different systems this becomes important. If data is not harmonized, then data must be manually integrated into databases which can be a time consuming and expensive effort depending on the data set. Data harmonization through standardized information models can streamline the addition of data from new devices into

utility databases and systems. This can improve the benefit achieved by adding new participants in utility programs. This also provides the potential to reduce data processing time and understanding data taxonomy, which helps with the data accuracy and raises the utility confidence on the data integrity.

6

CONCLUSIONS AND NEXT STEPS

This study reviews the requirements for connectivity and their interoperability that can provide both utility and customer benefits. The study identified nine use cases that reflect the key benefits that interoperable grid connectivity can tangibly support utility economics for energy efficiency and DR programs. Table 6-1 summarizes these use cases and their benefits. While connected and interoperable systems provide various intangible benefits, it would be hard to articulate the value integrated deployments of DER technologies without understanding the economic benefits they provide relative to their traditional deployment costs.

**Table 6-1
Examined Utility Use Cases for Communications Interoperability Assessment**

Utility Use Cases	Defining Factors
Reliable backhaul communications	Failures in the backhaul communication between DER and managing entities (utility, aggregator, or owner) is a large factor in attrition of available devices. Technologies to improve reliability of these connections can increase the confidence that the smart grid and its operators' have persistent connectivity connected devices.
Integration of new devices and systems	The proliferation of smart and connected devices means that utility may be faced with large numbers of DER that may be integrated. This can make integration of new interfaces and capability of devices – for local and grid integration benefit – difficult and expensive. Interoperability can streamline this process through standardization.
Integrate disparate systems and architecture	Utilities may be work with multiple entities (aggregators, third-party service providers) to give their customers options for providing grid services to utilities. Interoperability can help utilities integrate these disparate customer/grid systems into existing architectures and utility systems.
Lower risk of vendor lock-in or stranded assets (or asset re-use)	Vendors or manufacturers can change terms, go out of business, or otherwise become unavailable to utilities their customers. Interoperable and open communication standards can future-proof device capabilities and allow the connection to this DER to persist even if vendors or manufacturers may not.
Device and/or system installation and commissioning	A significant cost in utility programs is the installation and commissioning of new systems. Interoperability can increase efficiency and reduce costs for commissioning and integration through automation and other common practices.
Assess and access device/system functionalities	Utilities rely on statistical analyses to quantify the response from a portfolio of utility demand response or energy efficiency programs. Connectivity and interoperability can allow utilities to query DER about their near-term and future capabilities which can simply the assessment of the capabilities of a portfolio. This can improve accuracy in grid planning and operations.
Two-Way Data Communication for Grid Management	Connectivity and interoperability can allow utilities to validate response of individual DER, increase the number of monitoring points on the grid, and conduct analytics of grid resources like creation of customer or DER load shapes.
Customer enrollment and service selection	Providing customers will options for enrolling in grid services through a variety of utility, energy service provider, or aggregator can enable proactive customer engagement in utility offerings through seamless device integration and an increase in interoperable customer options.
Data harmonization from devices and systems	Integration of new data streams into utility systems often requires harmonization of the meaning and syntax of data streams. Interoperability can ease harmonization across disparate device and systems.

Benefit cost ratios that exceed one (1.00) reflect investments that are less expensive than conventional supply-side alternatives. For investments that are made for service quality or new product development the metrics are less obvious. Improved service quality may not reduce overall cost and therefore rates. Instead they may produce more satisfied customers, or a higher reliability on the grid, or shorter wait times for service connections. These create value but each must be evaluated in a different way.

Likewise, interoperability considerations for connected devices and systems within grid- and customer-systems may also reduce costs, improve grid reliability, or result in a better customer experience that results in increasing customer satisfaction. In competitive markets these forces become even more important in the form of lower acquisition costs, lower service cancellations and higher renewal rates all of which increase profits, reduce business risk and assist in attracting shareholder investments. Each capital investment must be evaluated in the way that is relevant to the objectives it is intended to achieve and the business model under which it operates is expected to operate.

The applications of the use cases for interoperable connectivity is specific to utility requirements. Each of these recommendations must be assessed accordingly for accuracy before any business decisions are made. As next steps, the connectivity and interoperability requirements and the use cases developed in this study can be leveraged for utility energy efficiency and DR programs and the economic benefits they provide. This can be done through a quantitative analysis of data and/or small-scale pilot program to understand the efficacy and effectiveness of the economic benefits of interoperable connectivity. While economics is a key factor for utility deployments of interoperable and connected systems, other factors such as energy and carbon savings, and customer expectations and satisfaction should also be part of the assessment to ensure the utility and the societal objectives are considered for widespread deployments of the programs.

A

EXAMPLES OF TERMS AND CONDITIONS TO ALLOCATE INVESTMENT RISKS

The following sections provide examples of terms and conditions between a utility and a regulator (acting on behalf of the customer or the ratepayer) include:

Competitive Electricity Markets

The key conditions of a competitive electricity markets include the following:

- Many buyers and sellers so that no individual buyer or seller can influence the price of the commodity
- Information is disseminated quickly and with accuracy
- There are no significant market barriers such as transactional or financial (high capital costs)

Under these conditions, societal welfare is maximized and regulators look to achieve these outcomes as closely as possible. Allocative efficiency reflects how closely price tracks marginal cost plus an economic return to compensate investors for the risk they assume. As a regulated monopoly, utilities have an incentive to charge prices that deviate from the allocative optimal. In fact, regulators often also violate this rule through adders and rate designs that are designed to produce subsidies.

In a competitive market technical efficiency is also achieved. Technical efficiency refers to employing that combination of capital, labor and resources in such a way that the average cost of production is at a minimum. Electric utilities, as a highly capital-intensive industry, are adept at making investments, either capital or labor, that reduces the average costs of production. Examples might be a resource plan which calls for the construction of generation that is natural gas based rather than coal or nuclear due to the lower capital and running costs.

“Willingness to Pay” versus “Cost of Service”

The regulatory compact between utilities and its customers has a two-fold focus: (1) establish prices based on the actual prudent costs (i.e., emulate competition and avoid monopoly pricing); and (2) provide incentives to maintain a reasonable level of efficiency in serving the customers. Rates are set with reference to the Total Revenue Requirement (TRR) - costs. The TRR identifies the actual prudent costs necessary to enable an efficiently managed firm to operate effectively and allow the company an opportunity to earn a fair return on a forward going basis. Once the rates are set, the regulator becomes somewhat passive as the utility interacts with the forces of input markets and customers' demand to produce a flow of services, incur actual costs, and receive cash flows. If the flow of services, costs, and revenues reasonably reflect the conditions expected at the time the rates were set, then a fair balance is achieved where the utility can continue to operate as expected. Alternatively, if market forces unexpectedly alter the actual

costs or revenues from the expected levels, then an adjustment in the form of a new rate case is initiated. That is how the traditional regulatory framework ensures that investors continue to provide capital and consumers continue to receive universal service at reasonable prices.

Managers of unregulated firms face oversight from several different sources, including pressure from competitors, competition for the control of the management of the firm, pressure from bondholders and banks, as well as explicit regulation truncating property rights such as labor laws, safety regulation, and environmental regulation, in addition to the implicit public regulation that private firms, especially large corporations, often face under the guise of corporate social responsibility. All these factors impinge on the prerogative of management. The utility faces all these same pressures, except for the pressure from competitors, i.e., market forces. In managing the implementation of the regulatory compact and the balance implied by the bargain, the regulator is placed in the same position as the market in an unregulated industry. The regulator—with the power to audit, investigate, confer, and evaluate—of necessity diminishes the prerogatives of management, just as market forces compel managers of unregulated firms to conform to operations that promote cost efficiencies. The courts have connected this efficiency standard to the fair return allowed to the utility investors: “A public utility is entitled to such rates as will permit it to earn a return ... equal to that generally being made ... in other business undertakings which are attended by corresponding risks and uncertainties ... it has no constitutional right to profits ... [made by] highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.”²⁴

Risk Assumption and Rate of Return

The question for the regulator in implementing the regulatory contract becomes: which types of risks are part of the normal cost recovery process and should be assigned to customers and which are normal business risks that are born by investors? It is this question that has confronted the regulatory process throughout history and has become more acute in recent years as some of the long-held beliefs about the operation of utilities have been challenged. For instance, the assumption that growth in sales will provide the necessary cash flow to support capital investment is, perhaps, no longer a reasonable assumption. Further, in some cases, the belief that costs are stable over time or that utility managers have control over those costs is mistaken due to broader changes in the economy. Finally, since the utility is an extension of the state, policy changes requiring the outlay of costs further change the method by which the bargain is implemented. When these exogenous shocks disrupt the process, regulators have adapted by making pragmatic adjustments to re-establish the original bargain to preserve the original risk and cost allocations (i.e., the fair balance between investors and customers).

²⁴ Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 692–93, 1923).

The significance of revenue requirements is that it reflects the “cost of service” for the provision of electric service. That is distinguished from “willingness to pay” a reflection of the value or worth consumers attribute to the consumption of any good or service as reflected in the amount of money they are willing to pay.

Revenue Requirements

Revenue requirements are used to establish rates. Regulated utilities are authorized to recover their revenue requirement. These costs are comprised of ongoing operations and maintenance (O&M) costs plus the debt service on their accumulated net capital investments plus a rate of return intended to reflect the underlying business risk they are assuming, which is adjusted to ensure shareholders are adequately compensated and the utility has adequate access to capital markets to ensure the ability to meet customer growth.

The revenue requirement is typically given by the following equation:

$$\text{TRR} = \text{TC} = [\text{RB} - \text{D}] \text{ROR} + \text{OE} + \text{d} + \text{T}$$

Where: TRR = total revenue

TC = total cost RB = rate base or value of capital

D = accumulated depreciation

ROR = weighted average cost of capital equals the cost of equity (profit to owners) multiplied by the percent of equity used to fund the firm plus the cost of debt (average interest rate paid on bonds) multiplied by the percent of debt used to fund the firm

OE = operating expenses d = annual depreciation cost T = taxes.

The equation above provides a simplistic exposition of the total revenue requirement required by the utility and masks the complexities of the administrative process. In practice, each cost component involves direct analysis of the costs in question as well as application of the regulatory policies and rules derived from legislation, rulemaking, legal decisions, and regulatory practice. Once all the policies and practices are applied to determine the TRR, the total actual costs of supplying these services represent the total prudently incurred costs (implying that the prudence standard has been applied to all the factors included in the TRR). The regulator must review all costs proposed to be included in the TRR and make judgments regarding the effectiveness of management decisions in controlling costs in lieu of the competitive market discipline. The rates or prices charged to customers should reflect the costs incurred by the utility on a prospective basis so that the prices, when they go into effect, provide sufficient revenue to cover the actual prudent costs incurred to supply the customers.

The three major interconnections in the contiguous 48 states—Eastern Interconnection, Western Interconnection, and the Electric Reliability Council of Texas (ERCOT)—accommodate a mix of investor-owned utilities (IOUs), cooperatively owned utilities, and government-owned utilities. Within these ownership types are several structures, as shown in Figure A-1.

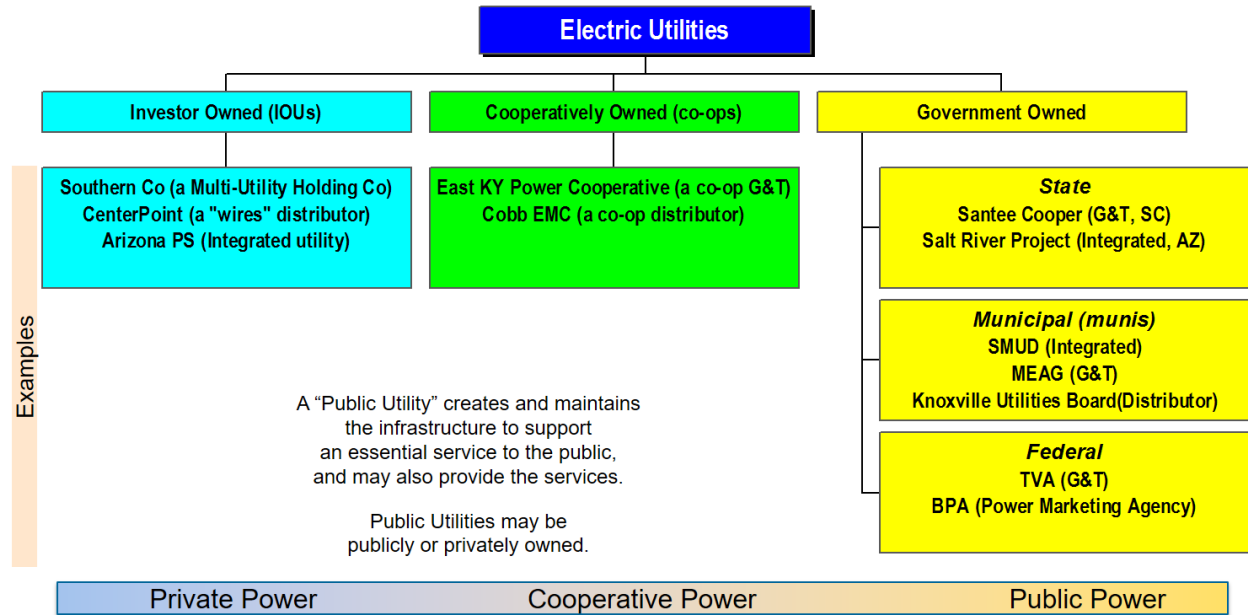


Figure A-1
Classification of utilities in the United States, with examples

IOUs include holding companies that can own multiple utilities of various types—fully vertically integrated utilities, transmission and distribution utilities, and distribution-only utilities. IOUs are mostly rate-of-return regulated, meaning that the regulatory commissions monitor the utilities’ return on equity investment, and they target rates and rate structures that provide adequate return to allow the utility to raise needed capital. Corporate boards govern IOUs. IOUs pay property taxes, federal and state income taxes, and any other applicable taxes.

Cooperative utilities are customer-owned and governed by boards elected from among the “members,” or customers. Cooperative utilities are debt financed, but they collect a surplus or net income that builds up as equity on their balance sheets. A federal government agency makes low-cost debt available for cooperatives, but they may obtain debt from other sources as well. The companies are generally self-regulated about their rates because the customers own the organization’s equity and are responsible through their board for the decisions the utility makes. Their regulatory objectives may be wider than IOU’s. For instance, Municipal utilities often also operate natural gas and water utilities. The performance as evaluated by the ratepayers elected boards will also include other metrics that are focused on how satisfied customers are with their local utility. Ultimately municipal utilities must meet the same level of performance that IOU’s achieve.

Government utilities are owned by governments—federal, state, or municipal—and governed by a board. They are debt financed, but they collect a surplus or net income that builds up as equity on their balance sheets. Some government entities extract dividends from their utilities, using these funds in lieu of other taxation of the constituent or customer populations.

Regulatory policy intended to emulate competitive markets has its focus on IOU's. But those policies trickle down to public power providers. So, for a regulated utility the used and useful test for costs to be included in rates becomes the same standard for public power. Which means that capital investments that fall short of expectation - shortened life of reduced load shape impacts subject utilities to unrecoverable costs. For an IOU that means shareholders will likely have to make up the difference. For public power utilities that means rates are higher than they otherwise be. Neither of these outcomes are meet the objectives of a technically effect electric utility.

Competitive and Deregulated Markets

Third-party service providers face a substantially different capital evaluation process driven by short-term commodity prices, customer acquisition and portfolio risks. However, matching the portfolios they have created through their customer acquisition activities requires them to ensure they do not undertake unexpected price and quantity risk, or develop new products and services that jeopardize the cash flows for the operations.

It seems counter intuitive that in competitive market interoperability becomes less of a concern. As is often the case the margins in competitive markets are thin. Long-term interoperability considerations are often ignored in favor of short-term investment returns. The value of interoperability becomes a long-term benefit, which regulated utilities can manage much more effectively.

However, a countervailing effect is the driver of competitive retail prices. Load weighted marginal costs and the underlying customer load volatility is the main drivers of customer price and directly affects the acquisition of new customers. Capital investments that allow for the management of these components will produce high value to customers and allow third-party service providers to acquire more profitable customers. Interoperability investments by third-party service providers, microgrid operators, and other DER and storage suppliers will become an important factor.

In principle, prices could be set so that each customer bears the costs of the risks created by their individual load volatility. For administrative reasons, however, it would usually be practical to apply such individual treatment only to the largest customers. For most customers, prices would usually be set so that each customer group bears the costs of the risks created by their aggregate load volatility. Systems that allow for the management of those customer groups and keeps those costs to a minimum will be the likely to succeed

Program Design and Economic Costs Tests

For any program intended to produce load shape changes, which benefit ratepayers the following cost tests are considered:

Total Resource Cost Test (TRC) – also known as the all-ratepayer test. This is the viewpoint of all customers within the service territory and considers quantifiable costs and benefits. Closely related to the TRC is the societal cost test (SCT), which is the viewpoint of society (everyone) and often considers other more difficult to quantify societal impacts such as environmental or other non-energy benefits.

Utility Cost Test (UCT) – the viewpoint of the sponsoring utility (if the utility sub-contracts the program implementation another test called the Program Administrator Test – PACT. The PACT reflects the administrative costs to deliver the program). Incentives are considered here if the amount does not exceed what the conventional supply costs would be.

Ratepayer Impact Test (RIM) – originally called the non-participant test, the viewpoint of non-participants, those customers not involved in the program. This can have considered a measure of how well rates reflect avoided costs.

Participant Test (PCT) – the viewpoint of the participating customers. Ultimately if customers are not better off then participation target will unlikely be met.

The cost tests are described in a 1987 report from the California Public Utilities Commission entitled “California Standard Practice Manual”²⁵. This manual has seen several revisions and remains the standard for evaluating utility load shaping programs.

There are several methods typically used to perform the calculation of the cost tests. The first is the use of an economic evaluation model available from several software companies. An evaluation model includes background information such as basic facts and knowledge about utilities and the cost tests that can be used as a foundation for the calculations. The use of an evaluation model requires a software license that may cost up to several thousand dollars per year, but will allow a relatively inexperienced user to achieve satisfactory results. An alternate method is the use of a spreadsheet to perform the cost calculations, but this requires the expertise of an experienced analyst.

The reason either an evaluation model or experienced analyst is needed is that the calculations are only as good as the data used. The data that is required for calculating the cost tests may either be easily obtained, such as in a top-down estimate based on assumptions or it may be a bottom-up estimate with a lot of detail and nuance. Either way the results are always subject to interpretation and reflect the art of program evaluation.

Calculation of Cost Tests

The explanation for the calculation of the cost tests provided within the California Standard Practice Manual are relatively complex to account for all the subtleties associated with economic evaluation. The following is a simplified explanation for how to perform the calculations for the cost tests. The intent in presenting this material is not to replace the Standard Practice Manual, but to aid in understanding the mechanism for each test, which will aid in the design of programs for efficiency and demand response.

²⁵ http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf

In what form are the results of the calculations? Results for the cost tests are given either as a ratio (Benefits divided by Costs equals Benefit-Cost Ratio)²⁶ or as a net result (Benefits minus Costs equals Net Benefits). Both forms are popular. When calculating a Benefit Cost Ratio an increase in Benefits (numerator) or a decrease in Cost (denominator) will cause the magnitude of the result to increase. Similarly, when calculating Net Benefits (a subtraction operation) an increase in Benefits (first term) and a decrease in Costs (subtracted term) will cause the magnitude of the result (difference) to increase.

The Benefits and Costs are comprised of five independent variables: supply costs, electric revenue, incentive, utility costs, and participant costs. The key to understanding the mechanism of calculation is to understand whether the variable is: A variable is either a benefit or a cost depending on if the proposed program increases or decreases the magnitude of the variable. Take for example an incentive and the participant and utility tests. An increase in incentive is a benefit within the participant test, but is a cost within the utility test. Conversely, a decrease in incentive is a cost in the participant test, but a benefit for the utility test.

Data

A description of the independent variables and guidance on typical values is provided below.

Capacity refers to the peak demand or power that a utility must supply to meet customer demands. This may be for one hour or several hours in the summer or winter for most utilities on the continental U.S. The capacity values listed here are considered “least cost” capacity and reflect the least cost supply-side alternative, which is usually the annualized cost of a combustion turbine.

Energy values reflect the average cost per kWh produced by the utility for an additional one kWh delivered to the bus bar. Line losses have not been included. These values are averaged over the seasonal and time-of-day designations. For the example below the summer is six months and the winter is also six months. On-peak is 12 hours Monday through Friday while Off-peak is all other hours.

Each utility will want to define these values themselves and should work with their Rates or Resource Planning departments to define the seasons and on and off-peak periods along with the capacity and energy costs.

²⁶ Note: Not Cost/Benefit Ratio.

Supply Costs²⁷

The supply costs form the basis of economic evaluation of cost effective energy efficiency potential. The penetration of intermittent wind resources in the Texas and western plains has significantly changed the load dispatch order and the shape of demand and energy cost profiles.

Table A-1
Avoided Cost of Capacity (\$/kW-year)

Summer	\$80.00	“
Winter	\$0.00	“

Avoided Cost of Energy (\$/kWh)

For example, ERCOT's calculation of the avoided cost of energy in 2018 avoided cost is \$0.03757/kWh.

Electric Revenue

Utility rates may take on as many different levels and forms as there are utilities. Generalizing is difficult but it can usually be said that their rates are going to be like the underlying avoided costs. Only the residential customer has time-differentiated rates in the example below. Commercial and Industrial are of a different structure such as demand-energy or energy only.

Table A-2
Rates

	Average ²⁸
Residential	\$0.1165

Incentives

There are two bases for the development of incentives. The first is the amount needed to motivate potential participants to participate in a program or purchase an efficiency measure up to the amount that would result in a subsidization. This cap is usually determined by the utility cost test. To provide incentives that cause the utility cost test to fall below 1.0 would imply that the utility would be better off implementing the supply-side option rather than the demand-side option.

²⁷ Source: <https://www.puc.texas.gov/industry/projects/electric/38578/38578.aspx>

²⁸ Source: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a

The second basis is to ignore the customer behavioral aspects and provide the full amount of the benefit produced by the avoided costs. For demand response programs this amount would reflect the capacity saved by the measure. Using the values provided above, a one kW capacity reduction could produce an incentive of \$75/kW year excluding demand losses. Most utilities do not provide the entire estimated benefit as a hedge against less than actual measured impacts, net-to-gross effects and persistence.

For energy savings incentives the incentive is based on the avoided energy costs expected over the course of a year through the implementation of the measures. For a 100kWh measure savings per month the benefit would be $100 \times \$0.092/\text{kWh}$ or \$9.20 per month. The utility may want to adjust these amounts to reflect the actual measured impacts, net-to-gross effects and persistence.

Utility Costs

Utility costs reflect the administrative and general expenses a utility incurs in the delivery of an efficiency or demand response measure. These costs would normally include incentive but may also include sub-contractors who have been hired by the utility to deliver the programs, see Program Administrator's cost test. These costs may be lump sum such as \$1 million per year. They may be \$/implemented measure such as \$1.50 for each rebated LED lamp.

Participant Costs

These costs are specific to the measures being incented by the utility. The amount after rebate would be different to the participant for an LED lamp versus an electric heat pump. The net participant costs would depend on the incremental measure costs compared to the baseline measure and the demand and energy savings produced by the measure.

Other Data

Other data needed to supplement the information provided by the costs tests and which enhance an economic analysis include the following:

Consumption of the Baseline Measure and Treatment Measure

Consumption data consists of two components – energy and demand and is the engine that produces the cost savings for participants and non-participants and is often the subject of much debate. Changes in consumption between the baseline usage and the treatment usage produce the estimated savings that occur due to the installation of the measure. Applying the energy and demand savings to the avoided costs, above, produces the annual cost savings that can be used to assess the economic impacts of the treatment measures to the utility and its customers. (Note: this is not the same as the savings to the participants. This would require using rates rather than avoided costs plus any additional capital or O&M the customer pays)

These annual impacts would be extended to include the impacts that occur in future years up to the point in time when the equipment is replaced. This may either be the results of the age of the equipment or in some cases the replacement caused by newer more efficient measures coming into the marketplace. Discounting of the future benefits to today's dollars provides a means to make comparisons among different measures and programs and allow the utility to maximize the resources it devotes to program implementation. (See other data: discount rate below)

A customer's demand reflects the peak rate of consumption they use, usually measured over an hour or fifteen-minute period. Coincident demand reflects that rate but at the point in time when the utility is at their system peak. This is referred to as coincident demand and is important in program evaluation and system planning.

**Table A-3
Example Impact Evaluation**

Demand Impacts	Baseline Coincident kW	Treatment Coincident kW	Demand Savings
Sum	0.50	0.45	0.05
Win	0.40	0.30	0.10

Energy Impacts	Baseline kWh	Treatment kWh	Energy Savings
Sum on-peak	1,000	850	150
Sum off-peak	750	700	50
Win on-peak	500	450	50
Win off-peak	750	500	250

Energy loss factors, by season and peak and demand loss factors at system peak

Loss Factors – Energy and Demand

Loss factors are used to account for the energy and demand losses that occur through the delivery of electricity from the generator to the ultimate end-user. These losses are primarily caused by transformation losses from one voltage to another, although losses occur at every point along the transmission and distribution system. Customer size is the most significant factor when determining voltage delivery. Large customers will find it more economic to take delivery at high voltage, 69kV, and transform the power to their own needs using their own equipment. Therefore, the losses tend to be lower than residential which will typically take voltage at 240V. These transformation losses produce higher loss factor for residential than industrial and in most cases commercial. Each utility typically conducts loss studies to develop estimates of these factors but the following table illustrates values often used in evaluation of power economics.

**Table A-4
Loss Factors - Demand and Energy**

	Res	Com	Ind
Demand Line (Peak) Loss Factors:	15.0%	12.0%	7.5%
Energy Line Loss Factors:	12.0%	7.5%	5.0%

Reserve Margins

Reserve margins are an additional benefit produced by energy efficiency and demand response programs. Utilities will normally have additional generating resources available to cover unexpected contingencies such as generator outages or transmission line failure. Although there are many ways to handle those contingencies most utilities will adjust their loads by fifteen to twenty percent to cover those instances.

**Table A-5
Reserve Margins**

	Summer	Winter
Applicable Generation Capacity Reserve Margin:	15%	15%

Discount Rates for Conducting a Net Present Value Analysis of Costs and Benefits

As previously mentioned the benefits of an energy efficiency measure may accrue over the life of the measure, in some cases as many as ten to fifteen years. Utilities will discount the costs and benefits to make comparisons among different investment alternatives – efficiency measures or supply-side investments. Discount rates are used to adjust future value to what they would be in today’s dollars.

Net-to-Gross adjustments (NtG)

Net-to gross adjustments refer to an adjustment sometimes made to the benefit side of the economic evaluation to reflect the behavioral impact of customers who would install efficiency measures without the inducement by the utility. These are also sometimes called free riders. They receive the incentives when none is needed to obtain their participation.

Some utilities ignore this effect for many reasons but primarily because they assert that if the TRC cost test is passed the distributional effects of an incentive payment are not relevant. Other reasons for ignoring the free rider effect, or using a net to gross of 1.0, is that customer behavioral research has had difficulty in estimating what these values are.

Persistence and Leakage

Persistence refers to how long the efficiency or demand response measure remains in place while it is operational. For technology-based efficiency measures, say for example a high effect air conditioning unit persistence is not an issue. For behavioral programs such as in-home display units or bill inserts that make suggestions to reduce consumption the impacts may only last for a short while.

Leakage refers to the removal of efficiency or demand response measures out of the service territory where the utility serves. There are two aspects to this leakage. The first is common when instant rebates are offered with no proof of residency. Out of service territory participants

will receive the rebate but the equipment will not be installed and producing the savings for the utility.

The second type of leakage also has several variants. For instance, an eligible utility customer may purchase but never installs the measure. Another is when the measure is properly installed but is removed for some other reason after some period. This removal may be due to moving by the participant, it may be that a black market exists for the measures where they may be sold or finally the participant does not like the service qualities of the product and replaces them with the original technology.

Number of Eligible Participants and Measures per Participant

For quantifying total benefits and establishing realistic implementation targets it is necessary to develop estimates of eligible participants. The efficiency measures may replace technologies owned by such would-be participants. For instance, a high efficiency central air conditioning program will be most successful with homes with existing central air conditioners, not window or no air conditioners at all.

For an on-site audit program high efficiency lighting is often offered. It is important to know how many lamps are replaced at each location.

Measure Incremental Cost and Average Life

The incremental cost of each efficiency measure is the appropriate cost to use in the benefits-cost analysis. For example, a high efficiency air conditioner may cost an additional \$1,500 for a similar size and expected life. The economics of encouraging that investment would use the \$1,500.

In those instances where the service quality of the measures differ between the baseline and the treatment then other methods needs to be used to compare the investments. Discounted benefit – cost or levelized cost approaches are useful for this comparison.

Incremental Operations and Maintenance of the Installed Measure(s) for both the Participants and the Utility

If the efficiency measure has a different maintained cost or measure life then the economics should account for that. Discounted benefit –cost or levelized cost approaches are useful for this comparison.

Utility or Program Administrator Costs of Implementation

All costs that are directly related to the implementation of efficiency and demand response measures should be captured and included in the economic evaluation. Cost elements such as advertising, labor, incentives, and promotional material would be included. Indirect costs should also be included to the extent they can be measured. Office costs, office services and other common costs should also be included to the extent they are variable in nature.

Total Resource Cost Test (TRC)

A measure of the net cost of the program for energy efficiency or demand response, the total resource cost (TRC) test includes the costs for both the participants and the utility. It compares the costs to implement the measure to the avoided costs and operating and maintenance savings

the program produces for the participant and the utility. Said another way, the TRC provides a comparison of all implementation costs to the supply-side resources it saves. When a program passes the TRC test, it indicates that total resource costs are less and the cost of service for customers, on average, will decrease.

The calculation allows all resources to compete on equal an equal basis, which is often referred to as a “level playing field” by resource planners. Incentives are not included within the calculation because incentives are considered a transfer payment (benefit payment or subsidy) from non-participants to participants.

Closely related to the TRC is the societal cost test, which uses a societal discount rate instead of a discount rate for average cost of capital as well as the sum of benefits, especially environmental, attributable to a program.

In this section, summarize the result of the calculation for total resource cost. List any assumptions and include text on interesting information regarding the future value of the TRC. Will it increase, decrease, or stay the same. And if so, why? If warranted, include the calculation for societal benefit making note of key drivers, such as a reduction in emissions of greenhouse gases and savings in water and other natural resources.

TRC = avoided costs / implementation costs

Utility Cost Test (UCT)

The utility cost test looks at the economics of energy efficiency and demand response from the viewpoint of the utility. If the costs incurred by the program administrator are less than the avoided supply costs, then the cost of service for customers, on average, will decrease. The utility cost test includes the incentive as a cost, so this test is usually referenced to inform the decision on the amount of incentives paid by a utility to program participants.

Resource planners use the utility cost test, as part of the calculation of how much the utility would need to spend to ensure adequate capacity and energy, which the utility is obligated to provide. Based on this calculation, the resource planner selects either supply-side resources or demand-side resources, such as a program for energy efficiency or demand response that will minimize for the utility the needed revenue requirements in terms of net present value. If the utility were to pay high incentives that cause the result of the utility cost test (benefit cost ratio) to drop below 1.0 then non-participants are better off if the utility installed supply-side resources instead of demand-side resources.

A commonly stated argument associated with this test is that utilities are a regulated business and therefore can pass through all their costs. The fallacy in this argument is the ignoring of the fact that utilities have an obligation to serve using the most cost-efficient resources making utilities responsible to their stakeholders to the type of impact (supply-side or demand-side) used to meet the load requirements of their customers.

Ratepayer Impact Measure Test (RIM)

The ratepayer impact measure test—sometimes called the all-rate-payers test—calculates the effect on rates because of implementing an energy efficiency or demand response program. Rates are typically based on groups of customers with similar patterns of aggregate load to accurately

estimate the underlying cost of service. An energy efficiency or demand response program that changes the average load must account for any changes needed to rate. Utilities are familiar with changing rates because periods of load growth produce a similar need. For example, adding generation produces distributional effects like energy efficiency when marginal supply costs are greater than average supply costs.

Use of the ratepayer impact measure test has produced debate about the use of average rates versus the use of average customer bills. The effect has been to develop efficiency programs that either provide access to all customers so that they may see reduced bills or allow for opt-out provisions that allow customers to sidestep the costs and resulting impact to rates that arise from implementing a program for energy efficiency or demand response. Use of technology for advanced metering as well as new rate structures that are more closely aligned with costs have lessened the attention on this issue.

Participant Cost Test (PCT)

A measure of the economic attractiveness to customers, the participant cost test is a key indicator as to the amount of incentive needed as well as for determining the expected level of participation. If the participant cost test is beneficial to the participant, then there likely is not a need for the utility to intervene with an incentive and communication materials to overcome informational barriers are likely the most appropriate strategy. On the other hand, if the measure is not economical for the participant, but is economical for the utility, then an incentive is appropriate to reduce costs for both the participant and the utility. Avoid technologies whose costs are high and whose impacts are either small or uncertain. In this last case, the financial requirements to satisfy the potential participant does not justify the expense for non-participants.

One of three options are common: the technology makes financial sense to the participant and utility so incentive is not warranted, the technology makes sense for the utility and an incentive is warranted, the technology is not economical for either the utility or participants and no further action is required until advances in the performance or cost of the technology occur.



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