PNNL-25633

U.S. DEPARTMENT OF ENERGY
Office of Electricity Delivery and Energy Reliability (OE1)

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Valuation of Electric Power System Services and Technologies

August 2016

Prepared for the U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, under Contract DE-AC05-76RL01830

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UNITED STATES DEPARTMENT OF ENERGY
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Prepared for
the U.S. Department of Energy
under Contract DE-AC05-76RL01830

Funded by the U.S. Department of Energy, Office of Energy Policy and Systems Analysis

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Executive Summary

Accurate valuation of existing and new technologies and grid services has been recognized to be important for stimulating investment in grid modernization. Clear, transparent, and accepted methods for estimating the total value (i.e., total benefits minus cost) of grid technologies and services are necessary for decision makers to make informed decisions. This applies to home owners interested in distributed energy technologies, as well as to service providers offering new demand response services, and utility executives evaluating the best investment strategies to meet their service obligation.

However, current valuation methods lack consistency, methodological rigor, and often the capabilities to identify and quantify multiple benefits of grid assets or new and innovative services. Distributed grid assets often have multiple benefits that are difficult to quantify because of the locational context in which they operate. The value is temporally, operationally, and spatially specific. It varies widely by distribution systems, transmission network topology, and the composition of the generation mix.

The Electric Power Research Institute (EPRI) recently established a benefit-cost framework that proposes a process for estimating multiple benefits of distributed energy resources (DERs) and the associated cost. This document proposes an extension of this endeavor that offers a generalizable framework for valuation that quantifies the broad set of values for a wide range of technologies (including energy efficiency options, DER, transmission, and generation) as well as policy options that affect all aspects of the entire generation and delivery system of the electricity infrastructure. The extension includes a comprehensive valuation framework of monetizable and non-monetizable benefits of new technologies and services beyond the traditional reliability objectives. The benefits are characterized into the following categories: sustainability, affordability, and security, flexibility, reliability, and resilience.

This document defines the elements of a generic valuation framework and process as well as system properties and metrics by which value streams can be derived. The valuation process can be applied to determine the value on the margin of incremental system changes. This process is typically performed when estimating the value of a particular project (e.g., value of a merchant generator, or a distributed photovoltaic [PV] rooftop installation). Alternatively, the framework can be used when a widespread change in the grid operation, generation mix, or transmission topology is to be valued. In this case a comprehensive system analysis is required.

Valuation Process

The elements of the valuation framework are shown in Figure ES.1.

Step 1: Define Question. The first step in the valuation process is to formulate the question the analysis will answer. Typical questions take one of two forms:

1. *What is the highest value investment option out of a portfolio of options necessary to meet the future states, regional, or federal objectives?* For example, integrated resource plans, transmission planning studies, and distributed resource plans attempt to answer this question by forecasting demand and then projecting the addition of new resources to meet demand and other system goals, such as compliance with environmental regulations.
2. *What is the total value of a particular resource, or a policy change?* For instance, what are the benefits and cost impacts and implications of system operation of integrating a gigawatt of wind capacity into a particular region? What would be the value of a rapid introduction of electric vehicles affecting generation dispatch and the emissions intensity of the power sector?

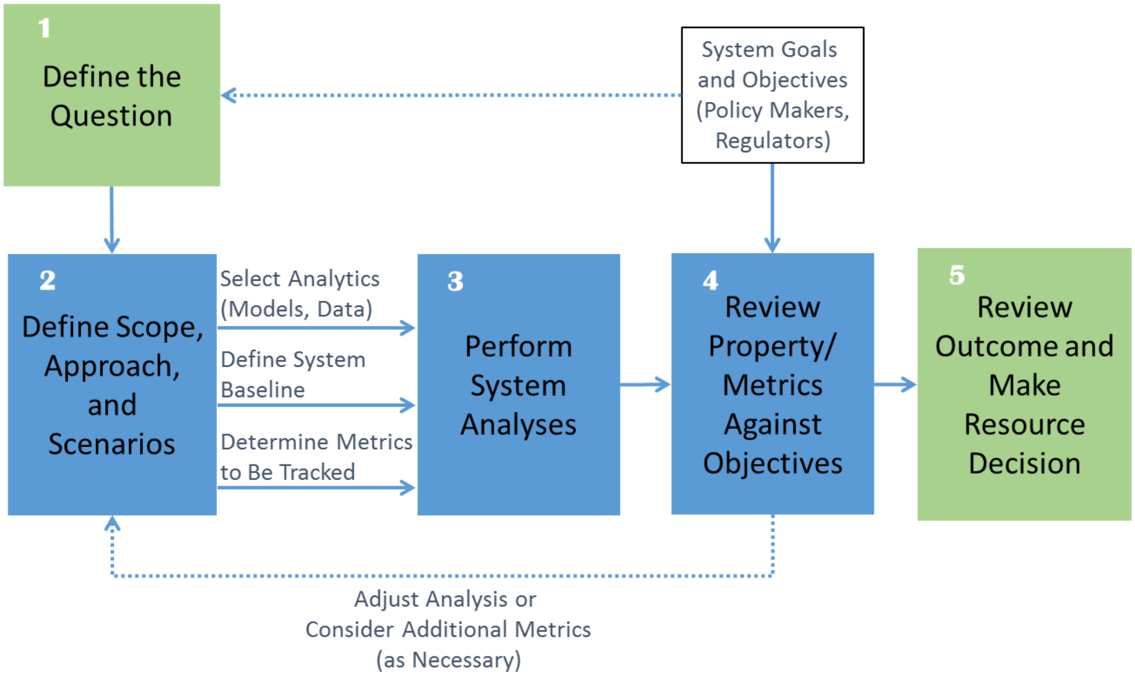

Figure ES.1. Elements of a Valuation Framework

Step 2: Define Scope, Approach, and Scenarios. Define the scope and approach for the analysis, as well as a set of scenarios that bound the uncertainties in the modeling assumptions. This step involves the definition of the system boundary to be analyzed and the system characteristics. It addresses the question of what techno-economic system behavior will need to be analyzed to study impacts at the appropriate level of detail?

Select Analytics. The analysis methodology to be applied should offer sufficient detail in system representation such that key system behaviors (power flow and market mechanisms) can be explored and system impacts can be studied. The system spatial boundary determines whether we study system impacts at a utility service territory level, or balancing authority, state-, or interconnect level. The sectoral boundary determines if, for instance, demand response resources are modeled as an integral part of a power flow model or are only represented as static boundary conditions to a power flow modeling approach. The outcome of this element is the specification of the modeling technique, including the sectoral and spatial domains, over which a change or intervention will be analyzed and valued.

Define system baseline. The system baseline is important because the value of resources is highly context-dependent and is not inherent to the resource itself. The baseline assumptions should be internally consistent and should represent a plausible picture of key economic indicators and technology characteristics. Often the assumptions are informed by outcomes of other models.

Determine characteristics and metrics to be tracked. We consider system characteristics to be an expansive description of the system in terms of its physical assets, load, associated risks and uncertainty, and the regulatory and market context created that shape and oversee the physical system. More specifically, system characteristics to consider include the following:

- load characteristics (such as the load shape and peak demand);
- existing assets (including generation, transmission, distribution, and consumer assets);

- costs (including capital, operations and maintenance [O&M], and variable); and
- regulatory structures (rate design, market rules, and resource adequacy mechanisms).

Metrics are measurements of system properties that represent features, characteristics, or behavior of the power system. The deployment of a new asset changes the system behavior. Specific metrics need to be determined that will be tracked across the set of scenarios to be analyzed. The valuation is then based on the set of metrics that represent a picture of the changes in the system behavior in response to a change or an intervention. Depending on the scope of the valuation, the set of metrics may be comprehensive or very limited and targeted.

Step 3: Perform System Analyses. Analyses with projections typically spanning several decades (usually to 2030 or 2040) should be conducted for the baseline cases and the various defined scenarios. The scenarios cover a certain value range of uncertain parameters (e.g., capital cost assumptions, fuel cost expectations, etc.). Often, but not always, several models will be used, and outputs of one model will be used as input to others. For instance, an expansion planning model will determine the future least-cost capacity additions to meet loads. The capacity additions (output of the expansion planning model) will then be incorporated into production cost model to verify the deliverability of the generation to the load centers and the implications on production cost due to the new capacity addition. The final outcome of this step is then one or more scenario result(s) expressed in terms of metrics defined in the previous step. The change in the metrics between the baseline and intervention case is then used to determine the total value of the intervention in question.

Step 4: Review System Properties/Metrics against Objectives. The most common metrics in valuation analyses are monetary, such as those measuring changes in system costs or revenue requirements. Other types of analyses may use non-monetary metrics. For example, reliability metrics quantify the likelihood of outages, and environmental sustainability metrics quantify impacts such as the amount of land cleared, air-emissions released, or protected species harmed. Non-monetary metrics can be translated into monetary values if assumptions are made about the economic value of what is being measured. For example, the value of lost load (VOLL) is used to estimate the economic damages caused to consumers by load not being served.[a] In some cases, developing quantitative metrics may not be possible, thus requiring reliance on a qualitative description of the characteristics or capability of the system.

Stakeholders and decision makers then review and compare the outcomes of the scenario analyses against any existing overarching system objectives. If one or more system objectives were defined as “hard” constraints (for instance, regulators decided that the distribution system must sustain category 5 storms), then all technology options must meet this requirement. Alternatively, the distribution planner may explore a more value-based approach, in which cost, resilience, or other system properties are investigated to determine which tradeoffs are most desirable.

Step 5: Review Outcome and Make Resource Decision. The final challenge in comprehensive valuation is the question of how to weigh changes in one metric against changes in another metric. Many decision makers, including state commissions, environmental regulators, utilities, transmission planners, and market operators, must consider tradeoffs between metrics when making decisions. One approach is to aggregate metrics into one measure that quantifies a holistic view of the impacts on system value. For monetary metrics, the most common approach for combining metrics is to calculate the present value of costs and benefits that occur over time. Such analysis must consider the time value of money, allowing for the tradeoff between costs avoided in one period of time but increased at a later time. The benefits and

[a] Estimated value of lost load is based on short-term outages (LBNL 2009)

costs can either be used to calculate a benefit-to-cost ratio or the net present value. However, not all monetary values are additive and care needs to be taken in combining even values of similar units to avoid double counting of costs or benefits.

Definition of System Properties

This report delineates six properties of the power system that should be considered in a comprehensive valuation analysis. For each property, we (1) define the property, (2) identify subproperties that further clarify components of the properties, (3) identify metrics that are commonly used to measure each property or subproperty, and (4) provide examples of how each property is or may be considered in a valuation analysis.

Table ES.1 provides an overview of the six topical areas of system properties with some higher level definition.

Table ES.1. Summary of System Properties

Property	Description
Affordability	Provide electric services at a cost that does not exceed customers' willingness and ability to pay for those services.
Reliability	Maintain power delivery to customers in the face of routine uncertainty in operating conditions.
Operational Reliability	Deliver energy sufficient to meet current and near-term load obligations with existing assets under an expected range of conditions.
Planning Reliability	Deliver energy sufficient to meet projected long-term load obligations with existing and planned assets under an expected range of conditions.
Resiliency	Withstand and recover quickly from extreme external events such as natural disasters.
Robustness	Maintain system operations during an extreme external disruption.
Recoverability	Return the system to normal operation following a disruption.
Flexibility	Respond to future uncertainties that may stress the system in the short term and require the system to adapt over the long term.
Operational Flexibility	Respond to relatively short-term operational and economic variabilities uncertainties that are likely to stress the system or affect costs.
Planning Flexibility	Adapt to variabilities and uncertainties that are likely to stress or fundamentally alter the system in the long term.
Sustainability	Provide electric services to customers without negative impacts on natural resources, human health, or safety.
Environmental Sustainability	Deliver power with limited impact on environmental quality and human health.
Safety	Deliver power with minimal safety risk to workers and to the general population.
Security	Resist external disruptions to the energy supply infrastructure caused by intentional physical or cyber-attacks or by limited access to critical materials from potentially hostile countries.
Physical/Cyber Security	Prevent external threats and malicious attacks from occurring and affecting system operation.
Supply Chain Security	Maintain and operate the system with limited reliance on supplies (primarily raw materials) from potentially unstable or hostile countries.

Relation between Value Streams and System Properties

A value stream (the constituent of the total value of an intervention) relates to a system property in the following way. Value streams (negative or positive) are generated by changing the baseline property of the system (grid) to a new property. A value stream is the difference between the end-state system property and the original or baseline property. For instance, if a distributed energy storage device was installed at the end of a feeder to provide outage management services, then the change in CAIDI (customer average interruption duration index) and CAIFI (customer average interruption frequency index) are the value streams. The value stream may be expressed in monetary units based on the estimated VOLL to determine reduced outage cost. The storage device would also generate other value streams by changing system properties (or subproperties) that express power quality characteristics and total system cost.

Findings and Insights of Valuation Practices

Valuation in the electric utility sector has been performed for many decades. It was generally referred to as cost-benefit analysis and explored the cost relative to benefits of new and conventional technologies and services in various planning activities, including resource adequacy (RA) analysis, integrated resource planning (IRP), transmission planning, and more recently, distribution resource planning (DRP). While adequate for the time, new disruptive technologies and greater emphasis on reliability and resilience to severe weather events, environmental impacts, as well as transparency of the entire analysis render the current processes insufficient.

Our analysis reveals the following key insights:

1. Valuation has to be done in a system context. The value of a single technology or grid asset to be deployed, can only be estimated by how it improves or impacts the system behavior as a function of time. Estimating value can be done either by a marginal analysis, in which the technology is a price taker, or by performing a system analysis that explores and considers system responses as a consequence of deploying a grid asset. The former approach is used for profitability assessments of a project or a technology, the latter usually attempts to estimate a broader set of value streams.
2. Six categories of system properties were defined as well as a generic valuation approach by which a wide range of technologies, services, and policy options can be valued comprehensively. The depth and breadth of the valuation approach depends on the stakeholder, the intervention (technology, services, or policy option) to be valued, resources available for the analysis, and the set of questions to be explored. Valuations may be very targeted, focusing only on profitability objectives of merchant generators, or they may be structured more comprehensively and holistically by considering all of the six categories of system properties and their impacts on them.
3. We introduced the concept of a "hypothetical social planner", who would evaluate any intervention or changes to the electric infrastructure from a viewpoint of total societal value creation. Such a framework, while challenging, could enable a more explicit, transparent, and overall holistic consideration of values, and thus, foster a more comprehensive tradeoff analysis than decision makers typically face. By taking the position of a social planner, we are trying to take a neutral standpoint in order to focus on considering all of the stakeholders' and consumers' interests, so that the valuation framework can be used as a starting point by any stakeholder or interest group.
4. We did not include equity as one of the six properties. Equity is an important consideration for policy makers and regulators requiring an understanding to whom value in the system accrues, and whether that apportionment of value is fair or desirable. Equity is generally considered at a more granular scale than the system-wide level we describe in this document. Of course, changes to the system will have heterogeneous impacts on different stakeholders and may increase net benefits for some but

decrease them for others. Examples include retail rates that differ by customer class or health or land impacts that may be highly localized. Similarly, customers will not all derive the same value from increased reliability and the other properties. The extent to which each property affects or is valued by individual (or classes of) ratepayers requires further evaluation than the system-wide analysis completed for this study.

5. The review of IRPs, transmission planning processes, RTO markets, and DRP processes revealed that planners and regulators account for several properties, the most prominent and detailed being reliability and affordability. Planning processes are often tailored to specific objectives and thus limited by several factors:

   - Scope of resource may be limited due to narrow planning objectives. For example, transmission upgrades are rarely considered in integrated resource planning
   - Range of future scenarios may be limited to a 'business as usual' view of the world foregoing new control paradigms and emerging technologies
   - Scope of properties considered may be limited to tradeoffs between few properties or narrow view of properties because of jurisdictional limitations, within which a regulator can make decisions.

   Some IRPs and regional transmission planning entities consider operational and planning flexibility as an important value. In our analysis, security was rarely accounted for as a value in any of the planning processes. This may be due to the fact that there are company-level compliance requirements, at least on the cyber security side. Accounting for resilience as a value was not found to be explicitly considered in any of the planning processes. However, references to the desire to improve resilience in response to the extreme weather phenomena were found.

   The compartmentalization of different planning processes may limit the overall optimality of the process (and thus overall system value may not be maximized), although several explanations may make a fully integrated process unrealistic. First, integrating distributed resource planning, transmission planning, and distribution planning into the traditional IRP process faces technical hurdles. Second, the exclusion of a technology or sector from an IRP process may often be the result of the defined jurisdiction of an IRP, and is not necessarily an indication that the IRP or the state requirements for the IRP are defective. This lack of control extends to customer decisions as well; in the case of EE and DR.

6. Value is sometimes captured in market-based pricing of services rendered. In areas without competitive wholesale markets, value is sometimes monetized by avoided cost principles via regulatory constructs in order to meet a set of standards or technical requirements. Safety and reliability standards and environmental requirements are most often fixed design criteria, with which the transmission and distribution planners must comply. Setting and developing safety and reliability standards underlie valuation principles based on loss of life and loss of load, but are not always explicitly evaluated.

7. The detailed case studies revealed the following insights:

   a. Retirement of nuclear power plants – We are in a period of significant nuclear retirements, while at the same time the first new units in several decades are being constructed. Some retirements are due to mechanical failures that are very expensive to fix. Other retirements are due to current and near-term projected poor market conditions. The unique and most important characteristics of a nuclear power plant are its zero air emissions (from electricity generation), low variable cost, and high output. However, nuclear plants have less desirable features, including high capital cost, safety concerns regarding the entire fuel cycle, and limited operational flexibility. The problem facing nuclear power is that outside of California and the northeastern Regional Greenhouse Gas

Initiative states, nuclear technology's lack of carbon emissions has no explicit value: merchant owners receive no compensation for that value. In states with vertically integrated utilities, the state can recognize the value of nuclear power from a public perspective. The fundamental valuation problem is one of private investment (merchant generators) versus public investment (the long-term benefit of retaining nuclear power).

b. Distributed energy storage – Energy storage has been recognized as a resource with desirable characteristics and features for future grid operations under high penetration of variable production renewable generation, such as wind and solar generation resources. However, in only a few instances are several features being valued. The most notable instances in which energy storage systems are valued include frequency regulations markets developed in response to Federal Energy Regulatory Commission Order No. 755 (pay for performance), which was motivated by unfair treatment of fast-responding grid assets for the provision of frequency regulation services in Independent System Operator (ISO)/RTO markets, and the California Energy Storage Procurement targets of 1.325 GW, where the California Legislature recognized the intrinsic value of storage as a mitigation strategy to accommodate the fluctuations in the generation from wind and solar capacity in the distribution system and the bulk power system.

8. Quantitative estimation of a comprehensive set of values of a new technology, service, or policy is predicated on the notion that one can first identify the value streams and then find appropriate tools and data to analyze the system impacts relative to a base case. In most cases, this requires quantitative system modeling capabilities, such as power flow modeling. As the desire to conduct more comprehensive quantitative valuation increases, so must the modeling and analytics capabilities and data availability improve. For instance, quantifying the full resilience value of a DER resource as a mitigation strategy for resolving long-term supply disruption lacks robust data on long-term VOLL for many customer classes. Similarly, the estimation of the avoided cost of restoration, given a certain threat scenario is difficult. Improvement in the modeling and analytics would be necessary in order to estimate more comprehensively the total value of many distinct value streams. Improvements include the following:

   a. Transmission-Distribution seam – There is a seam between distribution system planning and transmission planning tools. To bridge the gap such that distributed resources, behind or before the meter, can be visible and thus be valued in the transmission system requires linkages of two, independent modeling and simulations platforms (AC power flow modeling in transmission network and AC power flow modeling for distribution systems). Only when this gap is closed can we value certain behaviors of distribution assets (for instance, ride-through capabilities of a PV inverter) in the transmission system.

   b. Generation-transmission seam – The IRP process does not generally consider many transmission alternatives in the scenario definition. Instead it focuses on generation capacity or RA. Transmission planners often consider a narrow range of benefits of new investments, including production cost savings and capacity value, but also flexibility and resilience. The tradeoff among different technology solutions along multiple values would provide greater insight into cost optimality or affordability values.

   c. Multi-objective optimization tools – Most of the analytics tools have cost minimization as their objective. Aspects of flexibility and sustainability are often modeled as constraints to the cost-minimization scheme to meet changing or stricter compliance standards. However, there may be value in reformulating the problem as a multi-objective problem, in which the result is a solution space defined by measures of cost, flexibility, sustainability, and other properties. This, in turn, will require some decision support mechanism for decision makers to navigate through the solution space, in which the ranking of a technology solution is not a simple function of cost, but a function of several parameters.

Acknowledgments

This work was sponsored by the Office of Energy Policy and Systems Analysis (EPSA), U.S. Department of Energy (DOE). All results and any errors are the responsibilities of the authors and do not represent the opinion of Pacific Northwest National Laboratory, The Brattle Group, or its clients.

The authors would like to acknowledge the following DOE staff who provided constructive feedback and guidance in the development of this report: Lara Pierpoint, Sandra Jenkins, Jeanette Pablo, and Andrew Stocking.

Acronyms and Abbreviations

AB	Assembly Bill
AC	alternating current
ACE	area control error
AEO	Annual Energy Outlook (performed by the EIA annually)
AMI	advanced metering infrastructure
APS	Arizona Public Service
CAA	Clean Air Act
CAIDI	Customer Average Interruption Duration Index
CAISO	California Independent System Operator
CIM	Common Information Model
CIPS	Critical Infrastructure Protection Standards
CO_2	carbon dioxide
CPP	Clean Power Plan
CPUC	California Public Utility Commission
DA	Day-Ahead
DER	distributed energy resource
DHS	U.S. Department of Homeland Security
DOE	U.S. Department of Energy
DR	demand response
DRP	distribution resource plan(ning)
DSM	demand-side management
E3	Energy + Environment Economics
EE	energy efficiency
EIA	Energy Information Administrations
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ES-C2M2	Electricity Subsector Cybersecurity Capability Maturity Model
ESS	energy storage system
FERC	Federal Energy Regulatory Commission
FPL	Florida Power and Light
GHG	greenhouse gas
GW	gigawatts
IEEE	Institute of Electrical and Electronics Engineers
IOU	investor-owned utility
IRP	integrated resource plan(ning)

ISO	independent system operator
IT	information technology
LACE	levelized avoided cost of electricity
LBNL	Lawrence Berkeley National Laboratory
LCOE	levelized cost of electricity
LCR	Local Capacity Requirement
LIPA	Long Island Power Authority
LOLE	loss of load expectation
LOLH	loss of load hours
LOLP	loss of load probability
LSE	load serving entity
LTSA	Long Term System Assessment
MISO	Midcontinent Independent System Operator
MVP	multi value project (MISO established an approach for transmission planning with an integrated view of values of future transmission expansions.)
MW	megawatt or 10^6 watt
MWh	megawatt-hour(s)
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corporation
NYISO	New York ISO
O&M	operations and maintenance
OSHA	Occupational Safety and Health Administration
PCS	power conditioning system
PG&E	Pacific Gas & Electric
PJM	Pennsylvania, Jersey, Maryland Interconnection
PNNL	Pacific Northwest National Laboratory
PSC	Public Service Commission
PUC	public utility (utilities) commission
PV	photovoltaic(s)
PVRR	Present value of the revenue requirements
QER	Quadrennial Energy Review
RA	Resource Adequacy
RegA	Regulation A
RegD	Regulation D
RGGI	Regional Greenhouse Gas Initiative
RMI	Rocky Mountain Institute
RPS	renewable portfolio standard
RT	Real-Time

RTO	Regional Transmission Operator
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCC	social cost of carbon emissions
SCED	Referred to as Security Constrained Unit Commitment and Economic Dispatch
SPP	Southwest Power Pool
T	ton(s)
T&D	transmission and distribution
TVA	Tennessee Valley Authority
UCAP	unforced capacity
VOLL	value of lost load
VSL	value of a statistical life
WECC	Western Electricity Coordinating Council

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1.0 Need for Comprehensive Valuation Methods

Accurate valuation of services delivered by existing and new technologies is important for prioritizing investments in modernizing the electric grid to meet national, regional, or state energy and climate objectives. Clear, transparent, and accepted methods for estimating the total value (i.e., total benefits minus cost) of grid technologies and services are necessary for decision makers to make informed decisions. This applies to home owners interested in distributed energy technologies, as well as to service providers offering new demand response services, and utility executives evaluating best investment strategies to meet their service obligations.

However, current valuation methods lack consistency, methodological rigor, and often the capability to identify and quantify multiple benefits of grid assets or new and innovative services. Distributed grid assets often have multiple benefits that are difficult to quantify because of the locational context in which they are operated. The value is temporally, operationally, and spatially specific. It varies widely by distribution system, transmission network topology, and the composition of the power generation mix. Rocky Mountain Institute reviewed 16 studies that estimated the value of distributed photovoltaic (PV) technologies reflecting diverse penetration levels, system contexts, assumptions, and methodologies.[1] The results offer little consensus on the level and character of the net benefits of distributed PV technologies reflecting the large diversity; net benefits range from 0 to 11 cents/kWh. The Electric Power Research Institute (EPRI) recognized the lack of methodological rigor and consistency in how the impacts of distributed technologies are identified and monetized. It launched an effort to develop a cost-benefit framework for distributed energy technologies that was published in 2015. This work improved the rigor and consistency of the valuation process. It improved the traditional analyses for distribution and bulk power system impacts. It addressed customer and societal impacts characterized as reduced emissions and general economic effects.[2]

The EPRI benefit-cost framework focused specifically on distributed energy resources (DERs). An extension of the EPRI work is needed that broadens the valuation scope of the framework to a wider set of technologies and benefits. The extended framework needs to allow the analysis to quantify the broad set of benefits and costs for a wide range of technologies (including energy efficiency options, DERs, transmission, and generation) as well as policy options that affect all aspects of the entire generation and delivery system of the electricity infrastructure. The spectrum of benefits needs to be broad and should include categories such as sustainability, affordability, security, flexibility, and resilience.

The Quadrennial Energy Review (QER) also addresses the methodological shortfall of the valuation process by stating the following:

> A key element for addressing the operational and business model concerns posed by new technologies centers on the valuation (i.e., “What are the benefits of new services and technologies to the grid? And conversely, “What is the cost of the services the grid provides to customers?”) There is no agreement on the answers, though, as answers depend on the situation…..
>
> There currently are no transparent, broadly accepted methods that can be used by stakeholders to determine the cost and benefits associated with integrating new services and technologies into the grid. Clearer valuation methods would empower legislators and regulators in their efforts to address their local needs as they formulate strategies and plans to provide a portfolio of electricity options that meet their state-specific goals for reliable, affordable, and clean electricity.[3]

This document defines the elements of a generic valuation framework and process as well as system properties and metrics by which value streams can be derived. The valuation process can be applied to determine the value on the margin of incremental system changes. This process is typically performed when estimating the value of a particular project (e.g., value of a merchant generator, or a distributed photovoltaic (PV) rooftop installation). Alternatively, the framework can be used when a widespread change in the grid operation, generation mix, or transmission topology is to be valued. In this case a comprehensive system analysis is required.

2.0 Elements of a Valuation Framework

The evaluation framework proposed herein includes particular terminology related to the associated valuation process as described in the following sections.

2.1 Definitions

This document uses a set of terms in the context of valuation and estimating value, including valuation and value streams, system properties, metrics, and system outcomes and objectives, all of which are defined below.

Valuation and Value Stream – The common definition of valuation refers to estimating value or worth. In the electric power sector, valuations are used when making decisions related to both the operations and planning time frames. Valuations involve countless actions, analyses, and decisions made by a wide range of stakeholders, including customers, asset owners, grid operators, regulatory bodies, policymakers, and advocacy groups. Operators dispatch generation facilities based on least-cost principles; resource planners project future resource costs and develop capacity expansion plans; and regulators approve retail rates based on least-cost and least-risk principles. Each decision to operate or build certain assets or use electricity is made in order to achieve a set of goals or objectives, which often requires making tradeoffs between two or more desirable outcomes. In this way, these decisions are based on a valuation of the action to be taken that lead to a conclusion that the set of benefits of taking the action outweighs the costs.

We define the total value of an investment (deployment of a grid asset or implementation of a service) as the total benefit minus its cost. A value can be derived from multiple benefits or multiple services that a grid asset can deliver. For instance, distributed energy storage may provide an energy service, while at the same time providing capacity. In addition, the storage device may provide outage management services and upgrade deferral, as well as local voltage control services. Each of these services generates a value stream that together, when appropriately aggregated, determines the total value of the storage device.

The benefits are usually monetized into one dollar value to subtract it from the cost of the investment. The resulting figure represents the total value. Value is usually nominated in dollars for a given year (e.g., 2016 $).

System Properties – A system property is an attribute of the system itself or its behavior. This document adopts the categorization of system properties proposed by the U.S. Department of Energy (DOE). Properties are binned into six topical areas: (1) reliability, (2) resilience, (3) flexibility, (4) sustainability, (5) affordability, and (6) security.[4] Properties have subproperties defining higher granularity to its parent property. The properties and their constituent subproperties are further described in Section 3.0.

A value stream (the constituent of the total value of an intervention) relates to a system property in the following way. Value streams (negative or positive) are generated by changing the baseline property of the system (grid) to a new property. A value stream is the difference between the end-state system property and the original or baseline property. For instance, if a distributed energy storage device was installed at the end of a feeder to provide outage management services, then the change in CAIDI (customer average interruption duration index) and CAIFI (customer average interruption frequency index) are the value streams. The value stream may be expressed in monetary units based on the estimated VOLL to determine reduced outage cost. The storage device would also generate other value streams by changing system properties (or subproperties) that express power quality characteristics and total system cost.

Metrics – Metrics are physical measurements of a system property or subproperty or a measure of a monetary unit. For instance, a metric under the category of sustainability could be the emissions of a criteria pollutant at a point source over a given period.

System outcomes and objectives – System properties can be used to describe an outcome of a policy implementation or a deployment of a grid asset. Similarly, system properties can be used to express a policy or investment objective. For instance, limiting the emissions of criteria gas within a region can be viewed as an objective. Any implications of this objective causing additional cost to be recovered through a retail rate change could be considered an outcome expressed by the metric "average retail rate" under the property "affordability."

Hypothetical social planner – In defining a generic valuation process, we take the view of a hypothetical social planner, who would evaluate any intervention or changes to the electric infrastructure from a viewpoint of total societal value creation. Such a framework, while challenging, could enable a more explicit, transparent, and overall holistic consideration of values, and thus, foster a more comprehensive tradeoff analysis than decision makers typically face. By taking the position of a social planner, we are trying to take a neutral standpoint in order to focus on considering all of the stakeholders' and consumers' interests, so that the valuation framework can be used as a starting point by any stakeholder or interest group.

2.2 Valuation Process

This report proposes a valuation framework for estimating the value of grid technologies and services for the electric grid. Technology deployment and new service applications affect the grid in various ways specific to the technology placement, system characteristics such as grid topology and generation mix, and the overall operational characteristics of the entire electric infrastructure. We consider a technology deployment or a new service as an intervention to the existing power system relative to a baseline. The intervention to the system could be capacity additions (generation), upgrades of existing infrastructure (transmission and distribution), distributed energy technology additions, an energy efficiency measure, or a change in policy. To estimate the magnitude of impacts in response to an intervention, analyses must be performed. The analyses can vary in their breadth and depth of system representation depending on the system focus and question to be addressed.

2.2.1 Marginal Analysis versus System Analysis

Analyses for valuation are performed either as a marginal analysis or as a comprehensive system analysis. The marginal analysis studies the impact of an intervention as one unit or one increment of a new investment influences the system on the margin without a system response. A comprehensive system analysis estimates impacts of interventions that affects the system behavior, usually in multiple ways that include changes in capacity additions and generation dispatch. Each method has advantages and disadvantages.

The marginal analysis is often simplified by estimating the value of an intervention relative to a static system that will not respond to the intervention. This analysis often is called "price-taker" because the intervention does not affect a system response. This valuation method is used when estimating the profitability of a single project that is assumed to be sufficiently small, such that it does not influence the pricing of the service it provides. Marginal analyses are performed to estimate value at current market conditions as well as for a future point in time (say 2030 or 2040). The challenge when estimating future marginal values is to define plausible future market and grid operational conditions that can be used as a base case.

Comprehensive system analyses, in contrast to marginal analyses, enable the analyst to value interventions at larger magnitudes that are likely to influence installed generation and transmission and distribution (T&D) capacity, as well as economic dispatch, and in turn the cost or price projections of services. These analyses are often performed for longer-term valuation assessments of policy options or new technology adoptions.

2.2.2 Steps of the Process

The elements of the valuation framework are shown in Figure 2.1 and described below. The framework applies to both marginal and system analyses.

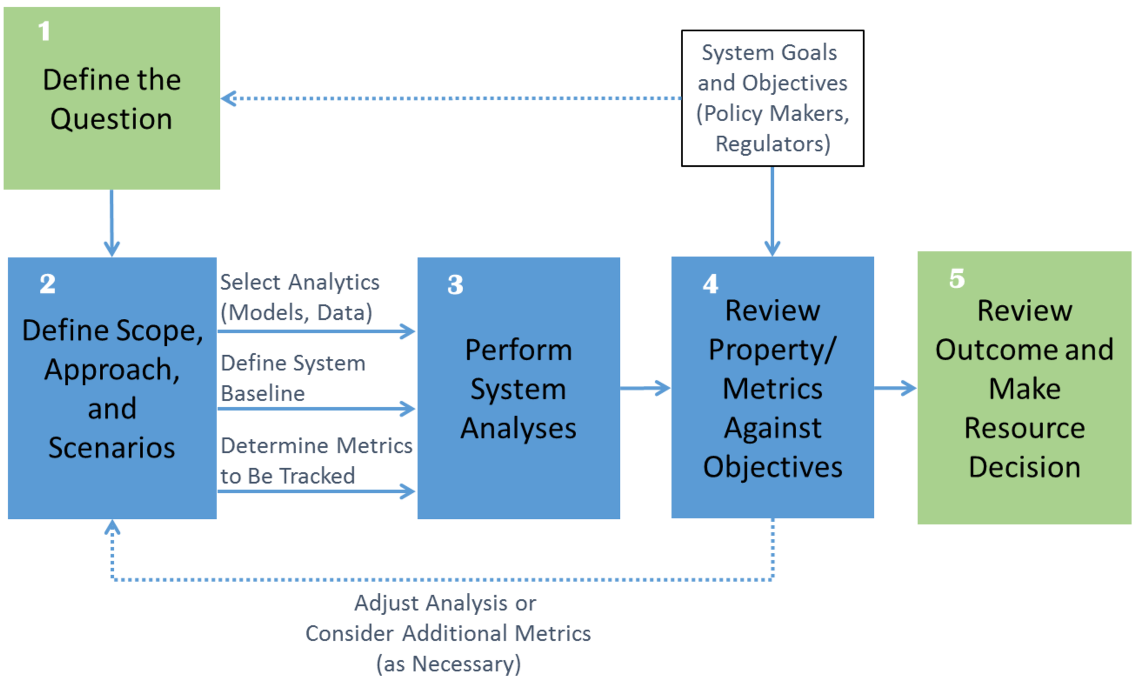

Figure 2.1. Elements of the Valuation Framework

<u>Step 1: Define the question</u>. The first step in the valuation process is to formulate the question the analysis will answer. Typical questions take one of two forms:

1. *What is the highest value investment option out of a portfolio of options necessary to meet the future states, regional, or federal objectives?* For example, integrated resource plans, transmission planning studies, and distributed resource plans attempt to answer this question by forecasting demand and then projecting the addition of new resources to meet demand and other system goals, such as compliance with environmental regulations.

2. *What is the total value of a particular resource, or a policy change?* For instance, what are the benefits and cost impacts and implications of system operation of integrating a gigawatt of wind capacity into a particular region? What would be the value of a rapid introduction of electric vehicles affecting generation dispatch and the emissions intensity of the power sector? What would be the benefit and cost implications of a national carbon policy such as the U.S. Environmental Protection Agency's (EPA's) Clean Power Plan?

Step 2: Define scope, approach, and scenarios. Define the scope and approach for the analysis, as well as a set of scenarios explore the influence of the modeling assumptions. This step involves the definition of the system boundary to be analyzed and the system characteristics. It addresses the question of what techno-economic system behavior will need to be analyzed to study impacts at the appropriate level of detail?

Select Analytics. The analysis methodology to be applied should offer sufficient detail in system representation such that key system behavior (power flow and market mechanisms) can be explored and system impacts can be studied. The system spatial boundary determines if we study system impacts at a utility service territory level, or balancing authority, state-, or interconnect level. The sectoral boundary determines if, for instance, demand response resources are modeled as an integral part of a power flow model or only represented as a static boundary condition to a power flow modeling approach. If the former is the case, distribution system models may need to be used to represent appropriate impacts of new load conditions as they affect the transmission system. Inter-sectoral aspects are sometimes of interest. For example, natural gas-electricity interdependence, or water availability in hydropower dominating regions may require expanding the analysis to other sectors or natural system modeling in order to study inter-sectoral interactions and dependencies. Inter-sectoral analyses are complex and require significant amounts of data and calibration, but they provide additional value from insights gained into the interdependencies of the infrastructures of natural constraints that are of importance in the context of resilience and sustainability questions. The outcome of this first element is the specification of the modeling technique, including the sectoral and spatial domains, over which a change or intervention will be analyzed and valued.

Define the system baseline. The system baseline is important because the value of resources is highly context-dependent and is not inherent to the resource itself. For example, adding wind or solar power to a system in which all existing generation is fueled by coal provides more absolute emissions reductions than adding the same resources to a system in which existing generators are primarily nuclear or hydro power. The baseline definition can be relatively simple for a marginal analysis in which the value of an intervention is determined relative to the current state of the grid. Definition of the baseline can be more complex for a system analysis that projects the evolution of the power system into a future year (e.g., 2030 or 2040). Then the challenge for the baselining element is to define a reasonable set of assumptions about a future state of the electric infrastructure and fuel price projections and expectations. There is no "right" baseline. Many U.S. studies use the Energy Information Administrations (EIA) Reference Case assumptions for the Annual Energy Outlook (AEO), which has clearly defined fuel price assumptions and future cost characterizations for existing and new technologies, as well as the projections of current federal and state energy policies. The baseline assumptions should be internally consistent and should represent a plausible picture of key economic indicators and technology characteristics. Often the assumptions are informed by outcomes of other models.

Determine the characteristics and metrics to be tracked. We consider system "characteristics" to be an expansive description of the system's physical assets, loads, associated risks and uncertainties, and the regulatory and market contexts created that shape and oversee the physical system. More specifically, system characteristics to consider include the following:

- load characteristics (such as the load shape and peak demand);
- existing assets (including generation, transmission, distribution, and consumer assets);
- costs (including capital, operations and maintenance [O&M], and variable); and
- regulatory structures (rate design, market rules, and resource adequacy mechanisms).

Metrics are measurements of system properties that represent features, characteristics, or behaviors of the power system. The deployment of a new asset changes the system behavior. Specific metrics need to be determined that are tracked across the set of scenarios to be analyzed. The valuation is then based on the set of metrics that represent a picture of the changes in the system behavior in response to a change or an intervention. Depending on the scope of the valuation, the set of metrics may be comprehensive or very limited and targeted. The metrics usually are a function of time (year across the projection horizon) and location within the system. As discussed in Section 3.0, the metrics representing system properties are linked to a set of values.

Step 3: Perform system analyses. Analyses with projections usually over several decades (usually to 2030 or 2040) should be conducted for the baseline cases and the various scenarios defined before. The scenarios cover a certain value range of uncertain parameters (e.g., capital cost assumptions, fuel cost expectations, etc.). Often, but not always, several models are used, and outputs of one model are used as input to others. For instance, an expansion planning model determines the future least-cost capacity additions to meet loads. The capacity additions (output of the expansion planning model) are then incorporated into the production cost model to verify the deliverability of the generation to the load centers and the implications for production cost due to the new capacity addition. The final outcome of this step is the results from one or more scenarios that are expressed in terms of metrics defined in the previous step. The change in the metrics between the baseline and intervention case is then used to determine the total value of the intervention in question.

Step 4: Review the system properties/metrics against objectives. The most common metrics in valuation analyses are monetary, such as those measuring changes in system costs or revenue requirements. Other types of analyses may use non-monetary metrics. For example, reliability metrics quantify the likelihood of outages, and environmental metrics quantify impacts such as the amount of land cleared or the protected species harmed. Non-monetary metrics can be translated into monetary values if assumptions are made about the economic value of what is being measured. For example, the value of lost load (VOLL) is used to estimate the economic damages caused to consumers by the load not being served.[b] In some cases, developing quantitative metrics may not be possible, and this may require reliance on a qualitative description of the characteristics or capability of the system. For instance, if undergrounding of the distribution system assets is considered as a retrofit resilience improvement in areas that are potentially threatened by hurricane storms, then the value of the undergrounding would be a qualitative measure of "improved resilience to high wind scenarios." The analyst may retain the qualitative measure, rather than monetizing it through an estimated VOLL. Justifications for that decision could be that there are no reliable data for long-term supply disruption of electricity, or that estimates of the likelihood of a hurricane striking the particular location may not be known. The outcome of this particular undergrounding project valuation would then be expressed by metrics of cost in quantitative terms, and by a resilience descriptor of "improved resilience against category 4 or 5 hurricane scenarios."

Stakeholders and decision makers then review and compare the outcome of scenarios against any existing overarching system objectives. If one or more system objectives were defined as "hard" constraints, for instance, the distribution system must sustain category 5 storms, then all technology options must meet this requirement. Thus, a constraint represents a very high value. Alternatively, the distribution planner may explore a more value-based approach, in which cost, resilience, or other system properties are investigated to determine which tradeoffs are most desirable.

Step 5: Review the outcome and make a resource decision. The final challenge in comprehensive valuation is the question of how to weigh changes in one metric against changes in another metric. Many

[b] Estimated value of lost load is based on short-term outages (LBNL 2009)

decision makers, including state commissioners, environmental regulators, utilities, transmission planners, and market operators, must consider tradeoffs between metrics when making decisions. One approach is to aggregate metrics into one measure that quantifies a holistic view of the impacts on system value. For monetary metrics, the most common approach for combining metrics is to calculate the present value of costs and benefits that occur over time. Such analysis must consider the time value of money, allowing for the tradeoff between costs avoided in one period of time but increased at a later time. The benefits and costs can either be used to calculate a benefit-to-cost ratio or the net present value. However, not all monetary values are additive and care needs to be taken in combining even values of similar units to avoid double counting of costs or benefits.

Based on our review of processes used throughout the industry in valuing impacts of different types, we have found no standard practice in the industry for combining metrics into a single value of the system. In many cases, several metrics are monetized and included in the calculation of the net present value or benefit-cost ratio, and non-monetizable metrics are separately quantified or described qualitatively. This approach is commonly used in utility integrated resource planning studies, which often evaluate several relevant metrics, combine monetary metrics where possible, and describe the preferred portfolio based on a qualitative analysis of tradeoffs between the metrics. Using multi-attribute utility functions to weigh metrics against each other would be a more robust approach to identifying the highest value option available, but we have not found evidence of such approaches being commonly used. This approach requires determining which metrics are accounted for and developing relative weights for each metric. It is likely that different stakeholders may weigh each metric differently. While the field of multi-criteria decision making is relatively mature, it has not been customarily applied in the electric infrastructure planning process. New guidelines need to be established to elicit from decision makers appropriate weights that represent the individual person’s attitude and significance regarding the set of values.

In the next section, we review the system properties and metrics that are most commonly considered across the electric power sector to derive value.

3.0 System Properties and Metrics

In this section, we delineate six properties of the power system that should be considered in a comprehensive valuation analysis. For each property, we (1) define the property, (2) identify subproperties that further clarify components of the properties, (3) identify metrics that are commonly used to measure each property or subproperty, and (4) provide examples of how each property is or may be considered in a valuation analysis.

The six properties identified in this report are affordability, reliability, resiliency, flexibility, sustainability, and security. Table 3.1 summarizes these properties and subproperties.

Table 3.1. Summary of System Properties

Property	Description
Affordability	Provide electric services at a cost that does not exceed customers' willingness and ability to pay for those services.
Reliability	Maintain power delivery to customers in the face of routine uncertainty in operating conditions.
Operational Reliability	Deliver energy sufficient to meet current and near-term load obligations with existing assets under an expected range of conditions.
Planning Reliability	Deliver energy sufficient to meet projected long-term load obligations with existing and planned assets under an expected range of conditions.
Resiliency	Withstand and recover quickly from extreme external events such as natural disasters.
Robustness	Maintain system operations during an extreme external disruption.
Recoverability	Return the system to normal operation following a disruption.
Flexibility	Respond to future uncertainties that may stress the system in the short term and require the system to adapt over the long term.
Operational Flexibility	Respond to relatively short-term operational and economic variabilities uncertainties that are likely to stress the system or affect costs.
Planning Flexibility	Adapt to variabilities and uncertainties that are likely to stress or fundamentally alter the system in the long term.
Sustainability	Provide electric services to customers without negative impacts on natural resources, human health, or safety.
Environmental Sustainability	Deliver power with limited impact on environmental quality and human health.
Safety	Deliver power with minimal safety risk to workers and to the general population.
Security	Resist external disruptions to the energy supply infrastructure caused by intentional physical or cyber-attacks or by limited access to critical materials from potentially hostile countries.
Physical/Cyber Security	Prevent external threats and malicious attacks from occurring and affecting system operation.
Supply Chain Security	Maintain and operate the system with limited reliance on supplies (primarily raw materials) from potentially unstable or hostile countries.

When taken together, the properties describe the ability of a power system to meet the intended goals as outlined by the DOE[5]—goals that are broadly consistent with those articulated by electric power sector regulators and policy makers across the United States.[c] In addition, we considered recent research by the staff at Pacific Northwest National Laboratory (PNNL) on desired grid qualities for considering the need for additional grid components, or architecture.[6] EPRI also recently released a framework called the Integrated Grid for analyzing DERs that includes benefits and costs that occur within the distribution system and the bulk system as well as customer and societal impacts; the benefits at the distribution and bulk system level are primarily concerned with changes in costs (capital costs, net fuel/O&M costs, and customer equipment costs), reliability improvement, resiliency improvements, emissions, and general economic effects.

The properties defined in this report are intended to be reasonably independent of each other but cannot be considered to be entirely orthogonal of one another. For instance, an investment to improve the resilience of a distribution system is likely to improve the reliability of service to customers as well. There is a correlation between the definition of resilience and reliability. This is in contrast to an investment that directly affects several properties by different mechanisms. For example, the addition of new generation capacity may be motivated by a desire to increase the reliability of the system, but it will also affect affordability by increasing system costs and it can potentially affect sustainability, depending on the net impact on air emissions or other environmental concerns.

We include under affordability the total costs incurred across the system, including costs that are incurred to increase the system capabilities of other properties, such as increased reliability or increased sustainability through lower air emissions. However, the value of achieving changes in the system outcomes is included in the other five properties and measured, in part, through various metrics specific to each property. For example, if renewable generation facilities are constructed to reduce greenhouse gas (GHG) emissions, affordability metrics will, from a societal perspective, account for any incremental system costs of building renewable generation facilities. The value of achieving lower GHG emissions is accounted for in the sustainability metrics as reduced tons of GHG emissions or as the avoided social cost of the GHG emissions. In this view, the goal of system planning or market designs is not to simply minimize costs to make power affordable, but to analyze whether the tradeoffs of higher costs are justified by the value provided through other properties.

The intent of providing such a list of properties is to delineate the full set of value streams that various planning processes *might* consider in evaluating new resources and regulations. However, this does not necessarily mean that the effect on each property-specific value stream will be consequential to each resource decision, because the scale of the impacts will differ depending on the changes being considered and the characteristics of the system. The relative importance of each property will likely differ across different stakeholder groups, because ratepayers, utilities, regulators, and merchants all have different objectives. It may be the case that the change in one or more properties need not be evaluated if there is either sufficient evidence that the change in the property will be negligible, or if the relevant stakeholders do not place material weight on the property(ies) in question.

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[c] For example, the New York Public Service Commission lists its mission is to "ensure affordable, safe, secure, and reliable access to electric, gas, steam, telecommunications, and water services for New York State's residential and business consumers, while protecting the natural environment. The Department also seeks to stimulate effective competitive markets that benefit New York consumers through strategic investments, as well as product and service innovations." Available at: http://www3.dps.ny.gov/W/PSCWeb.nsf/ArticlesByTitle/39108B0E4BEBAB3785257687006F3A6F?OpenDocument.
The California Public Utility Commission "serves the public interest by protecting consumers and ensuring the provision of safe, reliable utility service and infrastructure at reasonable rates, with a commitment to environmental enhancement and a healthy California economy." Available at: http://www.cpuc.ca.gov/aboutus/

The discussion of each property below includes sample metrics that measure the capability of the system to provide that property. Metrics differ in terms of the units and the timescales. The primary metrics for valuations are often expressed in monetary units, such as system costs (from a societal perspective) or revenue requirements (from a ratepayer perspective). Metrics with non-monetary units, such as environmental emissions or loss of load expectations (LOLE), are indicative, if not a precise measure, of the value captured in each property. In some cases, these quantified metrics can be translated into ratepayer or societal value comparable to the costs incurred, such as through the social cost of carbon for carbon dioxide (CO_2) emissions. Metrics also differ in whether they provide information about perceived system capabilities, historic system performance (lagging metrics), or projected system performance (leading metrics).

We do not include equity as one of the six properties. Equity is an important consideration for policy makers and regulators requiring an understanding to whom value in the system accrues, and whether that apportionment of value is fair or desirable. Equity is generally considered at a more granular scale than the system-wide level we describe in this document. Of course, changes to the system will have heterogeneous impacts on different stakeholders and may increase net benefits for some but decrease them for others. Examples include retail rates that differ by customer class or health or land impacts that may be highly localized. Similarly, customers will not all derive the same value from increased reliability and the other properties. The extent to which each property affects or is valued by individual (or classes of) ratepayers requires further evaluation than the system-wide analysis completed for this study.

Similarly, we do not include economic development as a system property beyond the economic development benefits provided by low-cost electricity. Economic development is typically a political consideration to provide direct benefits to a subset of the population (such as those who will be employed at a new or existing plant), while spreading the costs across a wide range of ratepayers. The net economic benefits may justify regulators making decisions, but we view those benefits as largely beyond the electric power system.

3.1 Affordability

3.1.1 Definition

Affordability refers to the ability of the system to provide electric services at a cost that does not exceed customers' willingness and ability to pay for the services.[d] All else being equal, a system with a lower total cost of supplying electricity creates greater value to its users and to society as a whole. Holding other properties of the system constant, lower costs of electricity will generally increase consumer surplus and improve the economic competitiveness of industries that rely on electric power as a key input. For this reason, the affordability of a system ultimately reflects the costs of supplying electricity to consumers.

Customers pay for electricity via rates that are designed to, at least in principle, recover the cost of producing and delivering electricity.[e] Ratemaking is beyond the scope of this document but it is important to note that in some states customers in aggregate pay for all of the costs of producing and delivering

[d] This definition of affordability is similar to the one presented in (Taft 2015): "ensures system costs and needs are balanced with the ability of users to pay."

[e] Municipalities, cooperatives and federal power marketing agencies set their own rates. Issues with regulatory lag (the delay between when costs are projected and when they are incurred) will results in utilities either under or over recovering their costs. For more discussion, see: http://www.raponline.org/docs/RAP_Lazar_ElectricityRegulationInTheUS_Guide_2011_03.pdf

electricity by design (rate-regulated vertically regulated utilities), while in other states customers pay for the cost of transmission and distribution in regulated rates, but pay market prices for generation.[f] Average rates measured as total costs divided by total sales to end-use customers is a useful proxy for average customer rates in rate-regulated vertically integrated states. In states with wholesale generation markets, a good proxy for average rates is the total cost of transmission and distribution plus the wholesale cost of energy.

Affordability, which reflects system costs and consumer rates, is not independent of the other properties. The total costs incurred for operating, maintaining, and adding to the system are directly affected by the need to achieve objectives reflected in the other properties described below. In some cases these needs are binding constraints (or thresholds) that must be met. Any binding constraint placed on the system (such as an emissions limit or a reliability standard) changes its cost. Similarly, decisions to increase the security or resilience of the system (such as a tightening of safety standards and increased storm hardening) also affect costs that in most cases will be passed to customers.

Metrics for affordability can be measured from both a total cost perspective and a ratepayer perspective.

We define total system costs as the economic or accounting cost of building, maintaining, and operating the system.[g] System costs are often divided into sub-categories based on the timing and function of the incurred costs and/or the section of the system to which they are associated. For example, costs can be divided into three broad components:

- capital costs – costs incurred for adding new resources, for a unit modification or upgrade, or for a major maintenance event that requires replacement of significant equipment;
- variable operating and maintenance costs – costs incurred for producing electricity (sometimes referred to as production costs) that change with the amount of energy generated, including fuel procurement; and,
- fixed operating costs – costs incurred for maintaining and operating a plant regardless of operations.[h]

Costs are also often reported in terms of the function they support: generation, transmission, distribution, or retail. The EIA's National Energy Modeling System (NEMS), for example, relies on estimated system costs, such as capital investment costs, fuel costs, and operation and maintenance costs, for the full range of generation asset types when developing forecasts in its AEO.[i] Whether an analysis of system costs

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[f] Rates for individual customers cannot be calculated from first principles because they are political decisions usually made at the state and local levels to achieve a variety of goals including economic development (for example low rates for job-producing industrial customers) and equity (for example subsidization of residential customers by another class of customers). In states/regions with carbon policies, allowance allocations fall into the political category as well.

[g] The costs of externalities are often included in the calculation of societal costs. Here, we separate the costs of the system that are recovered through rates under affordability and the societal costs (or value streams) of externalities in the other properties defined below. For example, the costs of environmental externalities are considered in this paper to be included in the sustainability property and the value of providing reliable electricity is calculated in the reliability property

[h] The distinction between variable and fixed operating costs can often be vague. For example, maintenance of a generation facility can either be based on the number of operating hours, which would be considered a variable, or based on a regular schedule regardless of operation, which would be a fixed cost.

[i] Note that NEMS captures a broader system than the electric sector taking into account the impact of electric sector outcomes on fuel prices and load. EIA, "Table 8.2. Cost and Performance Characteristics of New Central Station Electricity Generating Technologies," Assumptions to the Annual Energy Outlook 2015, U.S. Energy Information Administration, September 10, 2015.

considers costs across the whole system or includes costs from adjacent systems will depend on scope of the analysis and the appropriate definition of the "system" for the question being asked.

Affordability from a ratepayer perspective measures total consumer payments for electricity compared with value and ability to pay. Affordability from an aggregated ratepayer perspective is often based on the present value of revenue requirements (PVRR). The revenue requirement metric is more common in vertically integrated systems because customer rates are set based on projected variable costs (which are passed through) and capital costs plus a commission-approved return on the investment. In regions with restructured markets, the metric of total customer payments based on market prices for energy and capacity and regulated rates for transmission and distribution are more common.[j]

Affordability for individual ratepayers depends on the total costs and the rate structure. Ratemaking is a regulatory process for allocating costs to different customer classes (e.g., residential versus industrial) using different types of charges (e.g., volumetric versus fixed). Attempts have been made to quantify the gap between "affordable" home energy bills and actual energy bills, at the state and county level, by calculating a county- and income bracket-level average for the household cost of both heating and electricity usage. [k] In addition, many states have ratepayer advocate offices that are charged with representing ratepayers in regulatory proceedings, where ratepayer costs are a primary concern.[l]

3.1.2 Valuing Affordability

Affordability, often measured by total system and ratepayer costs, is a central consideration in most analyses of the addition of new resources, changes to regulations, or changes to rules affecting the electric power system. For example, the cost impacts of a new resource type can be complex; the addition of the new resource type can have capital and operating costs, while offsetting costs of alternative resources that provide similar capabilities. Some new resource types may create new value streams not previously available or able to be valued. As we summarize below and in later sections, integrated resource planning, transmission planning, wholesale market design, and distribution planning processes all take affordability into account.

A detailed system analysis is required to capture the impact that the addition of a new resource will have on total system costs. However, no detailed system analysis can anticipate the future perfectly. In addition, all models rely on simplifications. Scenario/sensitivity analysis must be employed to explore a reasonable range of input assumptions and also to determine whether more detail is warranted.

A simple comparison of the costs of different resource types alone is insufficient for estimating the impacts of new resources on system affordability because of the differences in how the resources operate and the impacts that they have on the system. For example, the levelized cost of electricity (LCOE) is one commonly used metric for comparing the costs of generation resources. LCOE combines capital, fixed, and variable costs into a single metric in terms of dollars per megawatt-hour in order to compare different technologies. The flaw in calculating LCOE is that capital, fixed, and variable costs are divided by an *assumed* amount of annual generation (in megawatt-hours). If the annual generation is roughly the same,

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j In deregulated markets, payments for transmission and distribution facilities are most commonly set through the calculation of a revenue requirement, similar to in regulated markets.

k See http://www.homeenergyaffordabilitygap.com/index.html

l For a list of ratepayer advocacy offices by state see http://www.state.nj.us/rpa/advoc.htm and "Energy Affordability and Energy Service Choices: Three Perspectives," prepared for DEFG's Low Income Energy Issues Forum, October 2014.

the LCOE comparison can be meaningful. For example the costs of new baseload nuclear and coal plants can be compared in this way. But peaking plants that operate for a limited number of hours per year will have a very high LCOE. The implication is that peaking plants (which have low capital costs but high variable costs) are too expensive to consider. LCOE also does not consider the avoided costs of generation from each type of resource operated. Comparing the LCOE to the levelized avoided cost of electricity (LACE), which will depend on the resource mix and load characteristics specific to each system, provides planners with a better sense of the value of energy provided by a resource but still provides a limited view into system planning decisions.[m] Such values should be considered to be indicative of costs potentially for screening purposes, but are generally insufficient to make resource decisions.

As discussed below in Section 4.1, all of the IRPs we reviewed consider affordability based on the PVRR or a closely-related metric. In these studies, the costs of installing and operating several portfolios of resources are analyzed for meeting system requirements and are compared against other metrics for determining the best portfolio for the utility to pursue. System-wide planning allows for the analysis of how the costs of additional resources can offset the costs (or increase) of other resources in the system as well as the costs imposed by a resource on the system. Models for calculating the differences in costs between portfolios include production cost models (normally run for one or more representative years) that simulate the dispatch of resources to meet hourly or sub-hourly energy demand, and capacity expansion models (normally run over a period of 10 years or more) that identify the lowest cost units to meet future peak and energy demand and in some cases environmental regulatory constraints.

In transmission planning (see Section 4.2), planners primarily identify the least-cost approach for meeting reliability criteria under different scenarios. Most of the regional transmission organizations (RTOs) analyze whether transmission investments will reduce costs for energy through production cost models. A few regions consider additional cost savings due to avoided capacity, reduced energy losses, access to higher quality renewable resources, or avoided reliability-driven transmission projects.[n]

Wholesale markets in several regions of the United States procure energy, ancillary services, and (in some cases) capacity through a market mechanism that sets prices for each product at the marginal cost of meeting system demand while maintaining the system within necessary reliability thresholds. The security constrained economic dispatch processes for optimizing the output of generation resources aims to minimize total system-wide production costs within reliability constraints. Pricing mechanisms are also used to achieve other properties such as lower emissions by requiring emitters to procure allowances from a limited pool of allowances created by regulators, such as in a GHG cap and trade program.

In addition to new resources, changes in regulation and market rules also consider system costs. For example, the expansion of the Energy Imbalance Market in the western United States with additional

[m] "While the economic decisions for capacity additions in EIA's long-term projections use neither LACE nor LCOE concepts, the LACE and net value estimates presented in this report are generally more representative of the factors contributing to the projections than looking at LCOE alone. However, both the LACE and LCOE estimates are simplifications of modeled decisions, and may not fully capture all decision factors or match modeled results." EIA, Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015, June 2015. Available at: https://www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf

[n] We discuss this in more detail in Section 4.3.

participants considered the affordability benefits, as have recent proposed changes in ancillary service market rules in Electric Reliability Council of Texas (ERCOT).[o]

3.2 Reliability

3.2.1 Definition

Under the Federal Power Act, the Federal Energy Regulatory Commission (FERC) must review and approve "mandatory and enforceable reliability standards" developed by the North American Electricity Reliability Council (NERC).[p] NERC does not provide a single definition of reliability, but instead states that reliability includes two concepts, adequacy and operating reliability, which they define as follows:[7]

- Adequacy is the ability of the electric system to meet the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.
- Operating reliability is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

Along those lines, we define reliability as the ability of the system to maintain power delivery to customers in the face of routine uncertainty in operating conditions. This uncertainty is driven by factors including fluctuations in load, generation from variable renewable resources, availability of fuel, and outages of generation, transmission, and distribution assets. In the next section, we provide more specificity to this definition of reliability by defining two subproperties that align with the NERC concepts: operational reliability (similar to operating reliability) and planning reliability (similar to adequacy).

3.2.2 Subproperties and Example Metrics

We divide reliability into two subproperties, operational reliability and planning reliability, based on the timescales in which reliability is considered. For each subproperty we provide a list of metrics commonly used in system operations and planning.[q]

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o The list of economic benefit analyses completed for the expansion of the CAISO Energy Imbalance Market can be found here: https://www.caiso.com/informed/Pages/EIMOverview/Default.aspx The economic benefit of the ERCOT ancillary service market designs changes can be found here: http://www.brattle.com/system/news/pdfs/000/000/982/original/Cost-Benefit_Analysis_of_ERCOT's_Future_Ancillary_Services_%28FAS%29_Proposal.pdf?1450901946

p For a list of reliability standards set by NERC and approved by FERC, see: NERC, United States Mandatory Standards Subject to Enforcement, http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States, accessed May 2016.

q The full set of NERC reliability standards covers a wider range of aspects of electric system operations and planning than included in this report, including: communications equipment; personnel performance, training and qualifications; and facilities design, connections, and maintenance. See: NERC, United States Mandatory Standards Subject to Enforcement, http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States, accessed May 2016.

The reliability metrics are based on the approaches used by system planners' plan to meet the mandated operational and planning reliability standards set by NERC and its regional entities. In general, standards for both operational reliability and planning reliability are set without explicit consideration of the economic cost or societal value of reliability.[r] For this reason, the metrics for measuring reliability are usually non-monetary and are used to quantify the past or projected frequency of interruptions or the amount of standby capacity available to operate when needed. However, the value of reliability is sometimes estimated using the VOLL metric, as described below.

3.2.2.1 Operational Reliability

Operational reliability refers to the ability to deliver energy sufficient to meet current and near-term load obligations with existing assets under an expected range of conditions. Operational reliability is maintained by system operators continuously tracking electrical conditions on the system, including frequency and voltage, and using the available resources to maintain balance between generation and load. Operational reliability metrics are tracked at the supply plant and at both the low-voltage distribution-level and high-voltage transmission, or bulk power system level.

Wholesale power systems maintain safe and reliable operations in part by procuring regulation services and operating reserves. Regulation services are intended to correct for relatively small imbalances and operating reserves are intended to be available to operate in the case of a contingency events, such as the sudden loss of generation or transmission facilities. In addition to the real-time tracking of system frequency and voltage, existing metrics that are commonly used to retrospectively measure and value reliability performance include both consumer and bulk power system reliability metrics.

Distribution system reliability metrics include the following:

- **System Average Interruption Frequency Index (SAIFI) –** The frequency with which service to the average distribution customer is interrupted. Interruptions may be due to distribution outages, transmission outages, or supply shortages.[8]
- **System Average Interruption Duration Index (SAIDI) –** The average outage duration of each distribution customer served.
- **Customer Average Interruption Duration Index (CAIDI) –** The average duration of individual outages faced by customers. Calculated as SAIDI/SAIFI.

Bulk power system reliability metrics include the following:

- **Area Control Error (ACE) –** ACE is the instantaneous difference between scheduled and actual net generation and demand within a given balancing authority area tracked by system operators.[s] Imbalances in customer demand and generation result in unintended inflows or outflows from neighboring systems to a Balancing Authority that can affect system reliability within the Balancing Authority and in neighboring systems.[9]

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[r] NERC Rules of Procedures states that "each [performance] requirement…achieves an objective that is the best approach for bulk power system reliability, taking account of the costs and benefits of implementing the proposal." However, NERC notes that "these 'cost and benefits' are not explicitly developed. Ultimately, the ballot body, which decides on standards, decides on its cost effectiveness." NERC, Definition of "Adequate Level of Reliability," approved December 2007, p. 7, http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

[s] For a more complete definition see "Glossary of Terms Used in NERC Reliability Standards," March 18, 2016, available. Available at http://www.nerc.com/files/glossary_of_terms.pdf

- **Control Performance Standard 1 (CPS1) –** CPS1 calculates how a Balancing Authority's ACE contributes to frequency imbalances within the system on a 12-month rolling basis.[10] Minimizing deviations in frequency over time is critical to maintaining system reliability.
- **Frequency and severity of emergency events –** All systems can call emergency events when supply becomes tight. For example, the Pennsylvania, Jersey, Maryland Interconnection (PJM) has several types of emergency events, including Primary Reserve Alerts, which are declared when estimated primary reserve is less than the forecast requirement.[11] Emergency events indicate when the system is at risk of not meeting load and reliability may be threatened.

3.2.2.2 Planning Reliability

Planning reliability takes a longer view of reliability as the ability to meet projected long-term load obligations with existing and planned assets under a specified range of conditions. Planning reliability is maintained by procuring sufficient resources such that these outcomes in the operational time frame can be managed and peak load conditions can be met. NERC regional entities primarily set standards for long-term bulk power system planning reliability based on the projected number and duration of lost load events or the total quantity of unserved energy, including the following:[t]

- **loss of load probability (LOLP)** –The probability of a supply shortage occurring within a given year, expressed as the probability of an event occurring in a given year.
- **loss of load hours (LOLH) –**The number of supply shortage hours expected in a given year, expressed as the number of hours. A common LOLH standard is 2.4 expected hours per year.[12]
- **loss of load expectation (LOLE) –**The number of supply shortage events expected in a given year, expressed as number of events. A common LOLE standard is 1 expected outage per 10 years.[13]
- **expected unserved energy –** The expected total amount of load unserved due to supply shortages, expressed either in terms of energy (GWh) or percentage of total annual load.[14]

The planning reliability standards are converted to a reserve margin (defined below) that system planners can use to track progress toward maintaining planning reliability.

- **Reserve margins** – A measure of the degree to which available supply exceeds expected peak load.[u] U.S. power systems have typically had reserve margins of approximately 15% or greater. Systems with low reserve margins are at greater risk of supply shortage in the event of higher than forecasted load and the loss of output from generation facilities. System planners develop reserve margin targets through probabilistic modeling of load and supply availability. This modeling informs how much capacity is needed to meet a given supply adequacy standard.

Resources contribute different portions of their nameplate capacity to meeting reserve margins. System planners reduce the nameplate or maximum capacity of generators and other supply sources to account for their unavailability during peak load hours. For example, the capacity value of dispatchable fossil units is often measured in terms of unforced capacity (UCAP), which derates the capacity credit based on the unit's forced outage rate. Non-dispatchable resources such as wind farms are assigned capacity values well below their nameplate capacity. For example, panhandle wind in ERCOT receives a 12% capacity credit and coastal wind receives a 56% credit.[15] In addition, the capacity credit for non-dispatchable

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[t] The ERCOT does not have mandated resource adequacy targets. Resource adequacy standards for other regions are set by NERC regional entities.

[u] Reserve margins are calculated as (total capacity / expected peak load – 1)

resources may be a function of the amount of similar capacity on the system. For example, the capacity credit of solar facilities in California declines from over 50% at a penetration of 5% of energy to less than 20% credit at 15% penetration.[16]

The following two additional planning reliability metrics have been tracked more recently:

- **availability of supply with dual fuel or firm fuel contracts** – Concerns about natural gas supply during winter months have recently led system planners to track the gas generators that can either be fueled with a separate gas such as oil, or have firm gas contracts. Systems such as PJM have begun to provide performance incentives to encourage gas plants to install dual-fuel capabilities or procure firm fuel contracts.[17]
- **flexible capacity**[v] – The California Public Utility Commission (CPUC) now requires utilities to procure sufficient flexible capacity such that they can reliably meet the largest three-hour ramp in system load, net of wind and solar generation.[w] Large ramps in net load occur in late afternoon as load is increasing and solar generation is decreasing simultaneously. This requirement is in addition to California's traditional resource adequacy requirement.

3.2.3 Valuing Reliability

Reliability standards typically do not explicitly consider the cost-effectiveness or the economic value of reliability to consumers. NERC notes that in setting reliability standards across North America cost-effectiveness is not considered on a system-wide level because "costs versus benefits, including societal benefits, can only be determined by the individual users, owners, and operators."[x]

However, one approach to measuring the value of reliable service or, in other words, the economic costs of outages to consumers is through calculation of the VOLL. VOLL refers to the cost of unserved load to consumers, and is measured in terms of dollars per megawatt-hour unserved. To estimate the economic cost of an outage, the VOLL for the system can be multiplied by the duration (hours) and magnitude (average unserved energy per hour) of an outage.

[v] The term "flexibility" is used in different ways throughout the electric power sector. We use "flexible capacity" here to reflect the most common naming convention for capacity that is able to quickly start and ramp to ensure generation and load remain balanced. In this way, the flexible capacity provides reliability value to the system by ensuring that the system does not exceed frequency thresholds during periods of significant changes in net load (total demand net of renewable generation). Such capabilities can also contribute to system flexibility (which we discuss in Section 2.4 below) by giving system operators options for responding to unforeseen circumstances that could otherwise result in high cost outcomes.

[w] See https://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.aspx.

[x] "They will have different perspectives on what is "cost effective" for them, and they will exercise their judgments by participating in the standards drafting process, and ultimately, when they cast their ballots to approve or reject a standard. A goal of the standards is to achieve an adequate level of reliability across North America." NERC, Definition of "Adequate Level of Reliability", approved December 2007, pp. 6-7, http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

VOLL is difficult to quantify due to the variation across factors, including the type of customer, the outage duration, and the scale of the outage.[y] Studies of commercial and industrial consumers indicate that they have higher VOLLs than residential consumers. For example, estimates of residential VOLLs from previous studies vary from $0 – $18,000/MWh, commercial VOLL estimates vary from $10,000 – $78,000/MWh, and industrial estimates vary from $3,000 – $31,000/MWh.[18] VOLL also differs by outage duration; longer outages (i.e., 12 hours versus 1 hour) tend to have higher overall costs but lower marginal VOLLs.[19] These variations in VOLL across several dimensions make using a single VOLL value in regulatory planning challenging.

The addition of capacity, either generator supply, transmission capacity, or distribution system capacity, provides value to consumers by enhancing the reliability of the power system. The societal value of incremental capacity improvements depends on the specifics of the system, including the system's current level of reliability, the reduction in projected outages due to the addition, and the VOLLs of customers. Improving the reliability of an already highly reliable system will have diminishing returns in terms of value created for consumers. An economically optimal reserve margin would account for the tradeoff between the incremental costs of adding capacity with the declining value of increased reliability.[20]

3.3 Resiliency

3.3.1 Definition

Resiliency is the ability of the system to withstand or, if compromised, recover quickly from extreme external events such as natural disasters.[z] Resiliency threats tend to be idiosyncratic, of low probability, and have varying degrees of magnitude in terms of scale and duration. The types of uncertainties and the capabilities to respond to them differentiate resiliency from reliability. Resiliency reflects the ability of the system to respond to the threat of non-routine disruptions that are difficult to predict or plan for, whereas reliability risks are driven by common, internal, but uncertain factors such as generator and transmission line outages, load variability, and intermittent and variable wind and solar generation. The idiosyncratic and low-probability nature of resiliency risks makes measuring and valuating resiliency challenging. As such, incorporation of resiliency metrics is generally less advanced than reliability metrics.

3.3.2 Subproperties and Example Metrics

This definition of resiliency consists of two subproperties: **robustness** and **recoverability**. The metrics we identified below for both subproperties refer to a system's exposure to extreme events and how well the system performs in the face of an extreme event. The most common metrics do not estimate the value of resiliency to customers, which we discuss in the section below.

Unlike some of the other properties discussed thus far, many of the metrics that might be used to measure various aspects of resiliency are not yet widely used or agreed upon. The DOE recently developed a

y For a summary of the different approaches for calculating VOLL, see London Economics International, "Estimating the Value of Lost Load," June 2013 (http://www.ercot.com/content/gridinfo/resource/2014/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf) and Sullivan, Michael, et al. "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States", January 2015. (https://emp.lbl.gov/sites/all/files/lbnl-6941e.pdf).

z The QER report made a similar distinction between reliability and resiliency.

conceptual framework for developing resiliency metrics.[21] The DOE study framework for resiliency metrics recommends using metrics that are probabilistic in order to capture both the likelihood and consequences of extreme events. The report notes that the types of models used to estimate resiliency can vary significantly, from simple spreadsheet models to large system models, depending on the system and threat being analyzed. The report recommends that all resiliency metrics exhibit several features, including being useful and usable, being quantifiable, enabling comparison across systems, and reflecting uncertainty.

3.3.2.1 Robustness

Robustness is the ability of the system to maintain operations during an extreme external disruption.[22] By their nature, extreme external disruptions, whatever the source, threaten the operations of the system and customer access to electricity. Furthermore, such disruptions are difficult to plan for in that the extent and scope of the threats are not known in advance (compared, for example, to the risk of an outage at a single large generating station or a single transmission line). Because resiliency risks are difficult to measure, very few metrics are used to measure resiliency in today's power system, including both the potential for outages due to such events and the extent to which the system may avoid such outages. However, relevant metrics could include *leading* measures of the extent to which the system is prepared for the unknown, as well as *lagging* measures of the impact of previous disruptions. Several of these *lagging* measures could also be estimated with probabilistic models under a number of different scenarios. Some examples of metrics for robustness include the following:

- **share of assets (e.g., transformers) that have been storm-hardened**[aa] – Assets built to higher construction standards for the purposes of maintaining operation under extreme conditions, such as severe weather events, will allow the system to maintain operation under a diverse set of conditions.
- **share of distribution lines that have been undergrounded**[bb] – Reduced exposure that distribution lines have to external factors will allow the system to maintain operation during extreme conditions that may otherwise cause outages, but may expose wires to flooding.[cc]
- **number and type of backup systems**[dd] –The availability of redundant capacity that can operate in the case of outages due to extreme conditions will allow the system to maintain operation.
- **capacity and/or load with islanding capability –** The ability of system operators to maintain sections of a larger system in the case that other sections are unavailable increases the ability to maintain operations during extreme conditions.

3.3.2.2 Recoverability

Recoverability is the ability to return the system to normal operation following a disruption. Ultimately, the impact that an extreme event has on users of the electric system is not only a function of the extent of

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[aa] See NAS 2012, "Physical protection of critical facilities includes hardened enclosures for key transformers…"

[bb] See NAS 2012, "The use of underground cable, multiple feeds to the customer with automatic switching, loop circuits whereby customers can be switched from one feeder to the next, and other forms of redundancy significantly improve reliability at additional expense."

[cc] For example, see Consolidated Edison's plan for making improvements following Hurricane Sandy titled the "Post Sandy Enhancement Plan" that includes a section on efforts necessary to storm harden underground systems that are threatened by flooding. Available at: http://www.coned.com/publicissues/PDF/post_sandy_enhancement_plan.pdf

[dd] See discussion of the important of recovery transformers and other backup equipment in NAS 2012.

any outages or load reductions, but also of the time required to return to normal system operations. For some extreme events, which are by definition difficult to prepare for, a temporary loss of service may be inevitable, but users and other stakeholders will more highly value a system that can be restored quickly than one that takes days or weeks for normal service to resume. As with robustness, measuring the recoverability of a system in the face of an extreme event can be difficult. Nonetheless, several metrics indicate a system's recoverability as well as the estimated recovery time based on probabilistic modeling.[ee] Some examples of each are as follows:

- **black start capacity –** The amount of capacity that can start without an operational system;
- the amount of **available backup generation and equipment** including backup transformers;[ff]
- the presence or extent of **advanced metering infrastructure** (AMI), which can provide information that helps utilities optimize their response;
- simulation-based estimates of the **expected duration of outages** when faced with an extreme event;
- the **time until restoration of critical services**[gg] – Restoring power to critical social services such as hospitals, police, and fire is most important in the event of an emergency. Systems that can restore these critical services quickly provide value to customers;
- the **time until full system restoration –** Systems that can restore service to all customers, not just a subset of critical services, in a timely manner provide greater value to customers than systems with long restoration times.

3.3.3 Valuing Resiliency

Similar to reliability, the value of enhancing a system's resiliency can be calculated based on estimates of the VOLL metric. As with reliability risks, a customer's VOLL due to resiliency risks is a function of several factors, including outage severity and scope, duration, the extent to which other services (e.g., water and fuel supply) are affected, and customer-specific preferences. However, the cost of an outage to consumers from resiliency risks may be very different than those of standard reliability risks. The severity and duration of extreme event outages are likely very different than those of standard reliability risks, resulting in different societal costs of outages. For example, evidence suggests that the cost to consumers of a long-duration outage is lower on a dollar per kilowatt-hour basis than a short-duration outage, but the total economic costs are greater due to the longer duration of the outage.[23] However, analysis of the VOLL during outages of longer than 12 hours, which is common during outages caused by extreme external events, is limited and further evaluation of the outages will be required to properly quantify the value of making resiliency-related investments.[hh]

[ee] Of course, the accuracy of these models will be highly dependent on assumptions. For example, the time for the distribution system to be restored to full working order will depend in large measure on the ability of utility workers to get to affected sites. However, extreme events such as weather are likely to also have substantial effects on roads and other transportation systems, which may in turn make response times unpredictable.

[ff] The NAS 2012 report includes detailed discussion of mobile high-voltage recovery transformers for temporary use in the event of a coordinated attack on key substations, for example.

[gg] For an example of Restoration and Recovery Analysis see Section C.5 of "Conceptual Framework for Developing Resilience Metrics for U.S. Electricity, Oil, and Gas Sectors," Sandia National Laboratories, September 2014.

[hh] "For resiliency considerations that involve planning for long-duration power interruptions of 24 hours or more, the nature of costs change and the indirect, spillover effects to the greater economy must be considered." Ibid.

3.4 Flexibility

3.4.1 Definition

Flexibility is the ability of the system to cost-effectively respond to future uncertainties, such as new technologies, demand shifts, fuel supply factors (price or availability), and environmental regulations, that may stress the system in the short term and require the system to adapt over the long term. The value of a system depends not just on its ability to embody the other properties laid out in this section, but also on its ability to adapt to changes in the economic, regulatory, and technological landscape, over the short and long term, in order to continue to deliver value in the future.[24] All else being equal, a lower expected cost of responding to uncertainty and a reduced risk of high-cost outcomes both increase the value of the system.

Flexibility is closely related to the concept of optionality—accepting with certainty cost increases in the present in order to provide the system with options for operating or adapting to future conditions and thus decreasing the risk of a significantly less valuable (or more costly) system in the future. Planning to achieve increased flexibility in the system provides insurance value to the users of the system and to society as a whole by increasing the likelihood of maintaining high levels of the other system properties over a range of conditions and time frames. All things being equal, a social planner would prefer to have a system that can adapt to changing conditions over a variety of time frames, with relatively low associated adjustment costs. While affordability tracks outcomes under expected conditions, flexibility is more concerned with the *range* of possible cost outcomes, and with ensuring that relatively low-probability outcomes do not result in unacceptably high levels of cost.

Our definition of flexibility also reflects the following related concepts that are important but that may be difficult to measure:

- extensibility – the ability of the system to extend into new capabilities beyond those required when the system first becomes operational;
- scalability – the ability of the system to meet a range of demand levels; and
- interoperability – the ability of the system to interact with and connect a wide variety of resources and systems both in and outside of the energy sector.[25]

Designing a system in accordance with these principles allows it system to better respond to near- and long-term uncertainties, by increasing both the economic robustness of the system to unexpected perturbations and the agility to alter the long-term development path of the system in response to the shocks.

As with reliability, flexibility can be considered on different time frames. Accordingly, it is helpful to distinguish between operational flexibility and planning flexibility.

3.4.2 Subproperties and Example Metrics

3.4.2.1 Operational Flexibility

Operational flexibility is the ability of a given system to respond to relatively short-term operational and economic uncertainties that are likely to stress the system or affect costs. Examples of these uncertainties include fuel shortages, unexpectedly high peak demands, and the variability of renewables. Possible operational flexibility metrics could either be those that characterize a system's capability for flexible response to demand and supply shocks or could provide measures of system performance that are consistent with the definition of flexibility proposed here. These metrics are familiar or intuitive, if not universally used as explicit measures of flexibility. The value to a particular system of increasing any given metric will depend on the range of uncertainties that may occur.

The following metrics are likely to be indicative of the operational flexibility of a system:

- **cost and/or price volatility** will in part reflect the frequency with which transmission congestion or reliance on expensive "peaker" units creates price spikes, both of which should be relatively rare events;[26]
- **renewable curtailment levels**, in other words the inability to employ a generation resource with zero marginal generation cost, is in part reflective of a system's inability to flexibly accommodate the variability of renewables.[ii]
- higher levels of **transmission capacity from neighboring regions (megawatts)** provide a system with more options to adjust to short-term demand or supply shocks cost-effectively;
- greater levels of **system ramping capacity (megawatts per minute)** afford system operators more ability to cost-effectively respond to short-term fluctuations in load, asset availability, and renewable generation;
- **fast start capacity (megawatts)** provides another option for responding to system variability that may in some cases be economical; and
- **distribution feeder hosting capacity** measures the number of PV technologies that can be accommodated without adversely affecting power quality or reliability under normal operating conditions.[27]

3.4.2.2 Planning Flexibility

Planning flexibility is the ability to adapt to uncertainties that are likely to stress or fundamentally alter the system in the long term, such as load growth, long-term fuel price trends, environmental regulations, and the emergence of new technologies. While operational flexibility represents value created by the short-term operation of a fixed system under a wide variety of conditions, planning flexibility instead reflects value created by having a system that is better situated to evolve to meet needs 5, 10, or 20 years from today. As such, planning flexibility is also closely related to the agility of the system—how decisions today position system planners to be able to re-direct the system's development in response to new information about technological development, long-term input prices, or other conditions.

Measuring planning flexibility can be more challenging than measuring operational flexibility, in that greater uncertainty is associated with the longer time horizon, meaning that the range of possible outcomes can be both wider and harder to predict. Accordingly, there is a lack of well-developed, standardized metrics that capture the complexity and underlying value of planning flexibility, although stochastic analysis within planning processes is becoming more common. Nevertheless, some metrics that are indicative of a system's ability to adjust to changing conditions do exist, as listed below.

- **Cost and/or price volatility** reflects the range of outcomes and the potential for undesirable high cost outcomes due to the ability of the system to adapt to changing market conditions over the long term.

[ii] Frequent curtailments of wind and solar generation may be a consequence of insufficient operational flexibility of a system. See, e.g., National Renewable Energy Laboratory, "Flexibility in 21st Century Power Systems," p. 3.

- **Fuel diversity of generating capacity (% reliance on a resource),** which bridges operational and planning flexibility, is a commonly used metric that provides an indication of the extent to which a system can respond to short- and long-term developments in fuel prices and environmental regulations without requiring large capital investments.[28]
- While metrics are not well-developed, having **excess transmission network capacity** in place allows a system to respond to longer-term shifts in load and generation caused by population growth or the emergence of new generation technologies or resources.
- The **time to permit and build generation and transmission additions,** while not widely studied, could be a basic, but meaningful indicator of a system's agility that will depend on the markets and regulatory institutions in place.

3.4.3 Valuing Flexibility

Flexibility is not generally priced, regulated, or standardized, and while efforts to value flexibility within existing planning processes are emerging, the approaches taken are diffuse and do not coalesce on any single metric. An example is provided by Dominion, whose 2015 IRP includes "fuel supply concentration" and "capital investment concentration" as two of the six criteria upon which candidate resource plans are evaluated.[jj] Meanwhile, the Tennessee Valley Authority's (TVA's) 2015 IRP evaluates candidate resource plans using a "system regulating capability" metric, while variable energy resource penetration and flexibility turn down factor are also reported.[kk]

In the IRP processes reviewed in conjunction with this report, the most commonly used analytical approach to valuing some aspects of flexibility over a 10 to 20 year period is risk analysis, often based on Monte Carlo simulations, which presents another way of capturing some of the value of operational flexibility over a longer time frame. The analyses examine total system costs for a given resource portfolio over a range of power prices, fuel prices, peak demand levels, and other relevant factors, in an effort to understand the distribution of possible system cost realizations and avoid low-probability, high-cost outcomes. While they are not standardized, various risk-based metrics are developed in the IRPs, and

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[jj] See 2015 Dominion IRP, p. 127. Specifically, the study notes that "an overreliance on any one fuel source is not desirable and reports the "total percentage of electric energy generation from natural gas-fired facilities within the Studied Plans over the Planning Period," where a lower value is favorable. With respect to the second measure, the study states that "portfolios that include disproportionate capital expenditures on any single generating unit or facility could increase financial risk to the Company and its customers." The metric evaluated is "the ratio of the single generating unit or facility's capital spent to the Company's current rate base," where a lower value is again favorable. The latter metric was included in Dominion's Portfolio Evaluation Scorecard for the first time in 2015. Fuel diversity has been emphasized in different ways in resource planning for a longer period of time. See, e.g., 2014 IRP (p. 105) and 2013 Dominion IRP.

[kk] Specifically, TVA calculates its "system regulating capacity" metric as the sum of regulating reserve capacity, demand response capacity, and quick start capacity, all divided by peak load. TVA states that it "considers the ability of the system to respond to load swings…as a key future consideration for long-range resource planning," and notes that this measure of flexibility "is reduced when renewables are strongly emphasized." This is the first time that TVA has used this metric to assess the performance of a resource portfolio. See pp. 68-71, 102, 113.

the metrics measure some of the value of operational flexibility.[ll] This is discussed at greater length in Section 5.1.

At the same time, transmission planning can be characterized as generally lacking an analogous risk-based approach, or other approaches that value flexibility. For example, a 2015 WIRES report observed that most economic transmission planning efforts evaluate system-wide costs only for average conditions, despite the fact that many recent disruptive events (including price spikes during the "Polar Vortex," 2011 weather events in ERCOT, and the 2000-2001 California Power Crisis) saw high costs but limited reliability effects.[29]

3.5 Sustainability

3.5.1 Definition

Sustainability is the ability of the system to provide electric services to customers with limited negative impacts on natural resources (including land, water, and air resources, protected species, and vegetation), human health, and safety.[mm] Depending on the technology, the provision of electric service can potentially pose risks to the natural environment, to the health and safety of the general public that lives near generation resources and other assets, and to the safety of the workers who operate and maintain those assets.[nn]

3.5.2 Subproperties and Example Metrics

3.5.2.1 Environmental Sustainability

The first subproperty is environmental sustainability, which is the ability to deliver power with limited impact on the environment and human health. The provision of electric power can cause environmental harm in many ways, including air emissions, solid waste impacts, land use impacts, and impacts on habitat or endangered species. Many of these entail either localized or global risks not just to the natural environment but also to human populations. Many well-developed, widely used metrics measure impacts from the operation of the electrical grid (and in particular, the impacts of generation), although a full assessment of impacts on the environment and/or human health will depend on absorptive capacity and other environmental factors. Metrics include the following:

- **Emissions rates of CO_2 and other GHGs (tons of CO_2-equivalent per megawatt-hour)** measure the carbon intensity of electricity generation, where lower values are associated with smaller adverse impacts.

[ll] For example, after conducting a Monte Carlo analysis, PacifiCorp compares different resource plans not only on the basis of the expected present-value revenue requirement of each portfolio and scenario, but also on the basis of the expected present-value revenue requirement for the three highest-cost outcomes for each portfolio and scenario. Similarly, Dominion executes a similar Monte Carlo analysis and evaluates each plan based in part on the standard deviation of its cost outcomes and on the standard deviation of its relatively high-cost outcomes.

[mm] Note that this is separate from the benefits to health and safety that are provided by the actual electricity, such as increased public safety from streetlights or improved public health impacts resulting from the electricity used in treating drinking water.

[nn] For a more complete listing of environmental impacts see this brochure, "Environmental Impacts of Power Plants" from the Public Service Commission Wisconsin available at: https://psc.wi.gov/thelibrary/publications/electric/electric15.pdf

- **Emissions rates of SO_2, NO_X, and other criteria pollutants (pounds per megawatt-hour)** measure the extent to which electricity generation results in pollutants that adversely affect ambient air quality.
- **Emissions of mercury and other toxic air pollutants** can increase the risks of human exposure to mercury.
- **Water consumption (gallons per megawatt-hour)** measures the consumptive water use of power plants, which can adversely affect aquatic plant and animal communities and species.[30]
- Power plants that use "once-through cooling" may not consume significant quantities of water but through water usage generate **water temperature impacts** that can affect temperature sensitive plants and animals in the body of water where the effluent is discharged;[31]
- **Tons of ash** generated by a coal power plant is an indicator of landfill needs and the associated environmental impacts from landfilling activities.[32] .
- **Land use (acres)** measures the land requirements and the potential environmental impacts (such as land cleared and loss of habitat) for the generating facility itself but also potentially for supply lines or waste storage and disposal.[33]
- **Lifecycle impacts** from the materials and production processes necessary for new equipment will vary significantly across resource types, sources of materials, and locations of production.

For all of the listed metrics, lower values are associated with smaller adverse impacts on the environment and/or human populations.

A second subproperty of sustainability (as used in this report) is the ability to deliver power safely, with minimal safety risk to workers and to the general population. The list of potential threats to workers includes accidents at generating stations or from the transmission and distribution system.[34] Downed power lines can also pose safety risks to the general public or to workers in other industries.[35] Finally, the issue of nuclear fuel handling and storage safety also entails risks to both workers and the general public.

Some common metrics that are used to measure the overall safety of the industry include

- **incidence rates of non-fatal occupational injuries and illnesses** within the electric power industry, and
- nationwide industry totals for **fatal injuries per year**.[oo]

3.5.3 Valuing Sustainability

Similar to reliability, the most common approach for valuing sustainability in system planning is for a separate regulatory analysis to be completed that imposes constraints on the system or individual resources. These analyses differ across cases and cost-effectiveness is considered explicitly in some cases and not considered in others. For example, the EPA promulgates rules and regulations for air emissions,

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[oo] The Bureau of Labor statistics regularly reports injuries, illnesses, and fatalities by industry. In 2014, for the electric power generation, transmission, and distribution industry, they estimated 1.1 non-fatal occupational injuries and illnesses per 100 full-time workers and reported 12 total fatalities. See Bureau of Labor Statistics Injuries, Illnesses and Fatalities program, at http://www.bls.gov/iif/. In particular, see "TABLE A-1. Fatal occupational injuries by industry and event or exposure, all United States, 2014," Census of Fatal Occupational Injuries, Bureau of Labor Statistics and "TABLE 1. Incidence rates of non-fatal occupational injuries and illnesses by case type and ownership, selected industries, 2014," Employer-Reported Workplace Injuries and Illnesses – 2014), Bureau of Labor Statistics.

such as the National Ambient Air Quality Standards, that set standards for air emissions based on analysis required in the Clean Air Act[36] and may necessitate the installation of equipment to reduce emissions, operational constraints on the resource, or purchase of emissions reduction credits from other facilities.

An example of an analysis that values changes in air emissions is the calculation of the social cost of carbon emissions (SCC) completed by the Interagency Working Group on Social Cost of Carbon in 2013 and updated in 2015.[pp] The study analyzed the societal costs of additional emissions of carbon dioxide, the most common GHG, and calculated a range of values for the marginal costs additional emissions impose on society. The SCC is explicitly included in evaluating the cost-effectiveness of federal policies. For example, the DOE uses this value to set energy efficiency standards and the EPA used it to calculate monetized climate benefits of the Clean Power Plan. System planners can also use the SCC to value changes in carbon emissions beyond any regulatory requirements.[37]

The negative impacts of many environmental pollutants have in some measure been internalized by emissions limits under cap-and-trade systems or other regulatory measures. In such a case, relative to an electric system without those constraints, the system has higher levels of sustainability but also has increased costs (or equivalently, has decreased affordability). The fact that these regulations exist does not mean that the pollutants involved are no longer relevant to the question of measuring or valuing sustainability. At the same time, the existence of these emissions limits or other regulations does not mean that their impact on the sustainability of the system is zero. It is very likely that the resulting emission levels still have adverse environmental impacts.

With respect to the valuation of safety, a similar approach to that described above is the norm—standards implicitly place a value or shadow price on safety, which in turn may place upward pressure on system costs. For example, the Occupational Safety and Health Administration (OSHA) issues rules and standards designed to improve the safety of workers working on or near electric power lines, based in part on an analysis of the net benefits of those standards.[qq]

Translating changes in conditions that affect safety or human health to economic value most commonly relies on the value of a statistical life (VSL), which uses empirical evidence to calculate the implied value people place on making decisions with a higher probability of the loss of life. The EPA currently recommends using a VSL estimate of $7.4 million (in 2006 dollars), but has historically recommended a range of VSL estimates, from $0.7 to $12.9 million in 2001 dollars.[38]

As is discussed in greater detail in Section 5.1, sustainability considerations are also incorporated into some IRP processes. However, the relative importance of these sustainability considerations in the ultimate decision is unclear.

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pp Interagency Working Group on Social Cost of Carbon, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis: Under Executive Order 12866, Revised July 2015... https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf

qq See, for example, Occupational Safety and Health Administration "Fact Sheet: Electric Power Generation, Transmission, and Distribution and Electrical Protective Equipment Final Rule." 2015. Available at https://www.osha.gov/dsg/power_generation/subpart_v_factsheet.pdf

3.6 Security

3.6.1 Definition

Security, in this context, refers to the ability of the system to resist external disruptions of the energy supply infrastructure caused by intentional physical or cyber-attacks or by limited access to critical materials from countries that may be hostile to the United States.

3.6.2 Subproperties and Example Metrics

As the definition suggests, the security of the power system can be broken down into two subproperties: (1) the ability to prevent external threats and malicious attacks from occurring, and (2) the ability to maintain and operate the system with limited reliance on supplies (primarily raw materials) from potentially unstable or hostile countries. We discuss each of these aspects of energy security below.

3.6.2.1 Physical or Cyber Security

Physical attacks on infrastructure include attacks on generating stations, substations, transmission lines and towers, above-ground distribution lines, and control centers.[39] For example, in 2013, a substation in California was attacked by a sniper.[40] Cyber-attacks include attempts to access and/or disrupt utility data and industry control systems, such as Supervisory Control and Data Acquisition (SCADA) systems. In their review of the potential for terrorism-related attacks on the U.S. power system, the National Academy of Sciences noted that "cyber-attacks are unlikely to cause extended outages, but if well-coordinated they could magnify the damage of a physical attack."[rr] A recent example of a cyber-attack occurred on the power system in Ukraine, which resulted in the loss of power to 225,000 people for three hours.[41]

Many of the same metrics used to measure reliability and resiliency can be applied to measuring physical and cyber security. Very few metrics exist to track the unique threats posed by security risks. In 2015 the Department of Homeland Security (DHS) noted that the security metrics for the electricity sector "remain a work in progress," highlighting the need for traditional metrics to be adapted for new risks.[42] DOE's private-public partnership, the National Electric Sector Cybersecurity Organization Resource, is currently working on developing security metrics for the electric sector.[43]

The Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2) developed by the DOE in partnership with the DHS, helps utilities and grid operators assess their cybersecurity capabilities and prioritize their investments to enhance cybersecurity.[44] These metrics track efforts to increase security as opposed to measuring the number of prevented attacks. NERC conducts sector-wide grid security exercises, GridEx, that test the response of the industry to simulated grid attacks.[45]

3.6.2.2 Supply Chain Security

The security of the energy sector is driven in part by the system's reliance on inputs along the supply chain from unstable or hostile countries. Growth in domestic unconventional oil and gas production has

[rr] "If they could gain access, hackers could manipulate SCADA systems to disrupt the flow of electricity, transmit erroneous signals to operators, block the flow of vital information, or disable protective systems. Cyber -attacks are unlikely to cause extended outages, but if well-coordinated they could magnify the damage of a physical attack." NAS 2012.

made the United States less reliant on foreign sources for fuel.[ss] However, the United States still relies on foreign sources for other raw materials and equipment used in the power sector. Many clean energy technologies, such as wind turbines, rely on rare earth metals that may become more difficult to procure in the future. Wind turbines use rare earth elements that are highly concentrated in China—dysprosium, terbium, europium, neodymium, and yttrium—which could limit wind-powered clean energy deployment in the future if material availability cannot meet demand.[46]

Metrics for tracking the power sector's reliance on supplies from unstable or hostile countries are not well established. The exception is reliance on foreign fuels, which is tracked by the EIA. Metrics that could be established and tracked include

- an inventory of materials and equipment relied upon;
- the country of origin for relied-upon materials and equipment; and
- the quantity of backup or stockpiled materials or equipment.

3.6.3 Valuing Security

As for resiliency and reliability, the value of security to consumers can be estimated using the VOLL metric. However, the severity and duration of outages due to security threats are likely very different than those of standard reliability risks or resiliency risks. As such, security risks likely pose a different societal cost. There currently is limited analysis available for the costs and likelihood of such events.

[ss] In 2015, only 0.3% of natural gas was imported from sources outside of North America. See Energy Information Administration, "U.S. Natural Gas Imports by Country" and "U.S. Natural Gas Consumption by End Use." http://www.eia.gov/dnav/ng/ng_move_impc_s1_a.htm and http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm, respectively.

4.0 System Properties in Current Planning Processes

System planners, operators, and regulators use a diverse set of methods and processes to evaluate, plan, and operate their systems. System planning studies implicitly complete valuations of different resources but often do not provide analyses that result in a final monetary value or a value-weighted metric that can be compared across resource options. This section reviews the extent to which current approaches for identifying and attracting new resources consider and value the properties defined in the previous section.

The current planning processes are fragmented across different studies and organizations that are intended to consider the need for, or value of, a certain set of resources, such as generation, transmission, or distribution assets, by analyzing a subset of property metrics. They do not consider the same metrics and properties in their analyses, and there is no process for considering the potential for resources across the system to provide value. For example, vertically integrated utilities in some states evaluate supply and (in some cases) demand options for meeting future resource needs through integrated resource plans. Independent system operators (ISOs) design wholesale markets to provide price signals for the efficient procurement of sufficient energy, ancillary services, and capacity. Environmental regulators at the federal and state levels evaluate the potential to improve air emissions and water quality based on the availability of technology and/or costs. Each planning process considers system properties across different time scales and to some extent the tradeoffs between various properties.

Planning processes are often tailored to specific objectives and thus limited (in some cases by design) by several factors:

- **The scope of properties considered** may be limited to the tradeoffs between a few properties or a narrow view of a property. Regulators are limited to their jurisdictional scope within which they can make decisions. A narrow view of properties will limit the ability to make decision that increases system value.
- **The scope of resources or assets considered** may be limited to a subset of resources to analyze for meeting the planning objectives. For example, transmission upgrades are rarely considered in integrated resource planning. This is often the result of specific responsibilities assigned to planners at different levels of the system and can limit the ability to identify the resources that can provide the most value to the system.
- **The range of future scenarios considered** may be limited (or too tightly tied) to a "business as usual" view of the world or the recent past. Such limits mean planning processes do not consider a wide enough range of key drivers to future planning needs or sufficiently consider low-probability but high-impact events, which can also limit the ability to identify opportunities for increasing the system value.
- There are also **technical challenges** to analyzing certain properties or alternative resources. As outlined in previous sections, a well-developed analysis of the electric power system requires the availability of relevant data, analytical techniques and models, and expertise that may not exist, be available to the project team, or be of sufficient quality to be informative. In many cases, the capabilities and resources are not yet available because certain value streams and alternative resources have only recently emerged, or were less salient when the planning processes were initially designed.

The consideration of all possible options or properties may be neither necessary nor practical for all analyses. Comprehensively analyzing resources with very different capabilities, locations within the power system, and impacts on the system can be unrealistic or excessive. A decentralized process is often appropriate when focusing on specific tradeoffs (electrical reliability versus wetland impacts) or allowing for a wider range of stakeholders to participate. On the other hand, a disaggregated approach, where the responsibility for different elements of the system is fragmented among different entities or processes can result in boundaries or seams that limit the ability to identify optimal outcomes on a societal basis.

The following sections provide a review of four widely used system operation and infrastructure planning processes: IRPs, transmission planning studies, development of wholesale market designs, and distribution planning. For each process, we provide a summary of the process, the alternative resources that are considered, and the properties and tradeoffs that are considered.

4.1 Integrated Resource Planning

An IRP is a utility process for analyzing and selecting the supply-side and demand-side resources to meet forecasted peak and total energy demand over a specified time period.[tt] Typically, IRPs analyze the tradeoffs between different resource options to meet system goals and objectives established by regulators. IRPs differ from state to state, because statutes and public utility(ies) commission (PUC) decisions dictate what the IRP must consider, how often the IRP must be submitted to the state, and how far out the analysis must extend.[uu] In some states where IRPs are not required, utilities are instead required to file long-term plans that are similar to IRPs. The TVA also publishes an Integrated Resource Plan, although it is not required to file this plan with any state utility commission.

The requirements set by policy makers or commissioners can limit the ability of planners to consider certain resources, identify specific metrics to track, and provide guidance on how to weigh tradeoffs between desirable system properties. For example, all IRP studies we analyzed require a reserve margin to be met, which provides the system planners with a threshold to meet over a certain time frame but does not give the planners the responsibility to determine how to value reliability versus affordability. The other most common constraint imposed on planners is environmental regulations that may be imposed

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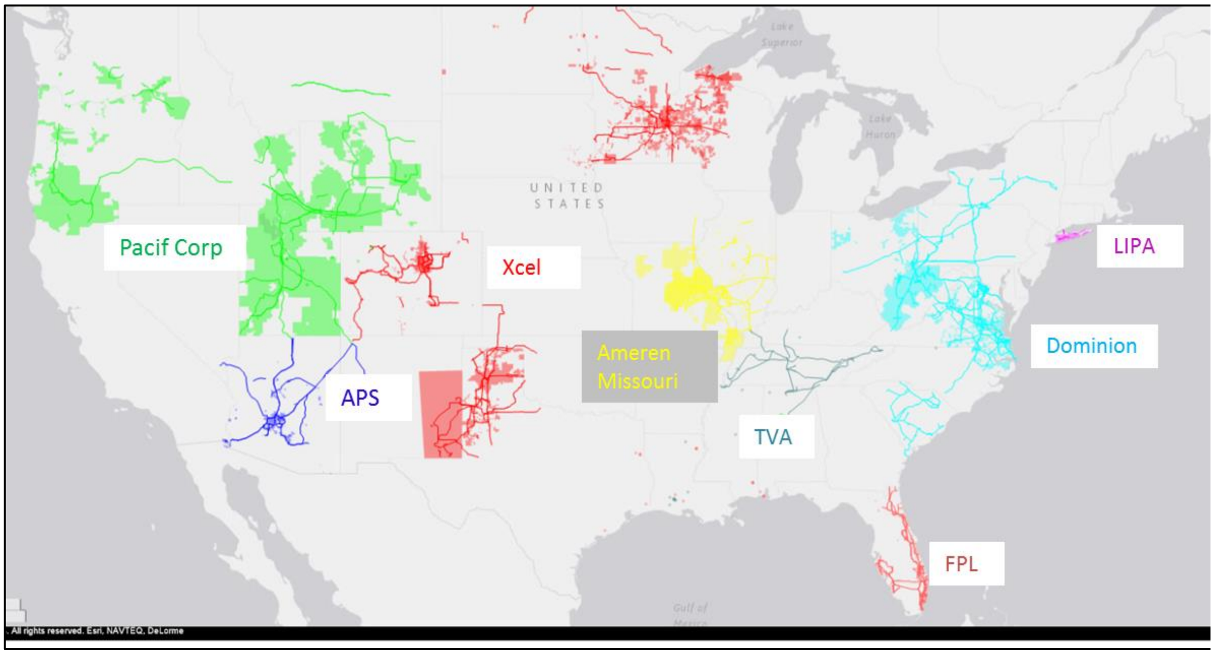
tt For example, Rocky Mountain Power in Utah, a division of PacifiCorp, states: "The integrated resource plan (IRP) is a comprehensive decision support tool and road map for meeting the company's objective of providing reliable and least-cost electric service to all of our customers while addressing the substantial risks and uncertainties inherent in the electric utility business." https://www.rockymountainpower.net/about/irp.html For a summary of IRP regulations, see Wilson, Rachel and Bruce Biewald. "Best Practices in Electric Utility Integrated Resource Planning," June 2013.

uu For example, the Missouri Code of State Regulations requires that every three years, each of the three largest electric utilities in Missouri files with the Missouri PSC a resource plan with a minimum planning horizon of 20 years. The "fundamental objective" of this planning process "shall be to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies." The statute requires that the utility consider demand-side resources, renewable energy, and supply-side resources "on an equivalent basis," that it uses "minimization of the present worth of long-run utility costs as the primary selection criterion," subject to constraints that include mitigation of (1) risks associated with cost uncertainty; (2) risks associated with new legal mandates; and (3) rate increases. The Missouri PSC then determines whether the planning process used by the utility complies with the statute. See http://s1.sos.mo.gov/cmsimages/adrules/csr/current/4csr/4c240-22.pdf, pp. 1-22.
Similarly, the Arizona Corporation Commission requires each of Arizona's electric utilities to file a 15-year plan every two years that will "demonstrate how it will meet its energy requirements in an efficient, cost-effective, and responsible manner." The rules include requirements for utilities to identify how they will comply with rules concerning demand response and energy efficiency, and with the state's Renewable Energy Standard. The Commission also approved amendments to the IRP rules that "would enhance consideration of other elements such as how much water electric companies use in the generation of energy and the level of harmful emissions and by-products such as coal ash that are created through generation." See http://www.azcc.gov/divisions/administration/integratedresource.asp.

either by the federal EPA or state-level environmental regulators. In these cases, the regulators have determined the environmental requirements placed on electric power resources and the additional costs of compliance are justified on a societal basis.

The most common approach for considering metrics of different properties and units is reporting the results for each scenario considered and providing an explanation based on the results of the advantages and disadvantages of choosing one portfolio of resources over another. None of the IRPs we reviewed defined a formulaic utility function for combining metrics into a single value to be maximized.

For this report, we reviewed IRPs developed by eight utilities: PacifiCorp, Arizona Public Service (APS), Xcel Colorado, Ameren Missouri, Florida Power and Light (FPL), Long Island Power Authority (LIPA), Dominion, and TVA.[vv] We focused on medium- to large-size utilities that represent a wide range of geographical locations and different levels of analytical sophistication. Figure4.1 shows the geographical location and the service territory of the utilities whose IRPs we reviewed.



Note: The map shows the whole territory of the utilities with public IRP documents. However, the IRPs reviewed are for one state in the utilities' territory. For Xcel, we reviewed its IRP for Colorado; for Ameren, we reviewed its IRP for Missouri; for Dominion, we reviewed its IRP for Virginia and North Carolina.

Figure4.1. Geographic Footprint of Reviewed Integrated Resource Plans

In our review, we focused on two main questions: (1) which system properties are considered in the IRP process and if so, how?; (2) which functions and technologies (i.e., generating technologies, storage, demand response, energy efficiency, transmission, etc.) were considered, and how was the potential value of those functions and technologies incorporated into the process?

[vv] Not all of the utilities call these planning documents IRPs, but they publish long-term planning documents that serve a similar purpose. Use of the term IRP is meant to include all of the long-term planning documents reviewed, which are listed below.

4.1.1 Alternatives Considered

IRPs are primarily analyses of generation resources conducted at the bulk power system level with the objective of identifying the portfolio that best meets the objectives outlined for the study. The extent to which the IRPs consider a wide range of resources provides insight into how comprehensive the analysis is. For example, distributed generation resources, such as solar PV technologies, are modeled only as adjustments to net load in many IRPs reviewed.[ww] On the other hand, APS and LIPA included different distributed generating technologies as options for meeting future needs at different levels of penetration.[47]

Similarly, while some IRPs explicitly model energy efficiency (EE) and demand response (DR) programs as options for optimizing the portfolio, other IRPs only incorporate EE and DR into their IRPs as exogenous reductions to their load projections. For example, APS included 1,722 MW of EE and DR capacity (or 15% of total capacity) in each scenario, a total that is driven by compliance with a state commission rule on EE.[48] On the other hand, PacifiCorp and TVA allow demand-side management (DSM) and EE, respectively, to compete against supply-side resources.[49]

Upgrades to the transmission system are not frequently considered in IRP studies, because these decisions are often the result of separate planning processes, in many cases conducted by other entities. For example, Dominion conducts an internal transmission planning process and also participates in PJM's Regional Transmission Expansion Plan process.[50] One exception is PacifiCorp, who in its 2015 IRP modeled two sensitivity cases with the addition of certain segments of the Energy Gateway projects to identify potential impacts on the resource portfolio and system costs.[51] Another is LIPA, who considers transmission additions as one of many alternative technologies as it decides how best to meet its resource planning goals.[52]

Similarly, upgrades to the distribution system itself are typically not considered as an alternative to generation across the IRP studies reviewed. However, California now requires its utilities to file distribution resource plans, which will "identify optimal locations for the deployment of distributed resources."[53] PacifiCorp, for example, also evaluates distribution EE options, such as conservation voltage reduction, for feasibility and cost-effectiveness, but opted not to model these measures in their 2015 IRP, "since savings from such measures are unreliable and generally not cost-effective."[54]

The apparent compartmentalization of different planning processes may limit the overall optimality of the process (and thus overall system value may not be maximized), although several explanations may make a fully integrated process unrealistic. First, integrating distributed resource planning, transmission planning, and distribution planning into the traditional IRP process faces technical hurdles. Second, the exclusion of a technology or sector from an IRP process may often be the result of the defined jurisdiction of an IRP, and is not necessarily an indication that the IRP or the state requirements for the IRP are defective. This lack of control extends to customer decisions as well; in the case of EE and DR, APS cited customer behavior, participation, and response to incentives (often set by the Commission) as risks limiting the extent to which such technologies could be relied upon in its planning process.[55]

4.1.2 Properties Considered

Among the six properties defined above, affordability, reliability, flexibility, and sustainability are the three properties most commonly evaluated within IRP studies. For the properties and subproperties that received relatively little consideration or discussion within the IRP documents reviewed (such as safety,

[ww] See, for example, Florida Power & Light, "Ten Year Power Site Plan 2015-20124," pp. 34-35; Public Service Company of Colorado, "2011 Electric Resource Plan," pp. 1-26 to 1-27.

resiliency and security), the utilities tend to have separate processes that address those issues, including compliance with regulatory standards. Presumably, the cost of compliance with regulatory requirements, such as U.S. Nuclear Regulatory Commission physical security standards or OSHA worker safety regulations, will be reflected in the total system costs calculated under different portfolios and scenarios, However, this is not explicitly addressed in the public IRP documents we reviewed.

In most cases, it is difficult to quantify how much weight a given property, or the metrics associated with a property, received in the ultimate planning decision. The discussion that follows thus necessarily focuses primarily on the information that was presented in the IRP documents.

4.1.2.1 Affordability

From our review of IRPs, it is clear that the main objective in planning the system is to meet all applicable reliability and sustainability requirements at the lowest cost to ratepayers. Affordability is evaluated in the IRPs through various metrics such as revenue requirements, annual average customer bills, or levelized rates (all expressed in present value terms), which measure the cost implication to their customers. The most common metric, used by all utilities whose IRPs were reviewed, is the PVRR over the period analyzed.[xx] PVRR measures the total projected ratepayer payments required to allow the utilities to recover their costs and earn the allowed return on capital. For example, Ameren calculates a probability-weighted PVRR that accounts for results across several scenarios and also translates the value into a levelized rate, reported in cents per kilowatt-hour.[56] All of the IRPs reviewed calculate the PVRR for each scenario modeled and typically use that metric as an important criterion in selecting which portfolio to pursue.

The level of sophistication varies across the IRPs reviewed. Some utilities, such as Xcel Colorado and Dominion, simply use revenue requirement as the sole metric related to affordability, whereas others develop one or more additional indicators to complement PVRR. Some examples include system average cost,[yy] year-over-year customer rate impacts,[zz] return on equity, earnings per share, and debt/capitalization.[57] However, none of the IRPs reviewed evaluated the rate implication across different customer classes.

4.1.2.2 Reliability

Reliability is typically incorporated into the IRP process as a reserve margin requirement, represented as a minimum percentage of capacity above the forecasted peak load in future years.[58] This approach does not allow for the planners conducting the analysis to make value-based tradeoffs between reliability and affordability, but requires that a certain reliability threshold is met while minimizing the costs to customers. The reserve margin is commonly set through a separate analytical study done by either the

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xx Dominion minimizes the net present value (NPV) of utility costs, which "include the variable costs of all resources (including emissions and fuel), the cost of market purchases, and the fixed costs and economic carrying costs of future resources" (2015 Dominion IRP, p. 111). While this terminology differs, a reasonable interpretation suggests that it is equivalent to the PVRR metric used in the other IRPs reviewed.

yy TVA calculates this metric (expressed in $/MWH) as the PVRR for the first ten years of the study divided by sales over that same period (2015 TVA IRP, p. 68).

zz PacifiCorp compares, for a limited number of scenarios, the year-over-year change in nominal revenue requirement.

ISO/RTO or the utility itself to meet a 1-in-10 LOLE, as required by NERC standards.[aaa] The IRPs analyze the different resources that result in the lowest cost to simultaneously satisfy projected energy demand and meet this reserve margin requirement.

Due to the long-term nature of the studies, planning reliability is the primary concern of IRPs. In some cases, operational reliability is implicitly included in the analysis through requirements for operational reserves and modeling of the hourly dispatch of the system using production cost simulations.

4.1.2.3 Flexibility

Beyond projections of PVRR under expected conditions, many of the IRPs we reviewed also analyzed potential resource portfolios across a range of future market conditions, and developed and reported metrics that correspond in part to the flexibility property defined above. Given the fixed nature of the portfolios analyzed in IRP processes, analyzing different market futures favors resource plans that are economically robust, which is one aspect of flexibility.

The most common sources of long-term uncertainty analyzed include natural gas prices, load, and CO_2 prices; the range of future market conditions were developed either through a scenario analysis (such as in APS's 2014 IRP) or based on Monte Carlo simulations (Ameren, Dominion, PacifiCorp and TVA).[bbb] In all cases, the IRPs evaluate the performance of different portfolios across a wide range of future outcomes. For example, in its 2014 IRP, APS developed six different scenarios that considered future market conditions based on different assumptions for natural gas prices, load growth, and environmental policies.[59] By reviewing their portfolio options across a range of scenarios, APS is identifying which set of resources will best be able to respond to each of five distinct scenarios that are markedly different from a "Current Path" assumption.

A Monte Carlo approach differs in that it incorporates one or more random (or "stochastic") elements into scenario development, in which the time-dependent trajectories of relevant inputs such as natural gas prices or load growth are based on random variation around an assumed distribution. IRPs that use this sort of analysis then optimize resource dispatch for each Monte Carlo iteration (taking the resource plan as fixed) and calculate the cost (measured by PVRR) associated with a given plan or portfolio under each iteration. This process is repeated several times (often hundreds of times), which allows for the calculation of a distribution of cost outcomes for each plan.[ccc] The distribution is then analyzed, and

aaa See e.g., 2014 Ameren IRP, Chapter 9, p. 3. Ameren refers to MISO's Planning Year 2014 Loss of Load Expectation (LOLE) Study Report (November 2013); 2014 Dominion IRP, p. 42. "PJM conducts an annual Reserve Requirement Study to determine an adequate level of capacity in its footprint to meet the target level of reliability measured with a Loss of Load Expectation ("LOLE") equivalent to one day of outage in 10 years. PJM's 2013 Reserve Requirement Study for delivery year 2017/2018, recommends using a reserve margin of 15.7% to satisfy the NERC/Reliability First Corporation ("RFC") Adequacy Standard BAL-502-RFC-02, Planning Resource Adequacy Analysis, Assessment and Documentation." For PJM's 2013 Reserve Requirement Study, see http://www.pjm.com/~/media/committeesgroups/committees/mrc/20131024/20131024-item-04-irm-study.ashx. APS uses loss of load probability studies to set its reserve margin at 15%. See 2014 APS IRP, p. 52: "Resources are installed to maintain at least a 15% planning reserve margin at the time of APS's summer peak, based on loss of load probability criterion."

bbb Some of the IRPs combined scenario and Monte Carlo analysis. For example, TVA analyzed each of five portfolio strategies across each of five different scenarios (e.g., "Current Outlook," "Stagnant Economy," etc.) by running 72 Monte Carlo simulations within each strategy-scenario combination.

ccc Affordability measures are the metrics that are most commonly evaluated using this process, but some IRPs examine other metrics as well. For example, PacifiCorp's Monte Carlo process also examines the distribution of outcomes with respect to energy not served, LOLP, and CO_2 emissions. See 2015 PacifiCorp IRP, p. 167.

permits the evaluation of a given plan over a richer set of potential outcomes, instead of over a handful of distinct scenarios.[ddd] The utility's ultimate choice of a plan is then guided not only by the average cost outcome associated with various portfolios but also by the risk associated with each. This may be especially useful if a planner is interested not only in cost outcomes under expected conditions but also in minimizing the risk of high-cost outcomes.

For example, after conducting a Monte Carlo analysis, PacifiCorp compares different resource plans not only on the basis of the expected (or average) PVRR of each portfolio and scenario, but also on the basis of the average PVRR for the three highest-cost outcomes for each portfolio and scenario. Dominion executes a similar Monte Carlo analysis and evaluates each plan based in part on the standard deviation of its cost outcomes and on the semi-standard deviation of its relatively high-cost outcomes. These risk metrics thus measure one aspect of a portfolio's flexibility by capturing the risk that normal variation in relevant factors results in undesirable outcomes.

Whether the planner is using pre-determined scenarios or a Monte Carlo approach, the risk analysis is still shaped by the planner's assumptions regarding changes over time in key inputs; nonetheless each approach has advantages and disadvantages as a method for assessing risk and robustness. Reliance on pre-defined scenarios necessarily limits the risk analysis to evaluating only a handful of scenarios (that may be relatively extreme), and then forces decision makers to subjectively weight the likelihood of each scenario. Given the inherent uncertainty in those factors, a Monte Carlo approach allows for analysis of risk over a broader range of outcomes and allows the risk analysis to be somewhat more objective. At the same time, the careful development of individual scenarios better ensures internal consistency, whereas Monte Carlo analysis may run a higher risk of generating alternative futures that would pose contradictions (such as a future with high gas prices, high carbon prices, and high load growth). Furthermore, scenario analysis and the different contexts represented by the individually specified scenarios may be more easily interpreted by the range of stakeholders interested in the outcome of a planning process than the distribution of scenarios generated by a Monte Carlo process.

The evaluation of fuel diversity metrics is another tangible way in which flexibility is occasionally incorporated into IRP processes. For example, APS specifically tracks both energy mix as a measure of fuel diversity and gas burn results along with metrics for revenue requirements, capital expenditures, CO_2 emissions, and water usage.[60] The APS IRP does not provide insight into how these metrics are weighed against others, although they are qualitatively discussed as benefits and disbenefits (depending on the scenario) in making the determination of the preferred resource plan. Similarly, Dominion's "Portfolio Evaluation Scorecard" includes fuel supply concentration as one of six metrics used in evaluating the four proposed portfolios.[eee]

[ddd] Consider the following stylized example. A utility has good reasons to believe that the most likely outcome over the next 20 years is for load to be flat over that time period, but also comes up with two alternative scenarios – one where load shrinks 1% per year, and one where load grows 1% per year. This yields three scenarios, all of which are very unlikely to be the exact outcome, and the high- and low-load growth scenarios are both tempting to dismiss as unlikely. On the other hand, a Monte Carlo approach might assume (again, based on the planner's expectations for different parameters) that in each year, load could grow by either -1%, 0%, or +1%, and randomly generate 100 different alternate futures with a distribution of load growth paths. Then each competing plan would be run through a dispatch model under each scenario and generate a *distribution* of potential cost outcomes. This allows the planner to more fully understand the range of outcomes (and relative likelihood of undesirable outcomes) that could result from each plan.

[eee] Dominion IRP, p. 127. The other metrics are System Cost, Standard Deviation in Average Energy Cost, "Cost Increase in High Cost Combination Sensitivity (%), Capital Investment Concentration, and CO_2 Intensity.

4.1.2.4 Sustainability

Sustainability was also commonly considered in the IRPs, although the approach and degree to which it was considered varied substantially. Typically, discussion of environmental impacts within IRPs was focused on compliance with environmental requirements set by environmental regulators. Most IRPs reviewed discussed the Clean Power Plan (CPP)[61], and several included at least a qualitative discussion of the existing environmental regulations relevant in their regions, such as the Mercury and Air Toxics Standard and Cross-State Air Pollution Rule. For example, PacifiCorp reviewed both federal and state regulations of GHG emissions as well as the status of non-GHG emissions standards.[62] Due to the uncertainty surrounding recent rulings on Regional Haze requirements, PacifiCorp also developed different scenarios in response to the outcome of the current litigation. On the other hand, discussion of environmental regulations was relatively limited in both the FPL and TVA IRP documents.[fff] It is also worth noting that IRPs for utilities operating in states with renewable portfolio standards treat these regulatory requirements similarly; they are constraints, with which all candidate portfolios must comply. Some resource portfolios either exceed the constraints or evaluate alternative compliance strategies.[ggg]

The most commonly reported sustainability metric was CO_2 emissions; it was reported as a metric in most IRPs that were reviewed.[hhh] Many of the plans constrained some or all of the candidate portfolios to ensure sufficient CO_2 reductions to comply with the CPP, and some plans resulted in reductions beyond those that are required for CPP compliance.[iii] In some cases, the potential for future CO_2 prices was considered and included in each IRP's analysis of system costs.[jjj]

Some IRPs evaluated other environmental metrics, including water consumption,[63] solid waste,[64] CO_2 intensity,[65] and spent nuclear fuel,[kkk] for each plan modeled. While FPL did not report water usage at the scenario level, they did report projected water usage, and also included qualitative discussion of several environmental properties, including impacts on wildlife and endangered species, water supply sources, and waste disposal, for potential new generation facilities.[66] APS also specifically tracked water usage from its generation fleet.[67]

In system valuation, the inclusion of CO_2 prices or other sustainability metrics such as water usage in the underlying analysis has the potential to significantly affect the resource selection decision, depending on the relative weights placed on various properties by the decision maker. However, our IRP review finds that while CO_2 and sometimes other environmental metrics were modeled, analyzed, and discussed, the IRP ultimately chosen often include high-emitting or water-intensive, but low-cost resources, and appear to place more weight on the incremental affordability than the incremental sustainability impacts. For example, APS selected the Base Plan, which has the highest CO_2 emissions in all scenarios analyzed and

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[fff] In TVA's case, this was in part reflective of the timing of the IRP process and the uncertainty surrounding the CPP at the time the resource strategies were developed (2015 TVA IRP, p. 81).

[ggg] See, for example, 2015 PacifiCorp IRP at p. 147, 150, 182. The cases considered by PacifiCorp alternatively assume early renewable resource acquisition, deferred renewable resource acquisition, or purchase of unbundled renewable energy certificates as strategies to comply with the Oregon renewable portfolio standard.

[hhh] See, for example 2015 PacifiCorp IRP at p. 177; 2015 Dominion IRP at p. 127; TVA IRP at p. 93.

[iii] For example, of 15 PacifiCorp "core cases," 14 incorporate an assumed 111(d) requirement (2015 PacifiCorp IRP, p. 150). Similarly, 4 of 5 portfolios considered by Dominion satisfy CPP requirements (2015 Dominion IRP, p. 129).

[jjj] For example, Dominion used a shadow price for CO_2 in developing its commodity price forecasts for its CPP-compliant scenarios. (Dominion IRP, p. 60) TVA assumed forecasted CO_2 prices for each of its five scenarios, with 2033 prices ranging from less than $10 per metric tonne in the "Stagnant Economy" scenario to nearly $60 per tonne in the "De-Carbonized Future" scenario.

[kkk] Id., However, note that spent nuclear fuel was identical for each strategy and scenario modeled.

the highest water usage in five of the six scenarios.[68] Similarly, PacifiCorp noted that "by the end of the 20-year planning horizon, emission reductions are similar among the top performing portfolios" and ended up choosing a portfolio that has CO_2 emissions that are roughly 10% higher than many other top-performing portfolios.[69]

Safety was not explicitly discussed in the IRPs reviewed.

4.1.2.5 Resiliency

Consideration of resiliency was absent from the IRPs reviewed. This is at least in part a function of the timing of the various IRP processes. For example, the LIPA IRP reviewed for this study was completed in February 2010. According to a 2015 status update, the next LIPA IRP process "is intended to result in a recommended resource portfolio that…promotes system resiliency."[70]

4.1.2.6 Security

Similarly, consideration or discussion of security-related concerns in the IRPs reviewed was relatively scarce. The exception is the Dominion IRP, which within the context of describing its planning assumptions, explained that the Company intends to spend $500 million over the next five to seven years to "improve its transmission system resiliency and security of its facilities" by upgrading its substation facilities to newly released NERC mandatory compliance standards.[71]

4.2 Transmission Planning

Transmission planning addresses the need for transmission additions to the system to ensure that power can reliably flow across the high-voltage transmission network, from generators to the demand centers under future system conditions. Transmission planning studies are conducted by utilities, ISOs, RTOs, and other regional transmission planning organizations (such as the Western Electricity Coordinating Council [WECC] and its subregions).[lll] The primary objective of transmission planning is to design a reliable system in which there are no violations of the reliability standards set by the NERC.[mmm] Transmission planning processes also consider the need for transmission upgrades due to the interconnection of new generation facilities to ensure they are able to reliably deliver power to the system.

In addition to reliability, transmission planners also consider in some cases whether there are sufficient economic or policy-related benefits to building transmission facilities and are now required to complete planning studies on a regional and interregional basis to comply with FERC Order No. 1000.[72] Planning studies focused on the economic benefits of transmission additions, known as "market efficiency" studies, analyze whether transmission facilities reduce system production costs, and specifically whether production cost savings exceed the costs of the transmission additions. Some regions also perform economic studies that consider a wider range of potential impacts on system properties and the tradeoff between the costs of the transmission additions and avoided system costs.

As part of our analysis of transmission planning, we reviewed the following:

[lll] Throughout this section we use the term RTO to refer to both ISOs and RTOs.

[mmm] The list of contingency conditions and system performance standards set by NERC can be found here: http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf

- seven RTO transmission planning processes – ISO New England (ISO-NE), New York ISO (NYISO), PJM Interconnection (PJM), Southwest Power Pool (SPP), California ISO (CAISO), Midcontinent ISO (MISO), and the ERCOT;
- one regional planning group – WestConnect; and
- a vertically integrated utility – Duke Energy.

The analysis primarily reviewed RTO planning processes rather than vertically integrated utility processes because they provide significant public documentation of their processes and results through stakeholder meetings and planning report. Several of the RTOs have also considered a wider range of properties affected by transmission additions. For non-RTO regions, we chose a regional transmission planning group in the WECC that covers the largest area, WestConnect, and the two utilities in the southeast due to their size.

Interregional planning efforts are not part of this review because these processes are in the early stages of development and implementation in response to FERC Order No. 1000. The development processes of merchant high-voltage direct current lines are also not included because these lines are primarily built to provide value to those who hold capacity rights and are not generally analyzed in terms of societal benefits.

4.2.1 Alternatives Considered

Transmission planning processes are required by FERC Orders No. 890 and 1000 to review alternatives to transmission solutions for overcoming reliability violations or reducing congestion.

> When evaluating the merits of such alternative transmission solutions, public utility transmission providers in the transmission planning region also must consider proposed non-transmission alternatives on a comparable basis.[73]

Alternative resources, such as additional generation capacity or demand-side resources, in some cases can provide lower cost solutions to particular issues, but are not a perfect substitute in all cases. Figure4.2 below shows the results of a 2014 study of transmission “market resource alternatives” that found utility-scale generation and energy storage provide the most complementary capabilities to transmission assets.[74]

		Transmission	Energy Efficiency	Demand Response	Utility-scale Generation	Distributed Generation	Energy Storage	Smart Grid - Distribution
What	Energy	●	◑	◑	●	◕	●	●
	Capacity	●	◑	◑	●	◑	◕	○
	Ancillary Services	●	○	◑	●	◕	●	◑
	Reduce system losses	●	◑	◑	○	◔	◔	◔
When	Long lifespan	●	◕	○	◕	●	●	●
	Continuous basis	●	◕	○	◑	○	●	●
Where	Regional	●	◑	◑	●	◔	◔	○
	Local	●	●	●	●	●	●	●
	Micro	●	●	●	○	●	●	●
How	System/Wholesale	●	○	○	●	○	●	○
	Customer/Retail	○	●	●	○	●	○	●
	TOTAL	●	◑	◔	◕	◑	◕	◑

● Provided ○ Not provided

Frayer, Julia and Eva Wang, "Market Resource Alternatives: An Examination of New Technologies in the Electric Transmission Planning Process." Prepared for WIRES, October 2014.

Figure4.2. Comparison of Services Provided by Transmission Alternatives

Transmission planners consider transmission alternatives in different ways in their planning processes. NYISO in its Congestion Assessment and Resource Integration Study analyzes scenarios with additional natural-gas combined-cycle capacity, DR, or EE, and compares the results to new transmission capacity based on the same set of metrics.[75] CAISO adjusted its transmission planning methodology in 2013 to more closely align with the deployment of "preferred resources" in the California planning process. If reliability needs are identified, CAISO identifies a transmission solution and "additional rounds of assessments are performed using potentially available DR, distributed generation, energy storage to determine whether these resources are a potential solution."[76] On the other hand, ISO-NE analyzes alternatives through several pilot studies and identifies challenges to relying on alternatives, including the large number of resources needed and the need for additional transmission upgrades should the resources be installed.[77]

In many cases, the decentralized nature of supply and demand-side resource development provides a barrier to identifying and implementing alternative approaches to transmission. For example, an RTO may be able to study whether adding demand-side resources will overcome reliability violations driven by increased load but is not capable on its own to add such resources. CAISO notes that they cannot approve such resources but can work with state agencies for the resources to be installed.[nnn] In many cases though, stakeholders are given an opportunity to propose lower cost solutions that are analyzed by the RTO and can then be implemented through alternative means if they are found to be the lower cost solution.

[nnn] "While the [CAISO] Board cannot 'approve' non-transmission solutions, these solutions can be identified as the preferred solution to transmission projects and the ISO can work with the appropriate state agencies to support their development." CAISO, 2015-2016 Transmission Plan, p. 28. https://www.caiso.com/Documents/Board-Approved2015-2016TransmissionPlan.pdf.

4.2.2 Properties Considered

This analysis evaluated the transmission planning processes based on the metrics transmission planners' use for identifying needs and analyzing solutions. The analysis categorized these metrics in terms of their contributions to the system properties defined in the previous section. In addition, we reviewed planning process metrics, such as the frequency of the analyses, the time frame considered in the analysis, and the different future scenarios considered over that time frame, which affect the ability of the transmission planners to respond to changes in the outlook for the system and estimate long-term benefits of proposed facilities over their physical life.

Table 4.1 provides a summary of our review of transmission planning processes across different transmission planning regions.[ooo]

[ooo] The sources for developing this table and the analysis in this section include: ISO-New England, 2015 Regional System Plan, November 5, 2015; NYISO, 2015 Congestion Assessment and Resource Integration Study, November 17, 2015; PJM, PJM Regional Transmission Expansion Plan Book 3: Baseline and Market Efficiency Results, February 28, 2016; MISO, MISO Transmission Expansion Plan 2015, 2015; MISO, Multi Value Project Portfolio: Results and Analyses, January 10, 2012; SPP, 2015 Integrated Transmission Plan 10-Year Assessment Report, January 20, 2015; SPP, 2013 Integrated Transmission Plan 20-Year Assessment Report, July 30, 2013; ERCOT, 2014 Long-Term System Assessment for the ERCOT Region, December 2014; ERCOT, 2015 Regional Transmission Plan Report, January 15, 2016; CAISO, 2015-2016 Transmission Plan, March 28, 2016; WestConnect, 2015 WestConnect (Order 890) Annual Ten-Year Transmission Plan, 2015; Duke Energy Carolinas West, Transmissions System Planning Guidelines, March 10, 2014.

Table 4.1. Summary of Properties Considered in Transmission Planning Processes

Region	Properties Considered	Property Metrics	Frequency	Time Horizon	Scenarios
ISO-NE Regional System Plan (RSP)	Reliability Affordability	*Reliability:* violations *Affordability:* production costs, congestion, energy costs (upon request)	Annual	10 years	1 scenario
NYISO Comprehensive System Planning Process (CSPP)	Reliability Affordability Sustainability	*Reliability:* violations *Affordability:* production costs, load payments, losses costs, capacity costs *Sustainability:* emissions (CO_2, SO_2, NO_x)	Biennial	10 years	10 scenarios
PJM Regional Transmission Expansion Plan (RTEP)	Reliability Affordability	*Reliability:* violations *Affordability:* production costs, load payments, capacity costs	Annual	15 years	3 scenarios
MISO Transmission Expansion Plan (MTEP)	Reliability Affordability Sustainability	*Reliability:* violations *Affordability:* production costs *Sustainability:* emissions (CO_2)	Annual	15 years	4 scenarios
Multi Value Projects (MVP)	Reliability Affordability	*Reliability: violations* *Affordability:* production cost, capacity costs, reserves costs, transmission costs, and policy costs	One time (2011)	40 years	2 scenarios
SPP Integrated Transmission Planning (ITP) Studies: Near-Term, 10-Year, 20-Year	Reliability Affordability Sustainability Flexibility	*Reliability:* violations *Affordability:* production costs, capacity costs, avoided transmission upgrades, reduced energy losses, wheeling revenues; *Sustainability:* emissions *Flexibility:* wind curtailments	Near-Term: Annual 10-Year/20-Year: Triennial	Near term, 10 year, 20 year	Near term: 1 scenario 10-Year: 2 scenarios 20-Year: 5 scenarios
ERCOT Regional Transmission Plan (RTP) and Long Term System Assessment (LTSA)	Reliability Affordability	*Reliability:* violations *Affordability:* production costs	RTP: Annual LTSA: Biennial	RTP: 6 years LTSA: 15 years	RTP: 2 scenarios LTSA: 6 scenarios
CAISO Transmission Plan	Reliability Affordability Sustainability Flexibility	*Reliability:* violations *Affordability:* production costs, capacity costs, RPS compliance costs, market power mitigation *Flexibility:* insurance value of high-impact, low-probability events *Sustainability:* emissions (CO_2, SO_2, NO_x)	Annual	10 years	RPS analysis: 3 scenarios
WestConnect Annual Ten-Year Transmission Plan	Reliability	*Reliability:* violations	Annual	10 years	---
Duke Energy Carolinas	Reliability	*Reliability:* violations	Annual	10 years	---

This review of the transmission planning studies revealed that properties are considered differently across the regions as set forth in the sections below.

4.2.2.1 Affordability

All of the ISOs and RTOs analyze the potential for new transmission facilities to improve system affordability, primarily through reductions in variable operating (production) costs. These analyses, commonly referred to as "market efficiency" analyses, study whether the addition of a new transmission line results in lower variable costs for supplying energy. The potential for production cost savings occurs during periods in which the system becomes congested and higher cost generators must be dispatched instead of lower cost units. The addition of transmission capacity to the congested region can allow for the lower cost units to generate and reduce the total system costs. Market efficiency studies analyze production cost savings for few future test years, up to 20 years, with annual savings interpolated for the years not modeled. In some cases, production cost savings in years beyond those modeled are assumed to continue to accrue.

Beyond production cost savings, the analysis of additional affordability metrics is inconsistent across RTOs. Several RTOs have considered multiple affordability metrics, including capacity resource cost savings, production cost savings under more realistic scenarios and those that stress the system (similar to the approach used for reliability analyses), capacity resource savings, avoided transmission costs for smaller reliability projects, and reduced costs for achieving policy goals, such as renewable portfolio standard (RPS) mandates.

SPP includes additional affordability metrics consistently in both its 10-year study (ITP10) and 20-year study (ITP20). For example in its ITP10 studies, SPP considers ten affordability metrics, as shown in Figure4.3, including the adjusted production cost savings, reduced ancillary service needs, avoided or delayed reliability projects, and capacity cost savings.

ITP 10-Year Assessment (ITP10) Benefit Metrics
Adjusted Production Cost Savings
Reduction of Emissions Rates and Values
Savings due to Lower Ancillary Service Needs and Production Costs
Avoided or Delayed Reliability Projects
Capacity Cost Savings due to Reduced On-Peak Transmission Losses
Assumed Benefit of Mandated Reliability Projects
Benefit from Meeting Public Policy Goals
Mitigation of Transmission Outage Costs
Increased Wheeling Through and Out Revenues
Marginal Energy Losses Benefits

Source: SPP, SPP, 2015 Integrated Transmission Plan 10-Year Assessment Report, January 20, 2015.

Figure4.3. SPP Integrated Transmission Planning Benefit Metrics

To identify the benefits of $3.4 billion in transmission investments on their system from 2012 to 2014, SPP evaluated the costs of operating the system with and without the projects over a 12-month period using actual market conditions from March 2014 to February 2015 and found "quantified benefits for the evaluated projects, including production cost savings, which are expected to exceed $16.6 billion over the 40-year period, which results in a benefit-to-cost ratio of 3.5."[ppp]

CAISO developed a detailed approach for analyzing a broader range of affordability metrics, known as the Transmission Economic Assessment Methodology, or TEAM. The methodology is applied to proposed transmission projects in its biennial transmission planning process through a separate economic analysis. MISO considered a broader range of affordability metrics in their multi value project (MVP)

[ppp] "In addition to [adjusted production cost] savings, this study also quantified benefits associated with reliability and resource adequacy, generation capacity cost savings, reduced transmission losses, increased wheeling revenues, and public policy benefits associated with optimal wind development. Some sources of additional value, which were either partially captured or excluded altogether, have not been quantified. These include environmental benefits, employment and economic development benefits, and other metrics like storm hardening and reduction in the costs of future transmission needs." SPP, The Value of Transmission, January 26, 2016, p.5. http://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf

analysis, including avoided capacity costs due to lower planning reserve requirements, decreased capital costs for renewable additions due to accessing improved resources, and avoidance of future transmission upgrades.

The Duke Energy guidelines for transmission planning include as an objective the "efficient and economic use of all generating resources," but the detailed planning assumptions and the 2014 IRP provide no further discussion of the consideration for transmission additions to reduce costs elsewhere on their system.[78]

4.2.2.2 Reliability

Reliability is the primary focus of transmission planning studies across all regions reviewed. As noted in Duke Energy Carolina's Transmissions System Planning Guidelines, "any reliable transmission network must be capable of moving power throughout its system without exceeding voltage, thermal and stability limits, during both normal and contingency conditions."[79]

Analysis of the reliability of the transmission system is primarily concerned with identifying potential "violations" that may occur in the future based on standards set by the NERC and its regional entities.[qqq] These standards provide detailed requirements for entities to follow and define scenarios to model based on several cases and contingencies to ensure that the system can continue to deliver power in response to a range of uncertainties within the electric power system, such as high load periods and outages of major generation and transmission facilities.[80] The scenarios in the NERC standards include the operation of the system under credible contingencies that can stress the system, such as the loss of significant generators or transmission lines.

Similar to IRP analyses conducted to meet reserve margins, the value of reliability is established by NERC standards and not by the transmission planners.[rrr] The role of the transmission planning process is to ensure that thresholds are not exceeded and to determine the lowest cost options for complying with the standards.

4.2.2.3 Flexibility

Uncertainty about future market conditions due to load growth, fuel prices, the generation mix, and environmental policies can result in very different system conditions across the potential scenarios.

[qqq] NERC states that the purpose of the standards is to "establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. In addition, transmission planners also follow planning guides specific to their system." NERC, Transmission System Planning Performance Requirements, TPL-001-4, [no date],

[rrr] As noted in Section 3.2 above, NERC does not explicitly consider costs in their determination of reliability criteria. "The definition of adequate level of reliability does not mention any specific measure of 'cost effectiveness' because costs versus benefits, including societal benefits, can only be determined by the individual users, owners, and operators. They will have different perspectives on what is 'cost effective' for them, and they will exercise their judgments by participating in the standards drafting process, and ultimately, when they cast their ballots to approve or reject a standard. A goal of the standards is to achieve an adequate level of reliability across North America. For various reasons, some users, owners or operators may choose to plan and operate their portion of the System to achieve a level of reliability that is above the standards." NERC, Definition of "Adequate Level of Reliability", approved December 2007, pp. 6-7, http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

Flexibility metrics, such as wind curtailments and savings over a wide range of future scenarios (especially particularly high cost events) are considered sporadically across the RTOs. For example, the planning process by ISO-NE reviewed for this document, only models a single future scenario while SPP and ERCOT model five or more scenarios in their long-range planning processes. Planning the transmission system across additional scenarios allows for identifying projects that can provide value by allowing generators to build in different locations depending on where load is projected to grow the most, by providing access to geographically constrained resources, and by providing access to additional generation in case units have to be retired due to new environmental regulations.

4.2.2.4 Sustainability

Some regions, such as NYISO, CAISO, and SPP, report changes in emissions of air pollutants from the generation fleet due to changes in the transmission system. These regions all track the emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and CO_2 due to changes in the transmission system. MISO reports CO_2 emissions as a part of their economic study. Other sustainability impacts of transmission facilities are considered by federal, state, and local regulators during the siting process once a need for transmission has been identified by the planning process.

4.2.2.5 Resiliency and Security

The transmission planning studies reviewed for this section did not include metrics for security and resiliency.[sss] The ERCOT 2014 Long Term System Assessment (LTSA) report included a "High System Resiliency" scenario that accounted for a potential future in which "the system could support major power transfers within ERCOT during potential 'black swan' events such as extreme weather events or large storms." The scenario also notes that for such a scenario to occur "the value of resilience and system flexibility is broadly recognized by stakeholders and regulators and hence the community is more willing to invest in infrastructure to ensure greater resiliency." In its 2016 study on transmission value, SPP notes that a benefit of transmission is storm-hardening but did not quantify the benefits in its analysis, noting "the focus on grid resiliency and need for effective system restoration plans are predicated on risk management of long lead time components of the bulk power system, like [extra high voltage] autotransformers."[81]

The security of the transmission network tends not to be improved by adding transmission capacity but is instead considered in other processes focused specifically on security, such as compliance with NERC Critical Infrastructure Protection standards for physical and cyber security[82] and through operational processes, such as information sharing, procurement, monitoring capabilities, and software upgrades.[83]

4.3 Wholesale Market Design

In several regions of the United States, electricity is supplied through competitive wholesale electricity markets rather than regulated utilities. These markets are administered by RTOs or ISOs.[ttt] Because

[sss] Note that NYISO uses the term "transmission security violation" to describe the violations to NERC criteria, which in this report are included under reliability. (NYISO, 2014 Reliability Needs Assessment, September 16, 2014.) ISO-NE also refers to "transmission security" in the context of providing reliable delivery of power in the 2015 Regional System Plan. ISO-New England, 2015 Regional System Plan, November 5, 2015.

[ttt] Throughout this section we use the term RTO to refer to both ISOs and RTOs. U.S. RTOs include the PJM Interconnection, the ERCOT, the California ISO (CAISO), ISO New England (ISO-NE), New York ISO (NYISO), the Midcontinent ISO (MISO), and the Southwest Power Pool (SPP).

resources are not centrally planned through an IRP process, valuation manifests in different ways in wholesale markets than in regulated utilities. In general, all RTOs perform four functions: administering operational markets, maintaining supply adequacy, planning for transmission, and scheduling transmission. This section focuses primarily on the role RTOs play in managing operational markets and maintaining supply adequacy. The previous section discusses the role RTOs play in transmission planning. By carrying out these functions, RTOs consider many of the properties and metrics identified earlier in this report.

4.3.1 Alternatives Considered in Wholesale Markets

Unlike a centralized IRP process, wholesale markets do not consider a list of specific alternatives and identify the optimal mix of alternatives. Rather, competition among a wide range of resources in wholesale markets should result in an efficient mix of resources and low societal costs of providing power, subject to reliability, sustainability, and other constraints as set by the system operator. To participate in wholesale markets, resources must qualify based on the rules specific to each market. System operators set the qualification standards for resources, and allow resources to compete if they meet that standard. Well-designed markets enable competition among new and existing supply, traditional and new types of technology, generation and demand-side resources, internal supply and imports, and centralized and distributed resources. The challenge of market design is to create market rules that result in fair and efficient competition that allow for merchant developers to identify opportunities for adding new resources to the system.

4.3.2 Properties Considered

4.3.2.1 Reliability

As in other systems, reliability requirements in RTOs are typically set by reliability standards that do not consider cost. However, RTO markets encourage reliability standards to be met in a cost-effective manner through competition among market participants. RTO markets are designed to ensure reliability relative to both the operational and planning time frames.

RTOs manage operational reliability through energy and ancillary service markets. Wholesale energy markets manage the commitment and dispatch of generators to meet load, taking into account each unit's costs and operating capabilities, as well as technical constraints on the system such as transmission constraints. Ancillary service markets competitively procure additional services that are needed to maintain reliability; these services are typically divided into three categories: frequency regulation,[uuu]

[uuu] U.S. RTOs include the PJM Interconnection, the ERCOT, the California ISO (CAISO), ISO New England (ISO-NE), New York ISO (NYISO), the Midcontinent ISO (MISO), and the Southwest Power Pool (SPP).

[uuu] Deviations in frequency, which result in the system frequency diverging from its system -wide target of 60 Hz in the U.S., can be caused by factors including load forecast error, unexpected changes in wind and solar generation, or a generator failing. Units that provide frequency regulation are typically equipped with automated generation control technologies and follow a signal to increase output or decrease output sent by the RTO, depending on the instantaneous frequency of the system. All balancing authorities, RTOs included, procure frequency regulation to meet NERC reliability standards.

contingency reserves,[vvv] and other services.[www] Frequency regulation refers to capacity that is procured to manage very short-term deviations between supply and demand, which affect system frequency and reliability metrics. Contingency reserves are capacity procured by RTOs to be available in case of a major contingency, such as a generator or transmission failure. Typically, the procurement of energy and ancillary services are co-optimized to consider the tradeoffs between the two products and minimize costs.[xxx]

RTOs traditionally have managed planning reliability by requiring that load-serving entities procure sufficient capacity to meet their peak load reliably. How this requirement is met varies between RTOs. PJM, NYISO, and ISO-NE have established centralized capacity markets to manage this process in a competitive manner. In California, load serving entities (LSEs) primarily procure capacity through bilateral contracts with suppliers, not a centralized capacity mechanism. MISO manages resource adequacy through a mixture of bilateral contracting and a centralized market. ERCOT differs from other RTOs because it does not centrally manage the procurement of capacity and does not have a mandated reliability standard. Instead, the ERCOT energy market is designed to provide adequate revenues for sufficient capacity to be attracted and retained.

After the 2014 Polar Vortex, RTOs began to explicitly consider how extreme cold weather events can affect the reliability of generators and resource adequacy. PJM updated their capacity market design with additional incentives for generators to be available when needed during a scarcity event.[84] These incentives are designed to encourage generators to enhance reliability by installing dual-fuel capability, paying for firm fuel contacts, or other methods.

When procuring capacity, RTOs implicitly consider tradeoffs between the value of reliability and affordability. For example, northeast RTOs have designed their capacity markets to have downward sloping demand curves. On average, the sloped demand curves are designed such that the RTO will meet their mandated resource adequacy standard. However, sloped demand curves allow RTOs to procure more capacity than needed if low-cost supply is available. If supply is tight, sloped demand curves allow RTOs to procure less capacity such that reserve margins can fall below target levels. Such circumstances are rare, because the demand curves are designed so that prices will be high when supply is tight, thereby incentivizing new supply to be built.

4.3.2.2 Affordability

RTOs account for the cost of reliably meeting customer load through three separate market mechanisms: wholesale energy markets, ancillary service markets, and in some RTOs, capacity markets. Wholesale

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[vvv] *Contingency Reserves* are typically classified in terms of how quickly they can come online once called. Traditionally, the two main classes of operating reserves are spinning reserves and non-spinning reserves. Spinning reserves refers to resources that are online, synchronized to the system frequency, and can ramp up quickly (generally in 10 minutes or less) if needed. Non-spinning reserves refer to resources that are offline and must turn on to provide power within 30 minutes. RTOs determine the quantity of reserves procured daily based on… The traditional distinction between spinning and non-spinning reserves is becoming less relevant with new technologies such as batteries, that can come online very quickly but are not 'spinning' in the traditional sense.

[www] The other services include: black start capacity and voltage support. These services are typically not procured through a market, but instead are contracted in the case there is found to be a system-wide deficiency.

[xxx] Ancillary services are services necessary to maintaining reliable delivery of power in the face of system uncertainties at a shorter time scale than RT energy markets, including load forecast errors, non-dispatchable renewable output forecast error, and the sudden loss of generation and/or transmission capacity

energy markets account for the variable costs of generating electricity to meet load, and reward generators that can generate power at a low cost. Ancillary service markets account for the cost to the RTO of carrying fast-ramping capacity to provide regulation and of holding some capacity as contingency reserves to mitigate the risk of contingencies such as a major generator outage.[yyy] Capacity markets account for the cost of carrying sufficient supply such that resource adequacy targets are met.[zzz] If an RTO is tight on supply, the total revenues across all three sources should rise to a level that a new competitive generator would earn sufficient revenues to enter the market. For an RTO with excess supply, the most uneconomic generators should receive total revenues less than costs and be incentivized to retire.

4.3.2.3 Flexibility

RTOs manage the need for operational flexibility through wholesale energy markets and ancillary service markets. These markets reward flexible resources that can provide high-value flexibility services. However, system operators have recently become concerned that markets do not sufficiently reward operational flexibility, which may result in challenges when integrating large penetrations of wind and solar. Markets are in the process of implementing new products that will further reward flexible resources.

All RTOs maintain two types of wholesale energy markets: Real-Time (RT) and Day-Ahead (DA) markets. RT markets, sometimes known as “balancing markets,” re-optimize the dispatch instructions made DA to account for forecast errors and other sources of uncertainty. Short-term RT markets increase the operational flexibility of the system by identifying the most efficient way for the system to accommodate unexpected system conditions, such as an unexpected drop in renewable generation or sudden outage of a transmission facility, that are only known in the RT operation of the system . Flexible resources that can respond with short notice to RT price signals are rewarded with higher revenues.

RTO ancillary service markets also contribute to system flexibility, and flexible resources that are capable of providing ancillary services are rewarded through higher revenues. RTOs are continuing to update ancillary service designs by refining the types and quantities of products that are needed to meet flexibility needs. RTOs are also updating market rules to enable participation of flexible resources, such as storage. By more precisely quantifying the value provided by flexible resources, RTOs can identify the optimal amounts and types of resources that are needed.

ERCOT provides an example of the benefits of ancillary service redesign. ERCOT has undertaken the “Future of Ancillary Services” initiative to define products that are more closely suited to the current and future needs of the system and take advantage of new technologies able to serve those needs.[85] By more precisely defining ancillary service needs, adding additional services, and enabling participation by more flexible resource types, ERCOT forecasts that it can procure less overall operating reserve capacity and reduce system costs by $15 million to $20 million per year.[86] In this way, ERCOT is more precisely defining their flexibility need. The market design proposed by ERCOT improves the flexibility of the system by matching the system’s needs for flexible resources with the technologies that are capable of providing the flexibility.

[yyy] Most RTOs procure ancillary service products, including regulation and contingency reserves, through competitive market products. Some ancillary services with very small procurements, such as voltage stability and black start, are procured through bilateral contracts instead of formalized market mechanisms.

[zzz] Some systems, such as ERCOT, do not have capacity markets. In these systems, prices on the energy market are allowed to rise to high levels, such that generators make sufficient revenue to incentivize efficient new entry. Other RTOs, such as CAISO, rely on bilateral contracts for capacity rather than centralized markets.

However, it is unclear whether systems currently sufficiently value flexible resources in the face of growing penetrations of variable wind and solar generation. Several RTOs are in the process of developing new so-called “ramp products” that will improve operational flexibility and help manage system ramps caused by variable renewables. For example, MISO recently implemented a ramp product specifically to help manage the challenges of integrating large amounts of renewable resources.[87] The uncertain output from variable resources can lead to “ramp scarcity.”[aaaa] The product is co-optimized in existing DA and RT markets. How RTOs manage planning reliability is also evolving with the addition of large amounts of wind and solar to the grid. California now requires LSEs to contract for “flexible capacity” to manage large ramps in load net of renewable generation (i.e., the “duck curve”) through its Flexible Resource Adequacy requirements.[88]

4.3.2.4 Sustainability

RTOs generally do not explicitly consider sustainability in their analysis and market operations, and it is widely accepted that it is not appropriate for them to do so within their roles as the system operators. However, the variable and capital costs of complying with environmental regulations, such as allowance prices or increased operating costs, are typically included in a plant’s energy bid for ISO energy markets. The fixed costs of installing emission control technology to comply with environmental regulations are considered when determining whether to build or retire capacity. Therefore, prices within RTO markets do reflect the costs of complying with relevant environmental regulations and are reflected in the costs that consumers pay for RTO energy services.

4.3.2.5 Resiliency and Security

Although RTOs are mandated to maintain resiliency and security through operational protocols, duplication of facilities, and protection against malicious attacks, wholesale markets for energy, ancillary services, and capacity do not consider resiliency in a significant way. Most ancillary services are designed to protect against failures that can occur during normal operating conditions, such as a large plant or transmission line going offline. They are not designed to protect against a major catastrophic failure caused by an attack or a natural disaster. However, some products that are valued in ancillary service markets, such as black start capability and microgrids, are designed to help return the system to power after an outage.

4.4 Distribution Resource Planning

This section describes how valuation takes place in distribution system resource planning and identifies valuation gaps. This section focuses on California’s distribution resource planning (DRP) process because it is the most formalized process for distribution resource planning and valuing distributed resources.

In conventional distribution system planning, decisions are made about whether and how to upgrade or expand distribution system assets to enable utility operations and meet system reliability requirements. The valuation properties of affordability and reliability are most prominently considered in conventional

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[aaaa] MISO defines “ramping scarcity” as: “a short-lived scarcity condition, when there is not enough ramp-able generation capacity in Real-Time, but there is enough total capacity online; so there is a need to sacrifice clearing one product, such as online contingency reserve, for shortage in the “up” direction and Regulation Service for shortage in the “down” direction.” See https://www.misoenergy.org/Library/Repository/Communication%20Material/Strategic%20Initiatives/Ramp%20Product%20Questions%20and%20Answers.pdf for additional details on MISO’s proposed ramp product

distribution system decision making. The cost of upgrades and compliance with standards (primarily reliability standards) are the primary drivers. The properties of resiliency, flexibility, and security (in terms of protecting distribution system equipment) are considered in some instances and to a lesser degree relative to the primary drivers. In distribution planning the costs of distribution system upgrades or expansions are weighed either explicitly or implicitly against reliability requirements and the desired level of hardness or security of the system. Typically, distribution planning occurs as part of routine utility operations to meet system needs at reasonable costs.

The California DRP process expands upon traditional distribution system planning to consider impacts of significant penetrations of DERs.[89] California's DRP process is intended to help achieve state environmental and energy policy goals through grid modernization.[90] The valuation property of sustainability, specifically the GHG emissions metric, is indirectly addressed as a system constraint rather than a property that is traded off against other properties. Meeting system reliability requirements is a foundation of all distribution system planning, in California and elsewhere. When planners weigh alternatives, they eliminate from consideration those that do not meet system reliability requirements.

In California, increasing levels of DERs led to the passage of Assembly Bill (AB) 327 (PU Code 769)[91] in 2015, which requires utilities to file DRPs to evaluate locational benefits and costs of distributed resources. In Pacific Gas & Electric's (PG&E's) first DRP filing in July 2015, PG&E applied "the criteria in Public Utilities Code Section 769 to identify optimal locations for the deployment of DERs within PG&E's service area."[92] PG&E asserts that because DER impacts can be positive or negative and can vary by location "it is important to identify locations where DERs seem to best reduce the overall costs of providing electricity via the electric grid. Such locations could be defined as potential and preliminary "optimal" locations, recognizing that additional analysis would be required to determine feasibility."[93] Therefore, the optimality in California's DRP process is defined as reducing the overall costs of providing electricity. As pointed out in the section below, the system properties of reliability, resiliency, security, and flexibility are considered in the DRP process in terms of incurred or avoided costs.

4.4.1 Alternatives Considered in California DRPs

CPUC's guidance ruling for DRPs, found in Rulemaking (R.) 14-08-013, requires utilities to develop a unified locational net benefits methodology for DERs.[94] The CPUC directed utilities to start with a commission-approved cost-effectiveness calculator developed by Energy + Environment Economics (E3) and then add other locational costs and benefits as appropriate.[95] PG&E combined elements from E3's calculator with value components spelled out in the Commission's original guidance ruling in R.14-08-013 to come up with the complete list of value components in Table 4.2 that PG&E proposes to use in locational impact analysis for DERs.[96] Each value component in Table 4.2 assumes consideration of an implicit valuation tradeoff. The last column in Table 4.2 was added for this report and shows the assumed tradeoff for each value component in terms of the system properties in this report. In each case, cost is traded off against one or more of the system properties.

Table 4.2. Value Components Considered by PG&E in Locational Impact Analysis

#	Component	PG&E Definition	Valuation Tradeoffs Implied
1	Sub-Transmission, Substation, and Feeder Capital and Operating Expenditures (Distribution Capacity)	Avoided or increased costs incurred to increase capacity on sub-transmission, substation, and/or distribution feeders to ensure system can accommodate forecast load growth	Cost, flexibility to respond to load growth, reliability
2	Distribution Voltage and Power Quality Capital and Operating Expenditures	Avoided or increased costs incurred to ensure power delivered is within required operating specifications (i.e., voltage, fluctuations, etc.)	Cost, reliability
3	Distribution Reliability and Resiliency Capital and Operating Expenditures	Avoided or increased costs incurred to proactively prevent, mitigate, and respond to routine outages (reliability) and major outages (resiliency)	Cost, reliability, resiliency
4	Transmission Capital and Operating Expenditures	Avoided or increased costs incurred to increase capacity on transmission lines and/or substations to ensure system can accommodate forecast load growth	Cost, reliability
5a	System or Local Area Resource Adequacy (RA)	Avoided or increased costs incurred to procure RA capacity to meet system or CAISO-identified Local Capacity Requirement (LCR)	Cost, reliability
5b	Flexible RA	Avoided or increased costs incurred to procure flexible RA capacity	Cost, flexibility
6a	Generation Energy and GHG	Avoided or increased costs incurred to procure electrical energy and associated cost of GHG emissions on behalf of utility customers. Pertains to GHG reduction by distributed resources	Cost, sustainability
6b	Energy Losses	Avoided or increased costs to deliver procured electrical energy to utility customers due to losses on the T&D system	Cost, reliability
6c	Ancillary Services	Avoided or increased costs to procure ancillary services on behalf of utility customers	Cost, reliability
6d	Renewable Portfolio Standards (RPSs)	Avoided or increased costs incurred to procure RPS-eligible energy on behalf of utility customers as required to meet the utility's RPS requirements. Pertains to GHG reduction by distributed resources	Cost, sustainability
7	Renewables Integration Costs	Avoided or increased generation-related costs not already captured under other components (e.g., ancillary services and flexible RA capacity) associated with integrating variable renewable resources	Cost, reliability, flexibility
8	Any societal avoided costs that can be clearly linked to the deployment of DERs	Decreased or increased costs to the public that do not have any nexus to utility costs or rates	Cost, sustainability
9	Any avoided public safety costs that can be clearly linked to the deployment of DERs	Decreased or increased safety-related costs that are not captured in any other component	Cost, sustainability

PG&E's process for calculating the locational impacts of DERs includes determining the impact of the DER on the electric grid and then translating that impact into a cost, whether avoided or increased, and aggregating all costs into a single present value of locational net benefit across all of the value components.[97] The other investor-owned utilities (IOUs) in California follow a similar process. Consideration is not given to non-monetized system properties.

4.4.2 Properties Considered

This section examine how California's requirement for new DRPs aligns with the framework described in this report and the valuation system properties defined herein.

4.4.2.1 Reliability

At the core, distribution system planning is all about providing operational and planning reliability to ensure that customers' demand for energy can be met through the distribution system. California's DRP process is unique in that it also explicitly addresses operation and planning reliability related to existing and future penetration levels of DER. The guidance ruling contained in R.14-08-013 requires California utilities to develop three 10-year scenarios for DER growth through 2025, including geographic dispersion.[98] This introduces planning flexibility into the DRP process by making potential variations in DER penetration levels and locations visible and by allowing distribution system planning decisions to be made accordingly. This supports reliability over the planning horizon. Institute of Electrical and Electronics Engineers (IEEE) reliability indices of SAIDI, SAIFI and CAIDI are often used by utilities and regulators as key metrics of reliability performance. The DRP process assesses the value of DERs by identifying where in the system costs and benefits are realized due to differing types and amounts of DERs. Ultimately, the DRP process seeks to identify the optimal locations in terms of lowest cost for types and sizes of DER, while meeting reliability requirements.

4.4.2.2 Flexibility

The rapid integration of renewable resources in transmission and distribution systems creates operational challenges for the ISO, including short steep ramps, over-generation risk, and decreased frequency response. Therefore, flexible resources that can ramp up and down, respond for a defined period of time, change ramp directions quickly, store energy or modify use, react quickly and meet expected operating levels, start with short notice from a zero or low-electricity operating level, stop and start multiple times per day, and accurately forecast operating capability are increasingly valuable to CAISO. Enhanced market mechanisms are needed for CAISO to appropriately value flexible resources.

Flexibility is dealt with inconsistently across different utility types and based on requirements of regulators and states. In the case of California's new DRP requirements, flexibility (operational and planning flexibility), is a key system property that is being incorporated into distribution system plans. Flexibility is valued in DRPs by estimating the cost to accommodate the DER being considered. In other words, flexibility is indirectly represented by an increase in hosting capability for an increment of DER at a specific location.

4.4.2.3 Safety

In this framework, safety is considered a subproperty of the system property of sustainability. In all cases distribution system planning concerns itself with safety. The distribution system basic requirements are for the safe delivery of power and safe system maintenance. In California and other areas with distributed resources, there are concerns about worker safety during power outages in the presence of DERs that are not known or controlled by the utility. During an outage reverse power flow from distributed resources could injure a lineman doing repairs to the system.

This point was illustrated in the first set of DRP submittals in California; a gap was noted in one company's submittal that had to do with lack of information for first responders about the DER equipment needed for them to safely address system maintenance and outages. In this sense, DERs present a negative value for the subproperty of safety due to lack of information and potential risk to first responders. In a comprehensive valuation of DERs, the safety risk addressed here should be examined.

4.4.2.4 Security

Security is considered in distribution planning to the extent that the utility and regulatory body support hardening of the distribution system so that it is not subject to destruction as a result of vandalism, sabotage, or extreme weather events. Distribution planners make an implicit valuation in determining the extent to which increased costs will be traded for a more robust and secure system. The decisions about what type of distribution system security equipment to install are typically based on utility-specific standards.

4.4.2.5 Affordability

Distribution system planning is the process of planning to meet customer energy needs and system requirements in the most cost-effective way. In this sense, keeping total system costs low is a basic characteristic of distribution system planning. Because IOUs are motivated to reduce costs within their authorized revenue requirements, distribution planning also regularly focuses on affordability from the perspective of reducing production costs. Distribution assets are a significant fraction of a utility's infrastructure investment and operating expense; therefore, cost minimization is essential to keeping retail rates at reasonable levels.

When comparing alternatives in utility resource planning, total system costs are often represented in terms of the present value of the total utility revenue requirement. This total cost is amortized and recovered through utility customers' rates. The customer burden to afford electric services relative to income is typically not subject to PUC regulation and is often addressed by federal or state energy assistance programs.

As indicated previously, in PG&E's first DRP filing, PG&E proposed to determine the economic value of DERs by translating impacts into costs (be they positive or negative) and then aggregating costs into a single present value of locational net benefit impact for the life of the DER being considered.[99] A positive present value indicates deployment of the DER results in overall savings in the cost of providing electricity via the electric grid, while a negative present value indicates the DER may result in an increase in the overall cost.

In terms of customer payments, some utilities in the DRP filing in July 2015 expressed concerns that net metering is not accurately capturing the value or lack of value that DERs provide. They argue that a subset of customers who have solar PV systems avoid paying for the value they receive from using the distribution system, which undermines investor confidence and the financial health of the utility. This points to a valuation gap associated with being able to characterize the economic value provided by DERs temporally and spatially, and then designing rates and incentives that appropriately respond to that value.

Cost-allocation, compensation levels and ratemaking mechanisms for DERs that reflect the value DERs provide to the system cannot be established until the value and costs of DERs are characterized. Cost-allocation, compensation levels and ratemaking mechanisms will in turn affect the opportunities and incentives for additional DERs to be incorporated in the system in a way that creates value for all customers.[100]

4.4.2.6 Sustainability

DRPs in California do not explicitly address the sustainability subproperty of environmental and human health impacts. However, legislation in California that has promoted and incentivized distributed solar PV technologies and other renewables were designed to achieve environmental and human health impacts.[bbbb] Essentially, the valuation of environmental and human health impacts of DERs (to which DRPs are responding) was implicitly performed up front by legislators and the governor when RPSs and other initiatives were enacted. DRPs themselves do not address sustainability directly, only indirectly as a system requirement to meet the RPS requirements. Once the RPS requirements are met, decisions made by utility regulators will no longer be driven by sustainability. Utility regulators will continue to concern themselves with ensuring utilities meet mandates and customers energy needs in the most cost-effective way.

4.4.2.7 Resiliency

Resiliency in terms of robustness or recoverability is only marginally addressed in the California DRP process. For PG&E, it is being addressed in value component 3—distribution reliability and resiliency capital and operating expenditures. Aside from this, resilience of distribution system assets or as a new aspect of system response behavior is not addressed, other than under the reliability goals. NERC' Critical Infrastructure Protection Standards (CIPSs) requirements, however, include distribution system communications and, thus, cybersecurity aspects are covered through a general utility communications requirement.

4.4.3 Summary of Value Streams Considered in Distribution System Planning

Considerations for estimating value streams that are included, are not included, or are partially included in distribution system planning are summarized as follows:

- *Always incorporated* – The primary focus of DRP is the delivery of safe and reliable power in a way that is cost-effective. The system properties of reliability (operational and planning reliability) and safety (a subproperty of sustainability) are key and always incorporated. IEEE reliability indices of SAIDI, SAIFI and CAIDI are often used by utilities and regulators as key metrics of reliability performance.
- *Mostly incorporated* – Affordability, in terms of total system costs, is almost always incorporated into distribution system planning, including California's DRP process. Because IOUs are motivated to reduce costs within their authorized revenue requirement, distribution planning also regularly focuses on affordability from the perspective of reducing production costs. The customer burden to afford electric services relative to income are not subject to PUC regulation and are addressed by federal or state energy assistance programs. Distribution assets are a significant fraction of a utility's

[bbbb] The following California legislative and executive actions promote renewable energy and environmental outcomes:

- State of California Energy Action Plan – includes State Loading Order
- California Global Warming Solutions Act of 2006 – AB 32
- Renewable Portfolio Standard – 2002 SB 1078, 2006 SB 107, 2015 SB 350
- Emission Performance Standards – SB 1368
- Energy Storage Mandates – AB 2514
- Electric Vehicle Executive Order – Executive Order B-16-2012

infrastructure investment and operating expense; therefore, cost minimization is essential to keeping retail rates at reasonable levels. There is, however, a valuation gap associated with understanding the economic value provided by DERs and then designing rates and incentives appropriately that respond to that value.

- *Incorporated inconsistently* – Flexibility is dealt with inconsistently across different utility types based on the requirements of regulators and states and the need for system flexibility due to intermittent resources. In the case of California's new DRP requirements, flexibility (operational and planning flexibility) is a key system property that is being incorporated into distribution system plans because of the significant penetration of intermittent renewable resources and the increasing potential for responsive demands and energy storage. Security in terms of protecting distribution assets from vandalism, sabotage, and extreme weather are considered inconsistently from utility to utility.
- *Not considered* – Resiliency is largely not addressed in current planning methodologies, even in California. As with transmission system planning, the benefits to resiliency of maintaining delivery under extreme external disruptions have been qualitatively described in a few analyses, but doing so is rare. Valuation of resiliency is a new and emerging area of study, which is not currently well characterized in current distribution system planning practices, even in California, although PG&E and other utilities are attempting to quantify avoided or increased costs to prevent and respond to major outages.

5.0 Case Studies

To further illustrate the valuation framework discussed earlier for future analysis of the power system and potential changes to it, we provide two case studies in this section for which we review the valuation approaches that exist today for existing nuclear power plants and battery storage technologies. We highlight the extent to which the properties and metrics discussed in previous sections are included in those valuations and, as a result, the decisions for either adding new assets and services or retiring existing ones.

5.1 Nuclear Retirement Decisions

Nuclear plants are low variable cost plants that have no air emissions at the plant and few during the fuel cycle, but they have high ongoing fixed costs and high capital costs of construction.[101] Over the past several years, discussion of the future role of nuclear power plants in the United States has shifted significantly from talk of a "nuclear renaissance" after five units were approved between 2007 and 2009 to be built (Vogtle Units 3 and 4 in Georgia, Watts Bar Unit 2 in Tennessee, and Summer Units 2 and3 in South Carolina) to recent announcements of nuclear plant retirements, as listed in Table 5.1. The retirement of the nuclear power plants is likely to be replaced in part by carbon-emitting sources and thus result in either increased carbon emissions or higher cost compliance with a carbon emissions cap.

Table 5.1. Retiring Nuclear Facilities

Facility Name	Nameplate Capacity (MW)	Commercial Online Date	Owner	State	Regulatory Structure	Market/Utility	Retirement Date
Crystal River 3	860	1977	Duke Energy	FL	Regulated	Duke Energy	2013
San Onofre 2 & 3	2,150	1983/84	SCE/SDG&E	CA	Regulated	CAISO	2013
Kewaunee	566	1974	Dominion	WI	Deregulated	MISO	2013
Vermont Yankee	628	1972	Entergy	VT	Deregulated	ISO-NE	2014
FitzPatrick	848	1975	Entergy	NY	Deregulated	NYISO	2016/17
Fort Calhoun	479	1973	OPPD	NE	Regulated	SPP	2016/17
Clinton	1,078	1987	Exelon	IL	Deregulated	MISO	2017
Quad Cities	1,819	1972	Exelon	IL	Deregulated	MISO/PJM	2018
Pilgrim	677	1972	Entergy	MA	Deregulated	ISO-NE	2019
Oyster Creek	615	1969	Exelon	NJ	Deregulated	PJM	2019

The contrast between decisions about plant approvals and decisions to retire reactors provides insight into how nuclear generation facilities are valued by their owners and regulators.

Most of the retirements of regulated nuclear power plant units have been due to mechanical failures that were deemed too expensive to address. This was the case for both Crystal River[102] and San Onofre.[103] The Ft. Calhoun unit, which is owned and operated by the Omaha Power Public District, has had operational problems in recent years. Reasons for the Ft. Calhoun shutdown decision include its being a small single-unit station. At 479 MW, Ft. Calhoun is the smallest unit and station in the United States. Other cited reasons are the fixed cost of the unit (over $500/kW-yr), poor market conditions (low natural gas prices), and the lack of a regional or national carbon policy.[104]

Unit and station size are important factors in nuclear economics. The Nuclear Energy Institute reports that the size of a station is critical to the broad economics of a nuclear plant. [cccc] Units retiring due to economics tend to be at small stations.

Exelon announced the retirement of two nuclear stations in Illinois.[105] Quad Cities is a station in PJM that is almost 45 years old. It consists of two units that are smaller than stations built later, but the station capacity of 1,819 MW is quite high. It did not clear the recent PJM capacity market auction. Exelon also announced the retirement of Clinton—a 30 year-old single unit, 1,078 MW station in MISO. MISO's Illinois wholesale market energy and capacity prices have been weak. Exelon has reported combined losses for the two stations of $800 million over the last 7 years.

Owners of regulated units can take a long view of nuclear value, as most appear to be doing. This is clear from the analyses that supported the decisions to add new units discussed below. The potential for higher natural gas prices in the future and the possibility of a carbon policy factor into these decisions. The benefit of reducing carbon (with no associated economic benefit) can be valued by a regulated company and its regulators.[106] The Ft. Calhoun announcement, however, demonstrates that owners of regulated assets are also sensitive to the difference in the costs of continuing to operate nuclear facilities and alternative technologies (primarily natural-gas–fired generation).[dddd]

Regulated utilities also have the responsibility to serve customer load. They do that primarily by owning generation or having it under contract. In addition, if a regulated utility were to shut down a nuclear unit, they would have to replace the capacity, very often in the short term. A merchant owner has no such obligation. In addition, regulated utilities tend to limit their exposure to short-term markets by owning or contracting for generation.

On the other hand, merchant owners of nuclear units may consider the possible effects of higher future natural gas prices on a nuclear plant's profitability, but they may view such a potential favorable economic outcome as being too far out in time and of too low a probability to continue to wait while losing money based on current market revenues. In addition, they may not be willing to wait for the possibility of a carbon policy. Their views are driven by relatively near-term economics, which is appropriate for their private investment decision. Thus, we see more the unregulated units retiring.

As an example of a retirement decision of a small merchant station, Entergy explained in its press release announcing the closure of the Vermont Yankee nuclear power plant that the challenges it faced included low natural gas prices resulting in low wholesale energy prices, the high cost structure of a relatively small nuclear plant, and, in their view, market design flaws that result in "artificially low" energy and capacity prices.[107]

[cccc] "The smaller, older single units are most at risk in the competitive markets, but large nuclear plants producing electricity in the low- to mid-$30-per-megawatt-hour range are at risk of shutdown in MISO and western PJM." Comments of the Nuclear Energy Institute, Prepared for FERC, Settlement Intervals and Shortage Pricing In Markets Operated by Regional Transmission Organizations and Independent System Operators, Docket No. RM15-24-000.

[dddd] "While several members were regretful that the plant may need to shut down, the board also could not deny the financial reality that brought the plant to this point. 'You just can't keep losing money, until you say, 'Enough is enough,'' board member Thomas Barrett said. While numbers on the plant's revenue were not available, out of a $650 million operating budget, about $250 million is spent on operating Fort Calhoun alone, according to OPPD spokesman Mike Jones. "It just was not economically viable" to spend so much on one plant when power prices are low, he said." Bandyk, Matthew, UPDATE: Omaha utility proposes closing Fort Calhoun nuclear plant, SNL Financial LC, May 12, 2016.

5.1.1 Insights into New Nuclear Plant Decisions

Several nuclear units are under construction in service areas of regulated utilities, including in Georgia (Vogtle Units 3 and 4), South Carolina (Summer Units 1 and 2), and Tennessee (Watts Bar Unit 2). The reasoning behind the approval of these regulated units illustrates some of nuclear power's value streams. The decisions to approve the construction of the new nuclear plants occurred in 2007 and 2009 prior to a significant and sustained decrease in natural gas prices and before the full impact of the economic slowdown materialized.

In their decisions to approve the Summer units the South Carolina PUC found that nuclear facilities were the lowest cost generation resource. South Carolina Electric and Gas considered wind, solar, hydro, biomass, gas, and coal as alternatives to nuclear. They concluded that wind, solar, hydro, and biomass were not feasible alternatives to nuclear or fossil generation and that nuclear power was more cost-effective than power derived from gas or coal. They found nuclear power to be lower cost than coal-generated power without any consideration of future carbon pricing. In their analysis they considered carbon pricing of $15/T and $30/T starting in 2012 and escalating at 7% per year. They found gas to be more cost-effective than nuclear power without a carbon price, but not with either the $15/T or $30/T prices.

The TVA found the all-in costs of completing the Watts Bar 2 nuclear reactor unit to be $34/MWh lower than for a combined-cycle plant.[108] But, as we discuss in Section 3, the LCOE is not the best measure of cost-effectiveness unless the units compared exhibit similar dispatch. In TVA's analysis, the combined cycle plant was assumed to operate at 50% capacity factor, which likely was consistent with the natural gas prices at the time. This increases the LCOE relative to a nuclear unit operating at a high capacity factor. A similar analysis done today would have a lower variable cost for the combined-cycle plant due to lower natural gas prices and likely a higher capacity factor, which would lower the fixed cost component. Watts Bar and the combined-cycle plan would therefore be much closer in cost, if the analysis were done today. It should be noted that Watts Bar Unit 2 involves the completion of a second unit at the existing Watts Bar station. Unit 2's construction began in 1973 and was resumed in 2012.[eeee]

The PUC approvals also considered the flexibility benefit of diversifying their generation mix due to fuel price and environmental regulation uncertainty. For example, the Georgia Public Service Commission noted that:

> The Commission further finds that fuel diversity is necessary to protect ratepayers from fuel cost and environmental cost risks. Georgia Power has relied almost exclusively on new natural gas-fired generation to supply more than 25 years of growth in population and electricity usage in Georgia. Natural gas and coal prices have become increasingly volatile over this time period. The cost of complying with environmental controls for fossil fuel generation has also increased.[109]

The sustainability implications of nuclear plants, in terms of both safety and environmental impacts, were also considered in these regulatory orders. The Georgia Public Service Commission discussed the potential safety concern about spent nuclear fuel storage, but found that the issue would likely be resolved at the federal level. The South Carolina Public Service Commission (PSC) reviewed the impacts on land use, air quality, and water quality in their decision. The PSC also considered the zero air emission nature of nuclear power in it decision.

[eeee] For more information on history of Watts Bar, see: https://www.tva.gov/Newsroom/Watts-Bar-2-Project

5.1.1.1 Properties

Based on our review of these decisions and the characteristics of nuclear power plants, the value streams nuclear plants might provide are summarized in Table 5.2. This list is intended to highlight the potential for nuclear plants to provide both positive and negative value to the power system either by remaining online or retiring. The value associated with some properties will differ significantly depending on the system in which the power plants operate.

Table 5.2. Selected System (Sub-) Properties for Existing Nuclear Generation Facility

System Property	Subproperties
Affordability	Variable cost (low) Fixed O&M cost and capital expenditures (high) Emission cost where relevant (low)
Reliability	Availability, including fuel supply (high) Outage length (long)
Flexibility	Nuclear fuel costs (stable) Restart times (long)
Security	Physical and cyber-attack vulnerability (low)
Resiliency	Resilient to natural disasters (high)
Sustainability	Air emissions, including CO_2 (none) Cooling water requirements (large) Nuclear waste storage and/or disposal requirements (high)

Affordability

Market trends, including low natural gas prices, the entry of renewables, and low load growth, have threatened the economics of nuclear power plants.[110,ffff] The cost of retaining a nuclear unit in a regulated portfolio may not be very large and may be well worth the cost from a public perspective of a regulated utility. Exelon estimates that $6/MWh is required to keep a nuclear power plant from retiring in Illinois.[111] That is about $47 million per year for a 1,000 MW nuclear unit.

Several states, including New York and Illinois, have been considering ways to provide additional support to at-risk nuclear power plants. Both states have considered or proposed a Clean Energy Standard that mandates a percentage of energy be procured from zero-GHG–emitting technologies, including renewables and nuclear. These types of standards increase the value of a merchant nuclear plant by providing a revenue stream akin to renewable energy certificates (RECS) from an RPS policy.

The primary value drivers that are discussed for keeping the New York and Illinois units in operation include the impacts on the local economy and the increase in GHG emissions that will result from the loss of nuclear generation. For example, New York Governor Andrew Cuomo noted in a statement the potential for the closing of FitzPatrick to have significant impacts on the local economy.[112]

[ffff] Comments of the Nuclear Energy Institute, Prepared for FERC, Settlement Intervals and Shortage Pricing In Markets Operated by Regional Transmission Organizations and Independent System Operators, Docket No. RM15-24-000.

Sustainability

The lack of carbon emissions is almost universally recognized as a valuable property of nuclear power, but this property of nuclear generation as noted above is only monetized in California and the Regional Greenhouse Gas Initiative (RGGI) states. It is one of the key factors that distinguishes nuclear technology from all other technologies: zero carbon (for the electricity generation), dispatchable, and scalable to the desired megawatt level .[gggg]

Security, Resiliency, Flexibility and Reliability

These properties are rarely considered explicitly. Flexibility would be indirectly included in an IRP that looks at carbon and gas price scenarios, because its presence would reduce variation in production cost results.

5.1.1.2 Observations

Nuclear power's value as a large source of zero-emission, low variable cost power is universally recognized. Nuclear power's challenge is the high fixed costs associated with nuclear operations. Merchant owners seek profits from markets, and while they recognize the importance of nuclear power's sustainability benefits, those benefits are only priced in the Northeast RGGI States and in California. The EPA's Clean Power Plan (now stayed) may provide additional wholesale price support in many states if it is implemented.

Merchant owners value the reliability of nuclear power plants. The low outage rates and hence high output helps offset the high fixed costs.

Some of the power plant retirements we have seen were likely inevitable due to the high cost of repair, but the trend for merchant-owned units is becoming clearer. With low gas prices that are keeping wholesale prices down, and a general expectation that this pattern will continue, merchant owners with high fixed costs will be facing difficult decisions.

Nuclear power stations owned by regulated utilities can be, and often are, evaluated using a broader set metrics than those explicitly valued in existing wholesale markets, specifically affordability and reliability. Sustainability and flexibility are also considered. These stations do not have to "make a profit" for their costs have to be commensurate with the other value streams that they provide. For this reason, it does not appear that the regulated fleet of nuclear power plants faces the same bleak future as the merchant fleet.

5.2 Valuation Gaps for Energy Storage

Driven by RPSs established in 29 of the nation's states plus Washington D.C. and three U.S. Territories, the total contribution of renewable resources to the electricity generation portfolio in the United States is expected to grow substantially in the 2015 to 2025 time frame. The President's clean energy goals of achieving an economy-wide GHG reduction of 80% by 2050 will require further accelerated deployment of renewable energy resources. The current and projected increase of these sources will necessitate the

[gggg] Wind and solar are variable and have limited potential depending on local wind regimes and insolation. Nuclear however must be built in relatively large facilities to be economic, as noted above.

deployment of technologies that can address renewable variability in an environmentally sustainable fashion. Energy storage could provide additional flexibility to grid operations as more variable, renewable energy technologies are integrated into the grid.

Energy storage includes a suite of technologies that have the potential for deployment to assist the increasing penetration of renewable resources. The technologies show promise but it remains difficult to quantify or capture the benefits that energy storage systems (ESSs) may provide. This section defines the services ESSs provide, the shortcomings in existing valuation methods and markets, and finally, it evaluates how the attributes of energy storage fit into the proposed valuation framework.

Energy storage has a number of attributes that collectively differentiate it from traditional forms of power generation. Its capacity to provide distributed, highly responsive energy means it can address the flexible operations required to integrate renewables and increase grid reliability. Among the characteristics that drive the value of ESSs are the following:

- the capacity to act as both generation and load;
- the ability to provide benefits at the transmission, distribution, and customer levels;
- the ability to be housed in mobile units and moved between sites to address specific system needs, such as avoiding customer interruptions during extended maintenance operations, or deferring investment in distribution assets;
- the capacity to be more effective than conventional generation in meeting ramping requirements and responding to regulation signals at the sub-second level[113];
- the modular nature of energy storage, which allows it to scale up as needed to reduce the risk and present value costs of investments; and
- the capability to avoid startups of least-efficient peaking plants.

Existing production cost and capacity expansion tools fail to provide a complete and accurate characterization of the potential values that storage can provide. Further, control strategies that can be integrated into grid operational software and supervisory control of the storage unit exist in limited form. The lack of knowledge on the part of utilities, system operators, legislators, and regulators about the technical capabilities of energy storage is still a significant barrier.

The lack of knowledge about energy storage causes faulty modeling of the value of energy storage capabilities and an incomplete assessment of its capabilities. By not including all of the capabilities of energy storage, nearly all utility models underestimate the potential value streams, which dampen investment. Underinvestment in energy storage due to an inability to fully account for the services it provides can lead to sub-optimal outcomes during the resource planning process. For example, some models do provide 5-minute capabilities in tracking energy storage output, but even that level of detail undervalues the ability of energy storage to provide services at the second or even sub-second level.[hhhh] No models are currently capable of evaluating the full range of values described in the next section and performing a co-optimization routine to maximize the value provided by each service. As explored in Section 5.2.1, markets often fail to fully reward energy storage operators even when value is well defined.

[hhhh] KEMA in a study performed for the California Energy Commission found that fast (10 MW per second) storage was two to three times more effective than traditional generation at meeting ramping requirements. Thus, 10 MW of fast-ramping energy storage could provide as much ramping service as 20-30 MW of traditional generators. Fast response can arrest frequency excursions much more effectively, thus requiring less resources than more slowly responding generators.

5.2.1 Energy Storage Valuation Properties and the Capacity of Existing Tools and Markets to Capture Them

Energy storage can provide an extensive set of values, which can have differing purposes, affect varying locations within the grid topology, benefit multiple parties, and be subject to varying rules, requirements, and capabilities to capture them. In many cases, these services must be co-optimized in a manner that accounts for the fact that at any given time, an ESS cannot provide all services to all parties.

Services offered by ESSs can be placed into five categories:

- transmission services (transmission congestion relief and transmission deferral);
- bulk energy services (capacity and arbitrage);
- ancillary services (regulation services, spin/non-spin reserves, voltage support, , and black start service);
- distribution services (distribution deferral, volt/var control); and
- customer services (power reliability, time-of-use charge reduction and demand charge reduction).

This list is by no means comprehensive; however, it captures the bulk of the values highlighted in the literature reviewed for this study.

A definition for each of the primary values assigned to energy storage is presented in Table 5.3. Defined values for each of these services are presented later in this report, followed by a discussion of how energy storage values fit into the six properties present in the proposed valuation framework.

Table 5.3. Services Provided by ESSs[114]

Service	Value
Energy arbitrage	Trading in the wholesale energy markets by buying energy during off-peak low-price periods and selling it during peak high-price periods.
Regulation	An ESS operator responds to an area control error in order to provide a corrective response to all or a segment portion of a control area.
Spin/Non-spin Reserve	Spinning reserve represents capacity that is online and capable of synchronizing to the grid within 10 minutes. Non-spin reserve is offline generation capable of being brought onto the grid and synchronized to it within 30 minutes.
Voltage Support	Voltage support consists of providing reactive power onto the grid in order to maintain a desired voltage level.
Black Start Service	Black start service is the ability of a generating unit to start without an outside electrical supply. Black start service is necessary to help ensure the reliable restoration of the grid following a blackout.
Capacity	The ESS is dispatched during peak demand events to supply energy and shave peak energy demand. The ESS reduces the need for new peaking power plants.
Distribution Upgrade Deferral	Use of an ESS to reduce loading on a specific portion of the distribution system, thus delaying the need to upgrade the distribution system to accommodate load growth or regulate voltage.
Transmission Congestion Relief	Use of an ESS to store energy when the transmission system is uncongested and provide relief during hours of high congestion.

Service	Value
Transmission Upgrade Deferral	Use of an ESS to reduce loading on a specific portion of the transmission system, thus delaying the need to upgrade the transmission system to accommodate load growth or regulate voltage.
Power Reliability	Power reliability refers to the use of an ESS to reduce or eliminate power outages to customers.
Time-of-Use Charge Reduction	Reducing customer charges for electric energy when the price is specific to the time (season, day of week, time-of-day) when the energy is purchased.
Demand Charge Reduction	Use of an ESS to reduce the maximum power draw by electric load.
Source: Akhil et al. 2015.	

Fitzgerald et al. reviewed a broad range of literature in an attempt to understand the value of services offered by energy storage across the United States.[115]

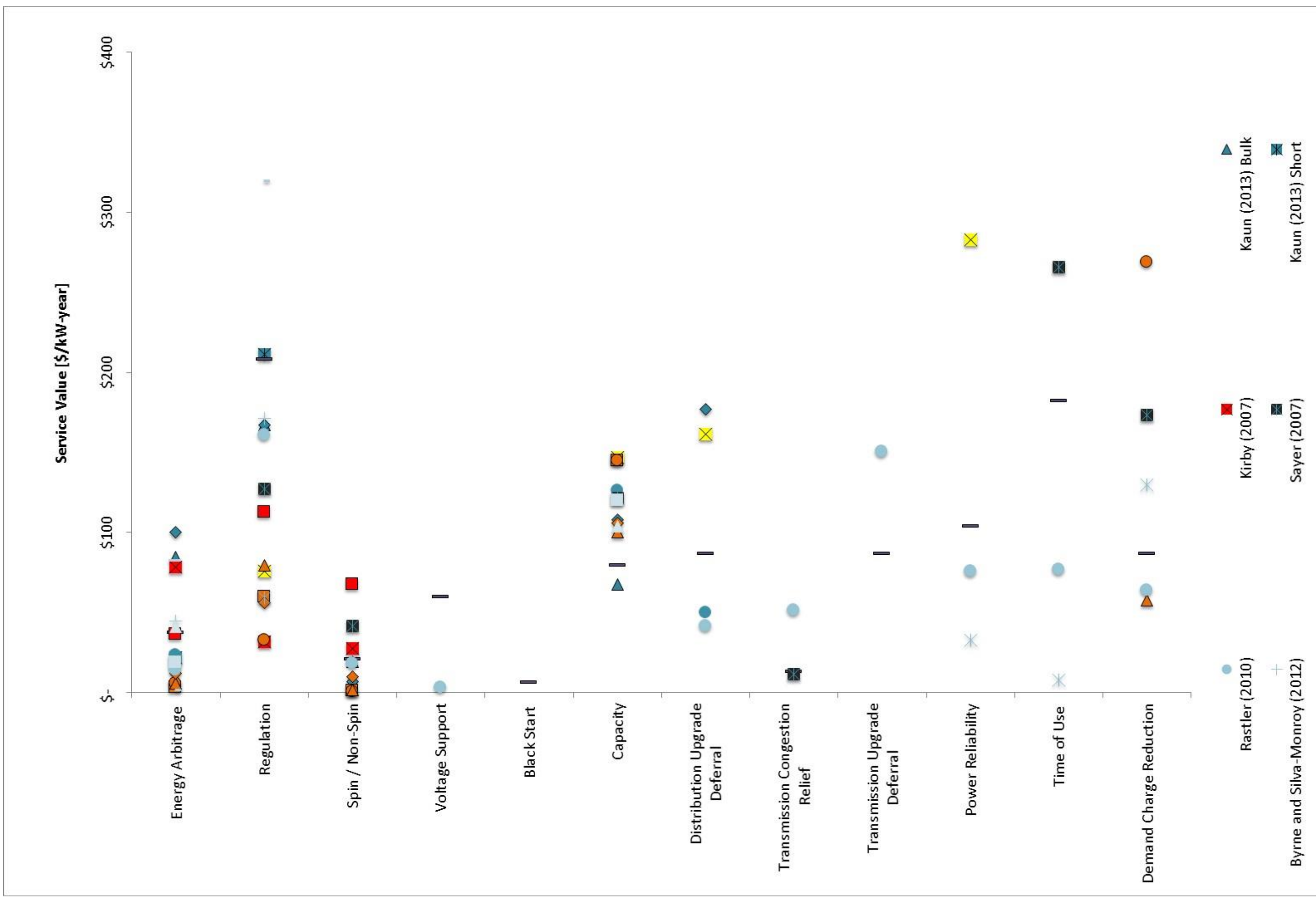

Figure5.1 documents the results of numerous energy storage valuation studies conducted within the past 10 years. The values estimated for each service, which are tied to market revenue or avoided costs, were modeled by the various research teams. In many cases, these values are not well understood within the region or captured through a market or ratemaking process. Grid-scale energy storage technologies are

not mature, and there is no consensus on the full range of values they offer or how to define them. The following should be noted:

- All values have been transformed into the dollars per kilowatt-hour per year ($/kW-yr) metric. Thus, if a 1 MW system generates a value of $50/kW-yr for arbitrage, its operator could expect to receive $50,000 in annual arbitrage revenue. In many cases, these values were not present in the literature; but with the total value of the service, the economic life of the battery system, the scale of the battery system and the discount rate, the value could be calculated.
- All values were adjusted for inflation using the Producer Price Index for Electric Power Generation, Transmission, and Distribution.[116]

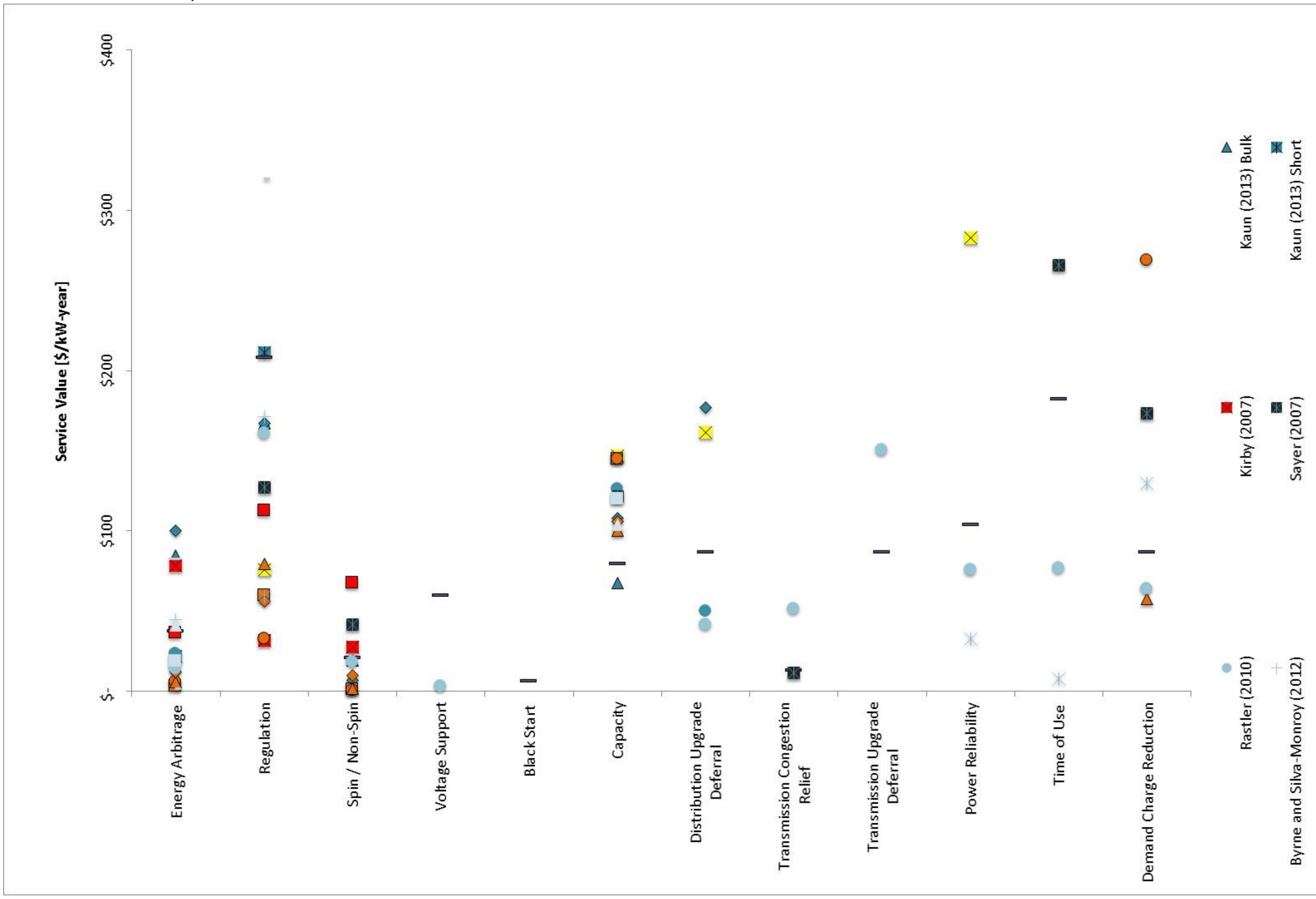

Figure5.1 is based on a chart originally generated by the Rocky Mountain Institute (RMI). PNNL built several additional references into the database and adjusted all values for inflation.[117, 118, 119, 120, 121, 122, 123, 124] All of the referenced documents, including those evaluated by both PNNL and RMI, are summarized

in

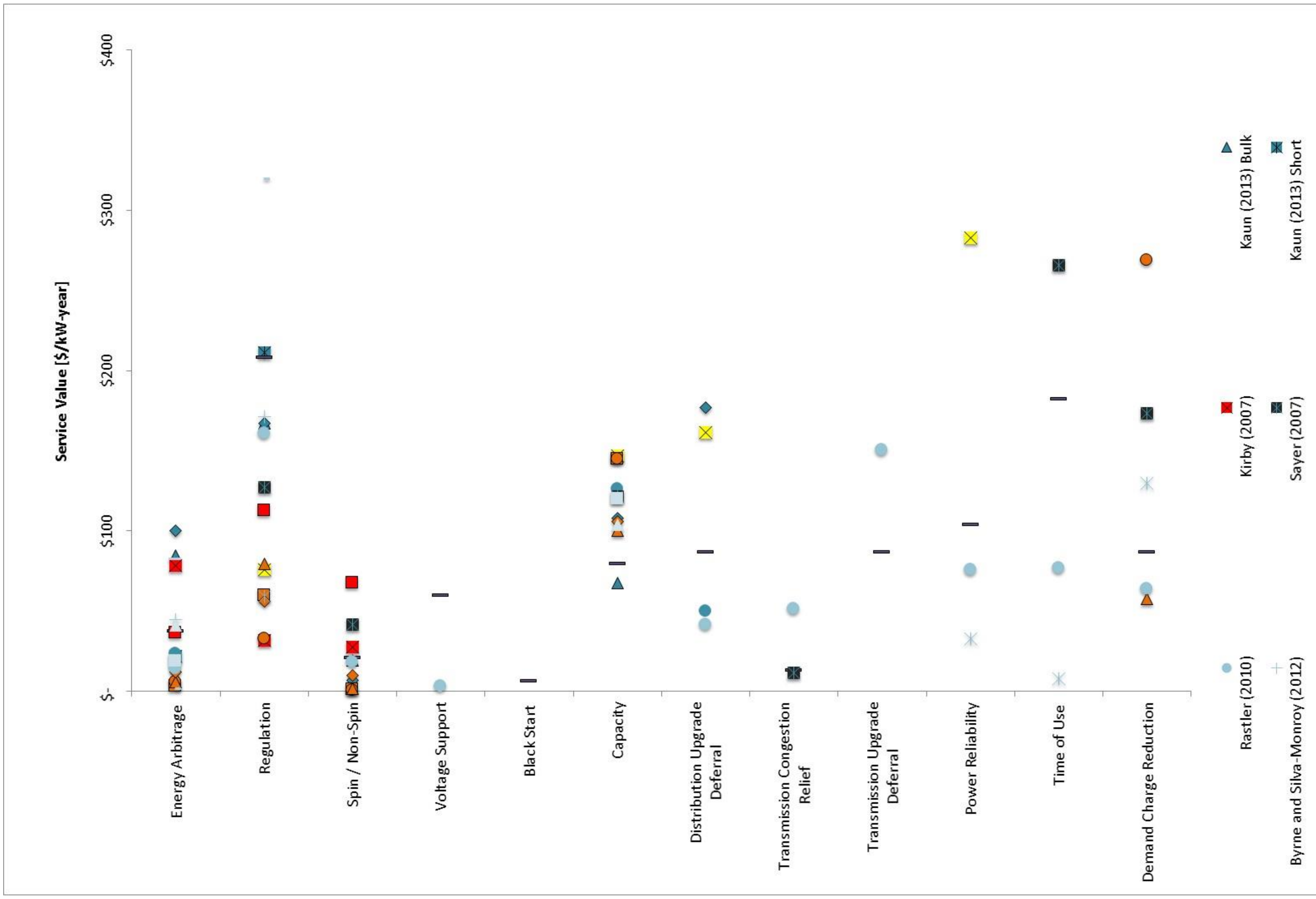

Figure5.1.

The studies capture a broad array of values and cover many regions throughout the United States. The results show that the modeled value varies widely between markets and regions. Also, the techniques used to assign values to these services differed between analysts, thereby affecting study results. Where markets exist (e.g., California, Texas), value for services traded in those markets (e.g., energy arbitrage, regulation services, spin/non-spin reserve) were derived from market transactions. For regulated utilities operating outside of organized markets, costs are estimated based on the cost avoided through the use of energy storage. For example, energy storage could be used to avoid an incremental cost of a peaking combustion turbine.

With all the limitations inherent in existing valuation methodologies, along with the challenges in demonstrating and capturing value in regulated and structured markets, a revised framework could be required to fully characterize the value of energy storage. Table 5.4 presents a qualitative assessment of energy storage values within the framework established in this report. The table includes both positive and negative values for energy storage in relation to other generation assets. The value streams noted in the table are neither quantified nor prioritized. The remainder of this section discusses these values and the ability of existing models and markets to realize them.

Source: Adapted from Fitzgerald et al. (2015).[125]

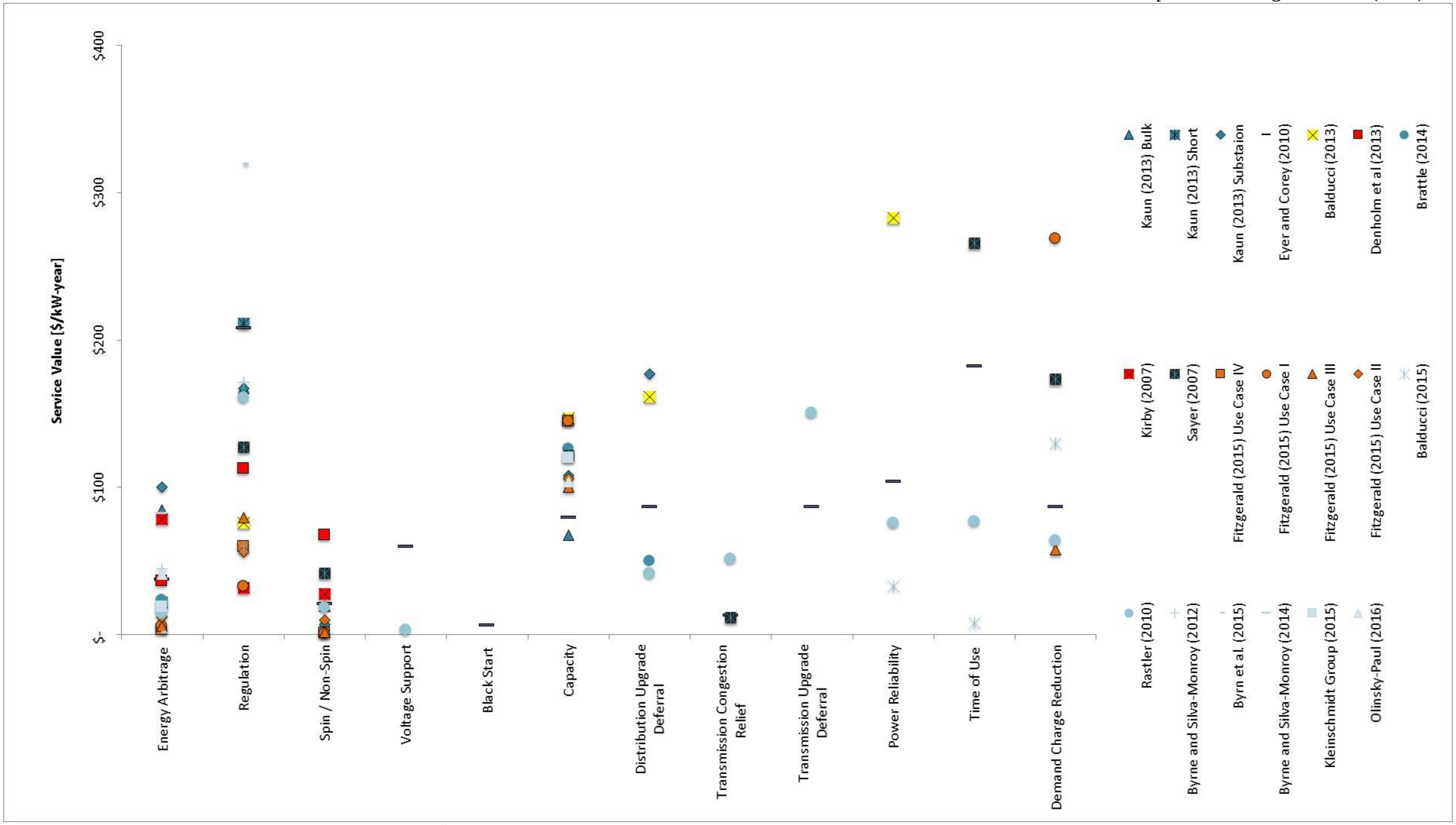

Figure5.1. Estimated Value of Services Provided by Energy Storage

Table 5.4. Summary of Value Streams from ESSs

System Property	Impact of ESSs	
	Positive	Negative
Affordability	• Low variable costs (+) • Behind-meter placements enable reductions in energy and demand charges to commercial and industrial customers, and can be used to manage load (+)	• High capital costs (-) • Lack of industry-approved architecture and control systems (-) • Low manufacturing readiness levels for many energy storage technologies (-)
Reliability	• Placement near end of feeders enables mitigation of outages in remote areas (+) • Voltage regulation and power factor correction limits the conditions that cause disturbances in the energy delivery systems (+)	• Challenges in siting, sizing, and controlling ESSs (-) • Limited energy content (-)
Flexibility	• Capacity to act as both generation and load (+) • Housing in mobile units enables energy storage to be moved between sites to address specific system needs (+) • Ability to be co-located with variable wind resources in order to avoid curtailment (+)	
Security	• Energy storage in microgrid settings can be used to island and isolate critical loads at U.S. military bases and other sensitive government and industrial sites (+)	
Resiliency	• Provides black start capability and can serve as backup generation in an islanded mode (+) • The ability to respond to frequency excursions at the sub-second level makes energy storage effective at responding to imbalances between generation and load (+)	
Sustainability	• The capacity to avoid startups of least-efficient peaking plants (+) • The ability to be more effective than conventional generation in meeting ramping requirements enables renewables integration (+)	• Production of hazardous waste in the development of battery systems (-)

5.2.1.1 Affordability

The high cost of installed energy storage presents the primary barrier to expansion. Table 5.5 presents a summary of cost and performance characteristics for energy storage technologies capable of providing the flexible resources necessary for extensive renewables integration. On a scale of 9, battery systems have achieved technology readiness levels of 7 (system prototype demonstration in an operational environment) to 8 (actual system completed and qualified through test and demonstration). Manufacturing readiness levels are lower, ranging from 6 (capability to produce or prototype system or subsystem in a production relevant environment) to 7 (capability to produce systems, subsystems or components in a production representative environment). The capital costs for battery systems presented in this table include 2011 values and costs forecast out to 2020. Variable costs are relatively low for energy storage systems.[126]

The capital cost reductions forecast below appear to be reasonable given recent industry advancements. Lithium-ion (Li-ion) battery systems, for example, have experienced sharp declines in costs in recent years. Li-ion battery systems available in the consumer marketplace have reduced in cost from $1,000/kWh in 2008 to $250/kWh in 2015. In 2015, grid-scale battery system costs reached as low as $550–$600.[127] Market penetration of electric vehicle and plug-in hybrid electric vehicles has increased Li-ion battery production and driven down costs in the process.

Table 5.5. Summary of Capital and O&M Costs for Technologies Analyzed. Note values are representative for 2011 technologies. 2020 values are in parentheses.

Parameter	Na-S Battery	Li-ion Battery	Pumped Hydro	CAES	Flywheel	Redox Flow Battery
Technology Readiness Level	8	8	9	8	8	7
Manufacturing Readiness Level (MRL)	6	7	7	7	5	6
Battery Capital Cost $/kWh(a)	415(290)	1,000 (510)	10	3	148 (115)	215 (131)
System Capital Cost $/kW			1,750 (1,890)	1,000 (850)	1,277 (610)	1,111 (775)
Power Conditioning System (PCS) ($/kW)	220 (150)	220 (150)				220 (150)
Balance of plant ($/kW)	85 (50)	85 (50)			85 (50)	85 (50)
O&M Fixed $/kW-year	3	3	4.6	7	18	39.5 (5)
O&M Fixed $/kW-year (PCS)	2	2				2
O&M Variable cents/kWh	0.7	0.7	0.4	0.3	0.1	0.1
Round Trip Efficiency	0.78	0.85	0.81	0.50	0.85	0.75

(a) The battery capital cost is per unit energy, while PCS and BOP costs are per unit power.

Adapted from Viswanathan et al. (2013)[128].

The costs detailed in Table 5.5 do not include those associated with siting, civil/engineering, information technology (IT), integration, interconnection, land, and other costs common to utility investments.

While the costs of ESSs are significant, the results derived from the reviewed studies suggest that by stacking value streams present at five points in the grid, energy storage when fully valued can be cost-effective. The reviewed studies found that energy storage sited down in the distribution system, capturing value at both the transmission and distribution levels, generated the highest level of benefits. Bulk power and transmission services such as arbitrage, black start, and transmission congestion relief are of a relatively lower value. The highest-value applications are in retail services (e.g., energy charge reductions, demand charge reductions), which represent the full cost of providing energy to customers. Other services (e.g., transmission congestion, voltage support) typically represent only one component of providing energy to customers. While these values are significant, there are a number of technological, market and regulatory barriers to realizing them.

The energy-limited nature of energy storage and the challenges associated with integrating it into existing asset management systems and controlling it to maximize the value derived from the services it provides also complicate the process of defining value and demonstrating that value to customers and utility commissioners. Further, the lack of an industry-approved architecture results in higher costs associated with one-off deployments.

5.2.1.2 Reliability

ESSs provide several services that improve grid reliability. They can be used to shave peaks, thereby managing system-wide and local resource adequacy requirements. ESS management of voltage regulation and power factor correction at the feeder level limits the conditions that cause grid disturbances. By siting energy storage near the end of a long rural feeder, energy storage can limit customer outages. The value of power reliability to customers in the literature reviewed for this study reached as high $273/kW-yr for a study of energy storage sited on an island near Seattle, Washington.[129]

The ability to realize these benefits is limited by the utility's capacity to effectively site, size, and control the ESS. Presently, models and grid-ready tools designed to perform these functions are at a nascent stage of development.

Organized markets do not monetize the ability of distributed energy storage to mitigate outages within the distribution system. Further, in regulated markets with vertically integrated IOUs, investments in energy assets, including energy storage, must be demonstrably cost-efficient. Energy storage value in these cases is largely defined in terms of avoided costs to the utility and not to the customer. Thus, customer interruption costs would not be monetized in the IRP process.

5.2.1.3 Flexibility

ESSs are extremely effective at increasing flexibility within the electrical grid. Their capacity to act as both generation and load, combined with their ability to respond to sub-second level regulation signals, makes them far more effective than conventional generation assets at providing balancing services and meeting ramping requirements.[130] ESSs are also mobile and modular, which reduces the risk associated with overinvestment in utility assets.

In recognition of the fast-ramping capability of energy storage, the CPUC in 2013 issued an order as required by AB 2514 with energy storage procurement targets for each of the three IOUs operating in the state. The decision specified certain capacity targets in 2014, 2016, 2018, and 2020. Procurement goals, which totaled 1.325 GW of energy storage capacity by 2020, included placement-based targets for systems placed behind the meter and within the distribution and transmission systems. The State of New York has also set procurement goals through a 100 MW load reduction program that includes EE, energy storage, and DR measures.

Within organized wholesale energy markets, energy storage can generate revenue by providing energy and ancillary services (e.g., frequency regulation, operating, and contingency reserves). These ancillary services expand flexibility in the grid. Ancillary services markets, however, present challenges to energy storage in that they are designed around the concept that these services are in addition to the principal objective of supplying energy. Energy storage, however, does not have a primary mission in the form of wholesale energy delivery. Without this primary revenue source or an opportunity cost to define price, energy storage designed to engage in ancillary service markets is in a challenging position vis-à-vis traditional generators, and can struggle to recover high investment costs. Resources with high fixed costs such as energy storage do not function well in marginal cost markets.[131] Recent FERC orders have served to level the playing field for energy storage in frequency regulation markets but challenges remain for other services.

At the transmission level, two FERC Orders address the market design of certain grid services (e.g., frequency regulations) that ESSs are well suited to provide. FERC Order 784 requires transmission providers to consider both speed and accuracy in the determination of regulation and frequency responses requirements, and FERC Order 755 ensures that providers of frequency regulation are paid just and reasonable rates based on system performance. In providing frequency regulation, organizations are required to include both a capacity payment that considers the marginal unit's opportunity cost and a pay for performance based on the mileage or the sum of the up and down signal followed by the provider.[132]

The first RTO or ISO to implement FERC Order 755 was the PJM in October of 2012. Other organizations that have implemented the ruling include the MISO in December 2012, CAISO in 2013, NYISO in June 2013, and ISO-NE in January 2014. While these FERC Orders have served to open up ancillary service markets to energy storage, their implementation has been inconsistent across the United States. Table 5.6 summarizes select market features in U.S. ISOs[133]. Note that ERCOT is not under FERC jurisdiction.

Table 5.6. Summary of Select Market Features in U.S. RTOs/ISOs

Service	RTO/ISO					
	PJM	MISO	CAISO	NY ISO	ISO-NE	ERCOT
Capacity Payment	Yes	Yes	Yes	Yes	Yes	No
Mileage Payment	Yes	Yes	Yes	Yes	Yes	Yes
Accuracy Payment	No	No	Yes	Yes	No	No
Basis of Mileage Payments	DA and real-time	Real-time	DA and real-time			

Mileage payments, which are tied to the energy absorbed into or discharged from the ESSs while following up and down frequency regulation signals, have fallen short of capacity payments and over time have fallen as market entrants have expanded. Thus, the competitive advantage for storage tied to its ability to provide energy quickly and accurately has declined over time. Byrne and Silva-Monroy estimated a significant drop in revenue potential to ESSs engaged in arbitrage and regulation in the ERCOT region over multiple years.[134] This condition could be reversed if the in-flow of market entrants slows due to declining profits and/or renewable integration capacity comes on line in the next decade, driving the need for more regulation services.

5.2.1.4 Security

Energy storage in microgrid settings can be used to island and isolate critical loads at U.S. military bases, hospitals, emergency shelters, and other sensitive government and industrial sites. Hurricane Sandy left thousands of customers in the northeastern United States without power for several days, leading to the development of storm-hardening plans in New Jersey and consideration of storm-hardening strategies across the nation. Microgrids, including energy storage, are one proposed storm-hardening strategy in the National Electrical Manufacturers Association's 2012 publication, After the Storm: Strategies for Reducing the Impact of Power Outages through a Stronger Smarter Electric Grid.[135] Energy security, however, is not directly compensated for in any market.

5.2.1.5 Resiliency

The ability of energy assets, including storage to black start without an outside electrical supply, is necessary to ensure the reliable restoration of the grid following a blackout. However, the lack of markets for black start, governor response, inertial response, and reactive power is a barrier to investment recovery by energy storage. Energy storage is fully capable of meeting the requirements for each of these services but in the case of black start and reactive power, each is paid at low FERC-approved cost of service rates. The lone report reviewed for this study that estimated the value of black start capabilities placed the value at a low $6/kW-yr.[136]

5.2.1.6 Sustainability

Energy storage has the capacity to reduce emissions by avoided startups of least-efficient peaking plants and by cost effectively integrating renewables. The National Energy Storage Assessment for Grid Balancing and Arbitrage conducted by PNNL in 2012 defined the future balancing requirements necessary to accommodate enhanced wind generation capacity under a hypothetical nationwide 20 percent RPS in 2020. It evaluated several technology options for meeting additional intra-hour balancing requirements and concluded that several storage technologies (sodium-sulfur, flywheels, and pumped storage) were cost-competitive with combustion turbines today, while Li-ion and redox flow batteries were likely to be cost competitive by 2020.[137]

The capacity for energy storage to reduce CO_2 emissions by avoiding wind energy curtailment and integrating PV can be monetized in regions with CO_2 emissions caps as avoided production costs from least-efficient fossil fuel generators. Valuation, however, depends on the capacity of existing models to define this value. As noted in the section covering valuation gaps in the retirement of nuclear power plants, all of the IRPs reviewed for this study track CO_2 emissions, which implies that CO_2 reductions are of value to regulatory bodies. In regions without CO_2 emissions caps, energy storage is not compensated for its capacity to aid in renewable integration.

5.2.2 Observations

Section 5.0 highlighted a number of services provided by energy storage, many of which are not captured within existing market structures. Further, production cost and capacity expansion models used in the development of IRPs do not recognize or monetize the distribution-level values associated with energy storage, including reduced energy losses and improved power quality for distribution feeders, deferral of distribution investments, or PV technology integration. The magnitude of the gap in these models differs by location. Uneven treatment of energy storage in the marketplace and within existing IRP frameworks makes it a challenge for storage developers and utilities to invest in storage technologies.

Organized markets and IRPs also often fail to monetize the ability of distributed energy storage to improve grid security and resiliency. Resiliency was not mentioned in any of the regulatory proceedings reviewed for this study. The lack of models and markets for valuing outage mitigation, governor response, inertial response, and reactive power places energy storage at a competitive disadvantage.

ESSs are mobile and modular, which reduces the risk and uncertainty associated with overinvestment of utility assets. This risk avoidance measure is not captured in the resource planning process.

Time-of-use rate structures could incentivize investment in ESSs used to shift load in order to minimize demand charges. Further, rules limiting behind-the-meter energy storage participation in regional energy markets through aggregation serve as a barrier to energy storage adoption.

The capacity for energy storage to reduce CO_2 emissions by avoiding wind energy curtailment and integrating PV technologies can be monetized in regions with CO_2 emissions caps as avoided production costs from least-efficient fossil fuel generators. In regions without CO_2 emissions caps, energy storage is not compensated for its capacity to aid in renewable integration.

6.0 Conclusions

Valuation in the electric utility sector has been performed for many decades. It was generally referred to as cost-benefit analysis that explored the cost relative to the benefits of new and conventional technologies and services in various planning activities, including RA analysis, IRP, transmission planning, and more recently, DRP. While adequate for the time, new disruptive technologies and greater emphasis on reliability and resilience in response to severe weather events, environmental impacts, as well as transparency of the entire analysis render the current processes insufficient.

Our analysis reveals the following key insights:

1. Valuation has to be done in a system context. The value of a single technology or grid asset to be deployed, can only be estimated by how it improves or impacts the system behavior as a function of time. Estimating value can be done either by a marginal analysis, in which the technology is a price taker, or by performing a system analysis that explores and considers system responses as a consequence of deploying a grid asset. The former approach is used for profitability assessments of a project or a technology, the latter usually attempts to estimate a broader set of value streams.
2. Six categories of system properties were defined as well as a generic valuation approach by which a wide range of technologies, services, and policy options can be valued comprehensively. The depth and breadth of the valuation approach depends on the stakeholder, the intervention (technology, services, or policy option) to be valued, resources available for the analysis, and the set of questions to be explored. Valuations may be very targeted, focusing only on profitability objectives of merchant generators, or they may be structured more comprehensively and holistically by considering all of the six categories of system properties and their impacts on them.
3. We introduced the concept of a "hypothetical social planner", who would evaluate any intervention or changes to the electric infrastructure from a viewpoint of total societal value creation. Such a framework, while challenging, could enable a more explicit, transparent, and overall holistic consideration of values, and thus, foster a more comprehensive tradeoff analysis than decision makers typically face. By taking the position of a social planner, we are trying to take a neutral standpoint in order to focus on considering all of the stakeholders' and consumers' interests, so that the valuation framework can be used as a starting point by any stakeholder or interest group.
4. We did not include equity as one of the six properties. Equity is an important consideration for policy makers and regulators requiring an understanding to whom value in the system accrues, and whether that apportionment of value is fair or desirable. Equity is generally considered at a more granular scale than the system-wide level we describe in this document. Of course, changes to the system will have heterogeneous impacts on different stakeholders and may increase net benefits for some but decrease them for others. Examples include retail rates that differ by customer class or health or land impacts that may be highly localized. Similarly, customers will not all derive the same value from increased reliability and the other properties. The extent to which each property affects or is valued by individual (or classes of) ratepayers requires further evaluation than the system-wide analysis completed for this study.
5. The review of IRPs, transmission planning processes, RTO markets, and DRP processes revealed that planners and regulators account for several properties, the most prominent and detailed being reliability and affordability. Planning processes are often tailored to specific objectives and thus limited by several factors:
   - Scope of resource may be limited due to narrow planning objectives. For example, transmission upgrades are rarely considered in integrated resource planning

- Range of future scenarios may be limited to a 'business as usual' view of the world foregoing new control paradigms and emerging technologies
- Scope of properties considered may be limited to tradeoffs between few properties or narrow view of properties because of jurisdictional limitations, within which a regulator can make decisions.

Some IRPs and regional transmission planning entities consider operational and planning flexibility as an important value. In our analysis, security was rarely accounted for as a value in any of the planning processes. This may be due to the fact that there are company-level compliance requirements, at least on the cyber security side. Accounting for resilience as a value was not found to be explicitly considered in any of the planning processes. However, references to the desire to improve resilience in response to the extreme weather phenomena were found.

The compartmentalization of different planning processes may limit the overall optimality of the process (and thus overall system value may not be maximized), although several explanations may make a fully integrated process unrealistic. First, integrating distributed resource planning, transmission planning, and distribution planning into the traditional IRP process faces technical hurdles. Second, the exclusion of a technology or sector from an IRP process may often be the result of the defined jurisdiction of an IRP, and is not necessarily an indication that the IRP or the state requirements for the IRP are defective. This lack of control extends to customer decisions as well; in the case of EE and DR.

6. Value is sometimes captured in market-based pricing of services rendered. In areas without competitive wholesale markets, value is sometimes monetized by avoided cost principles via regulatory constructs in order to meet a set of standards or technical requirements. Safety and reliability standards and environmental requirements are most often fixed design criteria, with which the transmission and distribution planners must comply. Setting and developing standards underlie valuation principles based on loss of life and loss of load, but are outside the scope of this work. For this analysis, meeting any technical requirement can be valued as a shadow price of delivering electric services.
7. The detailed case studies revealed the following insights:
    a. Retirement of nuclear power plants – We are in a period of significant nuclear retirements, while at the same time the first new units are being constructed in several decades. Some retirements are due to mechanical failures that are very expensive to fix. Other retirements are due to current and near-term projected poor market conditions. The unique and most important characteristics of a nuclear power plant are its zero air emissions (from electricity generation), low variable cost, and high output. However, nuclear plants have less desirable features, including high capital cost, safety concerns regarding the entire fuel cycle, and limited operational flexibility. The problem facing nuclear power is that outside of California and the northeastern RGGI states, nuclear technology's lack of carbon emissions has no explicit value: merchant owners receive no compensation for that value. In states with vertically integrated utilities, the state can recognize the value of nuclear power from a public perspective. The fundamental valuation problem is one of private investment (merchant generators) versus public investment (the long-term benefit of retaining nuclear power).
    b. Distributed energy storage – Energy storage has been recognized as a resource with desirable characteristics and features for future grid operations under high penetration of variable production renewable generation, such as wind and solar generation resources. However, in only a few instances are several features being valued. The most notable instances in which energy storage systems are valued include frequency regulations markets developed in response to FERC Order No. 755 (pay for performance), which was motivated by unfair

treatment of fast-responding grid assets for the provision of frequency regulation services in ISO/RTO markets, and the California Energy Storage Procurement targets of 1.325 GW, where the California Legislature recognized the intrinsic value of storage as a mitigation strategy to accommodate the fluctuations in the generation from wind and solar capacity in the distribution system and the bulk power system..

We draw the following insights from the energy storage case study:

- Affordability – The affordability in this example is viewed from the perspective of the technology's economic viability. The capital costs associated with the advanced battery technology are relatively high due to the nascent stage of the industry's development. Recent forecasts indicate that these costs are expected to fall as production levels rise and the industry matures. While energy storage can provide a broad spectrum of services, challenges remain with integrating it into existing asset management systems and defining dispatch control methods designed to maximize value.
- Reliability – The value of energy storage as a reliability resource has been recognized for various applications. The challenge remains with how to identify optimal placement, control, and sizing of the storage system to reach an optimum tradeoff between reliability and cost.
- Flexibility – While FERC Order 755 attempted to level the playing field for energy storage in frequency regulation markets, uneven treatment of energy storage in terms of how flexibility services are recognized in the marketplace, the valuation framework used to determine the value of each service, and the rules that must be followed to engage in these markets persists.
- Security – Energy storage in microgrid settings can be used to island and isolate critical loads at U.S. military bases, hospitals, emergency shelters, and other sensitive government and industrial sites. Microgrids with energy storage are one proposed storm-hardening strategy employed throughout the United States, but the value of security is not well defined or directly compensated in any energy market.
- Resilience – Energy storage enhances resilience as a result of its black start capability, capacity to quickly respond to load-generation imbalances, and inclusion in microgrids. While resilience is of critical importance, the lack of markets for governor response, inertial response, and reactive power is a barrier to investment recovery by energy storage.
- Sustainability – Energy storage enhances the reduction of CO_2 emissions by avoiding wind energy curtailment and integrating PV technologies. The sustainability value can be monetized in regions with CO_2 emissions limits by estimating the avoided production costs from least-efficient fossil fuel generators. In regions without CO_2 emissions limits, energy storage is not compensated for its capacity to aid in renewable integration

8. Quantitative estimation of a comprehensive set of values of a new technology, service, or policy is predicated on the notion that one can first identify the value streams and then find appropriate tools and data to analyze the system impacts relative to a base case. In most cases, this requires quantitative system modeling capabilities, such as power flow modeling. As the desire to more comprehensive quantitative valuation increases, so must the modeling and analytics capabilities and data availability improve. For instance, quantifying the full resilience value of a DER resource as a mitigation strategy to long-term supply disruption lacks robust data of long-term VOLL for many customer classes. Similarly, the estimation of the avoided cost of restoration, given a certain threat scenario is difficult.

Improvement in the modeling and analytics would be necessary in order to estimate more comprehensively the total value of many distinct value streams. Improvements include:

a. Transmission-Distribution seam – There is a seam between distribution system planning and transmission planning tools. To bridge the gap such that distributed resources, behind or before the meter, can be visible and thus be valued in the transmission system requires linkages of two, independent modeling and simulations platforms (AC power flow modeling in transmission network and AC power flow modeling for distribution systems). Only when this gap is closed can we value certain behaviors of distribution assets (for instance, ride-through capabilities of a PV inverter) in the transmission system.

b. Generation-transmission seam – The IRP process does not generally consider many transmission alternatives in the scenario definition. Instead it focuses on generation capacity or RA. Transmission planners often consider a narrow range of benefits of new investments, including production cost savings and capacity value, but also flexibility and resilience. The tradeoff among different technology solutions along multiple values would provide greater insight into cost optimality or affordability values.

c. Multi-objective optimization tools – Most of the analytics tools have cost minimization as their objective. Aspects of flexibility and sustainability are often modeled as constraints to the cost-minimization scheme to meet changing or stricter compliance standards. However, there may be value in reformulating the problem as a multi-objective problem, in which the result is a solution space defined by measures of cost, flexibility, sustainability, and other properties. This, in turn, will require some decision support mechanism for decision makers to navigate through the solution space, in which the ranking of a technology solution is not a simple function of cost, but a function of several parameters.

7.0 Appendix – Current R&D Activities under DOE Grid Modernization Initiative

In January 2016, DOE announced significant funding in grid modernization.[138] Under this investment there are two distinct foundational programs that are directly relevant to valuation.[139]:

- Foundational Analysis for Grid Modernization Laboratory Consortium Establishment/Analysis. This project will establish methodologies to establish detailed metrics that are designed to measure progress in grid modernization. The metrics will cover the following range of system properties: reliability, resilience, flexibility, sustainability, affordability, and security. The outcome of this 3-year project will be a baseline of the metrics and several use case application of the metrics with regional partners.
- Grid Services and Technologies Valuation Framework Development. Over a period of 3 years, this project will develop and test a valuation framework that consists of a set of methodologies to quantify specific values that a broad stakeholder community will need for investing in modernizing the nation's electric infrastructure. This research will also work with regional partners to demonstrate the usefulness of the valuation framework development.

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