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Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects

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Final Report, January 2010

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PRODUCT DESCRIPTION

This report presents a comprehensive framework for estimating the benefits and costs of Smart Grid projects and a step-by-step approach for making these estimates. The framework identifies the basic categories of benefits, the beneficiaries of these benefits, and the Smart Grid functionalities that lead to different benefits and proposes ways to estimate these benefits, including their monetization. The report covers cost-effectiveness evaluation, uncertainty, and issues in estimating baseline conditions against which a project would be compared. The report also suggests metrics suitable for describing principal characteristics of a modern Smart Grid to which a project can contribute.

Results and Findings

This first section of the report presents background information on the motivation for the report and its purpose. Section 2 introduces the methodological framework, focusing on the definition of benefits and a sequential, logical process for estimating them. Beginning with the Smart Grid technologies and functions of a project, it maps these functions to the benefits they produce. Section 3 provides a hypothetical example to illustrate the approach. Section 4 describes each of the 10 steps in the approach. Section 5 covers issues related to estimating benefits of the Smart Grid. Section 6 summarizes the next steps.

Challenges and Objectives

The methods developed in this study will help improve future estimates—both retrospective and prospective—of the benefits of Smart Grid investments. These benefits, including those to consumers, society in general, and utilities, can then be weighed against the investments. Such methods would be useful in total resource cost tests and in societal versions of such tests. As such, the report will be of interest not only to electric utilities, but also to a broad constituency of stakeholders.

Applications, Value, and Use

Significant aspects of the methodology were used by the U.S. Department of Energy (DOE) to develop its methods for estimating the benefits and costs of its renewable and distributed systems integration demonstration projects as well as its Smart Grid Investment Grant projects and demonstration projects funded under the American Recovery and Reinvestment Act (ARRA).

Disclaimer: DOE’s use of parts of the methodology described in this report does not constitute an endorsement of this report. As experience is gained from these projects, the methodology is expected to be refined.

EPRI Perspective

The goal of this report, which was cofunded by the Electric Power Research Institute (EPRI) and DOE, is to present a comprehensive set of methods for estimating the benefits and costs of Smart Grid projects.

Disclaimer: By publishing this report, EPRI seeks to contribute to the development of methods that will establish the benefits associated with investments in Smart Grid technologies. EPRI does not endorse the contents of this report or make any representations as to the accuracy and appropriateness of its contents.

Approach

The purpose of this report is to present a methodological framework that will provide a standardized approach for estimating the benefits and costs of Smart Grid demonstration projects. The framework also has broader application to larger projects, such as those funded under the ARRA. Moreover, with additional development, it will provide the means for extrapolating the results of pilots and trials to at-scale investments in Smart Grid technologies. The framework was developed by a panel whose members provided a broad range of expertise.

Keywords

American Recovery and Reinvestment Act (ARRA)
Cost and benefit analysis
Demonstration projects
Functionality
Smart Grid
Smart Grid benefits
Smart Grid costs

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Stephen Kuznetsov of NETL and Bernard Neenan of EPRI provided extensive in-depth reviews of preliminary drafts of the report, which greatly improved it. Erik Gilbert of Summit Blue Consulting helped in editing one of the sections.

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BACKGROUND

1.1 Overview of the Report

This report describes a methodological approach to estimate the benefits and costs of Smart Grid based on data attained from Smart Grid field demonstration projects. It provides a basis for the further development of ideas and refinements, as well as for developing a computational tool based on the concepts in this report.

This first section of the report presents background information on the motivation for the report and its purpose. Section 2 introduces the methodological framework, focusing on the definition of “benefits” and on a sequential, logical process for estimating them. Beginning with the Smart Grid technologies and functions of a project, it maps these functions to the benefits they produce. Section 3 provides a hypothetical example to illustrate the approach. Section 4 describes each of the ten steps in the approach. Section 5 discusses issues related to estimating benefits of the Smart Grid. Section 6 summarizes the next steps.

1.2 Motivation to Develop Methodology to Estimate Cost and Benefits of Smart Grid

Although promoted for several years, the Smart Grid concept has recently surged more prominently into broader public view and lexicon. By “Smart Grid,” we mean the integrated array of technologies, devices and systems that provide and utilize digital information, communications and controls to optimize the efficient, reliable, safe and secure delivery of electricity.

The Smart Grid will, it is hoped, be transformational, applying advanced technologies to optimize the performance of the power system and to benefit consumers and society at large, as well as utilities. The Smart Grid will enable enhanced integration of synchronized phasor measurement units, high temperature superconductor cables, flexible AC transmission, advanced relay protection and high voltage DC at the transmission level, with advanced metering infrastructure, advanced sensors, automated reclosers, automated voltage/VAR control and substation energy storage at the distribution level, with home area networking, autonomous demand response, smart appliances, plug-in hybrid vehicles, distributed generation and integrated building controls at the consumption level.

Many expect that Smart Grid technologies will also bring added value through time-based (i.e., dynamic) pricing of electricity, third-party service providers (e.g., demand response), and other market innovations and services. In addition, the Smart Grid will enable greater deployment of distributed and renewable resources and technologies such as energy storage, and solar and wind energy, and plug-in hybrid vehicles. Some of the many descriptions of the vision of a Smart Grid include those by FERC (2009), Masiello/KEMA (2008) and the National Energy Technology Laboratory (NETL 2007a,b). A report by the National Energy Technology Laboratory (NETL 2007a) compiled many of the technologies which the Smart Grid will use. The technologies fall within five Key Technology Areas, as illustrated in Figure 1-1. IC in the figure stands for Integrated Communications, which provide the platform upon which the other four Key Technology Areas rest.

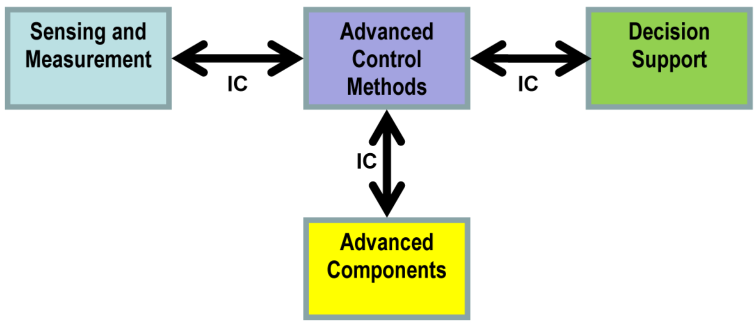

Figure 1-1
Interrelated Nature of Key Smart Grid Technology Areas

The national priority in supporting the development of the Smart Grid is reflected in Title XIII, "Smart Grid," of the Energy Independence and Security Act of 2007 (EISA), which set the goal of achieving a fully developed Smart Grid as a national policy. Following that priority, the U.S. Department of Energy (DOE) awarded contracts in 2008 to nine Smart Grid demonstration projects as part of its initiative to catalyze the build-out of the Smart Grid (DOE 2008a). These projects are listed in Table 1-1.[1]

[1] Appendix A has summaries of these projects. Eight of these projects were subsequently awarded additional funds in July 2009 through the American Recovery and Reinvestment Act.

Table 1-1
Renewable and Distributed Systems Integration (RDSI) – Smart Grid Demonstration Projects Awarded by DOE in 2008

Project Lead Organization	Demonstration Project	Benefits Described in Project Brief
Allegheny Power	Integration of distributed resources and advanced technologies.	Improve distribution system performance, reliability, and security of electric supply
ATK Launch Systems	Integrate renewable generation and energy storage resources, including compressed-air generation technology, wind-turbines, heat recovery systems, solar trough booster technology, a steam turbine, and hydro-turbine resources	Reduce load
Chevron Energy Solutions	Integrate solar energy, fuel cell, energy storage and control systems	Reduce peak load and measurably improve power reliability
City of Fort Collins	3.5 megawatt coordinated and integrated system of Mixed Distributed Resources	Achieve a 20-30 percent peak load reduction on multiple distribution feeders
Consolidated Edison Co.	Methodologies to achieve true interoperability between a delivery company and end-use retail electric customers	Enhance the reliability of the distribution grid and the efficiency of its operations
Illinois Institute of Technology	Distributed resources, advanced sensing, switching, feeder reconfiguration, and controls	Demonstrate that cost-effective power can be delivered to consumer precisely as the consumer requires it, without failure and without increasing costs
San Diego Gas and Electric	Dispatchable distribution feeder for peak load reduction and wind-farming	Improve stability and reduce peak loads on feeders/substations
University of Hawaii	Management of distribution system resources	Improved service quality and reliability, transmission congestion relief, and grid support functions
University of Nevada	Integrated photovoltaic systems, battery energy storage, and consumer products linked to advanced meters	Energy efficient homes that overcome electricity grid integration, control, and communications issues

A common objective of these projects is the reduction of peak demand for power; sharp peaks in power consumption result in inefficient, underutilization of electric system facilities. However, each project employs different Smart Grid technologies, devices and systems. Thus, to have a common basis for estimating the benefits of their individual projects, DOE's Office of Electricity Delivery and Energy Reliability (OE) initiated this study to develop a methodological framework which it could use to estimate benefits and costs of these and other Smart Grid demonstration projects.

Each of the DOE-funded demonstration projects has some aspect of renewable and distributed system integration (RDSI), which is enabled or facilitated by Smart Grid technology. Thus, because renewable and distributed energy systems are frequently integrated with Smart Grid projects, the methodological framework encompasses RDSI, along with a variety of other applications.

The Electric Power Research Institute (EPRI) also recently awarded Smart Grid demonstration projects (EPRI 2009). These projects have broad goals similar to those of the DOE projects and EPRI has joined in co-sponsoring this study. In the EPRI project initiative, several regional demonstrations and supporting research are focusing on the integration of distributed energy resources to form a “virtual power plant” employing integrated control of distributed generation, storage, renewables, and demand response technology. Partners in these demonstrations include:

- American Electric Power Service Corporation (AEP)
- Ameren Services Company
- Central Hudson Gas & Electric
- Con Edison
- Duke
- Electricité de France
- Entergy
- ESB Networks
- FirstEnergy
- KCP&L
- PNM Resources
- Public Service Enterprise Group
- Salt River Project
- Southern Company
- Southwest Power Pool, Inc.
- Tennessee Valley Authority (TVA)
- Wisconsin Public Service

Shortly after the study for our report began, the American Recovery and Reinvestment Act of 2009 (Recovery Act) made over $4 billion in federal funds available for Smart Grid investment grants and demonstration projects. While our study, and the DOE RDSI/Smart Grid demonstration projects and the EPRI demonstration projects initiated in 2008, all began prior to the passage of the Recovery Act, many of the benefits-analysis concepts in this report were developed at the same time that ideas were being developed for the funding opportunity announcements (FOAs) made by DOE OE in June 2009 (OE 2009a,b). Both FOAs call on projects applying for funds, and those that are eventually recipients of funds, to offer preliminary estimates of the benefits of their project and, once the project is underway, to provide data to DOE so that it can estimate project benefits and costs.

Although the purpose of our study was primarily to develop benefit-cost methods that could be used for the DOE RDSI/Smart Grid and EPRI demonstration projects initiated in 2008, the concepts and the general methodology are consistent with those in the FOAs. The FOAs stated that DOE was to develop the methodology in greater detail. In developing its methodology for estimating benefits funded by the Recovery Act, DOE is drawing on much of the work in this study. However, this study serves only to provide suggestions on methodology and DOE might not adopt all of them.

1.3 Purpose of the Report

The purpose of this document is to present a methodological framework that will provide a standardized approach for estimating the benefits and costs of Smart Grid demonstration projects. There are several reasons for having such a framework:

- Given the sizeable investments needed for, as well as the great potential of, the Smart Grid, there is a need for a fair, consistent and methodological approach to estimate the cost and benefits of Smart Grid based on data from Smart Grid field demonstration projects.
- The framework provides a way of identifying and defining the various types of benefits in a standardized way.
- The framework and the associated methods can be consistently and uniformly applied to all of the demonstration projects funded by the U.S. Department of Energy and by the Electric Power Research Institute.
- In addition, the approach is general enough that it can be applied to other Smart Grid demonstration projects, or to other larger Smart Grid projects.
- The framework provides a basis for a computational tool(s) that DOE and all Smart Grid stakeholders could use to determine the costs and benefits of Smart Grid deployments. It documents the thought process, approach, and underlying concepts and assumptions that led to creation of the computational tool.

The work documented in this report addresses the first four considerations listed above – the development of a methodological approach. It is anticipated that follow-up work will develop a computational tool, based on the concepts and approach laid out in this report. Thus, our report documents the basis of many of the assumptions and calculation methods to be employed in the computational tool.

The underlying philosophy of the methodological framework is to have both a standardized approach that can be uniformly applied to projects that have similar elements, as well as the flexibility to allow other methods, not considered thus far, to estimate certain types of project benefits when there are particular aspects of a project that do not "fit the mold." Smart Grid stakeholders might need to adjust assumptions, parameters, and calculations in the computational tool to better match their particular situation and analysis requirements.

Given the expansive relevance of the Smart Grid to many parties, we intend that this report will have a broad audience. It includes DOE, EPRI and their demonstration projects, stakeholders in other Smart Grid projects, as well as utilities, regulators and other interest groups.

Applications of the methodological framework in this report to the Smart Grid projects to which we have referred – the DOE RDSI demonstration projects, the EPRI demonstration projects and the Smart Grid Investment Grant projects supported by the Recovery Act – would be in a *retrospective* sense. That is, one would be collecting data on the actual, observed impact of a project. In contrast, one might wish to consider the benefits of *proposed* Smart Grid projects. In the latter context, application of the framework would be *prospective* – looking ahead or making a forecast. The general framework can be used in both contexts. A *retrospective* analysis relies on observed impacts to estimate the individual types of benefits. A *prospective* analysis uses models to forecast these benefits.

2
OVERVIEW OF METHODOLOGICAL FRAMEWORK

2.1 Previous Studies

The methodological framework and the specific methods, equations and parameters we suggest in this report are part of a broader evolution and development of methods to estimate the benefits and costs of Smart Grid projects. This development of methods will progress as more studies are done and as individual projects come to completion, all of which will add to the body of knowledge about the Smart Grid and its benefits.

In developing our methodological approach, we built upon many previous ideas. Although many studies have touted the benefits of the Smart Grid, far fewer have focused on developing a systematic way of defining and estimating them. Some of the more prominent efforts are summarized in Table 2-1.

Note that in listing these references, we are not suggesting that their results are appropriate estimates of current conditions, or that they should be used in our cost-benefit methodology (especially their specific numerical estimates). Rather, the summary illustrates different approaches that define and categorize Smart Grid benefits. Nevertheless, we used and/or adapted a number of ideas and concepts from these studies:

- Several studies grouped various types of benefits into basic categories. The more commonly defined categories were economic, reliability, environmental, and safety and security (e.g., NETL 2007). Studies that did not focus on defining categories listed various types of benefits that can be classified into one of these categories (Faruqhi et al. 2009, KEMA 2009, EPRI (Hemphill and Neenan) 2008b, Anders 2006, Kaanbert et al. 2003).
- Studies noted that most of the economic benefits for utilities were avoided or reduced operation and maintenance costs and deferred capital costs (Faruqui et al. 2009, KEMA 2009).
- Pullins (2008) and Baer et al. (2004) focused on identifying benefits according to the type of party that benefited from the Smart Grid – utility, consumer, society.

- Other studies focused more on the Principal Characteristics of the Smart Grid[2] and defined metrics for evaluating progress toward its full deployment nationwide (OE 2008, Miller 2008). Though the focus of this report is on a methodology for estimating benefits rather than metrics for the Principal Characteristics, we note that the idea of "value" used in many of the value metrics defined in connection with the principal characteristics (refer to DOE 2009) is inherently related to the idea of benefits.

[2] The seven principal characteristics of a Smart Grid have been identified as a way of describing the key attributes and progress in expanding the Smart Grid: (i) accommodates all generation and storage options, (ii) optimizes assets and operates efficiently, (iii) provides power quality for 21st century needs, (iv) resists attack, (v) self-heals, (vi) motivates and includes the consumer, and (vii) enables markets. Refer to "The Modern Grid Strategy – Characteristics of the Modern Grid (http://www.netl.doe.gov/moderngrid/opportunity/vision_characteristics.html) and to NETL (2007a,b,c and 2009a,b,c,d).

Table 2-1
Summary of Previous Studies on Methods to Estimate Smart Grid Benefits

Name of Study	Approach	Major Results
Faruqui, A., Hledik, R., Davis, C., "Sizing up the Smart Grid," presented at Elster EnergyAxis User Conference, February 24, 2009	Used iGrid model to quantify the customer-side benefits. For example, for benefits of dynamic pricing: • Peak reductions from dynamic pricing derived from PRISM model in which reduction is a function of the ratio of peak rates to existing rates, the sector, and the availability of automating technology • These peak reductions lead to avoided costs of generating capacity, energy and carbon-mitigation costs Similar approach used for benefits of energy efficiency, distributed energy resources and plug-in hybrid electric vehicles	Key assumptions used: • Generating capacity cost: $75/kW-yr • Wholesale electricity price: $100/MWh • CO2 price: $25/ton • Annual inflation rate: 2% • Discount rate: 8% • Reserve margin: 15% • Line losses: 9.2% • Peak demand growth: 1.5% per year • Annual increase in energy consumption: 1.3% per year Model estimates annual and present values of benefits due to present value of avoided costs of: • Meter operation and maintenance • Generating capacity • Energy from electricity (including value of ancillary services for distributed energy resources) • Energy from gasoline • Carbon • Reliability Present value of total net national benefit was estimated to be • If PHEV's included – $568 billion over the 2010-2050 time period • If PHEV's not included -- $226 billion over the same period

Table 2-1 (continued)
Summary of Previous Studies on Methods to Estimate Smart Grid Benefits

Name of Study	Approach	Major Results
KEMA, *Smart Grid Evaluation Metrics*, prepared for the GridWise Alliance (February 23, 2009)	Developed a set of metrics by considering (refer to Exhibit 2-1 in KEMA report): • American Recovery and Reinvestment Act's objective • Qualifying Smart Grid investments, as defined in the Energy Independence and Security Act of 2007 • Evaluation criteria from above two considerations, together with OMB evaluation guidance for Recovery Act, used to define Smart Grid project metrics	Suggested metrics fall under the following categories: • Economic Stimulus • Energy Independence and Security • Integration and Interoperability • Business Plan Robustness Some of these metrics could be considered as project benefits, such as: • Impact on costs to consumers (% and dollar decrease in rates) • Facilitation of renewable energy (incremental MW and % peak MW; % of DG and renewables than can be sensed and controlled) • Number of PHEV charging connected to V2G services • % improvement in losses • % and dollar amount of improvement in costs of failed equipment • Tons GHG and per MWh • SAIDI improvement • Reduced restoration time from major disruptions • Reduction in major outages • Improvement in loss of load probability

Table 2-1 (continued)
Summary of Previous Studies on Methods to Estimate Smart Grid Benefits

Name of Study	Approach	Major Results
Office of Electricity Delivery and Energy Reliability, *Metrics for Measuring Progress Toward Implementation of the Smart Grid*, results of the breakout session discussions at the Smart Grid Implementation Workshop, June 18-19 2008, Washington, DC. Prepared by Energetics, Inc., July 31, 2008.	Breakout sessions prioritized metrics that can be used to gauge progress toward implementation of the Smart Grid	Several metrics defined for each of the seven Principal Characteristics of the Smart Grid
Miller, J., "Smart Grid Metrics: Monitoring Our Progress," presented at the Smart Grid Implementation Workshop, June 19, 2008	Developed conceptual framework – a Smart Grid metric map – that links key technology areas to the Principal Characteristics of the Smart Grid, and those in turn to values (i.e., benefits)	Suggested the following value metrics, under the following categories: System Efficiency • System electrical losses • Peak-to-average load ratio • Duration congested transmission lines loaded >90% Economic • Peak and average prices, by region • Transmission congestion costs • Cost of interruptions and power quality disturbances • Total cost of delivered energy Reliability • Outage duration and frequency • Frequency of momentary outages • Power quality metrics

Table 2-1 (continued)
Summary of Previous Studies on Methods to Estimate Smart Grid Benefits

Name of Study	Approach	Major Results
(continued)		Security • Ratio of distributed generation to total generation • Number of consumers participating in energy markets Environmental • Ratio of renewable generation to total generation • Emissions per kWh delivered Safety • Injuries and deaths to workers and to the public
EPRI (Hemphill, R., Neenan, B.) (2008) *Characterizing and Quantifying the Societal Benefits Attributable to Smart Metering Investments*, Palo Alto, CA: Electric Power Research Institute. 1017006.	Reviewed pilots and state jurisdictional filings to identify how utilities have estimated societal benefits of smart metering. Also reviewed economics literature to identify analytical practices for estimating societal benefits.	Framework for identifying and monetizing societal benefits. Types of benefits identified: a) Reduced electricity costs to consumers from modified electricity consumption in response to demand response programs b) Reduced electricity costs to consumers from information provided to consumers c) More efficient use of electricity due to new products or services d) Reduced duration of outages from service improvements e) Macroeconomic benefits from changes in utilities' and consumers' spending patterns f) Reduced negative externalities

Table 2-1 (continued)
Summary of Previous Studies on Methods to Estimate Smart Grid Benefits

Name of Study	Approach	Major Results
(continued)		Examples of methods used by utilities, summarized in this report: a) Consumer awareness rate assumed (e.g., 50% in SDG&E study); elasticities from CA SPP. Avoided capacity costs based on Forward Capacity Auction, inflation of Cost of New Entry, or on a reliability pricing model (e.g., $4.50/kW-month) b) Value of feedback to consumers increases energy conservation (kW and kWh reductions) c) Assumed or forecasted adoption rates for smart meters and their effects on bills d) Value of electricity service to customers in meta-study (e.g., $3.45 damage with a 1 hour outage on a summer afternoon) e) Input-output model characterizes the magnitude of transactions between supplying and consuming sectors of the economy, and that is used to estimate direct and indirect macroeconomic impacts of expenditures, and f) Energy security benefit (e.g., from 0.57 to 1.14 cents per kWh, based on estimates of the premium on oil prices due to the oil cartel)
KEMA, *The U.S. Smart Grid Revolution: KEMA's Perspectives for Job Creation*, Prepared for the GridWise Alliance (January 13, 2008)	Used estimates from Duke Energy business case in filing to regulator for installing Smart Grid in part of its service territory – filing provided estimate of projected labor costs for smart meter implementation. KEMA extrapolated this business case to the U.S. as a whole – assumed 150 million smart meters.	Forecasted annual number of jobs in different sectors (direct utility Smart Grid, direct utility suppliers, transitional utility, indirect utility supply chain, contractors, and new utility or energy service company). During the 4-year deployment period: 278,600 jobs. During the 6-year steady-state period: 139,700 jobs.

Table 2-1 (continued)
Summary of Previous Studies on Methods to Estimate Smart Grid Benefits

Name of Study	Approach	Major Results
National Energy Technology Laboratory, Modern Grid Benefits, prepared for the U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability (August 2007)	Considers the following categories of benefits: • Reliability • Security and safety • Economics • Efficiency • Environment	Discusses benefits under each of the broad categories. Reliability • Reduction in outage duration and frequency • Fewer power quality disturbances • Virtual elimination of regional blackouts Security and safety • Reduced vulnerability to terrorist attack and natural disasters • Improved public and worker safety Economics • Reduction or mitigation of prices • New options for market participants Efficiency • More efficient operation and improved asset management at lower costs Environment • More deployment of environmentally friendly resources • Electrical losses reduced

Table 2-1 (continued)
Summary of Previous Studies on Methods to Estimate Smart Grid Benefits

Name of Study	Approach	Major Results
Pullins, S., "Smart Grid: Enabling the 21st Century Economy, presented at the Governor's Energy Summit, West Virginia (December 2008)	Benefit-cost study of benefit of Smart Grid in West Virginia, considered the following benefits: *Utility –* • Operational – outage management, improved processes, workforce efficiency, reduced losses, etc.) • Asset management – system planning, better capital asset utilization, etc. *Consumer –* • Reduced losses (improved reliability, power quality, alternatives to outages) • Better energy efficiency (less energy consumption, sale of DG power to the grid, reduced transportation costs – PHEV, etc.) Society • Reduced emissions (by reducing losses, enabling electric vehicles) • Mentions consumer benefits as well	Cites estimates of benefits to be \$638 billion to \$802 billion over 20 years, compared to costs of \$165 billion (based on EPRI 2004 study)

Table 2-1 (continued)
Summary of Previous Studies on Methods to Estimate Smart Grid Benefits

Name of Study	Approach	Major Results
Anders, Scott J., "San Diego Smart Grid Study: Modernizing the Grid,' presented at the MW Regional Summit (November 16, 2006)	Benefits considered: • Reduced congestion cost • Reduced blackout probability • Reduced forced outages or interruptions • Reduced restoration time • Reduced operations and maintenance costs • Reduced peak demand • Higher capacity utilization, leading to environmental benefits • Increased integration of distributed generation • Increased security to withstand attacks and natural disasters	Estimated benefits for different scenarios. Methods for calculating benefits not discussed in this presentation material.

Table 2-1 (continued)
Summary of Previous Studies on Methods to Estimate Smart Grid Benefits

Name of Study	Approach	Major Results
Baer, W.S., Fulton, B., Mahnovski, S., *Estimating the Benefits of the GridWise Initiative*, Phase I Report, prepared for the Pacific Northwest National Laboratory. TR-160-PNNL, Rand Corporation (Might 2004)	Developed taxonomy of benefits and then estimated benefits of demand response, improvements in power quality and reliability, and end-user benefits of improved efficiency. Framework emphasizes that: • Estimates must distinguish between intermediate and final benefits, • Benefits are often not independent of each other, and • Externalities are inherently difficult to quantify	Taxonomy of Benefits has three major stakeholder groups, each having many different sources of benefits. After distinguishing between intermediate benefits and final benefits, the latter are listed as: Utilities and Other Electricity Suppliers – • Generation and storage – Deferred capital costs – Lower O&M, fuel costs – Lower cost of capital – Higher cash flows, profits – Lower emission control costs • Transmission and distribution – Deferred capital costs – Lower O&M, fuel costs – Lower cost of capital – Higher cash flows, profits

Table 2-1 (continued)
Summary of Previous Studies on Methods to Estimate Smart Grid Benefits

Name of Study	Approach	Major Results
(continued)		Electricity End-Users • Lower power expenditures • Reduced costs of outages • Reduced backup power cost • Revenues or credits from ancillary service sales • Revenues from sales of onsite generated power • Cost savings from CHP and EMS • Productivity gains from redesigned processes Society (does not quantify) • Greater energy security, robustness and resilience • Reduced emissions and other environmental costs • Better accommodation of renewables • Facilitation of electricity industry restructuring • Fewer opportunities to manipulate the system • Greater public confidence in the electricity system Model calculates benefits from demand response • Calculates peak-load reduction based on market penetration, price elasticity of demand, wholesale peak, peak prices, percentage of peak load reduction shifted to off-peak, etc. Parameters based on previous studies' estimates. • Then calculates resulting deferrals in generation, transmission and distribution capital costs • Calculates capital cost deferrals from lower reserve margins

Table 2-1 (continued)
Summary of Previous Studies on Methods to Estimate Smart Grid Benefits

Name of Study	Approach	Major Results
(continued)		Calculate benefits of reduced outages and disturbances based on: • Previous estimates of costs of outages • Ranges of value of reliability and power quality: – Residential (0.15, 2, 10) in $/kWh for low, mid and high estimates – Commercial (10, 25, 40) – Industrial (7, 15, 40) • Assumed reduction (e.g., 33%) End-user benefits from improved efficiency (more efficient electricity use during off-peak periods) • Form improvement in energy management systems that building owners and tenants use to control heating, ventilation, air conditioning, and lighting.

Table 2-1 (continued)
Summary of Previous Studies on Methods to Estimate Smart Grid Benefits

Name of Study	Approach	Major Results
Kannberg, L.D., Chassin, D.P., DeSteese, J.G., Hauser, S.G., Kintner-Meyer, M.C., Pratt, R.G., Schienbein, L.A., Warwick, W.M., *GridWise: The Benefits of a Transformed Energy System*, PNNL-14396, Pacific Northwest National Laboratory (September 2003)	Estimates national benefits by considering scenarios/assumptions in which the Smart Grid can make existing assets more efficient: • Perform current functions, e.g., generation, more efficiently • Perform new functions, e.g., backup generation can provide services such as transmission reliability functions • Provide existing functions, e.g., load provides ancillary services • Increase reliability New assets can perform new functions such as load function arbitrage. Those benefits the result of the following attributes or mechanisms: • Higher asset utilization so that system operators can provide more services with same installed capacity and install less new equipment • Flatter load duration curves • Increased use of combined heat and power • More effective sources of ancillary services • Avoid costs – reduced capital costs, maintenance costs and shorter outages • Energy price stability from increased demand elasticity • Grid-friendly load as an active control measure	Generation deferral benefits from flattening the national load duration curve: Assumed 111 GW to 285 GW of currently excess generation capacity would be released to supply load growth and offset retirements; assumed $600/kW average cost of new generation. T&D outage reduction benefits: Assumed 50% reduction in transmission outage frequency from 50% market penetration of Smart Grid, avoiding lost revenue to utility of $3 million annually. Similarly, for distribution outages, avoided revenue loss is $48 million. T&D capacity deferral benefits: Assumed cost of transmission to be $150/kW of generation additions or load growth. Same assumptions as for generation capacity deferral benefits. Customer benefits – price-demand response: Assumed 6.0 MW/$ in demand response would reduce customer electric power bill by $6.9 billion and 9.68 GW in reduced peak load. Enhanced reliability and security: Assume reduced failure rate from smaller DG units. Customer outage benefits: Assume 50% reduction in outages, worth $8.5 billion.

2.2 The Concept of Benefit

2.2.1 Definition of Benefits

We define the term "benefit" to be an impact (of a Smart Grid project) that has value to a firm, a household, or society in general. To gauge their magnitude, benefits should be quantified if possible. In addition, to facilitate comparison, benefits may be expressed in monetary terms.

Examples of benefits include:

- Lower electricity costs to consumers (this benefit to consumers is what economists call a transfer payment and is discussed later in the report). These could be due to flatter load curves that result from smart meter applications and changes in consumer behavior in response to tariffs that provide incentive to use less electricity during peak hours.
- The value of lower transmission and distribution (T&D) losses. These benefits could be from an optimized T&D network and from having generation closer to load (distributed generation).
- Lower operation and maintenance costs. These would be from reduced need for O&M activity and from lower equipment failure rates.
- Reduced transmission congestion costs. These decreases would be from increased transfer capability from existing facilities.
- Reduced cost of power interruptions. These cost reductions would be a result of fewer and shorter interruptions.
- Better power quality. That is, there are fewer momentary interruptions and voltage sags and swells.[3]
- Reduced damages from greenhouse gas emissions. These benefits could be from lower electricity consumption (e.g., reduced loads by consumers reacting to increased information about their consumption levels), lower T&D losses, and generation from clean energy generation substituting for power from less clean sources.
- Extension of the life of both central station generating equipment and T&D equipment, thereby reducing overall capital equipment expenditures by allowing these equipment to operate longer before they need to be replaced.

[3] Power quality events are deviations in voltage, current or frequency from norms which affect the proper operation of equipment (Bollen and Gu 2006, Santoso et al. 2003). In this report, we use the incidence of momentary interruptions as a surrogate measure of the frequency of power quality events. According to the IEEE 1366-2003 definition, momentary interruptions are those less than 5 minutes in duration.

We emphasize that a benefit is an outcome of a project which has value – it is not simply a project's performance or intermediate outcomes of the project. The following examples clarify this distinction between "benefits" and intermediate outcomes:

- Customer participation is an example of an intermediate outcome of some Smart Grid projects, but we do *not* classify it as a benefit, per se. The reason is that customers' participation in programs in which a distribution utility offers smart meters coupled with a time-varying tariff structure does not have value in and of itself but, rather, leads to other impacts that do have value. A *benefit* in this case is the reduction in the customers' electricity bills – which is an economic benefit to the consumer.
- Reduced peak load is an impact, but does not itself have value; thus, it is not classified as a benefit. Reductions in peak load reduce a utility's generation and delivery costs as a result of greater efficiencies and improved utilization of assets. These provide cost savings to the utility. These savings are the benefit, not the peak load reduction in and of itself.
- As a third example, greater use of renewable energy options is an impact, though not classified as a benefit within our framework. The benefit of greater use of renewable energy is that it reduces emissions of greenhouse gases and other damaging pollutants. It is these reductions that are benefits; society values these reductions because of the resulting reduction in health effects, environmental impacts, and other damages and risks from climate change.

2.2.2 Categories of Benefits

For RDSI and Smart Grid systems, there are four fundamental categories of benefits:

- Economic – reduced costs, or increased production at the same cost, that result from improved utility system efficiency and asset utilization
- Reliability and Power Quality – reduction in interruptions and power quality events
- Environmental – reduced impacts of climate change and effects on human health and ecosystems due to pollution
- Security and Safety – improved energy security (i.e., reduced oil dependence); increased cyber security; and reductions in injuries, loss of life and property damage

Within each of the broad categories, there are several types of benefits. Note that these categories are defined to be mutually exclusive in terms of accounting for different benefits. It is worth noting that smart grid functions that lead to one type of benefit can also lead to other types of benefits. For example, improvements that reduce T&D losses (an economic benefit) mean that pollutant emissions are reduced as well (which is an environmental benefit).

2.2.3 Beneficiaries

The benefits and costs of RDSI/Smart Grid systems can accrue to different parties. It is informative to these different groups, as well as to the broad range of stakeholders, to identify those who receive the different types of benefits and their magnitude, and those who incur the costs. There are three basic groups of beneficiaries:

- Utilities are the suppliers of power and include electric utilities that generate power as well as the transmission and the load serving entities that deliver it (and integrated utilities that do all three). Many of the benefits (and of course the costs) to utilities are passed on to ratepayers, though the exact portion that is passed on varies from case to case.
- Customers are the end-users or consumers of electricity. They are ratepayers who benefit from changes in rates and services offered by utilities, as well as from improvements in reliability and power quality. The benefits to customers are reduced electricity bills, reduced damages from power interruptions and improved power quality.
- Society in general is the recipient of externalities of the Smart Grid – effects on the public or society at large – which can be either positive or negative in nature.[4] In general, the benefits in this category are reductions in negative externalities such as pollutant emissions. Positive externalities are generally more difficult to identify. Societal welfare benefits associated with efficiency improvements are not entirely reflected in the price of electricity; there are indirect, macroeconomic benefits such as job creation as well. These are difficult to estimate and we do not address them in this report. There are also benefits to, and damages borne by society at large that are not externalities in the strict sense of the formal definition, but which are linked to other types of market failures (e.g., oil security benefits). The latter types of benefits are included under the category of benefits to society in general.

Identifying these groups of beneficiaries enables one to distinguish *who* (which group in general) is benefiting from which types of smart grid investments.

[4] An externality is an effect of an activity of an "agent" (i.e., an individual or organization like a company) that also affects the wellbeing of another agent and the impact of which is not explicitly included in the price or cost. ., the activity is not taken into account by the agent when making its decision about that activity because it does not pay the externality cost associated with that act. For example, carbon dioxide emissions result from some forms of electricity generation. The emissions are generally thought to lead to climate change, which is likely to have significant economic and environmental impacts. Such impacts will affect the wellbeing of people and organizations. In the absence of any regulations or limits on emissions, or taxes or other direct costs tied to the level of emissions, these effects are not explicitly taken into account as a factor when a company decides how to generate that power, nor in the sale of that power to load serving entities.

2.2.4 Benefits Matrix

Figure 2-1 depicts a matrix for defining one of four types of benefits and costs of RDSI/Smart Grid systems and for categorizing the parties to whom these benefits and costs inure.

Category	Beneficiaries: Utilities	Customers	Society
Economic			
Environmental			
Reliability & Power Quality			
Security and Safety			

Figure 2-1
Benefits Matrix

Within any of the four benefit categories, there are one or more individual types of benefits.

The types of benefits on which we focus capture most of the overall benefits of a project but, as a practical matter, the list of benefits to be quantified is not necessarily exhaustive because some are very difficult to measure or are relatively small compared to the other benefits.

In defining types of benefits (in Section 4), we define them so that they are: easy to understand by non-specialists; measureable (i.e., preferably from first the observation of an effect and then to quantifying it); an impact whose value can be monetized; explainable of how the system leads to these benefits; out*come* oriented; and for the most part non-overlapping. By out*come* oriented, we are referring to the *ultimate* benefits to individuals and organizations, rather than engineering or project accomplishments or intermediate impacts of the project.

In addition to the groups of beneficiaries we identify in Figure 2-1, there are other groups of stakeholders as well. They include:

- Original equipment manufacturers, software providers, system integrators, energy service providers (e.g., those providing demand response resources), and operations and maintenance providers
- Environmental and other special interest groups
- Regulatory agencies and governments

In our framework, we consider the first group in this list as providers of Smart Grid systems and services to the project. They provide value added for their equipment and services, which we aim to estimate (i.e., benefits), and there are of course costs for their products and services, for which they are compensated. Thus, in our framework, we consider their revenues and costs to be economic transfer payments from one party to another.

Although it is not an objective of our framework to estimate the benefits to special interest groups, the framework separately identifies different types of benefits and their sources, and thus might be used to estimate the benefits from different individual perspectives. For example, environmental benefits would be of greatest interest to environmental interest groups.

The third group above is represented by considering the benefits to the three groups of beneficiaries – each of which is of concern to and implicitly represented by one or more regulatory and/or other government agencies – that is, by considering the overall total benefits.

2.2.5 Total Benefits

In general, benefits are reductions in costs and damages, whether to firms, consumers or to society at large. We have defined the various benefits to minimize instances of transfer payments between these groups of beneficiaries to make it easier to calculate the total benefits, and to enable calculations of benefits from the separate perspectives of each group:

- The benefits to utilities (including generation, transmission and distribution utilities and cooperatives) are reduced operation and maintenance costs, deferred capital costs and other reductions in their costs.
- The benefits to consumers are reductions in their electricity bills and in the damages caused by power interruptions and power quality events.
- The benefits to society at large are reductions in negative externalities and related market failures.

Total benefits are the sum of the benefits to utilities, consumers and society at large – except that any transfer payments between these beneficiary groups must be taken into account.

Various other studies use the term “societal” benefits to refer to benefits to consumers and/or to society at large or, alternatively, to the total benefits. Because it has been used in these various different ways, we avoid using the term “societal” benefits.

2.2.6 Precision of Estimates

There is a third dimension to the matrix of benefits in Figure 2-1, which represents the level of precision in the estimated magnitudes of these benefits and costs. A reasonable way of characterizing the general level of precision is to use broad categories such as:

- Modest level of uncertainty in quantitative estimates and/or in monetization (the project might specify percentile values)
- Significant uncertainty in quantitative estimates and/or in how to monetize
- Highly uncertain
- Cannot be quantified

In general, estimates of different types of benefits within each category would be expected to have different levels of precision. Figure 2-2 adds this third dimension to the matrix in Figure 2-1. Note that there is *not* necessarily any relationship between the magnitude of an estimate of a benefit (which is generally a reduction in costs or damages) and the relative precision of that estimate.

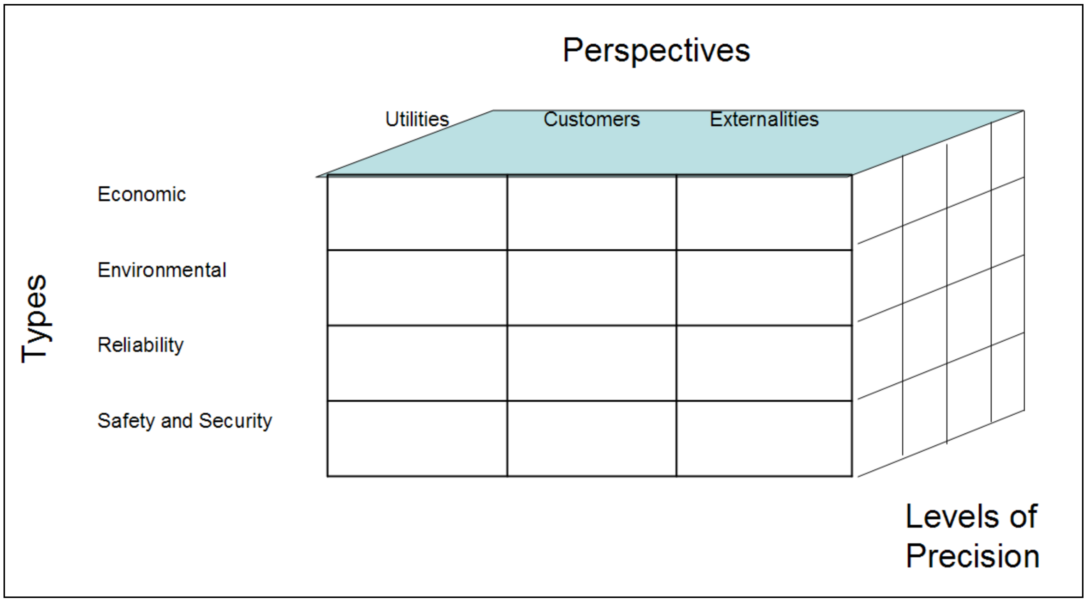

Figure 2-2
Types, Perspectives and Levels of Precisions of Estimated Benefits and Costs

2.3 Smart Grid Elements, Functions and Benefits

To develop a method of estimating the benefits of RSDI/Smart Grid systems, we undertake a sequence of analysis to define the following:

1. Types of RDSI/Smart Grid technologies or systems that might be deployed in a project
2. A standardized set of different functions (functionality is the term that the Smart Grid community uses) which different RDSI/Smart Grid technologies and systems might have (e.g., adaptive protection is one of these functions); a technology can have one or more functions
3. Metrics for the seven Smart Grid characteristics, so as to help characterize the attributes of the deployment and the benefits derived from these characteristics
4. Operational purposes or mechanisms of each function
5. Types of benefits and costs expected to be derived from each functional purpose (i.e., a mapping between purpose and benefits (and costs))

Steps b) and c) relate to processes whereby the Smart Grid systems (defined in Step a)) leads to impact. Smart Grid characteristics are generally out*put*-oriented impacts; they describe the extent to which the Smart Grid is built (Step c)). The benefits and costs are out*come*-oriented impacts; they characterize the value of the Smart Grid. Figure 2-3 illustrates the sequence of analysis.

Section 4 details the results of this analysis – that is, metrics that describe the performance of a Smart Grid project, the list of metrics suitable for gauging the Principal Characteristics that a project supports, the standardized set of Smart Grid functions that might be provided, the standardized set of Smart Grid benefits, and the mappings between functions and benefits.

To help projects to implement this approach, we have also defined guidelines on the data needed that projects or other stakeholders can use to calculate these benefits (refer to Section 4).

By using the relationships or mappings illustrated in Figure 2-3, one can associate with its functional characteristics the types of benefits a project might provide. Then, the quantitative magnitude of the benefits can be estimated by compiling the data needed to calculate each type of benefit. The ten steps are summarized below and are described in Section 4.

Table 2-2, which is adapted from the one used in the FOAs (DOE 2009a,b), summarizes the way in which the framework defines the categories of benefits of Smart Grid projects, the sources of the benefits and the data needed to estimate these benefits.

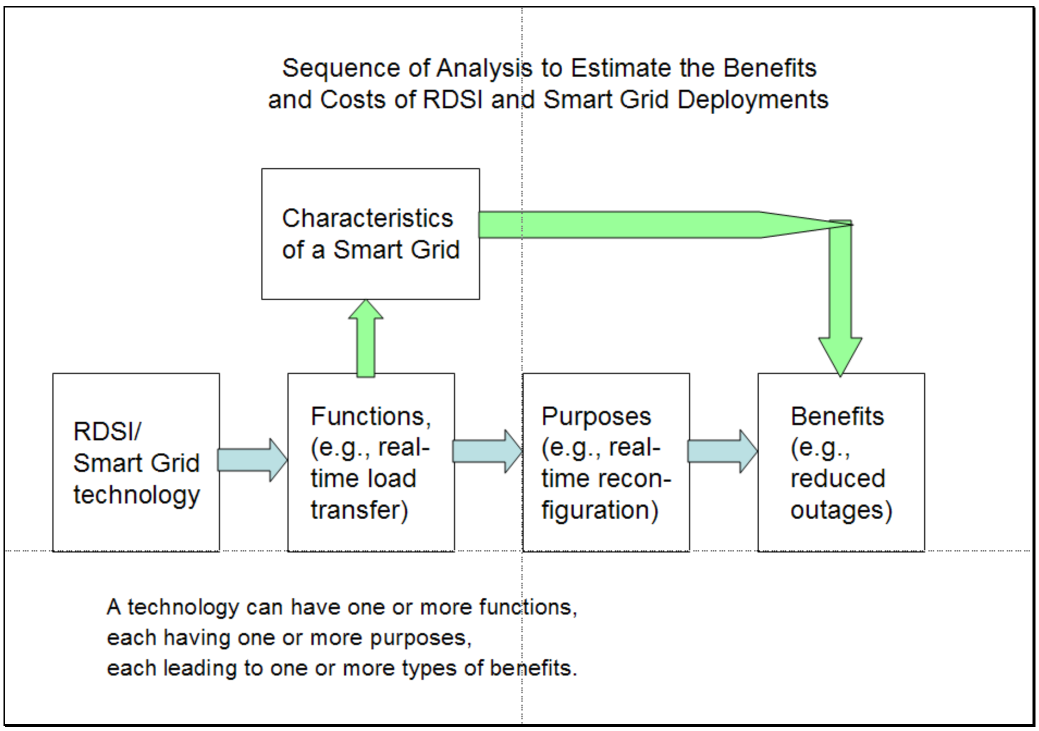

Figure 2-3
Sequence of Analysis for Benefit-Cost Estimation of RDSI and Smart Grid Deployments

The “Benefit Category” in the table refers to one of the four broadly-defined categories of benefits. As discussed further in Section 4, different types of benefits are calculated different ways.

There is uncertainty in any estimate of benefits. This uncertainty can arise from limitations in the study design, e.g., in the experimental sampling design used to evaluate the benefits of different residential pricing structures, in the data available to quantitatively estimate different types of benefits, and in the conversion factors used to convert reliability, environmental, and energy-security related benefits into monetary values. However, to the extent possible, it is generally worthwhile to make such estimates using the scientific literature (including the economics and social science literature) to guide experimental designs, statistical analysis, and selection of monetary conversion factors. Given the uncertainty in any estimates of benefits, it is useful to suggest the general extent of uncertainty associated with each estimate (as indicated in the "Levels of Precision" dimension in the typology in Figure 2-2).

In Table 2-2 – Summary of Benefits, the Sources of these Benefits and the Data which Project-Funding Recipients can Expect to Report, the "Source of Benefit" column lists some of the possible intermediate outcomes or goals of projects. These intermediate outcomes give rise to the various benefits listed in the column to the left.

The right-most column in Table 2-2 lists data which the project can expect to compile so as to be able to estimate each category of benefits.

Table 2-2 is not meant to encompass every possible proposed project nor be a comprehensive listing of every possible benefit and associated data need. The benefits and data elements listed in the table reflect, however, what we regard to be the more significant benefits in terms of their magnitude, for most projects. Thus, we suggest that it be used as a standard, consistent framework for defining the types of benefits. Section 4.4 provides details on the various types of benefits.

2.4 Ten-Step Approach for Cost-Benefit Analysis

Given the standardized sets of Smart Grid functions, benefits and mappings we defined, we suggest a ten-step process which projects, DOE or others can follow to estimate a project's benefits and costs:

Characterize the Project

1. Project elements – Review the project's technologies/elements and goals
2. Functions – Identify, from a standardized set, the Smart Grid functions which each project element could provide and what will be demonstrated
3. Characteristics – Assess the Smart Grid Principal Characteristics that are reflected in the project

Estimate Benefits

1. Benefits – Map each function onto a standardized set of benefit categories
2. Baseline – Define the project baseline and how it is to be estimated
3. Data – Identify and obtain the data needed to estimate the baseline and to calculate each type of benefit
4. Quantified benefits – Calculate quantitative estimates of the benefits
5. Monetized benefits – Use economic conversion factors to estimate the monetary value of the benefits

Compare Costs to Benefits

1. Costs – Estimate the relevant costs
2. Cost-Benefit – Compare costs to benefits

Depending on the type of Smart Grid application, a project would have different types of benefits. Not all projects have all types of benefits. Furthermore, consistent with the idea that the framework provides flexibility, a project might suggest other types of benefits which it might provide. In these instances, a project should explain these benefits, how they differ from those listed in this report, and the data needed to estimate these benefits.

Table 2-2
Summary of Benefits, the Sources of these Benefits, and the Data which Project-Funding Recipients can Expect to Report

Benefit Category	Benefit	Source of Benefit	Information Reported by Project, with and without the Smart Grid Deployment
Economic	Electricity cost savings – Lower electricity cost to consumers	• Flatter load curve (from load shifted to off-peak periods, e.g., from consumer behavior and smart appliances that can respond to price signals) • Dynamic pricing and/or lower electricity rates (reflecting reduced generation costs with flatter load curve) • Lower total electricity consumption	• Hourly load data, by customer • Monthly electricity cost, by cust3omer • Tariff description, by customer • Demographic and other information affecting demand • For firms, square footage and SIC code • Types of smart appliances in use
	Reduced generation costs from improved asset utilization	• Flatter load curve (from load shifted to off-peak periods, e.g., from consumer behavior and smart appliances that can respond to price signals) • Dynamic pricing and/or lower electricity rates (reflecting reduced generation costs with flatter load curve) • Lower total electricity consumption	• Generation costs (that reflect optimized generator operation) • Deferred generation capacity investments • Reduced ancillary service cost
	T&D capital savings	• Deferred transmission and distribution capacity investments • Reduced equipment failures	• Deferred T&D capital investments
	T&D O&M savings	• Reduced O&M operations costs • Reduced meter reading cost	• Activity-based O&M costs • Equipment failure incidents
	Reduced transmission congestion costs	• Increased transmission transfer capability without building additional transmission capacity	• Actual real-time capability of key transmission lines

Table 2-2 (continued)
Summary of Benefits, the Sources of these Benefits, and the Data which Project-Funding Recipients can Expect to Report

Benefit Category	Benefit	Source of Benefit	Information Reported by Project, with and without the Smart Grid Deployment
	Reduced T&D losses	• Optimized T&D network efficiency • Generation closer to load [from distributed generation (DG)]	• T&D system losses (MWh) • % of MWh served by DG
	Theft reduction	• Reduced electricity theft	• Estimated T&D system losses from theft (MWh)
Reliability and Power Quality	Reduced cost of power interruptions	• Fewer sustained outages • Shorter outages (reduced duration) • Fewer major outages	• SAIFI • SAIDI or CAIDI
	Reduced costs from better power quality	• Fewer momentary outages • Fewer severe sags and swells • Lower harmonic distortion	• MAIFI
Environmental	Reduced damages as a result of lower GHG/carbon emissions Reduced damages as a result of lower SOx, NOx, and PM emissions	• From the mechanisms below: – Lower electricity consumption from: o Intelligent appliances – Lower T&D losses from: o Optimized T&D network o Generation closer to load (DG) – Lower emissions from generation from: o Combined heat and power (CHP) o Renewable energy (RE) o Operating generators more efficiently o Avoiding additional generator dispatch with demand response	• Reduced CO2 emissions • Reduced SOx, NOx, and PM emissions o Hourly consumption by fuel type, compared to baseline/control group o % of MWh served by DG o T&D system losses (MWh) o MW of CHP installed o % of MWh served by RE o % of feeder peak load served by RE o Average heat rate of supply (or similar information)

Table 2-2 (continued)
Summary of Benefits, the Sources of these Benefits, and the Data which Project-Funding Recipients can Expect to Report

Benefit Category	Benefit	Source of Benefit	Information Reported by Project, with and without the Smart Grid Deployment
Energy Security	Greater energy security from reduced oil consumption	• Electricity substituting for oil by “smart-grid enabled” electric vehicles	• MWh of electricity consumed by electric vehicles
	Reduced widespread damage from wide-scale blackouts	• Reduced wide-scale blackouts	• Number of wide-scale blackouts

Abbreviations used in Table 2-2:
CAIDI – customer average interruption duration index
CHP – combined heat and power
DG – distributed generation
DR – demand response
MAIFI – momentary average interruption frequency index
MW – megawatts
MWh – megawatt hours
RE – renewable energy
SAIDI – system average interruption index duration index
SAIFI – system average interruption frequency index
T&D – transmission and distribution

Notes for Table 2-2:
Sustained outages are those > 5 min, excluding major outages and wide-scale blackouts
Major outages are defined using the beta method, per IEEE Std 1366-2003
Wide-scale blackouts are rare, extensive blackouts that cover a wide region.

3 HYPOTHETICAL EXAMPLE TO ILLUSTRATE THE APPROACH

This section provides a hypothetical example to illustrate the ten-step approach introduced in Section 2.4. Section 4 describes each of the steps in greater detail.

3.1 Example of Step 1: Review and describe the technologies, elements and goals of the project.

Provide a summary of the project such as that below.

Project Title: Hypothetical RDSI Project
Organization: CBA Team
Presenter: Not applicable
FY 2008 Funding: Not applicable

Overall Project Purpose and Objectives:

This hypothetical project is intended to illustrate the RDSI evaluation process. It provides a relatively simple example of the various mapping and measurement tools that can be employed to characterize the results and accomplishments of an RDSI-Smart Grid project.

This example assumes a hypothetical project aimed primarily at comparing the costs, performance and benefits of two approaches to load management: Consumer Demand Response and Utility Direct Load Control. It is assumed that two similar circuits will each be equipped with one of these approaches and a third circuit will serve as the control. Advanced metering infrastructure (AMI) will be installed on all three to provide a complete record of load variation at each point of customer contact and to provide feedback to participating consumers on their usage. In addition, the two way communications system installed for AMI will also be employed to provide voltage control on both test circuits. And because AMI will be deployed as part of this project, other benefits of AMI, such as outage and power quality (PQ) reporting will also be assessed. Impact on outage restoration time, reliability and PQ complaints will be monitored.

The Demand Response (DR) installations will consist of a consumer portal that receives a price signal and is programmed to control selected loads based on the consumer's price/consumption preferences (his utility function).

The Direct Load Control (DLC) installations will consist of two-way communications to each controllable load, with the ability to switch loads on or off and with confirmation of the resulting load change. Special tariffs will be developed for each customer group participating in the project. The consumer portal will provide direct feedback to the customer on his or her energy usage behavior and the associated costs.

2008 Approach and Results:
In this hypothetical project, pre-deployment data on the performance of the three test circuits were collected in 2008.

2009 Plans and Expectations:
In this hypothetical project:

- Customers are sought out to participate in the project; not all customers on a circuit would be expected or required to participate
- Special tariffs are designed for DR and DLC participants
- Equipment is selected and installed on the three circuits
- Software is developed to allow statistically sound conclusions of sample results
- Testing begins with a specific set of tariffs and pricing signals (these could be varied over the course of the project to determine sensitivities)

Technology Transfer, Collaboration, Partnerships

The project involves a host utility, customers and equipment vendors. Each will be interested in specific aspects of the results. The customers will be most interested in deciding if the savings in their electric bill justifies any inconvenience or discomfort they might have experienced. The utility will be interested in how well the equipment worked, how satisfied their customers were and whether the resulting load changes (as well as loss reduction from improved VAR control) and enhanced grid information justify the cost. They will also be very interested in determining which of the two approaches performed better from each of these perspectives. The vendors will be interested in whether their solution will lead to a profitable new business opportunity. And regulators will be interested in all the above, as input for future rate case deliberations.

Section 4.1 provides additional discussion on ways of describing a Smart Grid project.

3.2 Example of Step 2: Identify the functions

Based on a review of the hypothetical project, the primary Smart Grid functions it provides are:

- Automated voltage and VAR control
- Real-time load measurement and management
- Customer electricity use optimization

Section 4.2 defines all of the functions for Smart Grid projects in general.

3.3 Example of Step 3: Assess the principal characteristics of the Smart Grid to which the project contributes

Consider the functions which project elements provide (columns below), describe the purpose of each function (the cells in the table), and then identify the corresponding principal characteristic (rows) – refer to Table 3-1.

Table 3-1
Example of Mechanisms by which Principal Characteristics Provided by Smart Grid Functions

Principal Characteristic	Smart Grid Function		
	Real-Time Load Measurement & Management	Automated Voltage and VAR Control	Customer Electricity Use Optimization
Enables informed participation by customers	DSM tariff for consumers		Consumer feedback portal
Accommodates all generation and storage options			
Enables new products, services and markets	Creates DSM tariff		Creates DR market
Provides power quality for the range of needs in the 21st century economy	AMI monitors PQ		
Optimizes asset utilization and operating efficiency	Can manage what is measured	Loss and failure reduction	
Addresses disturbances through automated prevention, containment and restoration	Condition monitoring; emergency shedding	Avoids voltage collapse	
Operates resiliently against all hazards	DSM emergency role		

3.4 Example of Step 4: Map each function onto a standardized set of benefit types

Given the three main functions in this hypothetical project, from among the ones we have defined (columns across the top). The next step is to map these functions to the benefits they provide. Figure 3-1 illustrates this process. The three smart-grid functions this project provides are listed across the top of the figure. Consider each function in turn and how it can provide any of the benefits listed in the rows of the first column. For example, real-time load measurement and management shifts load to reduce the cost of generation which lowers electricity bills to consumers. This analysis should proceed for each function, until all three functions (in this example) are considered.

Figure 3-2 summarizes this analysis and identifies (with dots in the cell), within the whole matrix of functions and benefits, the benefits identified in the previous analysis in Figure 3-1. The green columns in Figure 3-2 highlight the functions provided by the elements in this project. Note that the integrated nature inherent in Smart Grid systems is such that a project with relatively few technologies can still have many different types of benefits. Refer to Section 4.4 for additional discussion of this step in the methodology.

Benefits	Functions		
	Automated Voltage and VAR Control	Real-Time Load Measurement & Management	Customer Electricity Use Optimization
Optimized Generator Operation			
Deferred Generation Capacity Investments			Shifts loads from peak times
Reduced Ancillary Service Cost	Reduces VAR purchase requirement	Shifts loads from peak times	
Reduced Congestion Cost			
Deferred Transmission Capacity Investments			Reduces transmission peaks
Deferred Distribution Capacity Investments		Reduces distribution peaks	Reduces distribution peaks
Reduced Equipment Failures			
Reduced Distribution Equipment Maintenance Cost			
Reduced Distribution Operations Cost	Reduces distribution losses; equipment failures		
Reduced Meter Reading Cost		Smart meters automatically read data	
Reduced Electricity Theft		AMI reduces electricity theft	
Reduced Electricity Losses	Improves T&D power factor	Reduces T&D loading	Shifts loads from peak times
Reduced Electricity Cost			Shifts loads from peak times and reduces consumption
Reduced Sustained Outages		Shifts loads from peak times	
Reduced Major Outages		Shifts loads from peak times	
Reduced Restoration Cost			
Reduced Momentary Outages			
Reduced Sags and Swells			
Reduced CO_2 Emissions	Reduces losses	Reduces consumption and losses	Reduces consumption and losses
Reduced SO_x, NO_x, and PM-10 Emissions	Reduces losses	Reduces consumption and losses	Reduces consumption and losses
Reduced Oil Usage (not monetized)		Reduces consumption and losses	
Reduced Widescale Blackouts			

Figure 3-1
Example to Illustrate How a Project's Smart Grid Functions Provide Benefits

FUNCTIONS

TYPES OF BENEFITS

			Functions													Energy Resources		
			Fault Current Limiting	Wide Area Monitoring, Visualization, and Control	Dynamic Capability Rating	Flow Control	Adaptive Protection	Automated Feeder Switching	Automated Islanding and Reconnection	Automated Voltage and VAR Control	Diagnosis & Notification of Equipment Condition	Enhanced Fault Protection	Real-Time Load Measurement & Management	Real-time Load Transfer	Customer Electricity Use Optimization	Distributed Generation	Stationary Electricity Storage	Plug-in Electric Vehicles
Economic	Improved Asset Utilization	Optimized Generator Operation																
		Deferred Generation Capacity Investments													•			
		Reduced Ancillary Service Cost								•			•					
		Reduced Congestion Cost																
	T&D Capital Savings	Deferred Transmission Capacity Investments													•			
		Deferred Distribution Capacity Investments											•		•			
		Reduced Equipment Failures																
	T&D O&M Savings	Reduced Distribution Equipment Maintenance Cost																
		Reduced Distribution Operations Cost								•								
		Reduced Meter Reading Cost											•					
	Theft Reduction	Reduced Electricity Theft											•					
	Energy Efficiency	Reduced Electricity Losses								•			•		•			
	Electricty Cost Savings	Reduced Electricity Cost													•			
Reliability	Power Interruptions	Reduced Sustained Outages											•					
		Reduced Major Outages											•					
		Reduced Restoration Cost																
	Power Quality	Reduced Momentary Outages																
		Reduced Sags and Swells																
Environmental	Air Emissions	Reduced CO_2 Emissions								•			•		•			
		Reduced SO_x, NO_x, and PM-10 Emissions								•			•		•			
Security	Energy Security	Reduced Oil Usage (not monetized)											•					
		Reduced Widescale Blackouts																

Figure 3-2
Functions Provided by the Smart Grid Project are Highlighted

3.5 Example of Step 5: Establish project baselines

Establishing the baseline is an important and sometimes difficult step to complete. The baseline represents the conditions that would have occurred had the project not have taken place. Section 4.5 discusses some of the key issues. The baseline is defined differently for different benefit metrics. Table 3-2 is a template/checklist to account for baseline considerations for each type of benefit, with each beneficiary identified. The type of benefit is listed down the first column, the beneficiary of each type of benefit is identified in the second column, and the corresponding baseline considerations are noted in the third column labeled “Step 5: Establish Baselines.”

To “fill in” Table 3-2, Section 4.5 discusses important considerations in defining an appropriate baseline. Section 4.6 describes how to quantify the benefits, including the data needed. Section 4.7 provides monetization parameter values.

Table 3-2
Baseline, Data, Quantification and Monetization Checklist

Type of Benefit	Beneficiary	Step 5: Establish Baselines	Step 6: Compile Data	Step 7: Quantify Benefits	Step 8: Monetize Benefits
Optimized Generator Operation – reduced generation costs	Utility				
Deferred Generation Capacity Investments	Utility				
Reduced Ancillary Service Cost	Utility				
Reduced Congestion Cost	Utility				
Deferred Transmission Capacity Investments	Utility				
Deferred Distribution Capacity Investments	Utility				
Reduced Equipment Failures	Utility				
Reduced Distribution Equipment Maintenance Cost	Utility				
Reduced Distribution Operations Cost	Utility				
Reduced Meter Reading Cost	Utility				
Reduced Electricity Theft	Utility				
Reduced Electricity Losses	Utility				

Table 3-2 (continued)
Baseline, Data, Quantification and Monetization Checklist

Type of Benefit	Beneficiary	Step 5: Establish Baselines	Step 6: Compile Data	Step 7: Quantify Benefits	Step 8: Monetize Benefits
Reduced Electricity Cost to Consumers	Consumers				
Reduced Sustained Outages	Consumers				
Reduced Major Outages	Consumers				
Reduced Restoration Cost	Utility				
Reduced Momentary Outages	Consumers				
Reduced Sags and Swells	Consumers				
Reduced CO_2 Emissions	Society in general Utility				
Reduced SO_x, NO_x, and PM-10 Emissions	Society in general Utility				
Reduced Oil Usage	Society in general				
Reduced Wide-scale Blackouts	Consumers Society in general				

3.6 Example of Step 6: Identify and compile the data

This step entails identifying and compiling the data needed from the project. The type of data needed depend directly on the benefits to be calculated and the corresponding baseline information which is needed to calculate those benefits. For each applicable benefit identified in the previous step, this step identifies and compiles the needed data. These data are to be collected both before and after the project installs the Smart Grid components.

Table 3-3
Example of Data Requirements

Applicable Benefits			Data Requirements (With and Without the Project)
Economic	Improved Asset Utilization	Optimized Generator Operation	
		Deferred Generation Capacity Investments	Actual and planned capital investments, amortized
		Reduced Ancillary Service Cost	Ancillary payments for VAR support #
		Reduced Congestion Cost	
	T&D Capital Savings	Deferred Transmission Capacity Investments	Actual and planned capital investments, amortized
		Deferred Distribution Capacity Investments	Actual and planned capital investments, amortized
		Reduced Equipment Failures	
	T&D O&M Savings	Reduced Distribution Equipment Maintenance Cost	
		Reduced Distribution Operations Cost	Actual versus projected costs without the project
		Reduced Meter Reading Cost	Actual versus projected costs without the project
	Theft Reduction	Reduced Electricity Theft	Actual versus projected costs without the project
	Energy Efficiency	Reduced Electricity Losses	Actual versus projected costs without the project
	Electricty Cost Savings	Reduced Electricity Cost	Actual versus projected costs without the project. Monthly bill and consumption. Price elasticities, by household
Reliability	Power Interruptions	Reduced Sustained Outages	SAIFI, SAIDI, CAIDI, MAIFI
		Reduced Major Outages	Number of major outages
		Reduced Restoration Cost	
	Power Quality	Reduced Momentary Outages	
		Reduced Sags and Swells	
Environmental	Air Emissions	Reduced CO_2 Emissions	CO2 emissions
		Reduced SO_x, NO_x, and PM-10 Emissions	SOx, NOx, and PM-10 emissions
Security	Energy Security	Reduced Oil Usage (not monetized)	Oil use
		Reduced Widescale Blackouts	

3.7 Example of Step 7: Quantify the benefits

The benefits of a project are the *difference* between conditions with and without the project in place. By "conditions," we mean electricity bills, generation costs, transmission costs, distribution costs, power interruptions, power quality, greenhouse gas emissions, other pollutant emissions, oil consumption, and accidents.

For example, to estimate the benefit, "lower electricity costs to consumers," the benefit is simply the difference between the total monthly bills actually paid by the consumers (e.g., households) who have smart meters installed compared to a randomly selected, representative control group of households who do not have a smart meter. The second-from-the-right column in Table 3-3 identifies the benefits that would be quantified in our hypothetical example.

Section 4.6 and Appendix C discuss the quantification of the various types of benefits in detail.

3.8 Example of Step 8: Monetize the benefits

To put different types of benefits on a common measure, it is useful to express them in equivalent economic terms – i.e., to monetize the benefits. The benefits in the "economic" category are already in dollar terms, e.g., reduced operation and maintenance costs. However, the other categories of benefits are generally not. For the costs of interruptions to consumers – industrial, commercial and residential – estimates are based on the value of service (as used in utilities' filings to public utility commissions) or empirical estimates of the value of lost load, as compiled from surveys of consumers. In our framework, benefits are monetized by multiplying the benefit (measured in physical units such as barrels of oil) by a damage or a willingness to pay (following the usual economics paradigm).

The right column in Table 3-2 represents monetization parameters or "unit values" we suggest for each type of benefit in the example. Section 4.7 provides monetization parameters for non-economic types of benefits.

3.9 Example of Step 9: Estimate the relevant costs

The relevant costs of a project are those incurred to deploy the project, relative to the baseline. These costs include:

- Capital costs for infrastructure (amortized so as to facilitate annual cost-benefit comparison)
- Costs of equipment and devices (also amortized)
- Fuel costs
- Labor for operations, maintenance, and repair and power restoration
- Installed costs of smart-grid support infrastructure and services, such as "back-room" information technology

In this example, we assume that these costs have been compiled and tabulated.

Section 4.8 provides additional discussion on estimating relevant costs.

3.10 Example of Step 10: Compare costs to benefits

Once costs and benefits are estimated, there are alternative ways of comparing them. The most straightforward and common ways are:

- Compiling the annual benefits and costs over the duration of the project – i.e., the differences compared to the baseline for both benefits and costs on the basis of their net present value
- Calculating the net present value, in which benefits minus costs each year of the project, are discounted using some agreed upon discount rate, which typically ranges from 3% to 7% (in real terms, adjusted for inflation); different rates might be used for sensitivity analyses but it is important to be transparent in these analyses and to explicitly state the discount rate used.

Section 4.9 provides additional discussion on how to compare costs to benefits.

4

DESCRIPTION OF STEPS IN THE COST-BENEFIT ANALYSIS OF SMART GRID PROJECTS

This section describes each of the steps in the methodological approach as summarized in Section 2, and as illustrated in Section 3. Several different types of metrics are suggested in this section:

- Project performance metrics, which gauge the technical performance of the system, and are useful for gauging how "well" the project performs from a technical standpoint (refer to Section 4.1)
- Principal Characteristics metrics, which indicate the ways in which the project contributes to the seven Principal Characteristics (as described in Section 4.2)
- Benefits metrics, which are the different types of benefits, as described further in this section (refer to Section 4.6)

Projects might select those most appropriate for their particular applications.

The rest of this section describes each of the ten steps in the overall approach.

4.1 Describe the Project

The initial step in estimating the benefits of a project is to describe it by identifying its Smart Grid elements (i.e., technologies, devices, and systems), goals and system performance metrics. Figure 4-1 is a representative template for summarizing key information.

We think it relevant to define system performance metrics for demonstration projects because they are deploying new technologies and/or innovative methods in an untested and/or novel way to provide new insights or proof of principles.

In particular, new technologies are being tested as part of the DOE RDSI program. Hence, evaluation of the performance of these new technologies is an important objective. Below are examples of parameters that might be appropriate to consider in such evaluations. These metrics relate to the direct performance and achievements of the project. They provide useful information about the success of the demonstration project. (Note that these are not measures of benefits of the projects.) Each project will need to develop metrics that are specific to its design and purpose. Table 4-1 lists suggested project-performance metrics.

Name of Project: ____
Lead Organization: ____
Other Participants: ____
Project Manager/ Contact: Information: ____
Planned Duration of Project: ____
Total Budget: ____
Federal Cost-Share: ____

Project Purpose and Objectives:

Project Summary – Brief Description of the Smart-Grid Elements of the Project:

Technology Transfer, Collaboration and Partnerships:

Hardware Investments and Estimated Costs (including installation, by year):

Software Investments and Estimated Costs (including installation, by year):

Administrative, Operation, Maintenance and other annual costs:

Tariffs and Notable Contractual Arrangements:

Project Approach and Interim Results:

Project Performance Measures:

Figure 4-1
Illustrative Template for General Information to Provide on the Project

Table 4-1
Illustrative Example – Metrics for the Technical Performance of a Project

Project Attribute	Project Performance Metrics
Distributed Generation	• Per cent availability of DG • Cost of operations ($/MWh) • Emissions (tons/MWh) • Islanding success rate • Solar capacity factor • Fault tolerance
Advanced Sensing and Switching	• Transfer speed • Percent successful transfer of sources and loads • Estimated number and/or duration of outages avoided
Feeder Configuration and Control	• Performance statistics on feeder electrical loss reduction; voltage regulation limits achieved • Two way power flow enabled
Microgrid Application	• Per cent successful automatic islanding and reconnection • Voltage and frequency in island mode • Efficiency • Fault tolerance
Provision of Ancillary Services	• Percent realization of market opportunities • Revenue collected • Costs incurred
Demand Reduction (Response)	• Realized load response to price signals (KW/$) • Response rates (KW/min.) • DER response to price signals (KW/$)
Building Energy Efficiency Upgrades	• Realized per cent improvement in heating efficiency, lighting efficiency, etc.
Advanced Distribution Fault Detection	• Percent successful fault identification and isolation • Percent improvement in time to repair • Percent reduction in facilities (users) impacted
Fault Tolerant Communications	• Communications channel availability • Number of successful cyber attacks • Percent of applications compromised by inadequate channel capability
AMI	• Percent successful interaction with load devices • AMI equipment failure rates • Percent successful meter reads

4.2 Identify Smart Grid Functions Provided by Project

Once the project-specific goals are understood, it will be necessary to determine which Smart Grid functions are activated by the assets proposed by the project. Smart Grid assets provide different types of functions to enable Smart Grid benefits. There are also policies and programs that may be implemented along with Smart Grid assets. For example, customers that have access to dynamic pricing programs have an incentive to use the supplementary information provided by advanced metering infrastructure (AMI)/smart meters. Examples of these policies and programs include, but are not limited to: Demand Response; Dynamic Pricing; Critical Peak Pricing; and Distributed Resource Interconnection Policy. Smart Grid assets could include:

- Advanced Interrupting Switch
- AMI/Smart Meters
- Controllable/regulating Inverter
- Customer EMS/Display/Portal
- Distribution Automation
- Distribution Management System
- Enhanced Fault Detection Technology
- Equipment Health Sensor
- FACTS Device
- Fault Current Limiter
- Loading Monitor
- Microgrid Controller
- Phase Angle Regulating Transformer
- Phasor Measurement Technology
- Smart Appliances and Equipment (Customer)
- Software - Advanced Analysis/Visualization
- Two-way Communications (high bandwidth)
- Vehicle to Grid 2-way power converter
- VLI (HTS) cables

These assets can be implemented to modernize the grid through the functions defined in Table 4-2:

- Fault Current Limiting
- Wide Area Monitoring and Visualization and Control
- Dynamic Capability Rating

- Flow Control
- Adaptive Protection
- Automated Feeder Switching
- Automated Islanding and Reconnection
- Automated Voltage and VAR Control
- Diagnosis and Notification of Equipment Condition
- Enhanced Fault Protection
- Real-time Load Measurement and Management
- Real-time Load Transfer
- Customer Electricity Use Optimization

These functions enable the integration of other energy resources defined in Table 4-3, including: Distributed Generation (DG), Stationary Electricity Storage (ES); and Plug-in Electric Vehicles (PEV). Table 4-4 presents suggested linkages between Smart Grid assets and Smart Grid functions. Other linkages are plausible as well – for example, high-temperature superconductivity (HTS) cables can support fault current limiting; two way communications can support flow control, display portal can support real time load measurement and management, etc.

4.3 Assess the Project's Smart Grid Principal Characteristics

The functionality of Smart Grid technologies and systems enables a project to advance the seven Principal Characteristics of the Smart Grid. These characteristics, developed by NETL's Modern Grid Strategy team, have been broadly adopted across the industry:

Enables informed participation by customers

- Consumers have access to new information, control and options to engage in electricity markets
  - Energy management
  - Investment in DER and PHEV
  - Offer resources to market
- Grid operators have new resource options
  - Reduce peak load and prices
  - Improve grid reliability
- E-bay level of activity

Accommodate all generation and storage options

- Seamlessly integrates all types and sizes of electrical generation and storage systems
- "Plug-and-play" convenience
  - Simplified interconnection processes
  - Universal interoperability standards
- Number of smaller, distributed sources will increase – shift to a more decentralized model
- Large central power plants will continue to play a major role.

Enables new and improved products, services, and markets

- Links buyers and sellers
- Consumer to RTO
- Supports the creation of new electricity markets
  - PHEV and vehicle to grid
  - Brokers, integrators, aggregators, etc.
  - New commercial goods and services
- Provides for consistent market operation across regions

Table 4-2
Definitions of Functions

Function	Definition
Fault Current Limiting	Fault current limiting can be achieved through sensors, communications, information processing, and actuators that allow the utility to use a higher degree of network coordination to reconfigure the system to prevent fault currents from exceeding damaging levels.
Wide Area Monitoring and Visualization	Wide area monitoring and visualization requires time synchronized sensors, communications, and information processing that allow the condition of the bulk power system to be observed and understood in real-time so that action can be taken.
Dynamic Capability Rating	Dynamic capability rating can be achieved through real-time determination of an element's (e.g., line, transformer etc.) ability to carry load based on electrical and environmental conditions.
Flow Control	Flow control requires techniques that are applied at transmission and distribution levels to influence the path that power (real & reactive) travels. This uses such tools as flexible AC transmission systems (FACTS), phase angle regulating transformers (PARs), series capacitors, and very low impedance superconductors.
Adaptive Protection	Adaptive protection uses adjustable protective relay settings (e.g., current, voltage, feeders, and equipment) in real time based on signals from local sensors or a central control system. This is particularly useful for feeder transfers and two-way power flow issues associated with high DER penetration.

Table 4-2 (continued)
Definitions of Functions

Function	Definition
Automated Feeder Switching	Automated feeder switching is realized through automatic isolation and reconfiguration of faulted segments of distribution feeders via sensors, controls, switches, and communications systems. These devices can operate autonomously in response to local events or in response to signals from a central control system.
Automated Islanding and Reconnection	Automated islanding and reconnection is achieved by automated separation and subsequent reconnection (autonomous synchronization) of an independently operated portion of the T&D system (i.e., microgrid) from the interconnected electric grid. A microgrid is an integrated energy system consisting of interconnected loads and distributed energy resources which, as an integrated system, can operate in parallel with the grid or as an island.
Automated Voltage and VAR Control	Automated voltage and VAR control requires coordinated operation of reactive power resources such as capacitor banks, voltage regulators, transformer load-tap changers, and distributed generation (DG) with sensors, controls, and communications systems. These devices could operate autonomously in response to local events or in response to signals from a central control system.
Diagnosis & Notification of Equipment Condition	Diagnosis and notification of equipment condition is defined as on-line monitoring and analysis of equipment, its performance and operating environment to detect abnormal conditions (e.g., high number of equipment operations, temperature, or vibration). Automatically notifies asset managers and operations to respond to conditions that increase the probability of equipment failure.
Enhanced Fault Protection	Enhanced fault protection requires higher precision and greater discrimination of fault location and type with coordinated measurement among multiple devices. For distribution applications, these systems will detect and isolate faults without full-power re-closing, reducing the frequency of through-fault currents. Using high resolution sensors and fault signatures, these systems can better detect high impedance faults. For transmission applications, these systems will employ high speed communications between multiple elements (e.g., stations) to protect entire regions, rather than just single elements. They will also use the latest digital techniques to advance beyond conventional impedance relaying of transmission lines.
Real-time Load Measurement and Management	This function provides real-time measurement of customer consumption and management of load through Advanced Metering Infrastructure (AMI) systems (smart meters, two-way communications) and embedded appliance controllers that help customers make informed energy use decisions via real-time price signals, time-of-use (TOU) rates, and service options.
Real-time Load Transfer	Real-time load transfer is achieved through real-time feeder reconfiguration and optimization to relieve load on equipment, improve asset utilization, improve distribution system efficiency, and enhance system performance.
Customer Electricity Use Optimization	Customer electricity use optimization is possible if customers are provided with information to make educated decisions about their electricity use. Customers should be able to optimize toward multiple goals such as cost, reliability, convenience, and environmental impact.

Table 4-3
Definitions of Enabled Energy Resources (EER)

Enabled Energy Resource	Definition
Distributed Generation (DG)	Smart grid functions allow utilities to remotely operate DG systems to control output, defer upgrades to generation and T&D assets, and improve voltage regulation. This category includes dispatchable, distributed generation such as combined heat and power, fossil fuel powered backup generators, bio-fuel powered backup generators (e.g., biodiesel, waste to energy, digester gas) or geo-thermal energy. It also includes variable, distributed generation such as solar and wind.
Stationary Electricity Storage	Remote utility control of electricity storage inflow/outflow reduces energy costs and enhances power generation and T&D capacity utilization.
Plug-in Electric Vehicles	Remote utility control of plug in hybrid electric vehicles (PHEV) and electric vehicles (EV) inflow/outflow reduces energy costs and enhances power generation and T&D capacity utilization.

Table 4-4
Linkage of Smart Grid Assets to Functions

Smart Grid Assets	Functions												
	Fault Current Limiting	Wide Area Monitoring, Visualization, and Control	Dynamic Capability Rating	Flow Control	Adaptive Protection	Automated Feeder Switching	Automated Islanding and Reconnection	Automated Voltage and VAR Control	Diagnosis & Notification of Equipment Condition	Enhanced Fault Protection	Real-Time Load Measurement & Management	Real-time Load Transfer	Customer Electricity Use Optimization
Advanced Interrupting Switch										•			
AMI/Smart Meters								•			•		•
Controllable/regulating Inverter							•	•					
Customer EMS/Display/Portal													•
Distribution Automation					•	•	•	•				•	
Distribution Management System			•		•	•	•	•			•	•	
Enhanced Fault Detection Technology										•			
Equipment Health Sensor			•						•				
FACTS Device				•									
Fault Current Limiter	•												
Loading Monitor			•						•			•	
Microgrid Controller							•						
Phase Angle Regulating Transformer				•									
Phasor Measurement Technology		•											
Smart Appliances and Equipment (Customer)													•
Software - Advanced Analysis/Visualization		•	•										
Two-way Communications (high bandwidth)		•			•	•	•	•			•	•	
Vehicle to Grid 2-way power converter													
VLI (HTS) cables				•									

Provides power quality for the range of needs in the 21st century economy

- Monitors, diagnoses and responds to PQ issues
- Supplies various grades of power quality at different pricing levels
- Greatly reduces consumer losses due to PQ (~$25B/year)
- Quality Control for the grid

Optimizes asset utilization and operating efficiency

- Operational improvements
  - Improved load factors and lower system losses
  - Integrated outage management
  - Risk assessment
- Asset Management improvements
  - The knowledge to build only what we need
  - Improved maintenance processes
  - Improved resource management processes
  - More power through existing assets
- Reduction in utility costs (O&M and Capital)

Addresses disturbances through automated prevention, containment and restoration

- Performs continuous self-assessments
- Detects, analyzes, responds to, and restores grid components or network sections
- Handles problems too large or too fast-moving for human intervention
- Self heals - acts as the grid's "immune system"
- Supports grid reliability, security, and power quality

Operates resiliently against all hazards

- System-wide solution to physical and cyber security
- Reduces threat, vulnerability, consequences
- Deters, detects, mitigates, responds, and restores
- "Fort Knox" image
- Decentralization and self-healing enabled

These Principal Characteristics of a Smart Grid have become a broadly accepted concept among the Smart Grid community (OE, 2008). The characteristics, and the metrics which many have suggested for each characteristic, are generally for measuring progress toward attaining characteristics of the Smart Grid on a national scale, rather than in individual projects.

However, the Principal Characteristics *are* relevant to individual projects because they will cumulatively lead to the build-out of the Smart Grid on a larger scale and thus contribute to progress toward the broader implementation and attainment of these characteristics nationwide.

At the same time, some of the previously-identified metrics are inappropriate to use at the scale of individual projects. This section suggests a set of metrics which projects can use to convey their contribution to providing Principal Characteristics of the Smart Grid.

We used three criteria in suggesting these metrics:

- The same metrics as those regarded as the more useful, higher-priority metrics as determined at the Smart Grid Implementation Workshop in June 2008 (OE 2008), *if* these metrics are relevant in a *project* (rather than service area or national) context.
- Additional metrics suggested in the U.S. Department of Energy's Funding Opportunity Announcement on Smart Grid Investment Grants (DOE FOA SGIG) (DOE 2009a, p. 10-11), so that projects applying for such grants will have a set of metrics to use that is consistent with those suggested in such announcements.
- Additional metrics which we regarded to be relevant and useful.

This step of the methodological approach, then, calls on the project to assess the elements of the project, identify the Principal Characteristics which it provides, and select metrics from among those listed in Table 4-5 under each of the characteristics. The metrics in regular font are those selected from the larger set of metrics originally identified in the Implementation Workshop (OE 2008). *The metrics in italics are those added by our study team (not among the metrics prioritized in the Implementation Workshop).* The metrics in blue font are ones used in the DOE Funding Opportunity Announcement (FOA) for Smart Grid Investment Grants (SGIG). Check the FOA for the exact wording.

Table 4-5
Standard Metrics for Smart Grid Characteristics of Projects

Smart Grid Principal Characteristic	Project Metrics for Smart Grid Characteristics ▪ Regular font – selected from the larger set of metrics originally identified in the Implementation Workshop ▪ *Italics – added by our study team* ▪ Blue font – used in the DOE FOA SGIG
1. Enables informed participation by customers	1.1 Number *(%)* of customers or premises in the project capable of receiving information from the grid *1.2 Number of consumer portals (consumer agents) in project* 1.3 Number of customers opting to make decisions or to delegate decision-making authority 1.4 Number of communication-enabled, customer-side of the meter devices installed 1.5 Number of customer-side of the meter devices sending or receiving grid-related signals 1.6 Number and % of electricity customers and magnitude of total load in service territory served by appliances that can communicate information and/or be controlled automatically 1.7 Amount of load managed (%) *1.8 Measurable energy savings by customers resulting from their response to price signals and better usage and cost information (includes shifting to more efficient appliances as well as adding insulation)* *1.9 Number of customers employing energy storage or generation systems that respond to pricing signals sent by the grid operator or other entity*
2. Accommodates all generation and storage options	*2.1* Percent of distributed generation and storage that can be controlled *directly; percent that can be influenced by pricing signals* 2.2 Percent of load, as measured by kWh and KW, served by distributed resources 2.3 Percent of off-peak renewable energy dispatching on-peak through storage 2.4 Load factor (average load divided by peak load) at various points in the electric system *2.5 Amount of energy or capacity delivered as an Ancillary Service Amount of DG that employs combined heat and power a result of the project* *2.6 Amount of DG that employs combined heat and power or a renewable source* *2.7 Ability to accommodate two way flow on distribution Amount of DG that employs combined heat and power a result of the project*

Table 4-5 (continued)
Standard Metrics for Smart Grid Characteristics of Projects

Smart Grid Principal Characteristic	Project Metrics for Smart Grid Characteristics ▪ Regular font – selected from the larger set of metrics originally identified in the Implementation Workshop ▪ *Italics – added by our study team* ▪ Blue font – used in the DOE FOA SGIG
3. Enables new products, services, and markets	3.1 Number of products with end-to-end interoperability certification, which are used in the project 3.2 Number of new residential products, which were not available two years prior, that are installed in the project *3.3 Amount of energy or capacity delivered as an Ancillary Service* *3.4 Number and % of annual vehicle sales in service area that involve plug-in electric and hybrid vehicles, whose use is enabled by the Smart Grid project*
4. Provides power quality for the range of needs in the 21st century economy	*4.1 Improvement in PQ index (e.g, total harmonic distortion in the circuit voltage)* 4.2 Number of power quality measurement points divided by number of customers 4.3 Number of power quality incidents that one can identify and anticipate *4.4 Number of customer complaints regarding power quality issues (reduction in customer estimated dollar losses resulting from PQ problem)* *4.5 Reduction in system KW losses and equipment failures due to improved PQ* *4.6 Number of installation points and percentage and magnitude of the total load covered by microgrids* *4.7 Number of installation points and percentage and magnitude of the total load covered by Supervisory Control and Data Acquisition (SCADA) systems* *4.8 Number of installation points and percentage and magnitude of the total load in the service territory covered by phasor measurement units (PMUs)* *4.9 Number of installation points and percentage and magnitude of the total load served by phasor data concentrators receiving data from PMUs that share all relevant data with external parties* *4.10 Number of installation points and percentage and magnitude of the total load served real time data management and visualization systems receiving data from PDCs and PMUs* *4.11 Number of installation points and percentage and magnitude of the total load covered by automated electric transmission systems or possessing advanced measurement*

Table 4-5 (continued)
Standard Metrics for Smart Grid Characteristics of Projects

Smart Grid Principal Characteristic	Project Metrics for Smart Grid Characteristics ▪ Regular font – selected from the larger set of metrics originally identified in the Implementation Workshop ▪ *Italics – added by our study team* ▪ Blue font – used in the DOE FOA SGIG
5. Optimizes asset utilization and operating efficiency	5.1 Amount of deferred generation (MW) as a result of the project *5.2 Amount of deferred station and line investment deferred as a result of the project* 5.3 Level of asset utilization or load factor (average load divided by peak load) *5.4 Reduction in O&M costs as a result of the project (including electrical losses and energy theft)* *5.5 Improvement in outage restoration time as a result of the project* *5.6 Reduction in grid equipment failures as a result of the project*
6. Addresses disturbances through automated prevention, containment and restoration	6.1 Percent of network nodes and customer interfaces that are monitored in real time *6.2 Improvement in reliability statistics as a result of the project* *6.3 Improvement (number and duration) in major area blackouts as a result of the project* *6.4 Improvement in outage restoration time as a result of the project* *6.5 Outages avoided through improved monitoring and deployment of DER/DR as a result of the project*
7. Operates resiliently against all hazards	7.1 Number alternative paths of supply to any load point on the distribution grid *7.2 DER penetration (%) and geographic diversity* 7.3 Number of successful cyber attacks *7.4 Improvement in outage restoration time as a result of the project*

Sources:
Smart Grid CBAT, based on priorities in “Metrics for Measuring Progress Toward Implementation of the Smart Grid: Results of the Breakout Session Discussions at the Smart Grid Implementation Workshop,” June 19-20, 2008, Washington, DC, prepared for the U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, by Energetics Incorporated, July 31, 2009. Additions /clarifications /modifications (in blue) were provided by the authors.

This list in Table 4-5 should not be a substitute for describing the functionality of the project, nor for identifying the appropriate types of benefits to estimate.

4.4 Map Functions to Benefits

As shown in Table 4-6, benefits were identified and categorized as Economic, Reliability, Environmental or Security and include 10 subcategories and 22 individual Smart Grid benefits. Table 4-7 provides definitions of each of the individual benefits. The linkage between functions and benefits is presented in Table 4-8 and the rationale for the benefits realized by each function is described below.

Table 4-6
List of Smart Grid Benefits

Benefit Category	Benefit Sub-category	Benefit
Economic	Improved Asset Utilization	Optimized Generator Operation Deferred Generation Capacity Investments Reduced Ancillary Service Cost Reduced Congestion Cost
	T&D Capital Savings	Deferred Transmission Capacity Investments Deferred Distribution Capacity Investments Reduced Equipment Failures
	T&D O&M Savings	Reduced Distribution Equipment Maintenance Cost Reduced Distribution Operations Cost Reduced Meter Reading Cost
	Theft Reduction	Reduced Electricity Theft
	Energy Efficiency	Reduced Electricity Losses
	Electricity Cost Savings	Reduced Electricity Cost
Reliability	Power Interruptions	Reduced Sustained Outages Reduced Major Outages Reduced Restoration Cost
	Power Quality	Reduced Momentary Outages Reduced Sags and Swells
Environmental	Air Emissions	Reduced CO_2 Emissions Reduced SO_x, NO_x, and PM-10 Emissions
Security	Energy Security	Reduced Oil Usage Reduced Wide-scale Blackouts

Table 4-7
Definitions of Smart Grid Benefits

Benefit	Description
Optimized Generator Operation	Better forecasting and monitoring of load and grid performance would enable grid operators to dispatch a more efficient mix of generation that could be optimized to reduce cost.
Reduced Generation Capacity Investments	Utilities and grid operators ensure that generation capacity can serve the maximum amount of load that planning and operations forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. Reducing peak demand and flattening the load curve should reduce the generation capacity required to service load, and lead to cheaper electricity for customers.
Reduced Ancillary Service Cost	Ancillary services including spinning reserve and frequency regulation could be reduced if generators could more closely follow load Ancillary services are necessary to ensure the reliable and efficient operation of the grid. The level of ancillary services required at any point in time is determined by the grid operator and/or energy market rules. The functions that provide this benefit reduce ancillary cost through improving the information available to grid operators.
Reduced Congestion Cost	Transmission congestion is a phenomenon that occurs in electric power markets. It happens when scheduled market transactions (generation and load) result in power flow over a transmission element that exceeds the available capacity for that element. Since grid operators must ensure that physical overloads do not occur, they will dispatch generation so as to prevent them. The functions that provide this benefit either provide lower cost energy or allow the grid operator to manage the flow of electricity around constrained interfaces.
Deferred Transmission Capacity Investments	Reducing the load and stress on transmission elements increases asset utilization and reduces the potential need for upgrades. Closer monitoring, rerouting power flow, and reducing fault current could enable utilities to defer upgrades on lines and transformers.
Deferred Distribution Capacity Investments	As with transmission lines, closer monitoring and load management on distribution feeders could potentially extending the time before upgrades or capacity additions are required.
Reduced Equipment Failures	Reducing mechanical stresses on equipment increases service life and reduces the probability of premature failure.
Reduced Distribution Equipment Maintenance Cost	The cost of sending technicians into the field to check equipment condition is high. Moreover, to ensure that they maintain equipment sufficiently, and identify failure precursors, some utilities may conduct equipment testing and maintenance more often than is necessary. Online diagnosis and reporting of equipment condition would reduce or eliminate the need to send people out to check equipment.
Reduced Distribution Operations Cost	Automated or remote controlled operation of capacitor banks and feeder switches eliminates the need to send a line worker or crew to the switch location in order to operate it. This reduces the cost associated with the field service worker(s) and service vehicle.

Table 4-7 (continued)
Definitions of Smart Grid Benefits

Benefit	Description
Reduced Meter Reading Cost	Automated Meter Reading (AMR) equipment eliminates the need to send someone to each location to read the meter manually.
Reduced Electricity Theft	Smart meters can typically detect tampering. Moreover, a meter data management system can analyze customer usage to identify patterns that could indicate diversion.
Reduced Electricity Losses	The functions listed help manage peak feeder loads, locate electricity production closer to the load and ensure that customer voltages remain within service tolerances, while minimizing the amount of reactive power provided. These improve the power factor, and reduce line losses for a given load served.
Reduced Electricity Cost	The functions listed could help alter customer usage patterns (demand response with price signals or direct load control), or help reduce the cost of electricity during peak times through either production (DG) or storage.
Reduced Sustained Outages	Reduces the likelihood that there will be an outage, and allows the system to be reconfigured on the fly to help in restoring service to as many customers as possible. A sustained outage is one lasting > 5 minutes, excluding major outages and wide-scale outages (defined below). The benefit to consumers is based on the value of service (VOS).
Reduced Major Outages	A major outage is defined using the beta method, per IEEE Std 1366-2003 (IEEE Power Engineering Society 2004). The functions listed can isolate portions of the system that include distributed generation so that customers will be served by the distributed generation until the utility can restore service to the area. Only the customers in the island, (i.e., < 5,000 customers) or smaller experience reduced outage time from this improved reliability.
Reduced Restoration Cost	The functions that provide these benefits cause fewer outages, which result in fewer restoration costs. These costs can include line crew labor/material/equipment, support services such as logistics, call centers, media relations, and other professional staff time and material associated with service restoration.
Reduced Momentary Outages	By locating faults or adding electricity storage, momentary outages could be reduced or eliminated. Moreover, fewer customers on the same or adjacent distribution feeders would experience the momentary interruptions associated with reclosing. Momentary outages last <5 min in duration. The benefit to consumers is based on the value of service.
Reduced Sags and Swells	Locating high impedance faults more quickly and precisely, and adding electricity storage, functions will reduce the frequency and severity of the voltage fluctuations that they can cause. Moreover, fewer customers on the same or adjacent distribution feeders would experience the voltage fluctuation caused by the fault.
Reduced CO_2 Emissions	Functions that provide this benefit can improve performance in many aspects for end-users. These improvements translate into a reduction in CO_2 emissions produced by fossil-based electricity generators.
Reduced SOx, NOx, and PM-10 Emissions	Functions that provide these benefits can improve performance in many aspects for end-users. These improvements translate into a reduction in SOx, NOx, and PM-10 emissions produced by fossil-based electricity generators.

Table 4-7 (continued)
Definitions of Smart Grid Benefits

Benefit	Description
Reduced Oil Usage (not monetized)	The functions that provide this benefit eliminate the need to send a line worker or crew to the switch location in order to operate it. This reduces the fuel consumed by a service vehicle or line truck. For PEV, the electrical energy used by PEVs displaces the equivalent amount of oil.
Reduced Wide-scale Blackouts	The functions listed will give grid operators a better picture of the bulk power system, and allow them to better coordinate resources and operations between regions. This will reduce the probability of wide-scale regional blackouts.

Table 4-8
Mapping of Functions to Benefits

Benefits			Functions													Energy Resources		
			Fault Current Limiting	Wide Area Monitoring, Visualization, and Control	Dynamic Capability Rating	Flow Control	Adaptive Protection	Automated Feeder Switching	Automated Islanding and Reconnection	Automated Voltage and VAR Control	Diagnosis & Notification of Equipment Condition	Enhanced Fault Protection	Real-Time Load Measurement & Management	Real-time Load Transfer	Customer Electricity Use Optimization	Distributed Generation	Stationary Electricity Storage	Plug-in Electric Vehicles
Economic	Improved Asset Utilization	Optimized Generator Operation		•													•	•
		Deferred Generation Capacity Investments													•	•	•	•
		Reduced Ancillary Service Cost		•						•			•			•	•	•
		Reduced Congestion Cost		•	•	•										•	•	•
	T&D Capital Savings	Deferred Transmission Capacity Investments	•	•	•	•									•	•	•	•
		Deferred Distribution Capacity Investments			•								•	•	•	•	•	•
		Reduced Equipment Failures	•		•						•	•						
	T&D O&M Savings	Reduced Distribution Equipment Maintenance Cost									•							
		Reduced Distribution Operations Cost						•		•								
		Reduced Meter Reading Cost											•					
	Theft Reduction	Reduced Electricity Theft											•					
	Energy Efficiency	Reduced Electricity Losses								•			•	•	•	•	•	
	Electricty Cost Savings	Reduced Electricity Cost													•	•	•	•
Reliability	Power Interruptions	Reduced Sustained Outages					•	•	•		•	•	•			•	•	•
		Reduced Major Outages		•					•				•	•				
		Reduced Restoration Cost					•	•			•	•						
	Power Quality	Reduced Momentary Outages										•					•	
		Reduced Sags and Swells										•					•	
Environmental	Air Emissions	Reduced CO_2 Emissions				•		•		•			•		•	•	•	•
		Reduced SO_x, NO_x, and PM-10 Emissions				•		•		•			•		•	•	•	•
Security	Energy Security	Reduced Oil Usage (not monetized)						•			•		•					•
		Reduced Widescale Blackouts		•	•							•						

4.4.1 Fault Current Limiting

Very high currents due to short circuits can cause severe mechanical stress on T&D equipment, resulting in failure or damage over time. These high currents can be limited to safe levels by inserting an electrical resistance into the circuit between the sources of the fault current and the equipment that must be protected. This capability is generally sought for application at the transmission level, but some utilities may also apply fault current limiters (FCL) on distribution where cost effective. FCLs are not commercially available at this time. Several equipment suppliers and research organizations (including DOE and EPRI) are pursuing the development of FCLs based on high temperature superconductivity (HTS) materials or semiconductor based devices. These advanced devices have a combination of performance characteristics that may make them practical for general application by utilities. However, this is several years away, and these will not likely be seen in near term projects. In the longer term, this function can lead to two benefits:

- Deferred Transmission Capacity Investments - Fault currents that exceed the interrupting capability of circuit breakers and other equipment can lead utilities to either replace the breakers with higher capability units, or reconfigure one or more substations. Both solutions can be very expensive and challenging from an operational perspective, particularly for critical substations. An FCL can prevent currents from exceeding the interrupting ratings of circuit breakers, or the maximum current rating of other equipment, which may, allow the utility to defer or eliminate the need for upgrades or reconfiguration.
- Reduced Equipment Failures - The FCL limits the level of fault current that flows through equipment, and reduces the associated mechanical stress and damage. This can increase equipment service life and reduce the probability of premature failure. Consider a very typical example on a large utility grid operating at 138 kV. If the original transmission fault current was 63 kilo-Amps (a 15,058 MVA fault power) and the modified fault with an FCL on a Smart Grid is reduced to 21 kilo-Amps (now only 5,019 MVA fault power), this is a very significant magnetic force reduction factor of 1/9 that amounts to a life extension of the transformer and associated switchgear. A unit may experience 15 medium to large short circuits per annum. It is this type of 1/9 fault reduction that can realize a 10 year life extension to a major piece of apparatus such as a 500 MVA transformer.

4.4.2 Wide Area Monitoring and Visualization

Wide area monitoring (WAM) is the ability to monitor transmission system conditions over large regions (multiple states) and display this information in ways that human operators can accurately interpret and act upon. Technologies such as phasor measurement units, data concentrators, and advanced software are used to provide a real-time operating picture of the bulk transmission system. This information will be available in grid control centers to help operators observe, analyze, and operate the system more precisely and reliably. This function can lead to six benefits:

- Optimized Generator Operation – All of the generators within an electrical interconnection are naturally synchronized with the system frequency. Each unit can produce real and reactive power, and contribute to the overall electrical stability of the interconnected system. Until recently, grid operators could only “observe” and analyze the stability performance of these generators using complex off-line simulation tools. WAMC, including phasor measurement units (PMUs) is enabling operators to observe the voltage and current waveforms of the bulk power system at very high levels of detail. This capability will provide deeper insight into the real-time stability of the power system, and the effects of generator dispatch and operation. It will allow operators to potentially optimize individual generators, and groups of generators, to improve grid stability during conditions of high system stress.
- Reduced Ancillary Service Cost - Ancillary services are necessary to ensure the reliable and efficient operation of the grid. As discussed above, ancillary services are provided by generators, and generally include operating reserves, frequency regulation, and voltage and VAR support. The level of ancillary services required at any point in time is determined by the grid operator and/or energy market rules. To a great extent, the level of ancillary services required is based on extensive operating experience and planning studies. Because of limitations in operating information and coordination between regional power grids, ancillary service levels may be necessarily conservative to ensure grid reliability. By improving the information available to grid operators, it is possible that ancillary service levels could be reduced, decreasing the cost of energy for market participants and utilities.
- Reduced Congestion Cost – As discussed under Optimized Generator Operation, WAMC allows grid operators a high resolution view of the power system and its stability. In many cases, transmission capability is limited by stability, not thermal capacity. To the extent that WAMC could enable grid operators in raise the stability limit of a transmission line or system interface, congestion could be reduced without reducing grid reliability.
- Deferred Transmission Capacity Investments – Raising the stability limit of a transmission line or grid interface could defer an upgrade need to increase capacity and reduce congestion.
- Reduced Major Outages – WAMC could help improve grid stability, and help grid operators avoid conditions that could lead to generator tripping or other results that could cause outages.
- Reduced Wide-scale Blackouts – Wide area monitoring will give grid operators in each control area a better picture of the bulk power system and allow them to better coordinate resources and operations between regions. This enhanced coordination will reduce the probability of wide-scale blackouts.

4.4.3 Dynamic Capability Rating

Capability ratings for power lines and equipment are typically based on thermal limits. Because of the inherent electrical resistance of normal conductor, the more current they carry, the hotter they become. Ratings on equipment (like transformers) are limited by the amount of heat that can be tolerated before damage or degradation occurs. Ratings on transmission lines are typically based on how low the conductor sags due to heating. Some transmission lines are stability limited, and are not operated up to their thermal limits.

Since ambient conditions, such as air temperature, wind speed, and moisture affect heat rejection from equipment, they can significantly affect the true power handling capability of lines and equipment. Utilities typically assign ratings to lines and equipment to account for seasonal changes, and also emergency conditions. These ratings are based on manufacturer specifications, utility standards, and operating experience. Although these ratings schedules attempt to account for changes in ambient conditions, they cannot account for the actual conditions in which system elements are operating at any point in time. For much of the time, these ratings may be conservative and may limit loading unnecessarily.

Dynamic Capability Rating utilizes sensors, information processing and communications to give grid operators a clearer picture of the true capability of network elements in real time. In cool or windy conditions, this could allow a grid operator to load a transmission line beyond its basic rating without overheating. In extremely hot weather, this could prevent a transformer from being loaded to the point of winding damage or failure. This function can lead to five benefits:

- Reduced Congestion Cost – Transmission congestion is a phenomenon that occurs in electric power markets. It happens when scheduled market transactions (generation and load) result in power flow over a transmission element that exceeds the available capacity for that element. Since grid operators must ensure that physical overloads do not occur, they will dispatch generation so as to prevent them. In some cases, a low cost generator may not be dispatched, because doing so would overload a transmission line. In such cases, a more expensive generator located on the "other side" of the limiting transmission line would be dispatched. The difference in cost between the more expensive generator and the less expensive generator (re-dispatch cost) is the congestion cost. The ability to increase the rating of a transmission line dynamically in response to actual conditions could free up capacity by avoiding or reducing congestion.
- Deferred Transmission Capacity Investments – Monitoring electrical and environmental conditions for transmission elements in near-real time including lines and transformers could enable utilities to defer upgrades. For example, ambient temperature and wind speed are critical factors that affect the rated capability of a transmission line which could be monitored to determine whether the lifetime of the investment could be extended. However it should be noted that this function could also advance upgrades. The information that is gained from all of the new sensing and communications will enable utilities to make better decisions, and this could include completing upgrades earlier. For example, a utility might advance an upgrade of a transformer that is discovered to be overloading (negative deferral), but you could reduce the chance that the transformer fails due to overloading.

- Deferred Distribution Capacity Investments – Monitoring electrical and environmental conditions for distribution elements in near-real time including lines and transformers could enable utilities to defer upgrades. For example, ambient temperature and wind speed are critical factors that affect the rated capability of a distribution line.
- Reduced Equipment Failures – Since equipment capability ratings are based on heating and the ability of the equipment to reject heat, ambient temperature and wind speed are critical factors in determining the physical impact of load on equipment such as transformers. Limiting the rating on equipment in extreme temperature conditions can increase increasing service life and reduce the probability of premature failure.
- Reduced Wide-scale Blackouts – Dynamic capability ratings will give grid operators a better picture of the condition of critical system components, including key transmission lines. For example, during a very hot day it would be possible for the real rating of a transmission line to be lower than the rating in the grid operations computer. Providing the grid operators with the actual information could reduce the probability of overloading the line and causing a critical fault that could trigger a blackouts.

4.4.4 Flow Control

In AC power systems, the impedance of lines and transformers determines how power flows from generators to load. As electricity follows "the path of least resistance", it does not necessarily go where engineers and grid operators would prefer. By increasing or decreasing the impedance of a line or transformer (resistance and reactance), power flow can be changed.

Today, flow control can be done with phase angle regulating transformers (PARs) or Flexible AC Transmission System (FACTS) devices. However, these solutions are often expensive, and they are not widely applied. New technologies such as superconducting cables hold promise due to their very low impedance, and could be used in combination with other devices to regulate power flow over critical areas of the system. For example, American Superconductor envisions pairing a very low impedance (VLI) cable with a phase angle regulator. Using the two together you can control the combination of a very low impedance with a controllable impedance. The cable by itself cannot do flow control, it can only reduce the impedance. This function results in four benefits:

- Reduced Congestion Cost – Transmission congestion costs are incurred when more expensive generation must be dispatched to avoid overloading a transmission line or interface. The ability to control impedance and "steer" power around a constrained interface could avoid congestion and its associated cost. As an example, assume a transmission line had a rating of 1,000 MW. Based on the scheduled dispatch at a particular time, the forecasted power flow over the line based on scheduled energy transactions would be 1,100 MW. By utilizing a controllable impedance element, the grid operator could draw power away from the limiting line, preventing the overload, while still delivering the desired power.
- Deferred Transmission Capacity Investments – load growth and generation additions can lead to increased loading on lines and transformers, to the point where transmission capacity investments become necessary. By managing power flow on critically loaded system elements using impedance control. For example, it could be possible for a utility to delay

adding transmission capacity for one or more years without running the risk of an overload. Each year that a capital investment can be deferred can yield a significant savings in the utility's revenue requirement (equal to the capital carrying charge of the upgrade). Therefore, flow control could yield direct savings based on the time that it could postpone a capacity investment.

- Reduced CO_2 Emissions – Reducing the impedance of the T&D system reduces energy losses, and consequently, the generation required to serve load. Provided that the generation reduced is fossil-based, polluting emissions are reduced.
- Reduced SO_X, NO_X, and PM-10 Emissions – Reducing the impedance of the T&D system reduces energy losses, and consequently, the generation required to serve load. Provided that the generation reduced is fossil-based, polluting emissions are reduced.

4.4.5 Adaptive Protection

Detecting and clearing electrical faults (short circuits) is critically important for ensuring public safety, preserving property, and minimizing damage to the electrical system itself. Faults are detected using protective relays that monitor current and voltage and send signals to circuit breakers or switches when conditions exceed set points. (Fuses are also used on distribution feeders, and sometimes as backup for circuit breakers to protect equipment such as large transformers.) Electric power systems are protected by complex systems of relays and switching devices whose settings and operation is carefully designed and coordinated by engineers as part of initial system implementation. Protection schemes are designed to provide reliable fault clearing under expected conditions, and are not frequently changed.(Fuses are also used on distribution feeders, and sometimes as backup for circuit breakers to protect equipment such as large transformers.)

Adaptive protection means that relay settings and protection schemes can be changed in response to changing system conditions. For example, a distribution feeder might be designed with relays set to trip if the current flowing from the substation exceeds a predetermined level. If generation was added to the feeder, it might require that the existing relay settings be changed to provide optimum protection. Since the feeder generation could come on or off, it might make protection highly complicated and expensive. By allowing the protection settings to be changed, the utility can ensure that the feeder is adequately protected, and that the generator can be integrated without prohibitive cost. Such a capability will also prove useful for reconfiguring feeder connections during outage or load transfer operations. Similar reasoning applies to transmission applications of adaptive protection. This function can provide two benefits:

- Reduced Sustained Outages – Modifying protection settings in response to changing conditions could enable utilities to better isolate system faults, and reduce the scope and duration of outages. Adaptive protection reduces the likelihood that there will be an outage, and allows the system to be reconfigured on the fly to help in restoring service to as many customers as possible.
- Reduced Restoration Costs – Fewer outages result in lower restoration costs incurred by the utility. These costs can include line crew labor/material/equipment, support services such as logistics, call centers, media relations, and other professional staff time and material associated with service restoration.

4.4.6 Automated Feeder Switching

Utilities design distribution feeders with switches so that portions of the feeder can be disconnected to isolate faults, or de-energized for maintenance.[5] In most cases, these switches are manually operated, and require a service worker to travel to the switch location, coordinate switching orders with a dispatcher, and then physically operate the switch. Automatic Feeder Switching makes it possible to operate distribution switches autonomously in response to local events, or remotely in response to operator commands or a central control system.

Automatic Feeder Switching does not prevent outages; it simply reduces the scope of outage impacts in the longer term. This function is accomplished through the automatic isolation and reconfiguration of faulted segments of distribution feeders via sensors, controls, switches, and communications systems. Automatic Feeder Switching can reduce or eliminate the need for a human operator or field crew for operating distribution switches. This saves time, reduces labor cost, and eliminates "truck rolls". This function can provide six benefits:

- Reduced Distribution Operations Cost – Automated or remote controlled switching eliminates the need to send a line worker or crew to the switch location in order to operate it. This reduces the cost associated with the field service worker(s) and service vehicle.
- Reduced Sustained Outages – Automated feeder switching means that the faulted portions of feeders can be isolated by opening switches. By reconnecting some customers quickly (within minutes), significant outage minutes can be saved. This only works when a significant number of customers receive service upstream of the fault, with an automated switch between them and the fault. This function presumes that the switching is done within the scope of a single feeder. Automatic switching does not prevent the outage for all customers; it simply reduces the scope of its impact in the longer term. In more advanced Smart Grid applications, combinations of Automated Feeder Switching, Distributed Generation (and storage) would allow some customers downstream of the fault to also receive service.
- Reduced Restoration Cost – Being able to operate distribution switches without rolling trucks means lower restoration costs.
- Reduced CO_2 Emissions – Fewer truck rolls for switching means less fuel consumed by a service vehicle or line truck and leads to reduced emissions.
- Reduced SO_X, NO_X, and PM-10 Emissions – Fewer truck rolls for switching means less fuel consumed by a service vehicle or line truck and leads to reduced emissions.
- Reduced Oil Usage – Fewer truck rolls for switching means less fuel consumed by a service vehicle or line truck and leads to reduced oil usage.

[5] This function presumes that the switching is done within the scope of a single feeder, and should not be confused with Real-Time Load Transfer which assumes that the un-faulted portion of a feeder could be served from an adjacent substation.

4.4.7 Automated Islanding and Reconnection

A microgrid is an integrated energy system consisting of interconnected loads and distributed energy resources which, as an integrated system, can operate in parallel with the grid or as an island. This disconnection and reconnection of the microgrid and the interconnected electric grid would be done automatically as needed based on grid conditions. This function leads to two benefits:

- Reduced Sustained Outages – Automated islanding and reconnection means portions of the system that include distributed generation can be isolated from areas with excessive damage. Customers within the island, or microgrid, will be served by the distributed generation until the utility can restore service to the area. Only the customers in the island experience reduced outage time from this improved reliability. While the outage may affect wide areas, and large numbers of customers, the island will most likely be no larger than a single distribution feeder (i.e., < 5,000 customers) or smaller.
- Reduced Major Outages – Automated islanding and reconnection means portions of the system that include distributed generation can be isolated from areas with excessive damage. Customers within the island, or microgrid, will be served by the distributed generation until the utility can restore service to the area. Only the customers in the island experience reduced outage time from this improved reliability. While the outage may affect wide areas, and large numbers of customers, the island will most likely be no larger than a single distribution feeder (i.e., < 5,000 customers) or smaller.

4.4.8 Automated Voltage and VAR Control

Automated voltage and VAR control is performed through devices that can increase or lower voltage and can be switched or adjusted to keep the voltage in a required range. Control systems could determine when to operate these devices, and do so automatically. This function is the result of coordinated operation of reactive power resources such as capacitor banks, voltage regulators, transformer load-tap changers, storage and distributed generation (DG) with sensors, controls, and communications systems. These devices could operate autonomously in response to local events or in response to signals from a central control system. By better managing voltage and VAR resources, the transmission and distribution network can be optimized for electrical efficiency (lower losses), and can allow utilities to reduce load through “energy conservation voltage reduction” while maintaining adequate service voltage. These load reductions will contribute to the amount of generation required. It should be noted that these might not be accomplished independent of other upgrades previously mentioned, or at least their impact may be reduced if this is undertaken after the other investments. This function provides five benefits:

- Reduced Ancillary Service Cost – Ancillary services are necessary to ensure the reliable and efficient operation of the grid. As discussed above, ancillary services are provided by generators, and voltage and VAR support devices. The level of ancillary services required at any point in time is determined by the grid operator and/or energy market rules. To the extent that reactive power resources can be better coordinated to reduce load and reactive power requirements from generation, ancillary service costs for voltage and VAR support could be reduced, decreasing the cost for market participants and utilities.

- Reduced Distribution Operations Cost – Automated voltage and VAR control eliminates the need to send a line worker or crew to the location of reactive devices in order to operate them. This reduces the cost associated with the field service worker(s) and service vehicle. The impact of this benefit is determined by estimating the percentage of a field crew's time is dedicated to capacitor switching, and then estimating the time saved by the field service personnel.
- Reduced Electricity Losses – Coordinating the settings of voltage control devices on the transmission and distribution system ensures that customer voltages remain within service tolerances, while minimizing the amount of reactive power provided.
- Reduced CO_2 Emissions – Energy reductions achieved through improved efficiency and energy conservation voltage reduction will reduce the amount of generation required to serve load. Assuming that the generation is fossil-based, emissions will be reduced.
- Reduced SO_X, NO_X, and PM-10 Emissions – Energy reductions achieved through improved efficiency and energy conservation voltage reduction will reduce the amount of generation required to serve load. Assuming that the generation is fossil-based, emissions will be reduced.

4.4.9 Diagnosis and Notification of Equipment Condition

Some equipment such as transformers and circuit breakers are critical to providing electric service to customers. Utilities test and maintain this equipment periodically in an effort to ensure that it operates reliably over a long service life. Because of the large amount of equipment, and the labor intensity of taking measurements and analyzing results, testing and maintenance can be very expensive, and may fail to identify critical equipment conditions before they lead to failure.

This function is the on-line monitoring and analysis of equipment, its performance and operating environment to detect abnormal conditions (e.g., high number of equipment operations, temperature, gas production or vibration). As a result, the function enables the equipment to automatically notify asset managers and operations to respond to a condition that increases a probability of equipment failure. This function results in five benefits:

- Reduced Equipment Failures – Monitoring equipment “continuously” and receiving reports of its condition will help utilities identify potential trouble before it worsens and leads to failure.
- Reduced Distribution Equipment Maintenance Cost – The cost of sending technicians into the field to check equipment condition is high. Moreover, to ensure that they maintain equipment sufficiently, and identify failure precursors, some utilities may conduct equipment testing and maintenance more often than is necessary. Online diagnosis and reporting of equipment condition would reduce or eliminate the need to send people out to check equipment.
- Reduced Sustained Outages – Some equipment failures cause outages, as well as environmental damage such as fires and spills and the time to restore power can be significant depending on the difficulty of the replacement, and the time it takes to obtain a replacement device. By utilizing on-line diagnosis and reporting of equipment condition, utilities could identify equipment problems before they cause outages.

- Reduced Restoration Costs – Outages caused by equipment failure will require restoration, and the utility will incur costs as a result. In some cases, the utility may pay a premium for the equipment and labor needed to restore service on short notice.
- Reduced Oil Usage – Fewer truck rolls for equipment replacement means less fuel consumed by a service vehicle or line truck and leads to reduced oil consumption.

4.4.10 Enhanced Fault Protection

Typically, distribution protective devices rely on high fault currents to cause them to be activated. Some faults (like a line lying on the ground) may not cause sufficient fault current to cause the protective relay to sense the fault quickly. Another problem is that multiple relays may sense the same fault and operate and all to try and clear it (which results in what?). Enhanced protection could detect faults that are hard to locate, and clear them without reclosing which can damage equipment over time. Enhanced fault detection with higher precision and greater discrimination of fault location and type with coordinated measurement among multiple devices could detect and isolate faults without full-power re-closing, reducing the frequency of through-fault currents. Using high resolution sensors and fault signatures, these systems could better detect high impedance faults.

Transmission protective systems are more complex than those used for distribution. High speed digital communications and computing will enable more sophisticated transmission protection schemes, such as line differential protection, adaptive relaying and System Integrity Protection systems (SIPS). This function provides six benefits:

- Reduced Equipment Failures – Enhanced fault protection may detect faults more quickly, and clear them without full-power reclosing that can subject equipment to repeated fault current. This reduces the mechanical stress and damage, increasing equipment service life and reducing the probability of premature failure. For example, a substation transformer might feed three distribution feeders, each of which experienced a high number of faults. Over time, the feeder faults and the reclosing used to isolate them would place a high degree of mechanical stress on the transformer windings. This stress could lead to failure of the transformer far sooner than its expected service life.
- Reduced Sustained Outages – Some faults can be difficult to detect and isolate. For example, a high impedance fault caused by a downed line lying on dry ground might not produce enough fault current to trip the closest circuit breaker or fuse, but it may create a fault that lasts long enough to cause an upstream circuit breaker to trip as a backup. (Relays are often coordinated to have multiple "zones" of protection, and a single relay may be intended to provide primary protection for one part of the system, and backup protection for another. Sometimes relays far from a fault can "overreach" and trip before the relay closest to the fault can clear it.) This would result in a larger than necessary number of customers experiencing the outage. With enhanced fault protection, a higher portion of hard-to-detect faults would be cleared by the closest device, and minimize the disruption to other customers.

- Reduced Restoration Cost – By more quickly and precisely locating and clearing faults, field service workers can spend less time searching for the cause of the fault. It is also possible that by better isolating the fault, less damage occurs. Be careful not to count this as part of the outage cost savings attributable to customers - since they are joint costs.
- Reduced Momentary Outages – Many utilities use distribution feeder reclosers and sectionalizing schemes to isolate faults and restore service to as many customers as possible. Although many customers do not suffer the long term outage associated with the permanent fault, they experience momentary interruptions as the reclosers follow the sectionalizing scheme. Enhanced fault protection could isolate faults more precisely without full-power reclosing, and prevent momentary interruptions for many customers. (Momentary interruptions are outages that last less than 5 minutes in duration, and are typically a few seconds in length.)
- Reduced Sags and Swells – High impedance faults can be caused by tree contact, broken conductors lying on the ground, or other short circuits that do not cause fault currents high enough to trip relays. Locating high impedance faults more quickly and precisely will reduce the frequency and severity of the voltage fluctuations that they can cause. Moreover, fewer customers on the same or adjacent distribution feeders would experience the voltage fluctuation caused by the fault.
- Reduced Wide-scale Blackouts – Protective systems that cover an entire area rather than just a single element, can prevent wide area blackouts.

4.4.11 Real-Time Load Measurement and Management

Devices such as smart meters and appliance controllers can monitor the energy use of customer loads over the course of the day. These same devices can be used to help customers respond to pricing signals so that system load can be managed as a resource. Real-time measurement of customer consumption and management of load through Advanced Metering Infrastructure (AMI) systems (smart meters, two-way communications) and embedded appliance controllers may help customers make informed energy use decisions via real-time price signals, time-of-use (TOU) rates, and service options. This function can provide ten benefits:

- Reduced Ancillary Service Cost – The increased resolution of customer load data will improve load models and help grid operators better forecast energy supply requirements. Improved forecasts, along with the ability to reduce customer demand effectively during critical periods, could reduce reserve margin requirements.
- Deferred Distribution Capacity Investment – Load growth and feeder reconfiguration can lead to increased loading on lines and transformers, to the point where distribution capacity investments become necessary. Smart meters and AMI will allow utilities to monitor customer loads and voltage more closely, and provide a platform for sending pricing signals that could influence consumption patterns. This could enable utilities to better anticipate and monitor feeder loading, and operate the distribution system closer to its limits. For example, it could be possible for a utility to delay building a new distribution feeder for one or more years without running the risk of low voltage problems. Each year that a capital investment can be deferred can yield a significant savings in the utility's revenue requirement (equal to

the capital carrying charge of the upgrade). Therefore, Real-Time Load Measurement and Control could yield direct savings based on the time that it could postpone a capital investment.

- Reduced Meter Reading Cost – The data from smart meters can be automatically uploaded to a central meter data management system. This avoids the need to read meters manually, reducing the cost of performing this function.
- Reduced Electricity Theft – Smart meters can typically detect tampering. Moreover, a meter data management system can analyze customer usage to identify patterns that could indicate diversion.
- Reduced Electricity Losses – Peak load tends to affect delivery losses more than average load, and managing this peak could lead to improvements in electricity delivery efficiency. Being able to manage customer demand will give the utility the capability of reducing peak load, and thereby reduce delivery losses.
- Reduced Sustained Outages – Today, most utilities rely on customer calls to identify power outages, and customer service representatives to enter the outage information into a computer system. Outage management systems have been designed to interpret this outage information and estimate the location of the fault based on the information. AMI systems are being developed to perform outage detection based on the status of smart meters. This should improve the accuracy of outage notification, and reduce the time to restore service.
- Reduced Major Outages – Major outages occur as a result of hurricanes, ice storms, or other natural events that affect large geographical areas and tens of thousands of customers or more. Restoring electric service following these events typically takes a few days or more because of the massive damage that must be repaired on the distribution system. When utility crews move through an area making repairs to the distribution system, there are times when some customers fail to have their service restored because of unseen/overlooked damage. In such cases, when service is restored in the area, the utility crews may have left the area before the utility can receive a follow-up call from the customer saying that they are still without service. This means that the customer will be without service until a crew has time to come back to the area to fix the problem, and outage minutes will continue to increase. With AMI, utilities will be able to identify those customers who remain without power after the utility believes that power should be restored. This should make it easier to get a crew back to the location more quickly, and reduce the amount of time the customer is out.
- Reduced CO_2 Emissions – Manual meter reading requires that a person drive from meter to meter once each billing cycle. This produces CO_2 emissions from the vehicle. Eliminating the vehicle miles traveled eliminates the associated emissions.
- Reduced SOx, NOx, and PM-10 Emissions – Polluting emissions associated with vehicle miles travelled are eliminated.
- Reduced Oil Usage (not monetized) – Eliminating vehicle miles traveled with automatic meter reading eliminates the associated fuel consumption.

4.4.12 Real-Time Load Transfer

In places that may have more than one distribution feeder in the area, circuits may be switched and electrical feeds rerouted to make the distribution more efficient or more reliable. This function allows for real-time feeder reconfiguration and optimization to relieve load on equipment, improve asset utilization, improve distribution system efficiency, and enhance system reliability. This function provides three benefits:

- Deferred Distribution Capacity Investments – Load growth and feeder reconfiguration can lead to increased loading on lines and transformers, to the point where distribution capacity investments become necessary. Switching a portion of distribution feeder A onto distribution feeder B will relieve the load on feeder A. In cases where feeder A and feeder B are connected to different substations, the load relief can have beneficial effects up to the substation level. This load shifting could enable utilities to postpone feeder upgrades for one or more years. Each year that a capital investment can be deferred can yield a significant savings in the utility's revenue requirement (equal to the capital carrying charge of the upgrade). Therefore, Real-Time Load Transfer could yield direct savings based on the time that it could postpone a capital investment.
- Reduced Electricity Losses – Higher line loading tends to affect delivery losses more than average load, and managing this peak could lead to improvements in electricity delivery efficiency. By being able to balance load among substation transformers and distribution feeders, the utility could reduce delivery losses.
- Reduced Major Outages– Transferring portions of a distribution feeder from one substation to another could enable a utility to store service to those customers more quickly than if they had to wait until the normal feeder was fully restored. Performing this load shifting manually would be impractical. However, by being able to do this remotely, a utility might be able to justify the cost in the interest of restoring some customers more quickly.

4.4.13 Customer Electricity Use Optimization

A key characteristic of the modern grid is that it motivates and includes the customer. This function enables customers to observe their consumption patterns and modify them according to their explicit or implicit objectives. These could include minimizing cost, maximizing reliability, or purchasing renewable energy, among others. Seven benefits are provided:

- Deferred Generation Capacity Investments – Utilities build generation, transmission and distribution with capacity sufficient to serve the maximum amount of load that planning forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. The Smart Grid can help reduce peak demand and flatten the load curve by giving customers the information and incentives to better manage their electricity usage. This should translate into lower infrastructure investments by utilities and cheaper electricity for customers.
- Deferred Transmission Capacity Investments – See Deferred Generation Capacity Investments above.

- Deferred Distribution Capacity Investments – See Deferred Generation Capacity Investments above.
- Reduced Electricity Losses – Higher line loading tends to affect delivery losses more than average load, and managing this peak could lead to improvements in electricity delivery efficiency. If the customer is aware of their electricity use and shifts it to off-peak times, the losses may be reduced.
- Reduced Electricity Cost – The information provided by smart meters and in-home displays may encourage customers to alter their usage patterns (demand response with price signals or direct load control), or conserve energy generally because they can see how much it costs and alter their behavior. Changes in usage can result in reductions in the total cost of electricity.
- Reduced CO_2 Emissions – Increased customer awareness of electricity use may lead to conservation which, in turn would decrease the electricity generation required and the associated emissions.
- Reduced SOx, NOx, and PM-10 Emissions – Increased customer awareness of electricity use may lead to conservation which, in turn would decrease the electricity generation required and the associated emissions.

4.4.14 Distributed Generation

Distributed generation (DG) is located on the distribution system, either on primary distribution feeders or behind the meter. DG supports economic, reliability, and environmental benefits depending on the resource type as shown in Table 4-9.

Table 4-9
Distributed Generation Benefits

Resource Type	Benefits		
	Economic	Reliability	Environmental
Biomass (solid)	Yes	Yes	Maybe
Biomass (gaseous)	Yes	Yes	Maybe
Diesel	Yes	Yes	No
Geothermal	Yes	Yes	Yes
Natural Gas	Yes	Yes	No
PV	No	No	Yes
Wind	No	No	Yes

- Deferred Generation Capacity Investments – DG can be used to reduce the amount of central station generation required during peak times. This may improve the overall load profile and allow a more efficient mix of generation resources to be dispatched. This could save utilities money on their generation costs.

- Reduced Ancillary Service Payments – The reserve margin is a required capacity above the peak demand that must be available and is typically on the order of 12% to 15% of peak demand. If peak demand is reduced, reserve margin might be reduced -- requires that the peak be permanently reduced, not just occasionally or periodically (when the sun shines on peak). The availability of the DG resources is critical here.
- Reduced Congestion Costs – DG provides energy closer to the end use, so less electricity must be passed through the T&D lines, which reduces congestion.
- Deferred Transmission Capacity Investments – Utilities build transmission with capacity sufficient to serve the maximum amount of load that planning forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. Providing generation capacity closer to the load reduces the power flow on transmission lines, potentially avoiding or deferring capacity upgrades. This may be particularly effective during peak load periods.
- Deferred Distribution Capacity Investments – DG could be used to relieve load on overloaded feeders, potentially extending the time before upgrades or additions are required.
- Reduced Electricity Losses – By managing peak feeder loads with DG, peak feeder losses, which are higher than at non-peak times, would be reduced.
- Reduced Electricity Costs – DG could be used to reduce the cost of electricity during times when the price of "grid power" exceeds the cost of producing the electricity with DG. A consumer or the owner of an EER realizes savings on his electricity bill.
- Reduced Sustained Outages – The benefit to consumers is based on the value of service (VOS).[6] Distributed generation could be used as a backup power supply for one or more customers until normal electric service could be restored. But, if it used as part of the recovery of the system, then its value is already accounted for, so we can't count individual customer benefits
- Reduced CO_2 Emissions – Renewable-based DG can provide energy with greatly reduced net CO_2 emissions produced by fossil-based electricity generators. However, depending on the type of DG and the central generation mix during peak and off-peak times, the impact can be positive or negative.
- Reduced SO_x, NO_x, and PM-10 Emissions – Renewable energy provides electricity without net SO_x, NO_x, and PM-10 emissions produced by fossil-based electricity generators providing energy and peak demand. However, depending on the type of DG and the central generation mix during peak and off-peak times, the impact can be positive or negative.

[6] Sullivan, Michael; Mercurio, Matthew; Schellenberg, Josh; Freeman, Sullivan & Co. "Estimated Value of Service Reliability for Electric Utility Customers in the United States," prepared for the U.S. Department of Energy Office of Electricity Delivery and Energy Reliability, LBNL-2132E June 2009.

4.4.15 Stationary Electricity Storage

Electricity can be stored as chemical or mechanical energy and used later by consumers, utilities or grid operators. In distributed applications, energy storage technologies most likely utilize inverter-based electrical interfaces that can produce real and reactive power. Depending on the capacity and stored energy of these devices, they can provide economic, reliability, and environmental benefits. Stationary Energy Storage supports thirteen benefits:

- Optimized Generator Operation – The ability to respond to changes in load would enable grid operators to dispatch a more efficient mix of generation that could be optimized to reduce cost, including the cost associated with polluting emissions. Electricity storage can be used to absorb generator output as electrical load decreases, allowing the generators to remain in their optimum operating zone. The stored electricity could then be used later so that dispatching additional, less efficient generation could be avoided. The storage can have the effect of smoothing the load curve that the generation fleet must meet. This benefit includes two components: (1) avoided generator start-up costs and (2) improved performance due to improved heat rate efficiency and load shaving.
- Deferred Generation Capacity Investments – Electricity storage can be used to reduce the amount of central station generation required during peak times. This would tend to improve the overall load profile and allow a more efficient mix of generation resources to be dispatched. This can save utilities money on their generation costs.
- Reduced Ancillary Services Cost – Ancillary services including spinning reserve and frequency regulation can be provided by energy storage resources. The reserve margin is a required capacity above the peak demand that must be available and is typically +15% of peak demand. If peak demand is reduced, reserve margin would be reduced.
- Reduced Congestion Cost – Distributed energy resources provide energy closer to the end use, so less electricity must be passed through the T&D lines, which reduces congestion.
- Deferred Transmission Capacity Investments – Utilities build transmission with capacity sufficient to serve the maximum amount of load that planning forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. Providing stored energy capacity closer to the load reduces the power flow on transmission lines, potentially avoiding or deferring capacity upgrades. This may be particularly effective during peak load periods.
- Deferred Distribution Capacity Investments – Electricity storage can also be used to relieve load on overloaded stations and feeders, potentially extending the time before upgrades or additions are required.
- Reduced Electricity Losses – By managing peak feeder loads with electricity storage, peak feeder losses, which are higher than at non-peak times, would be reduced.
- Reduced Electricity Costs – Electricity storage can be used to reduce the cost of electricity, particularly during times when the price of "grid power" is very high. A consumer or the owner of an enabled DER realizes savings on his electricity bill.

- Reduced Sustained Outages – Electricity storage can be used as a backup power supply for one or more customers until normal electric service can be restored. However, the backup would only be possible for a limited time (a few hours) depending on the amount of energy stored.
- Reduced Momentary Outages – When combined with the necessary control system, energy storage could act like an uninterruptible power supply (UPS), supporting end use load during a momentary outage.
- Reduced Sags and Swells – The same UPS capability could be used to enable load to ride through voltage sags and swells.
- Reduced CO_2 Emissions – Electricity storage can reduce electricity peak demand. This translates into a reduction in CO_2 emissions produced by fossil-based electricity generators. However, since electricity storage has an inherent inefficiency associated with it, electricity storage could increase overall CO_2 emissions if fossil fuel generators are used for charging.
- Reduced SO_X, NO_X, and PM-10 Emissions – Electricity storage can reduce electricity peak demand. This translates into a reduction in polluting emissions produced by fossil-based electricity generators. However, since electricity storage has an inherent inefficiency associated with it, electricity storage could increase overall emissions if fossil fuel generators are used for charging.

4.4.16 Plug-in Electric Vehicles

The batteries in plug-in electric vehicles (PEVs) can be portrayed as non-stationary energy storage devices. As such, they are similar to stationary energy storage devices and support economic, reliability and environmental benefits. By increasing vehicle fuel efficiency, they also support Reduced Oil Usage, an Energy Security Benefit. The benefits supported by PEVs include:

- Optimized Generator Operation – PEV electricity storage could be used to absorb generator output as electrical load decreases, allowing the generators to remain in their optimum operating zone. The stored electricity could then be used later so that dispatching additional, less efficient generation could be avoided. The storage could have the effect of smoothing the load curve that the generation fleet must meet. This benefit includes two components: (1) avoided generator start-up costs, because PEVs increase the load on the system, which reduces generator cycling and (2) improved performance due to improved heat rate efficiency and load shaving.
- Deferred Generation Capacity Investments – PEV electricity storage could be used to reduce the amount of central station generation required during peak times. This would tend to improve the overall load profile and allow a more efficient mix of generation resources to be dispatched. This could save utilities money on their generation costs.
- Reduced Ancillary Service Payments – PEV also helps to reduce the reserve margin requirement. The reserve margin is a required capacity above the peak demand that must be available and is typically +15% of peak demand. If peak demand is reduced, reserve margin would be reduced.

- Reduced Congestion Costs – Distributed energy resources provide energy closer to the end use, so less electricity must be passed through the T&D lines which reduce congestion.
- Deferred Transmission Capacity Investments – Utilities build transmission with capacity sufficient to serve the maximum amount of load that planning forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. Providing stored energy in PEVs, located closer to other loads, reduces the power flow on transmission lines, potentially avoiding or deferring capacity upgrades. This may be particularly effective during peak load periods.
- Deferred Distribution Capacity Investments – Electricity storage in the PEV could also be used to relieve load on overloaded feeders, potentially extending the time before upgrades or additions are required.
- Reduced Electricity Costs – The electricity storage in the PEV can be used to reduce the cost of electricity, particularly during times when the price of "grid power" is very high. A consumer or the owner of an enabled DER realizes savings on his electricity bill. The calculation is based on on/off peak price differentials.
- Reduced Sustained Outages – The PEV could be used as a form of electricity storage for backup power supply for one customer until normal electric service could be restored. However, the backup would only be possible for a limited time (a few hours) depending on the amount of energy stored. The benefit to consumers is based on the value of service (VOS).
- Reduced CO_2 Emissions – PEVs can reduce the amount of CO_2 produced per mile traveled, provided that the carbon intensity of the electricity generation is lower than that of gasoline. The electricity storage in PEVs could also reduce electricity peak demand. This translates into a reduction in CO_2 emissions produced by fossil-based electricity generators serving peak demand.
- Reduced SO_X, NO_X, and PM-10 Emissions – PEVs can reduce the amount of CO_2 produced per mile traveled, provided that the carbon intensity of the electricity generation is lower than that of gasoline. The electricity storage in PEVs could also reduce electricity peak demand. This translates into reduction in polluting emissions produced by fossil-based electricity generators serving peak demand.
- Reduced Oil Usage – PEVs increase the fuel efficiency of vehicles by capturing the kinetic energy released during deceleration and releasing it for powering the vehicle. This fuel efficiency gain translates into a reduction in oil consumption per mile traveled.

4.5 Establish Project Baseline(s)

Benefit-cost analyses of any policy action,[7] business decision, or, in this case, an investment in a Smart Grid project all are based on the "change" in benefits that are attributed to the Smart Grid system compared to the "change" in costs associated with implementing it. As a result, benefit-cost methods often use "difference" estimation methods when statistical methods are used to define a control state and a resulting project state.

In this section, baselines are defined broadly and include what statisticians, engineers, and researchers might term the control state, that is the pre-condition, or the state of the system that would have occurred had the action or project not been taken.

Implementing a Smart Grid project produces benefits by making a change for which measurement metrics and functions must be specified. These have been identified in the previous Sections 4.4 and 4.4. Since all benefit-cost analyses are based on measuring or assessing change, two cases (or states of the system) are required to measure the change that is to be assessed. These two cases are:

- Case 1 – the baseline (or control) conditions that reflect what the system condition would have been <u>without</u> the Smart Grid system (the …but for… case)
- Case 2 – the realized and measured conditions <u>with</u> the Smart Grid system installed

The quantification of a specific benefit is the change in that benefit metric between cases 1 and 2. While easily stated, developing baselines for specific projects and Smart Grid benefits can be difficult in practice. In many cases, the uncertainty in the estimates of a project's benefits might stem more from a difficult to measure baseline than from measurements taken during and after the implementation of the Smart Grid project.

4.5.1 Baseline for Smart Grid Projects – Concepts

Ideally, a baseline would depict the circumstances of the grid (or consumers if the Smart Grid project might reduce consumers' electricity bills) if the Smart Grid project had not been undertaken. From a practical perspective, the best baseline is a baseline that most accurately depicts the "without" project conditions. Some simple examples of candidate baselines for benefits that are likely to accompany Smart Grid projects are:

[7] For example, a policy action might involve a decision to invest in highways. The benefits in this case would be the improvement in metrics due to the investment over what would otherwise have been the case. This can even be extended to financial policies that might be set by the Federal Reserve Bank, where the benefits of setting an interest rate at a given level requires some estimate of the resulting financial conditions associated with the new interest rate versus the conditions that would occur if the rate remained unchanged. Selecting the right interest rate would involve picking a rate that produced the greatest benefits over time. However, the point is that a benefit-cost analysis of any decision or action requires that a change be measured to estimate the benefits produced. This approach is not unique to benefit-cost analyses of Smart Grid investments, demand response programs or energy efficiency programs. It is a step that must be taken in all benefit-cost assessments.

- Baseline Example #1:
  - Benefit – The benefit is a deferred investment in distribution capacity due to reduction in peak demand on a feeder.
  - Process – The Smart Grid project communicates hourly electric prices to customers and then customers decide (with or without additional enabling technology[8]) how much energy to use at different price points. The Smart Grid system provides prices that represent the costs to the system of delivering electricity to that customer in that hour.
  - Baseline – The peak demand that would have occurred for each customer[9] on the feeder if this Smart Grid functionality had not been installed. Recall, than an assessment of any policy action, business decision, or grid investment needs to have a baseline to produce an estimate of the change in conditions that can then be used in a benefits estimation calculation.
  - Project Measurement – Measure the peak demand for each customer receiving hourly price signals as part of the Smart Grid project.
  - Benefits Estimation – The estimated benefits are based on the value of the difference between the measured peak demand collected as part of the Smart Grid project data collection and the baseline, i.e., the peak demand that would have occurred if the Smart Grid project had not been implemented.
  - Potential Baseline – Baselines for pricing projects often use a pre-period (i.e., data on both the participants and the control group prior to the Smart Grid project being implemented) and post- project measurement of both participants in the Smart Grid project, and a group of similar control customers (hopefully with participants and non-participants assigned randomly[10]). This pre- and post-period baseline approach adjusts for differences between the pre and post-period (e.g., weather conditions) to be better controlled for in the project to produce a better baseline.

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[8] It is common now for customers facing hourly pricing to have enabling technologies that automatically help adjust energy use when prices reach different levels. This can be home energy management systems, or more advance energy management and control systems used in larger commercial establishments.

[9] In some cases, it may be adequate to use the peak demand that would have occurred on the feeder (in the absence of the Smart Grid project) without having to examine each customer individually. Another option would be to examine customer groups, e.g., residential customers and commercial customers. It all depends on the purpose for which the information is collected. To verify the load reduction on the feeder, a more aggregate baseline may be acceptable. If the goal is to extrapolate the peak demand reduction on this feeder to other feeders with a different mix of customers; then, increased granularity in terms of customer-specific peak reductions may be important. When selecting a baseline, the objective of the estimation effort should be considered.

[10] Even if the participants in the project have to enroll or in some way express a desire to be part of the project, it is still possible to take this pool of people and randomly select some of these volunteer customers to serve as a control group for the purposes of estimating the overall benefits of this part of Smart Grid system. There are a number of issues that arise in selecting program participants and non-participants that go beyond the discussion possible in this section (get reference to more information). As a general rule, random assignment should be used to the extent practicable.

- Baseline Example #2:
  - Benefit: Reduced outages as a result of a Smart Grid project.
  - Process: Adaptive projection in which relay settings would be automatically modified as system conditions change.
  - Baseline: The frequency and length of outages (and possibly *when*, e.g., business hours or night time) that would have occurred if the Smart Grid project had not been implemented.
  - Project Measurement: A measure of the number and duration of outages during the Smart Grid project implementation.
  - Benefits Estimation: An estimate of benefits is simply the value of the difference between the number and frequency of outages during the after the implementation of the Smart Grid and the baseline values.
  - Potential Baseline: Establishing a baseline for outages requires that some thought be given to what is the most appropriate and representative measurement. If the year preceding the Smart Grid project did not have any extreme weather; then, it might not be a representative baseline. As a result, a 3 year average of outages might be more appropriate.

As the two examples indicate, there might be a number of candidate baselines for each benefit and the Smart Grid project will have to select that baseline that is viewed as most representative of the state of the grid had the Smart Grid project not been implemented.

4.5.2 General Criteria for Baselines

There are a number of general criteria that should be considered when selecting a baseline for use in estimating a Smart Grid benefit. These include:

- Criterion 1: Representativeness – This is the most important criterion in that it considers how appropriate a selected baseline is as an actual approximation of what the state of the grid *would* have been if the Smart Grid project had not been implemented.
- Criterion 2: Acceptability – The selection of a baseline should be viewed as acceptable (i.e., make sense) to project stakeholders, utilities and regulators.
- Criterion 3: Operational – The baseline should be selected such that data can be collected on both the baseline and the comparable project data. A baseline for which the data cannot be collected is not useful.
- Criterion 4: Precise – The baseline should be precise with respect to the key performance metrics that are to be measured. For outages, it might be SAIFI and SAIDI. For other benefits, it might be the price or demand of electricity during peak periods, changes in customer bills, reduced system maintenance costs, reduced line losses, or other metric leading to benefits expected from that Smart Grid project.
- Criterion 5: Consistency – This is a benefit-cost framework that is meant to be consistently applied across different Smart Grid projects. As a result, the same or similar baseline metrics and measurements that can be applied across a range of Smart Grid projects is another consideration.

The criteria listed above will require careful consideration at the project level, but also some consideration across different Smart Grid projects such that some consistency in principles and application is maintained in benefit-cost analyses across projects.

4.5.3 Considerations in Selecting Baselines

There can be a number of complicating factors in selecting baselines. To Illustrate, take a Smart Grid project that calls for a micro-grid that can be islanded to increase reliability and grid efficiency. The benefits that might be associated with this project are shown in Table 4-10.

Table 4-10
Impacts/Benefits Associated with a Micro-Grid Project

1. Reduced electricity costs
2. Avoided on-peak charges
3. Reduced peak demand (a key intermediate impact that leads to several types of benefits)
4. Reduced peak losses
5. Reduced reserve margin requirement and cost
6. Reduced outage frequency and associated damage
7. Reduced outage duration and associated damage
8. Reduced restoration costs
9. Deferred generation, transmission and distribution investments
10. Reduced distribution operations cost
11. Reduced costs associated with extreme events – significant unexpected outages at power plants, price spikes in generation costs due to spikes in fuel costs (gas, oil or coal), transmission line failures and outages, extreme weather (1 in 20 year heat wave).

Some of the benefits in Table 4-10 seem to have relatively straightforward candidate baselines, but some of the categories that might account for significant benefits (e.g., incidence of extreme events and changes in kWh/W usage) might not easily lend themselves to selecting a baseline.[11]

[11] Considerable work has been done on baselines for demand response and price response associated with enabling Smart Grid functions. A summary of those methods used in the organized wholesale electricity markets can be found in North American Wholesale Electricity Demand Response Program Comparison – http://www.isorto.org/site/c.jhKQIZPBImE/b.2604461/k.6151/Documents_and_Issues.htm. For the wholesale market, standards for the determination of Baselines are found in NAESB's Wholesale Electric Demand Response Measurement and Verification Standards -- http://www.naesb.org/dsm-ee.asp. For the retail market, standards are found in the Retail Electric Measurement & Verification (M&V) of Demand Response Programs Model Business Practices. Another fairly extensive discussion about Demand Response baseline approaches and issues can be found in "Demand Response Measurement and Verification, Applications for Load Research," Association of Edison Illuminating Companies, Load Research Committee, March 2009.

Baseline Issues:

- Time Period – For example, the benefit "Reduced Restoration Costs" might not be relevant if a significant outage has not occurred in the selected baseline period, or if it does not occur during the time period. If this occurs, a simulation of restoration costs with and without the Smart Grid project might be needed.
- Extreme Events – One of the benefits of many Smart Grid investments, and one of the principals of the Smart Grid, is that it operates resiliently to avert hazards. Studies illustrating the benefits of demand response enabled by Smart Grid investments should recognize that it might be called upon infrequently, but when needed it provides substantial benefits.[12] In fact, most of the benefits of the program might occur in those "1 year out of every 5 year" events when the full capacity of the DR program is needed. Other aspects of the Smart Grid addressing overall resiliency are likely to have very large benefits, but address events that are classified as low-probability, high-consequence events. In this case, the benefit of the Smart Grid might more appropriately be viewed as a form of insurance, or a reduction in the economic consequences of those high consequence events (such as the major blackout that recently affected most of Brazil) that seem to hit every grid at least once every 5 years.[13]
- Dynamic Baselines – Some baselines might have a time trend element that will need to be addressed. For example, investments in generation and T&D that might be deferred by Smart Grid projects will vary over time. Similarly, the cost of maintaining the current grid system might increase over time, and electricity demand is expected to increase from one year to the next with implications for the system. To the extent possible, these factors should be included in the baseline and aligned with both the length of the Smart Grid projects – especially in light of the fact that the move to a Smart Grid environment is expected to be a long lasting investment.

[12] "DR Valuation and Market Analysis -- Volume II: Assessing the DR Benefits and Costs," Prepared for the International Energy Agency Demand-Side Programme, Task XIII, by D.M. Violette, R. Freeman, and Chris Neil, June 6, 2006.

[13] Baselines for estimating the benefits of mitigating the impact of extreme events in the literature on demand response have used concepts that incorporate the probability of these events occurring. This can be option value concepts or reductions in the Value at Risk (VAR). See IEA (2006) above and Pacific Northwest Power and Conservation Council's 6th Regional Power Plan (2009).

Given the baseline issues presented above, several categories of baselines could be considered:[14]

- Historic Baselines – For situations characterized by stable conditions over the project period, it might be possible to simply use historic data. Outage rates might be one example, but it still might be inappropriate to just use the most recent year as that might not have been a representative year. An average of 3 historical years might be a better baseline.
- Forecasted Baselines – Projections of electricity demand growth and increasing electricity prices might be needed to develop appropriate baselines for smart grid functions that are likely to improve these metrics. Past benefit-cost studies of the Smart Grid have typically used forecasts for baseline metrics that are expected to change over even short time periods.
- Volatility Analyses – This is related to forecasted baselines, but it takes into account that growth is not smooth. Peak demand might stay the same for two years, but then jump by 5% in the 3rd year. The Smart Grid may reduce the impacts of volatility and even reduce volatility in metrics such as electricity prices.
- Stress Cases – Baselines for system stress conditions might involve system modeling, but it might be the only way to address the sizeable benefits that might be linked to low-probability, high-consequence events.
- Control Groups – In projects that involve smart metering and time-varying tariffs, there is a desire to estimate their impacts on changing electricity consumers' behavior in response to price signals, and its effect on reducing peak load and customers' electricity bills. Baselines in these situations are ideally a control group of comparable customers (e.g., households similar in income and other household attributes and in house size), that are randomly selected from the target participant population. In some cases, it may be desirable to have several control groups that can be created in this manner. Each would serve as a control group for a different technology and time-varying tariff combination by examining the change between customers with different technology/tariff combinations.

One of the basic baseline approaches to assessing changes in the cost of grid maintenance and investment is to use a "Business as Usual" (BAU) approach. Many utilities currently have procedures they use to maintain the transmission and distribution systems. In other cases, there is already a trend in equipment replacement that should be considered. For example, assume that there is a trend to replace existing electro-mechanical meters with solid-state meters to increase measurement accuracy. To the extent business processes are in place for system maintenance and investment, these should comprise a BAU approach to setting baselines. BAU trends can be used to set costs and performance for many metrics at historical levels.

[14] The California Public Utilities Commission held a number of working groups addressing baseline issues as part of Rulemaking 07-01-041. See California Public Utilities Commission, "Decision Adopting Protocols For Estimating Demand Response Load Impacts," Decision 08-04-050 April 24, 2008, http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/81972.pdf and the resulting report -- "Load Impact Estimation for Demand Response: Protocols and Regulatory Guidance," Decision D0804050, Attachment A, California Public Utilities, Energy Division, April 2008. http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/81979.pdf

The appropriate benefits and costs to be used in a benefit-cost analysis are the incremental benefits and incremental costs associated with the Smart Grid investment. This should always be kept in mind when setting baselines, as it is the baseline that is used to determine the incremental component of both benefits and costs.

4.6 Identify Data Needs and Quantify and Monetize Benefits

Each project will be required to collect and report data that will be used to quantify and monetize the benefits of their project. Depending on the calculation, this data might be in the form of raw data (such as hourly load data) or in analyzed form (such as line losses).

The overarching principles in quantifying benefits are to:

- To the extent possible, estimate benefits by estimating the *difference* between conditions with the Smart Grid project in place, compared to *baseline* conditions that would have occurred without the project.
- Rely on data regarding what actually occurred in the project, rather than estimate them using some general approximating formula.

The latter point is a key one. We are <u>not</u> stating that projects with certain assets that provide certain functionality (as described in the mappings in Table 4-4) will <u>always</u> lead to benefits as defined in the mappings in Table 4-8. Rather, these mappings help to identify <u>possible</u> benefits, which must be verified by collecting data on the <u>actual</u> impacts of the project and then using the methods we describe to calculate the benefits.

The parameters needed to monetize the benefits may be quantified in terms of physical units (e.g., kWh). The quantified benefits will be monetized by applying a cost per unit. Appendix C presents a suggested approach for quantifying and monetizing smart grid benefits.

For many projects, the suggested calculations may serve as a base case example; each project may be able to gather data more appropriate for the benefits calculation for that specific project. As a result, these methods for quantifying and monetizing the benefits should be viewed as illustrating the calculation concept that each project should strive for using data that can be collected for that project to support the calculations.

To illustrate, the methodology for quantifying and monetizing the "Reduced Sustained Outages" benefit is discussed below.

The "Reduced Sustained Outages" benefit can be realized through six functions and three Enabled Energy Resources (EERs):

- Adaptive Protection
- Automated Feeder Switching
- Automated Islanding and Reconnection
- Diagnosis and Notification of Equipment Condition

- Enhanced Fault Protection
- Real-Time Load Measurement and Management
- Distributed Generation
- Stationary Electricity Storage
- Plug-in Electric Vehicles

Customer outage time could be logged by smart meters or outage management systems. This data could be compared with typical hourly loads to estimate the “load not served” during the outage. The value of the decreased load not served as a result of Smart Grid functions must be allocated based on the function’s contribution to reducing outage minutes. By applying a value of service (VOS) metric (i.e., by customer class and geographic region), the value of the load not served can be estimated as follows:

Value ($) = [Outage Time (hr) * Load Not Served (kW estimated) * VOS ($/kWh)]$_{\text{Baseline}}$ - [Outage Time (hr) * Load Not Served (kW estimated) * VOS ($/kWh)]$_{\text{Project}}$

An estimate of the load not served may be provided by the project at the time of reporting, or could be obtained from the baseline estimate generated when the project is established. For example, if all customers that experience the outage are residential, the project can simply report total outage time, load not served, and a single VOS metric. In a case where a project has 100 customers, 75 of whom are residential and 25 of whom are commercial, the project could report the total residential outage time, load not served, and the residential VOS metric, plus the total commercial outage time, load not served, and the commercial VOS metric.

If estimating the load not served from baseline data prior to project implementation, the project will need to consider the affect of load control and energy efficiency on the load not served. For example, load not served could decrease after project implementation due to customers using less energy, without any change in reliability (outage minutes).

4.7 Suggested Parameter Values for Monetization of Reliability, Power Quality, Environmental and Oil Security Benefits

Among the different categories of benefits, economic benefits are inherently expressed in monetary terms. However, other types of benefits are not. This section provides parameter values which may be used to monetize reliability, power quality, environmental and oil security benefits in conjunction with the methods discussed in Section 4.6 and Appendix C.

4.7.1 Parameters for Monetizing Reliability and Power Quality Benefits

This sub-section provides estimates for damages to end-users from power interruptions and power quality events. These estimates can be used to monetize the value of the reductions in these events – that is, the benefits – that a project can attribute to its Smart Gird deployments.

Since utilities commonly compile data on SAIFI, SAIDI and (to some extent) MAIFI, we describe how they may be used to monetize improvements in reliability and power quality. We draw on the most recent, and most comprehensive, study done to date (Sullivan et al. 2009). The estimates from this study are based on statistical (i.e., regression) analyses of meta-data compiled from 28 customer value of service reliability studies conducted by 10 major U.S. electric utilities from 1985 to 2005. The study expands on the previous work done by Lawton et al. (2003a, 2003b), Layton et al. (2004), LaCommare and Eto (2004), and Eto and LaCommare (2008).

Table 4-11 summarizes the results of the Sullivan et al. (2009) study. Depending on the data available about a project, different parameters in the table may be used. For example in Section 4.6, the Value of Service (VOS) parameter is the “Cost per un-served kWh” value in Table 4-9.

Alternatively, if instead SAIDI and SAIFI data are available, then one would consider the estimated “Cost per Event” listed in the table, for each of three sectors – medium and large commercial and industrial end-users, small commercial and industrial end-users, and residential customers.

Sullivan et al. (2009, p. xxvi) state that these cost estimates “can be reasonably applied to indicators like SAIDI and SAIFI for purposes of calculating the impacts of system improvements that are expected to impact these indicators.” They do provide a cautionary note that multiplying SAIDI by SAIFI would only approximate interruption costs because of the nonlinear nature of the relationship between interruption duration and cost.

However, the various damage functions for different types of customers are *almost* linear (refer to the figures in the Sullivan et al. report). Consequently, a simple linear averaging provides a reasonable approximation that generally slightly underestimates the interruption costs.

Table 4-11
Estimated Average Electric Customer Interruption Costs, by Duration and Type of Customer (in US 2008$)

Interruption Cost	Interruption Duration				
	Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I					
Cost Per Event	$6,558	$9,217	$12,487	$42,506	$69,284
Cost Per Average kW	$8.0	$11.3	$15.3	$52.1	$85.0
Cost Per Un-served kWh	$96.5	$22.6	$15.3	$13.0	$10.6
Cost Per Annual kWh	9.18E-04	1.29E-03	1.75E-03	5.95E-03	9.70E-03
Small C&I					
Cost Per Event	$293	$435	$619	$2,623	$5,195
Cost Per Average kW	$133.7	$198.1	$282.0	$1,195.8	$2,368.6
Cost Per Un-served kWh	$1,604.1	$396.3	$282.0	$298.9	$296.1
Cost Per Annual kWh	1.53E-02	2.26E-02	3.22E-02	$0.137	$0.270
Residential					
Cost Per Event	$2.1	$2.7	$3.3	$7.4	$10.6
Cost Per Average kW	$1.4	$1.8	$2.2	$4.9	$6.9
Cost Per Un-served kWh	$16.8	$3.5	$2.2	$1.2	$0.9
Cost Per Annual kWh	1.60E-04	2.01E-04	2.46E-04	5.58E-04	7.92E-04

Source: Sullivan, M.M., Mercurio, M., Schellenberg, J. (2009) "Estimated Value of Service Reliability for Electric Utility Customers in the United States," Report LBNL-2132E, prepared for the Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy, Berkeley, CA: Lawrence Berkeley National Laboratory, p. xxvi, Table ES-5, June 2009.

For example, assume that there are eight momentary interruptions of a few seconds each, one 1-hour interruption and one 8-hour interruption for a medium-sized industrial firm. Then, from Table 4-11, the estimated cost of these interruptions, if data were to available on each interruption, would be $134,235 (8 x 6,558 + 12,487 + 69,284), which compares approximately with the estimate if only SAIFI and SAIDI are known:

Estimate of interruption costs

= SAIFI x SAIDI x $\text{interruption\_cost}_{i,\text{SAIDI}}$

= 10 x 9/10 x [9,217 + 0.8 x (12,487-9,217)]

= $106,497

where $\text{Interruption\_cost}_{i,\text{SAIDI}}$ is the estimated interruption cost that corresponds to SAIDI for customer type i; in this example, $\text{Interruption\_cost}_{i,\text{SAIDI}}$ is interpolated for a SAIDI between 30 minutes and 1 hour.

This calculation can be repeated for each type of customer class and then summed across customer classes. Taking the difference between these estimates, after- versus before- smart grid deployment, one can calculate the reliability benefits of that project.

A similar approach can be used with MAIFI multiplied by momentary disturbance cost for each customer class, and the estimates summed across the customer classes.

Note that these benefits accrue to *consumers* in the form of reduced damages. Reductions in the costs to *utilities* to restore power are a separate category of benefits that accrue to *utilities*. In calculating the total benefits (which are the sum of those to utility, consumer and society in general), the two types of benefits are additive. No transfer payments are involved.

4.7.2 Parameters for Monetizing Benefits of Reduced Environmental Pollutants

This sub-section provides estimates that may be used to monetize the benefits associated with reductions in pollutant emissions, which are the primary type of environmental benefits from Smart Grid projects. The estimates are listed in Table 4-12. They are from a recently released National Research Council report, which represents arguably the most comprehensive study on the subject (NRC 2009), and from data on actual market transactions and projections.

Two types of values are provided in Table 4-12. One set of values is based on estimates of damages to the environment, including human health, from exposure to these pollutants (these are the data from the NRC report). Reductions in these damages, as a result of decreases in emissions, are benefits of some smart grid deployments. These benefits are not specific to utilities nor to their customers, but to society in general.

The second set of values is identified by *brown italics* in Table 4-12. These values are based on the prices of emissions allowances, either recent prices or, in the case of CO_2, projected prices. These allowances are purchased in annual auctions operated by the U.S. Environmental Protection Agency, or are traded in open markets. These prices may be used to estimate the benefits to *utilities* from their reducing their emissions.

Table 4-12
Estimates of Externalities and Market Prices of Emissions Allowances

Estimates and prices are all in 2008 USD.				
Pollutant (units for damages and prices)	Source of Pollutant or *Source of Price Data*	Low	Mid	High
CO_2 ($/metric ton)	All sources	1.02	16.85	102.14
CO_2 price in 2015 ($/metric ton)	*EPA Analysis of H.R.2454*		*14.10*	
CO_2 price in 2015 ($/metric ton)	*EPA Analysis of Waxman-Markey*	*14.10*	*16.27*	*28.21*
NO_x ($/ton)	Coal power plants in 2005	695	1,328	2,860
NO_x ($/ton)	Natural Gas power plants in 2005	470	1,736	5,005
NO_x ($/ton)	Coal & Gas weighted ave., 2005	639	1,483	3,589
NO_x ($/ton)	*NO_x Spot Prices in 2005*	*2,061*	*2,929*	*3,797*
NO_x ($/ton)	*NO_x Spot Prices in 2008*	*600*	*850*	*1400*
NO_x (cents/kWh)	All generation, incl. non-fossil, 2005	0.036	0.12	0.67
$PM_{2.5}$ ($/ton)	Coal power plants in 2005	2,656	7,252	26,555
$PM_{2.5}$ ($/ton)	Natural Gas power plants in 2005	2,656	12,256	163,418
$PM_{2.5}$ ($/ton)	Coal & Gas weighted ave., 2005	2,712	8,966	69,780
$PM_{2.5}$ (cents/kWh)	All generation, incl. non-fossil, 2005	0.009	0.070	0.71
PM_{10} ($/ton)	Coal power plants in 2005	143	347	1,328
PM_{10} ($/ton)	Natural Gas power plants in 2005	174	643	7,967
PM_{10} ($/ton)	Coal & Gas weighted ave., 2005	156	447	3,425
PM_{10} (cents/kWh)	All generation, incl. non-fossil	0.0005	0.0043	0.038
SO_2 ($/ton)	Coal power plants in 2005	1,838	5,924	11,235
SO_2 ($/ton)	Natural Gas power plants in 2005	1,838	5,720	44,940
SO_2 ($/ton)	Coal & Gas weighted ave., 2005	1,878	5,987	21,980
SO_2 ($/ton)	*SO_2 Spot Prices in 2005*	*727*	*1,085*	*1,714*
SO_2 ($/ton)	*EPA Spot Auction 2008*	*380*	*390*	*651*
SO_2 ($/ton)	*SO_2 Spot Prices in 2008*	*179*	*344*	*509*
SO_2 ($/ton)	*EPA Spot Auction, March 2009*	*61*	*69*	*494*
SO_2 (cents/kWh)	All generation, incl. non-fossil, 2005	0.12	1.24	5.92

Sources:

a) Externality estimates (in regular black font) are from the Committee on Health, Environmental, and Other External Costs and Benefits of Energy Production and Consumption (2009) *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use*, a report of the National Research Council, Washington, DC: The

National Academies Press, prepublication copy, October 19, 2009, Table 2-8, page 65; Table 2-17, page 90; Table 2-9, page 66; and Table 2-15, page 88. For SO2, NOx, PM2.5 and PM10 damages, "Low" is the 5th percentile estimate, "Mid" is the 50th percentile, and "High" is the 95th percentile among coal and natural gas power plants in the U.S. (*not* weighted by the generation of each plant).

b) For CO2 externality estimates, the low and high values are the lowest and highest values in the Committee on Health, Environmental, and Other External Costs and Benefits of Energy Production and Consumption (2009) report, Table 5-9, page 218, which span (real) discount rates from 4.5% to 1.5%, and which range from estimates of relatively low to relatively high damages due to climate change.

c) *EPA Analysis of H.R.2454* – U.S. Environmental Protection Agency, Office of Atmospheric Programs, "EPA Analysis of the American Clean Energy and Security Act of 2009, H.R. 2454 in the 111th Congress, 6/23/2009, available at http://www.epa.gov/climatechange/economics/pdfs/HR2454_Analysis.pdf. accessed October 16, 2009.

d) *EPA Analysis of Waxman-Markey* – U.S. Environmental Protection Agency, Office of Atmospheric Programs, "EPA Preliminary Analysis of the Waxman-Markey Discussion Draft, The American Clean Energy and Security Act of 2009 in the 111th Congress," 4/20/2009, available at http://www.epa.gov/climatechange/economics/pdfs/WM-Analysis.pdf, accessed October 16, 2009.

e) *NOx Spot Prices in 2005* – From visual inspection of graph based on data from Evoluation Markets, LLC and Cantor Environmental Brokerage, U.S. Environmental Protection Agency (2006) "NOx Budget Trading Program -- 2005 Program Compliance and Environmental Results," EPA430-R-06-013, Washington, DC: U.S. EPA Office of Air and Radiation, Office of Atmospheric Programs, September 2006, Figure 19, page 30, available at http://www.epa.gov/air/airtrends/2006/ozonenbp/onbpsec4.pdf#page=1, accessed October 17, 2009.

f) *NOx Spot Prices in 2008* – Estimates from visual inspection of graphs compiled from Cantor Fitzgerald data graphed in: U.S. Environmental Protection Agency, "The 2008 NOx Budget Trading Program -- Emission, Compliance and Market Data Report," available at http://www.epa.gov/airmarkets/progress/NBP_1.html, accessed October 16, 2009.

g) *SO2 Spot Prices in 2005* – Ellerman/Feilhauer/Parsons (2008) "The Puzzling SO2Price Spike of 2005-2006," MIT Center for Energy and Environmental Policy Research, May 20, 2008, available at: http://www.mit.edu/~jparsons/Presentations/SO2%20May%2008.pdf, accessed October 16, 2009.

h) *EPA Spot Auction 2008* – "2008 Acid Rain Allowance Auction Results," available at http://www.epa.gov/airmarkt/trading/2008/08spotbids.html, accessed October 16, 2009.

i) *SO2 Spot Prices in 2008* – Estimates from visual inspection of graphs compiled from Cantor Fitzgerald data graphed in: U.S. Environmental Protection Agency, "Acid Rain Program 2008 Progress Reports -- Emission, Compliance and Market Data Report," available at http://www.epa.gov/airmarkets/progress/ARP_1.html#so2allowances, accessed October 16, 2009. Low value is average price in January. High value is average price in December. Prices generally declined from the beginning of the year to the end of the year. Mid value is the midpoint.

j) *EPA Spot Auction, March 2009* -- 2009 EPA Allowance Auction Results (held once annually), available at http://www.epa.gov/airmarkt/trading/2009/09summary.html, accessed October 16, 2009.

k) GDP implicit price deflators – used to convert estimates into year 2008 U.S. dollars – are available at the Bureau of Economic Analysis, U.S. Department of Commerce, http://www.bea.gov/national/nipaweb/TableView.asp?SelectedTable=13&ViewSeries=NO&Java=no&Request3Place=N&3Place=N&FromView=YES&Freq=Year&FirstYear=1980&LastYear=2008&3Place=N&AllYearsChk=YES&Update=Update&JavaBox=no, accessed October 15, 2009.

The low and high values for damages from (non-greenhouse gas) emissions reflect the age and pollution abatement equipment installed in the power plants, as well as the population density in the region of the plant. The low and high values for CO_2 damages reflect the discount rates used and the damage functions used in the models that estimate these damages.

There is an important distinction between two types of values displayed in Table 4-12. The first type is a benefit to *society at large*, per ton reduction in pollutant; the second type is a reduced cost to the *utility* of complying with environmental regulations. In calculating an overall total benefit, the two types of benefits are additive.

Values in Table 4-12 may thus be used to provide monetary estimates of the benefits of reduced emissions as a result of a smart grid project. A project would need to estimate the emissions before the project, on the electricity generated for the area under study, and after the smart grid investments are in place. Then, based on the differences in emissions of different pollutants, one can calculate the economic benefit associated with these reductions.

4.7.3 Parameters for Monetizing the Benefits of Reduced Oil Consumption

The Smart Grid can enable greater use of electric vehicles and plug-in hybrid electric vehicles, which would reduce the demand by conventional vehicles for gasoline. Also, Smart Grid functions can lead to increased efficiency in utilities' operations, decreasing the need to use less efficient oil-fired power plants. This sub-section provides estimates that can be used to calculate the oil security benefits of any Smart Grid projects that enable reductions in oil consumption.[15]

[15] Some of the relevant studies on the subject of oil security include: Gately, D. (2004), Greene et al, (1998), Greene and Tishchishyna (2000), Hamilton (2005), Hughes et al. (2008), Huntington (2005), Leiby (2007), and Leiby et al. (1997).

The benefits of reducing oil consumption are the reduction in costs to U.S. society at large, in dollars per barrel, from reducing U.S. oil use. The oil premium, as calculated by Leiby (2007), has been used as a way of monetizing the benefits of improving oil security by reducing oil consumption.[16]

The most recent estimate of the oil premium uses the methodology developed previously by Leiby et al. (1997); it updates the previous estimates by considering more recent oil market developments, consumption, imports, economic conditions and prices in the 2006 to 2007 period (though these have again changed since then). The previous reported has been cited and its results used in previous U.S. Department of Transportation rulemakings, including the 2006 Final Regulatory Impact Analysis of CAFE Reform for Light Trucks, as well as in National Academies reports.

The more recent estimate (Leiby 2007) is that the benefits to society in general of reduced oil consumption are $13.58 per barrel, with a 90 percent confidence band of $6.71 to $23.25 (in 2004 US dollars). This estimate is the sum of two components: (i) the monopsony component, which reflects the benefit to society in general if the U.S. exerted its market power to reduce its oil demand and thus world oil prices; it is argued that such action would be justified in the face of OPEC monopoly power[17]; and (ii) macroeconomic adjustment costs from oil price disruptions, whose likelihood is increased by OPEC cartel policy. A third component, the costs of implementing policies to maintain oil security, including part of the cost of having a military presence in the Middle East, is *not* included in the estimate. The size of this third component is too difficult to estimate (Leiby 2007). The confidence band for the estimates is calculated from Monte Carlo simulation of risk-related parameters affecting the oil premium.

[16] This estimate is not tied to the nature of the market failure, i.e., these are externalities. Also, the estimate does not account for the benefits to Europe, Japan and other oil importers, nor does it account for trade policies on the part of either oil exporters or importers.

[17] OPEC, while a "clumsy" cartel, wields considerable market power by colluding to set production targets, thereby affecting market prices. Thus, the monopsony component is still an added cost to U.S. society.

Table 4-13 compiles the range of estimates from Leiby (2007), converting the original estimates in 2004 USD to 2008 USD using the GDP implicit price deflator.[18] Table 4-13 also lists oil premiums, expressed in units of kWh generated from oil. These estimates were calculated using an average heat rate of 10,400 Btu per kWh and 5.8 million Btu per barrel of oil.[19, 20] Once a project estimates its reductions in oil use in generating power and in its operations, then the reduction can be combined with an estimate of the oil premium to calculate the energy security benefit of the reduced oil consumption. The estimates of the kWh-equivalent oil premium in Table 4-13 may be used to monetize the benefits to society in general of reduced use of oil-fired power plants.

Table 4-13
Estimates of Oil Security Benefits from Reducing Oil Consumption

	Oil Premium ($/barrel oil, in 2008 USD)	kWh-equiv Oil Premium ($/kWh, in 2008 USD)
Low (5th percentile)	7.50	0.013
Mid	***15.00***	***0.027***
High (95th percentile)	26.00	0.047

Source: Based on original estimates in Leiby (2007), converted as described in the text.

Similarly, analysts can estimate the increased use of PHEV's and EV's, and the associated reductions in oil consumption. Based on these estimates, one can use the estimates of the oil premium in Table 4-13 to monetize the benefits of reduced gasoline consumption due to increased use of electric vehicles, including PHEVs, and associated decreased use of gasoline.[21]

Note that, using the same methodology, estimates of the oil premium would have been greater for oil prices and market conditions that exist in late 2009, compared to the late 2006 timeframe in which much of the analysis for the Leiby (2007) study was completed. At that time, the oil price was about $55 (in $2004). Recently, it is about $75 (in November 2009, in nominal dollars). Thus, the estimates in Table 4-13 generally underestimate the oil-security benefits, based on market conditions in late 2009.

[18] Using the GDP implicit price deflators as compiled by the Bureau of Economic Analysis: http://www.bea.gov/national/nipaweb/TableView.asp?SelectedTable=13&ViewSeries=NO&Java=no&Request3Place=N&3Place=N&FromView=YES&Freq=Year&FirstYear=1980&LastYear=2008&3Place=N&AllYearsChk=YES&Update=Update&JavaBox=no

[19] Average heat rate of 10,400 Btu per kWh for petroleum steam turbine. In 2007, as compiled by the Energy Information Administration, http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfilea7.pdf

[20] There are 5.8 million Btu per barrel of oil, as listed for example in http://bhs.econ.census.gov/BHS/MEC/ConversionFactorsTable.pdf

[21] There is no standard conversion from gallons of gasoline to barrels of oil. There are 42 gallons of oil in one barrel. Depending on refinery efficiency, type of crude oil, and the desired product streams, one barrel of crude makes about 19-1/2 gallons of gasoline, 9 gallons of fuel oil, 4 gallons of jet fuel, and 11 gallons of other petroleum products (http://www.gravmag.com/oilbarrel.shtml).

4.8 Estimate Costs

To determine the overall cost effectiveness of a Smart Grid project, in addition to the monetization of the project's benefits it is also necessary to collect project cost information. This provides the basis against which to determine whether a project has provided a positive return on investment.

In general, (a) cost data come directly from the project which is keeping track of project costs rather than estimated by DOE; (b) capital costs are amortized over time; each project is to estimate its activity-based costs, using its approved accounting procedures for handling capital costs, debit, depreciation, and taxes; and (c) both baseline and actual project costs should be tracked, with a distinction between costs that would normally be incurred in at-scale investment and those due to the R&D, demonstration and DOE reporting-requirement aspects of the project.

Identification of the appropriate costs to include in a cost effectiveness assessment will depend on the perspective of the entity for which the analysis is being conducted. The cost effectiveness of a project from an overall perspective could be different than the cost effectiveness of that same project from a utility's perspective. Consider, for example, a Smart Grid program in which a utility provides participants with an incentive payment if the customer is willing to reduce its peak demand during certain times. From the customer's perspective, this incentive is a benefit. From the utility's perspective, this incentive payment is a cost associated with the program. From an overall perspective, this exchange is simply a transfer payment from the utility to the participant. In the long run, the utility's cost is presumably exactly offset by the participant's increase in wealth, and the net effect is no change.[22] However, the smart metering and time-varying tariff in the program provide overall improvements in the efficiency of the utility's operating system, so that from an overall perspective there is a net increase in benefits.

A number of cost effectiveness tests have been developed, each with its own perspective and associated categories of costs and benefits.[23] A brief summary of the most common tests is provided below in Table 4-14.

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[22] There are, however, implications regarding the distribution of that wealth.

[23] These tests are described in detail in the California Standard Practice Manual.

Table 4-14
Summary of Types of Cost Effectiveness Tests

Test	Key Question	Benefits	Costs
Participant Test	Is the participant better off?	Bill decrease; customer incentives	Program costs (participant); participation fees
Total Resource Cost (TRC) Test	Is resource efficiency improved?	Avoided supply-side costs	Program costs (total)
Ratepayer Impact Measure (RIM) Test	Are rates lowered?	Avoided supply-side costs; participant fees	Revenue loss; customer incentives; program costs (utility)
Utility Cost Test	Are revenue requirements lowered?	Avoided supply-side costs; participant fees	Customer incentives; program costs (utility)

It will likely be desirable to assess the Smart Grid projects from a number of perspectives. At the least, as these are federally funded projects they should be assessed using the TRC test to represent the overall cost-effectiveness of the project to society as a whole.

It will likely be desirable to assess the Smart Grid projects from a number of perspectives. At the least, as these are federally funded projects they should be assessed using the societal version of the Total Resource Cost (TRC) test to represent the overall cost-effectiveness of the project.

This test universally includes all (utility, consumer, society) costs and benefits associated with the program and therefore is applicable regardless of which type of demand-side program is being evaluated. In general, these tests are applicable to smart grid evaluations, because a major driver of smart grid benefits will be avoided supply side costs realized through demand reductions, and assessing these impacts was the original driver behind the development of these models.

Costs associated with a Smart Grid project could be assigned to the following general categories. Note that not all of these costs would be included under all cost-effectiveness frameworks. Further, any given Smart Grid project would not necessarily incur costs under each of these categories, or could potentially have additional types of costs that are unique to that project. The cost data itself would be directly supplied by the project, which is keeping track of program costs through its budget tracking processes.

Table 4-15 lists the activity-based cost data which each project would track and provide estimates for the baseline. Costs are on an annual basis. Capital costs should be included on an amortized basis, rather than a lump sum basis. Specific mechanisms for performing this amortization would be based on each project's own approved accounting procedures for handling capital costs, debt, depreciation, and taxes.

Given the research-focused nature of the nine Smart Grid demonstration projects, it is important to separate the research and development (R&D) related costs from those types of costs that would be incurred under the full deployment scenario. Under full deployment, those R&D costs would represent a smaller – or even negligible - share of the overall cost as the program or technology is likely to have been fully tested at that point.

In assessing the cost effectiveness of the project, both R&D and non-research related costs should be included in the cost effectiveness analysis. However, isolating those costs would facilitate the process of drawing conclusions about the potential cost effectiveness of larger scale deployment, for which non-research costs might be scalable but R&D costs would be proportionally smaller.

Table 4-15
Activity-Based Costs to be Tracked for the Project and to be Estimated for the Baseline

General Category	Type of Cost
Program	• Planning and administrative
	• Smart Grid program implementation
	• Marketing
	• Measurement, verification, analysis
	• Participant incentive payments
Capital investments	• Generation
	• Transmission
	• Distribution
	• Other
Operation and maintenance	• Generation
	• Ancillary service
	• Transmission
	• Distribution, excluding meter reading
	• Meter reading, excluding fossil fuel cost
	• Participant incentive payments
	• Utility revenue reductions (e.g. lower sales associated with more efficient consumption of electricity)
Losses and theft	• Value of losses
	• Value of theft
Reliability	• Restoration costs

Table 4-15 (continued)
Activity-Based Costs to be Tracked for the Project and to be Estimated for the Baseline

General Category	Type of Cost
Environmental costs	• CO_2 control equipment and operation
	• CO_2 emission permits
	• SO_2, NOx, PM control equipment and operation
	• SO_2 and NOx emission permits
Energy security	• Cost of oil consumed to generate power
	• Cost of gasoline, diesel and other petroleum products for transportation and operation
	• Cost to restore wide-area blackouts if any actually occur during the project period
Research and development	• R&D costs

Costs should be estimated on the same time intervals for which benefits are calculated. Annual cost estimates are generally sufficient, although further granularity could be sought to the extent that it is available and could provide potentially useful information regarding the seasonal nature of costs and benefits. Further discussion regarding the importance of the analysis time horizon is included in Section 4.9.

4.9 Compare Costs and Benefits

Once the costs and benefits have been estimated, they can be compared to develop an understanding of the overall cost-effectiveness of the project. There are several methods by which the costs and benefits can be compared, each providing different insights. These methods are summarized below.

- **Annual comparison** – If costs and benefits are collected for each year of the study period, then an annual comparison can be made. This is useful in identifying specific years in which costs exceed benefits or vice versa. The comparison could be done on a seasonal or more granular basis to the extent that information is available.
- **Cumulative comparison** – Costs and benefits can be presented cumulatively over time, with each year's cost or benefit being the sum of that year's value plus the value of all prior years. This is helpful in identifying the "breakeven" point in time when benefits exceed costs.
- **Net present value** – For the entire study period, the net present value of the Smart Grid project can be estimated by subtracting costs from benefits in each year, discounting each annual net benefit amount, and then summing these discounted values. The net present value represents the total discounted value of the project – in other words, the total amount by which benefits exceed costs after accounting for the time value of money.

- **Benefit-cost ratio** – Either on a present value basis or on an annual basis, the project's value can be represented as a ratio of benefits to costs. If the ratio is greater than one, the project is cost-effective. If the ratio is less than one, it is not. This ratio is a simple way to represent the size of the benefits relative to the costs.

Regardless of which methods are used to assess cost effectiveness, the results will depend on the time horizon that is chosen as the study period. One option is to simply define the study period as the time period during which the demonstration project is active (typically two to three years). However, this does not capture benefits that would potentially be realized after the official "end date" of the project (for example, in a hypothetical Smart Grid project where customers are equipped with in-home information displays, the energy savings that result are likely to persist beyond a two or three year study window). Further, in thinking about the projects in terms of their potential to be deployed on a larger scale, it is desirable to consider a longer time horizon. Smart grid projects often take a 10 to 20 year perspective for assessing cost effectiveness. Another option is to focus on the expected lifetime of the technologies under consideration and compare the costs and benefits over this time period. At a minimum, projects should be evaluated using this last option, as it takes the most comprehensive and complete view of the impacts of the project. The other approaches would be used to evaluate the project over shorter timeframes.

It is important that the costs and benefits be compared over identical timeframes, as the nature of cost effectiveness analysis is time dependent. Since a dollar today is worth more than a dollar tomorrow, if a project's benefits are realized earlier in the study horizon than later, then the project is more likely to be cost effective. It is because of this that careful selection of the discount rate is important. The appropriate discount rate will depend on the perspective of the analysis and the specific assumptions of the project. For example, a social discount rate that reflects public priorities is typically lower than a utility's weighted average cost of capital. Previously, assumed discount rates have often ranged between three percent and seven percent. However, as selection of the appropriate discount rate is up to each individual project, based on its approved accounting procedures.

When extrapolating project costs and benefits to a represent a broader deployment scenario or timeframe, it is also important to consider the potential impacts of technological improvement and economies of scale on overall cost effectiveness. As Smart Grid technologies gain traction in the market and achieve increasingly higher adoption rates, the technologies are likely to improve due to the effect of learning on manufacturing processes and market feedback on the functionality of the products. Depending on the level of market penetration, economies of scale might also be achieved, lowering the per-unit cost of the devices. As such, in extrapolating the costs and benefits of Smart Grid programs, future research could benefit from the consideration of a maturity model for addressing these potential impacts. This research would be a longer-term effort and is not reflected within the framework we have developed thus far.

5
KEY ISSUES

This section discusses some largely unresolved issues in estimating the benefits and costs of the Smart Grid.

5.1 Uncertainty

This section outlines a general approach for dimensioning and expressing uncertainty in the estimates of costs and benefits. Two sets of metrics are proposed for use in the general methodological framework, with one extension proposed as an option. This option would enhance the information transfer regarding the uncertainty in the estimates.

The approaches are straightforward and easy to apply by non-experts in the elicitation and application of probabilities to cost-benefit analyses. We also anticipate that in most instances, the data will be insufficient to support more elaborate uncertainty analyses. In any event, there is an extensive literature on this topic for those who might want to investigate more sophisticated methods.[24] However, it is important to provide at least basic information dimensioning uncertainty in the cost estimates and project outcomes. The general approach presented in this section accomplishes this overall objective.

5.1.1 Categories of Precision

The general discussion of the concept of benefits in Section 2.2 took into account the precision of the estimates. This was expressed in Figure 2-2 (also shown on the next page) to indicate that there is a third dimension to the matrix of benefits which represents the level of precision in the estimated magnitudes of these benefits and costs.

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[24] References to a wider range of approaches for eliciting estimates of probabilities that can be used to dimension uncertainty around costs and benefits can look at many of the guidebooks that accompany decision analysis software tools (e.g., Crystal Ball or @Risk). Some literature in this area includes: Rand Corporation, "Evaluating Uncertainty in Cost Estimates A Practical Guide to Eliciting Expert Judgments," RAND TR-410-AF, 2007; O'Hagan, Anthony and Jeremy E. Oakley, "Probability is perfect, but we can't elicit it perfectly," Reliability Engineering & System Safety Volume 85, July-September 2004; Merkhofer, M.W. ``Quantifying Judgmental Uncertainty: Methodology, Experiences, and Insights," *IEEE Transactions On Systems, Man, And Cybernetics,* Vol. SMC-17, Pp. 741--752, 1987; and Ward, E., R. Miles, and D. Winterfeldt (eds.), Advances in Decision Analysis, Cambridge University Press, 2007. A good practical example of probability elicitation is shown in Shephard,G.B and C. W. Kirkwood, Managing the Judgmental Probability Elicitation Process: A Case Study of Analyst-Manager Interaction, IEEE *Transactions on Engineering Management*, Vol. 41, No. 4, 1994.

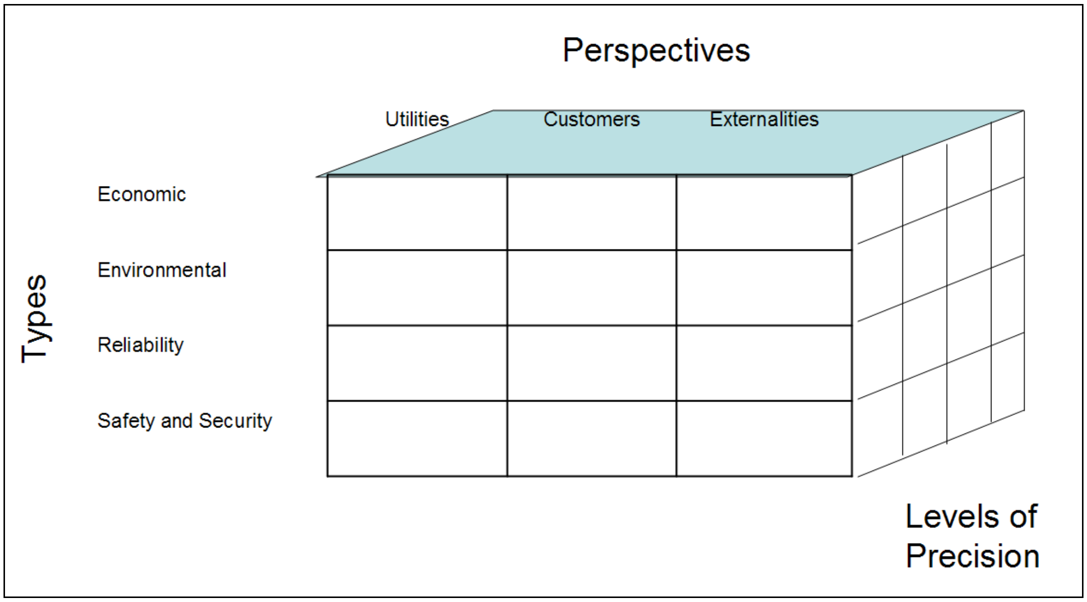

Figure 2-2 (shown again here)
Types, Perspectives and Levels of Precisions of Estimated Benefits and Costs

Precision is one way to dimension uncertainty in that precision often is used to quantify a range within which there is a probability that the true value will fall. For example, this is where we get the concept of an estimate being accurate to plus/minus 20% (around the estimate) with an 80% level of confidence comes from. From a statistical perspective, confidence intervals are not probabilities that indicate whether a given point estimate is the true value. Instead, they are range estimates where a range is specified as having a given probability that the actual value is within those boundaries.

In this benefit-cost methodological framework the goal is to dimension uncertainty such that useful information is transferred to potential users of the benefit-cost results regarding the likely range of the estimates.

The approach to be taken is based on judgmental assessments of uncertainties and ranges. This is a common method used by regional power planning agencies. It helps communicate the results by including a judgment regarding how precise the estimates are by the research team performing the benefit-cost analysis. The literature on subjective estimation of probabilities makes no specific recommendations, other than to try to use those individuals who are believed to have the most insight into the problem.

Some Smart Grid benefit estimates that are linked to environmental and social benefits might not be estimated with the same level as certainty as other benefits metrics; then, when the step is taken to monetize these benefits it would also be useful to characterize their relative imprecision.

Given that the goal is to communicate a degree of information regarding the precision with which the Smart Grid benefits and costs are estimated, a reasonable way of characterizing the general level of precision is to use broad categories. Four categories have been set out in this general methodology. Most estimates are expected to fall within the first two categories and every effort should be made to try to develop estimates that fall in the first category. If there are some estimates that are very uncertain – two additional categories are provided. The four categories and their implicit level of precision are shown below:

1. **Modest level of uncertainty** – Most estimates are expected to be subject to uncertainty. A modest level of uncertainty in quantitative estimates and/or in monetization implies a level of confidence and precision that is where the estimate is viewed to be +/- 20% with at least an 80% level of confidence, i.e., there is an 80% probability that the actual value is within +/- 20% of the estimate.
2. **Significant level uncertainty** – Some estimates might be subject to greater levels of uncertainty. The category "significant level of uncertainty" would be for estimates where the estimate is viewed to be +/- 40% with at least an 80% level of confidence, i.e., there is an 80% probability that the actual value is within +/- 40% of the estimate in quantitative metrics and/or in how to monetize (80% confident that the actual value is within +/- 40%)
3. **Highly uncertain** – This would be for estimates that are very uncertain and difficult to quantify. The implicit precision level is viewed as +/- 100% with a 95% level of confidence.
4. **Uncertainty range cannot be quantified** – This should be limited to benefits that fall into the speculative category and are so uncertain that they can only be expressed as an order of magnitude estimate.

These categories can be used as headers in Figure 2-2 shown above.

There might also be uncertainty in the costs of achieving the project benefits. This cost uncertainty is likely to be much smaller than the uncertainty in the benefits, but it should still be dimensioned within the "Modest" level of uncertainty category, or the Significant level of uncertainty as discussed above.

The idea of using this simple approach to characterize uncertainty is to provide some general assessment about the degree of uncertainty in estimates of different project benefits and costs. There is no assumption about the underlying shape of the probability distribution and there is no overall assessment of uncertainty.

5.1.2 Benefits as a Multiple of Costs

This approach is meant to augment the use of the precision categories shown in section 5.1.1. This approach takes groupings of benefits and expresses them as a multiple of project costs. Generally, there is less uncertainty associated with costs than with benefits estimates, because costs are more easily measurable and typically do not require approximation of a baseline.

This technique is a simple way of indicating the general order of magnitude of different types of benefits and is a way of highlighting the ones that are likely to be greater. The approach is equivalent conceptually to a one-tailed statistical test in that the focus is on whether the benefits exceed a given value, rather than having the benefits fall into a +/- range.

Three groupings should be used corresponding to the precision categories shown above.

1. Those benefits that are viewed as having a modest level of uncertainty taken as a sum are, in the judgment of the researchers, expressed as likely to be 2x, 5x or 10x costs. This can be used to express a level of reliability that the benefits indeed outweigh the costs. This approach is equivalent conceptually to a one-tailed statistical test in that the focus is on whether the benefits exceed a given value, rather than having the benefits fall into a +/- range.
2. The sum of modest and significantly uncertain benefits expressed as a likely multiple of costs. Again, this would be expressed as likely to be 2x, 5x or 10x costs.
3. The third grouping would be the sum of benefits represented by the modest, significant and highly uncertain benefits. These categories are all subject to precision and confidence level assumptions as illustrated in section 5.1.1 above. Benefits that are so uncertain such that only an order of magnitude can be presented would not be included in any of these multiples of costs.

There might also be uncertainty in the costs of achieving the project benefits. This cost uncertainty is likely to be much smaller than the uncertainty in the benefits, but it should still be dimensioned within the Modest level of uncertainty or the Significant level of uncertainty as discussed above.

5.1.3 Distributions Representing Benefit Uncertainty

The following discussion describes a way of characterizing the degree of uncertainty in estimates that is somewhat more informative than the simpler approaches described in the previous sections. Many benefit-cost and planning studies simply use a scenario analysis where a low case, a medium case and a high case for benefits and costs are specified. However, what else would one like to know about these scenarios?

Additional information that would be useful might include:

- How likely is each of these scenarios to occur?
- Are scenarios other than these three as likely or more likely to occur?
- What is meant by low, medium and high?
- Is the low scenario the lowest conceivable value?
- Is the high the highest conceivable value?

Just knowing these three values – a low scenario, a medium scenario and a high scenario – might not tell us much and might not capture the research judgment and available ancillary information very well.

To better represent uncertainty, a rough distribution approach can be useful. In this case, the research team expresses judgment regarding the likelihood of the different outcomes. While it might be difficult to answer this question precisely, it is possible, for example, to present information indicating that the high scenario is more likely to represent what actually happened than the low scenario. Offering some information on the relative odds of the high, medium and low scenario occurring might produce information such as that shown in Figure 5-2 below where the medium scenario is believed to be the most likely, the high scenario is believed to be more likely to occur than the low scenario (by a ratio of 3:2) and there is also a small possibility that the true outcome is either above the high or below the low scenario. Figure 5-2 portrays a distribution that embodies this additional information.

Researchers have used various methods of eliciting the probability values. As an example, a procedure where a project researcher is asked where he would bet the true outcome might fall within the categories shown in Figure 5-2 can be used. If he had to place a bet, would he bet that the true outcome would be more likely to fall in the high value range than in the low value range, and what odds would he give regarding the relative likelihood of the true value falling in one region versus another?[25] This is one simple example about how to elicit the probabilities in Figure 5-2. Generally, with some thought, such probabilities can usually be described to create the type of distribution illustrated in Figure 5-2, which communicates considerably more information that the use of only broad uncertainty levels as discussed in Section 5.1.1.

In the application shown in Figure 5-2, the distribution was designed to have a 90% confidence that the true value would fall in the middle three categories. As a result, the two "tails" represent values that would occur only 5% of the time.[26] Taken together, the two tails represent a 10% probability, with the range represented by the low to high value representing a 90% confidence interval.[27]

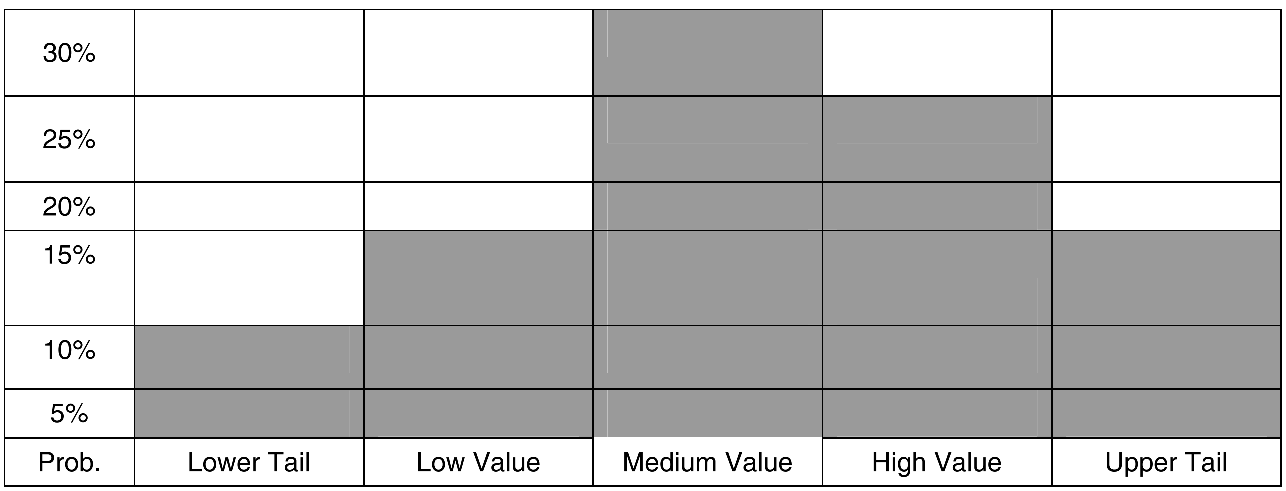

Figure 5-1
Uncertainty Distribution for a Category of Benefits

[25] This type of "gamble" approach is discussed in Wiegmann, D.A., "Developing a Methodology for Eliciting Subjective Probability Estimates," Final Technical Report AHFD-05-13/NASA-05-4 October 2005.

[26] The use of three point discrete point estimates using a 5% and 95% cumulative probability distribution along with a midpoint estimate is discussed in Keefer, D.L., "Certainty Equivalents for Three-Point Discrete-Distribution Approximations," Management Science, Vol. 40, No. 6, June 1994.

[27] This approach was used in: "Retrospective Assessment of the Northwest Energy Efficiency Alliance" by Summit Blue Consulting Published by the Northwest Energy Efficiency Alliance, October 2003, #E03-120.

5.2 Extrapolation of Project Results to Larger-Scale Deployment

The RDSI projects are limited-scale demonstrations of concepts and technologies that address various aspects of a Smart Grid. While these demonstrations represent important steps toward the realization of an integrated nationwide Smart Grid, considerable analysis will be required to extrapolate RDSI results to a broader field of application. Modeling and simulation will likely be needed to answer such questions as:

- Is there an existing valid *Business As Usual* scenario that can anchor the business case? If not, can modeling fill this need?
- How would a project's results change if the parameters were widely varied?
- How would a combination of several projects' results be integrated and would there be a synergistic outcome?
- How would economies of scope and scale affect the results of a given project or combination of projects?

While some tools already exist to address aspects of these issues, others are still in the planning or development stage. With regard to the latter, one promising avenue is a coordinated effort underway by NETL and PNNL. This effort seeks to answer a series of questions that are very similar to those listed above:

- How do we make the case for building a Smart Grid?
- What are the costs and benefits of different technologies with various penetration levels?
- Can we build Virtual Smart Grid Demonstration Projects and "see" the results from the virtual or simulated project without the cost of investing in an actual project?
- Can we extrapolate results of local Smart Grid deployments?
- Can we simulate an integrated system from consumers up to wholesale power markets?

The joint PNNL/NETL program intends to build tools that enable stakeholders to model Smart Grid technologies and strategies, creating a mechanism to link such simulations to business case assessments. Consistent with the framework presented in this report, it will divide Smart Grid benefits into three fundamental categories:

- Utilities/Ratepayers Benefits
- Consumer Benefits
- Benefits to Society in General

A library of "Potential Consumer and Societal Benefits" associated with the Smart Grid will determine how benefits can be quantified and how their value can be calculated. Doing this requires identification of current Smart Grid modeling and simulation tools (e.g. Open DSS, RDAP**,** and XpertSim), their integration where appropriate with PNNL's GridLAB-D tools, and the creation of new enhanced software. The initial focus will be on:

- Reduction of System Losses
- Reduction of Transmission Congestion
- Coordination of Voltage Control and Power Factor Correction
- Reduction of Peak Demand

Each of these initial topics would be immediately applicable to the set of RDSI benefits described elsewhere in this report. For example, consider the first *use case*:

5.2.1 Reduction of System Losses

It is well understood that losses on a distribution system can be reduced if distributed generators inject power into the system. The extent to which losses can be reduced on the distribution system and the impact on transmission system losses are less well understood. This use case will focus on examining the net reduction in system losses for varying penetration levels of renewables. Various control strategies will be examined to identify the optimal method of operation for maximum efficiency. Operating strategies which conform to IEEE 1547 as well as those that do not will be examined. Losses on both the transmission and distribution system will be examined.

This is a valuable case, but perhaps it could be expanded to explore how a wider set (not just renewables) of Smart Grid technologies could reduce T&D losses. This broader case would employ such RDSI deployments as DA, DR, storage, VAR dispatch, feeder to feeder switching, etc. to determine the maximum loss reduction possible and also the economically optimum level of loss reduction. The associated reliability benefits could also be captured.

This example clearly illustrates the kind of tools that will be important to a comprehensive analysis of each RDSI project and the potential interaction that can maximize the value of the overall Smart Grid program. Modeling and simulation will be needed to extrapolate the RDSI project results to more general national situations. Such modeling is a major activity that is beyond the scope of this report and that serves additional purposes, such as designing smart grid systems.

6
NEXT STEPS

Although the methodological approach is being developed for the nine DOE demonstration projects funded in 2008, our intent is that the approach will have broad programmatic application and that it could form the basis for consistently evaluating the cost and benefits of Smart Grid based on data attained from any Smart Grid field demonstration project including the results of field demonstrations as well as larger projects covering a utility's service area or a regional transmission organization's (RTO's) region. Thus, there is a need to implement this methodological approach in the form of a computational tool, together with specific guidelines for compiling the data needed for the tool. This important next step is in the process of being completed (as of November 2009).

Another activity in the near future is the likely application of the methodology developed in this study, together with the computational tool to be developed based in part on this methodology, to the nine RDSI-Smart Grid demonstration projects originally funded in 2008. Also, the methodology might be used for the EPRI Smart Grid demonstration projects as well.

It is expected that much will be learned in applying the Smart Grid cost and benefits computational tool to data attained from the DOE RDSI and EPRI Smart Grid demonstration projects. Lessons learned will be continuously employed during these projects to improve the CBA methodology and associated computational tools.

In addition to these projects, in the latter part of 2009, the Recovery Act provided funding of about $4 billion dollars in Federal funds in cost-shared Smart Grid projects. In both of these programs – the Smart Grid Investment Grant program and the Recovery Act – Smart Grid Demonstrations – recipients of these funds are required to provide data to DOE so that it can estimate the benefits and costs of these projects. The timing of this report coincides, by chance, with the imminent launch of many new projects funded under these programs. These projects are also likely to provide additional learning opportunities to improve the CBA methodology and the associated computational tools.

Given the considerable uncertainty and issues discussed in Section 5, more study and analysis are needed to address the more contentious and difficult issues, including:

- Extrapolating individual projects' results to estimate their broader implications for larger-scale deployment
- Estimating cost and benefits over longer time horizons; projects typically last 3-4 years, whereas the cost and benefits of Smart Grid projects are realized many years beyond that period
- Improved data collection so that the data inputs needed for the computational methods are compiled

Other issues and challenges that are important to address in the future are the following:

- Assigning benefits to different stakeholder groups [i.e., electric service provider, consumers (and individual consumer segments), and society] while avoiding double counting of benefit.
- Improving the monetization of the types of benefits that are difficult to convert to a monetary value, such as improvements in environmental emissions, reliability, safety, and security.
- Determining the degree to which different features of the Smart Grid contribute to a particular benefit (e.g., what portion of a benefit of emissions reduction is attributed to shifts in generation mix, lower T&D losses, and demand response, respectively); the initial focus in developing the methodology is on estimating the benefits of a project; being able to attribute portions of benefits to different individual smart grid investments and systems within an overall project is an important next step in expanding the methodology.
- Improving methods for establishing baseline technical and economic performance based on current and historical data, including the possible need for additional sensors to obtain these data.
- Accounting for changes in conditions between the baseline and demonstration periods in the cost and benefits analysis (e.g., accounting for changes in weather and load between baseline and demonstration periods).
- Extending the duration of the demonstration period and events encountered during the demonstration period so that Smart Grid features such as self-healing and outage management can be evaluated rigorously. In other words, will the demonstration period include a sufficient number and degree of off-normal operations to test the self-healing, restoration, and resiliency of Smart Grid? This additional experience will provide additional information about the nature of Smart Grid benefits and how they arise.
- Using empirical evidence to assess the degree to which Smart Grid demonstrations can measure cost avoidance such as cost savings achieved through avoidance of events such as outages, power quality events, and need to meet peak loads with relatively expensive sources of generation.

The Smart Grid uses one of the incredible transformational changes of the late 20th- and early 21st-centuries – the rapid growth and evolution of information technologies – to address one of the grand challenges of the early 21st century. That challenge is to transform the delivery of electric power, where the current infrastructure is highly constrained and outdated, to an integrated system that will deliver increasing amounts of electricity more efficiently, more reliably, and with less damage to the environment, while improving the nation’s energy security. Such a change will be vitally important to sustainably power the economic growth of the U.S. and other nations in the decades ahead.

7
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A

U.S. DEPARTMENT OF ENERGY'S RDSI/SMART GRID DEMONSTRATION PROJECTS ANNOUNCED IN 2008

Thursday, 1 May 2008

DOE Selects Projects for up to $50 Million of Federal Funding to Modernize the Nation's Electricity Grid and Achieve 15% Reduction in US Peak Load

U.S. Department of Energy (DOE) Assistant Secretary for Electricity Delivery and Energy Reliability Kevin Kolevar today announced the Department's plans to invest up to $50 million over five years (Fiscal Years 2008 - 2012), subject to appropriations from Congress, in nine demonstration projects competitively selected to increase efficiency in the nation's electricity grid.

The Renewable and Distributed Systems Integration (RDSI) technologies demonstrated in these projects aim to reduce peak load electricity demand by at least 15 percent at distribution feeders—the power lines delivering electricity to consumers—and are part of the Bush Administration's ongoing efforts to enhance the efficiency and reliability of our nation's energy infrastructure to ensure a reliable supply of energy to all Americans.

"Cutting-edge technologies that enhance the efficiency and dependability of the nation's electricity grid are critical to the Bush Administration's overarching goal of ensuring an affordable and reliable supply of electricity to the American people," Assistant Secretary Kolevar said. "These proposals will help to increase reliability in our electricity grid by defraying both the cost and effort associated with upgrading distribution lines or adding new generation capacity to meet peak electrical load, furthering our ongoing efforts to increase national economic and energy security."

The projects were selected in response to DOE's Office of Electricity Delivery and Energy Reliability (OE) April 2007 Funding Opportunity Announcement seeking applications for research and development activities to improve the security of controls systems for energy delivery and increase the use of distributed generation during peak load periods. Negotiations between selected applicants and OE will begin immediately to determine final project plans and funding levels. Selected projects include:

Allegheny Power will develop the "West Virginia Super Circuit" in conjunction with West Virginia University (WVU) Research Park, WVU Advanced Power and Electricity Research Center, North Carolina State University, Research and Development Solutions, Augusta Systems, Inc., and Tollgrade Communications. They will improve distribution system performance, reliability, and security of electric supply through the integration of distributed resources and advanced technologies. (Duration: 5 years; Cost: $5.4 million federal/4 million non-federal)

ATK Launch Systems, along with partners Rocky Mountain Power and P&E AUTOMATION, will demonstrate load reduction through an integrated network of diverse renewable generation technologies and intelligent automation. The project will integrate renewable generation and energy storage resources, including a novel compressed-air generation technology, wind-turbines, heat recovery systems, solar trough booster technology, a steam turbine, and hydro-turbine resources. (Duration: 5 years; Cost: $1.6 million federal/$2 million non-federal)

Chevron Energy Solutions will collaborate with Alameda County, PG&E, VRB Power Systems, SatCon Technology Corporation, the University of Wisconsin, the National Renewable Energy Laboratory, Lawrence Berkeley National Laboratory, and Energy and Environmental Economics to significantly reduce peak load and measurably improve power reliability at the Santa Rita Jail. The project will integrate solar energy, fuel cell, energy storage and control systems. (Duration: 3 years; Cost: $7 million federal/$7 million non-federal)

The City of Fort Collins, in cooperation with Larimer County, Colorado State University, InteGrid Lab, Community Foundation of Northern Colorado, the Governor's Energy Office, Advanced Energy, Woodward, Spirae, and Eaton, will research, develop, and demonstrate a 3.5 megawatt coordinated and integrated system of Mixed Distributed Resources in Fort Collins to Achieve a 20-30 percent peak load reduction on multiple distribution feeders. (Duration: 3 years; Cost: $6.3 million federal/$4.9 million non-federal)

Consolidated Edison Co. of New York, Inc., along with Verizon, Innovative Power, Infotility, and Enernex, will develop and demonstrate methodologies to achieve true interoperability between a delivery company and end-use retail electric customers, enhancing the reliability of the distribution grid and the efficiency of its operations. (Duration: 3 years; Cost: $6.8 million federal/6.2 million non-federal)

The Illinois Institute of Technology (IIT) will collaborate with Exelon/ComEd, Galvin Electricity Initiative, S&C Electric, and others to develop and demonstrate a system that will achieve "perfect power" at the main campus of IIT through the implementation of distributed resources, advanced sensing, switching, feeder reconfiguration, and controls. This effort will be replicable at any municipality-sized system. (Duration: 5 years; Cost: $7 million federal/$5.2 million non-federal)

San Diego Gas and Electric will develop a dispatchable distribution feeder for peak load reduction and wind-farming in conjunction with: Horizon Energy Group, Advanced Control Systems, Pacific Northwest National Laboratory, the University of San Diego, Motorola, and Lockheed Martin. The project aims to prove the effectiveness of integrating multiple distributed energy resources with advanced controls and communication systems to improve stability and reduce peak loads on feeders/substations. (Duration: 3 years; Cost $6.9 million federal/$4 million non-federal)

The University of Hawaii, in cooperation with General Electric, Hawaiian Electric Company, Inc., Maui Electric Company, Columbus Electric Cooperative, New Mexico Institute of Mining and Technology, Sentech, and UPC Wind, will explore the management of distribution system resources for improved service quality and reliability, transmission congestion relief, and grid support functions. (Duration: 3 years; Cost: $7 million federal/$8 million non-federal)

The University of Nevada will collaborate with homebuilder Pulte Homes, Nevada Power Company, and GE Ecomagination to address the construction of energy efficient homes that overcome electricity grid integration, control, and communications issues by building integrated photovoltaic systems, battery energy storage, and consumer products linked to advanced meters that enable and facilitate an efficient response to consumer energy demands. (Duration: 5 years: Cost: $6.9 million federal/$13.9 million non-federal)

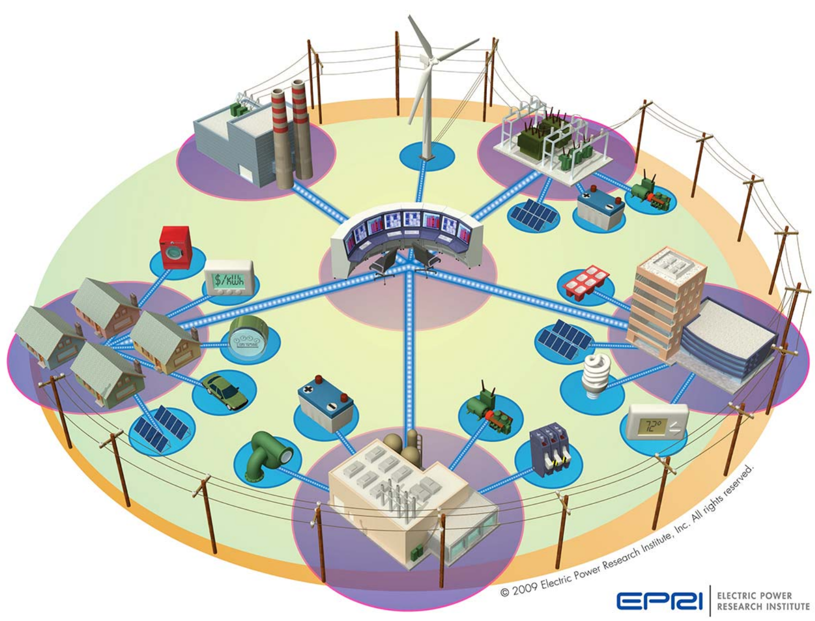
RDSI focuses on integrating renewable energy, distributed generation, energy storage, thermally activated technologies, and demand response into the electric distribution and transmission system. This integration is aimed toward managing peak loads, offering new value-added services such as differentiated power quality to meet individual user needs, and enhancing asset use.

Source: http://smartelectricnews.blogspot.com/2008/05/doe-selects-projects-for-up-to-50.html accessed October 8, 2008

B
ELECTRIC POWER RESEARCH INSTITUTE'S SMART GRID DEMONSTRATION PROJECTS INITIATED IN 2008

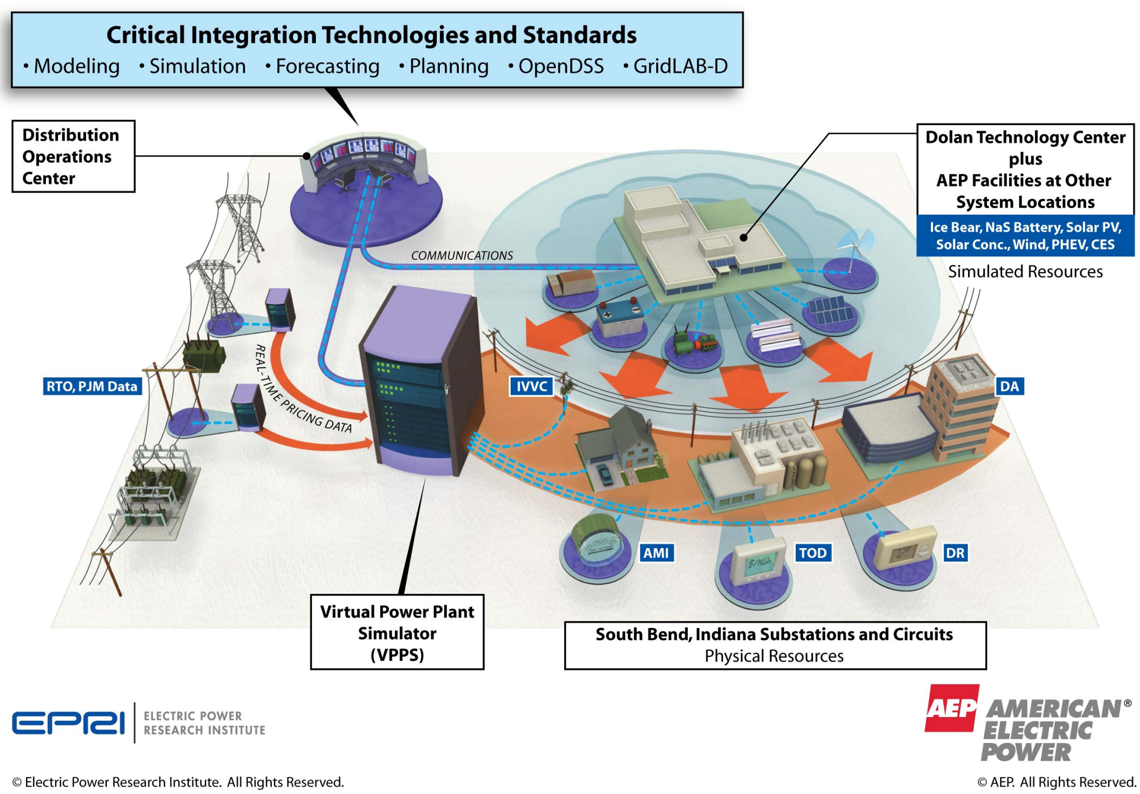
B.1 EPRI Smart Grid Demonstration Project

EPRI Smart Grid Demonstration Project includes a number of large scale smart grid projects as part of a five-year collaborative initiative with 19 utility members focused on integrating large-scale distributed energy resources (DER) including demand response, storage, distributed generation and distributed renewable generation into a "virtual power plant" to advance widespread, efficient and cost-effective deployment of utility and customer side technologies in the distribution and overall power system operations. Host-Site projects apply EPRI's IntelliGrid[sm] methodology to define requirements for the technologies and communication, information, and control infrastructures that support integration of DER. Operations experience, integration issues and lessons learned will reveal the full range of standards and interoperability requirements for these technologies to support the industry. Gaps revealed will identify critical areas of future smart grid research. Public updates are available on www.smartgrid.epri.com. The main objective of the demonstrations are to identify approaches for interoperability and integration that can be used on a system-wide scale to help standardize the use of demand-side resources as part of overall system operations and control. At the time of this publication, EPRI has identified and selected five smart grid Host-Site projects and by August 2010 EPRI expects to have a total of 10-12 projects selected.



B.2 American Electric Power (AEP) Smart Grid Demonstration Project Overview

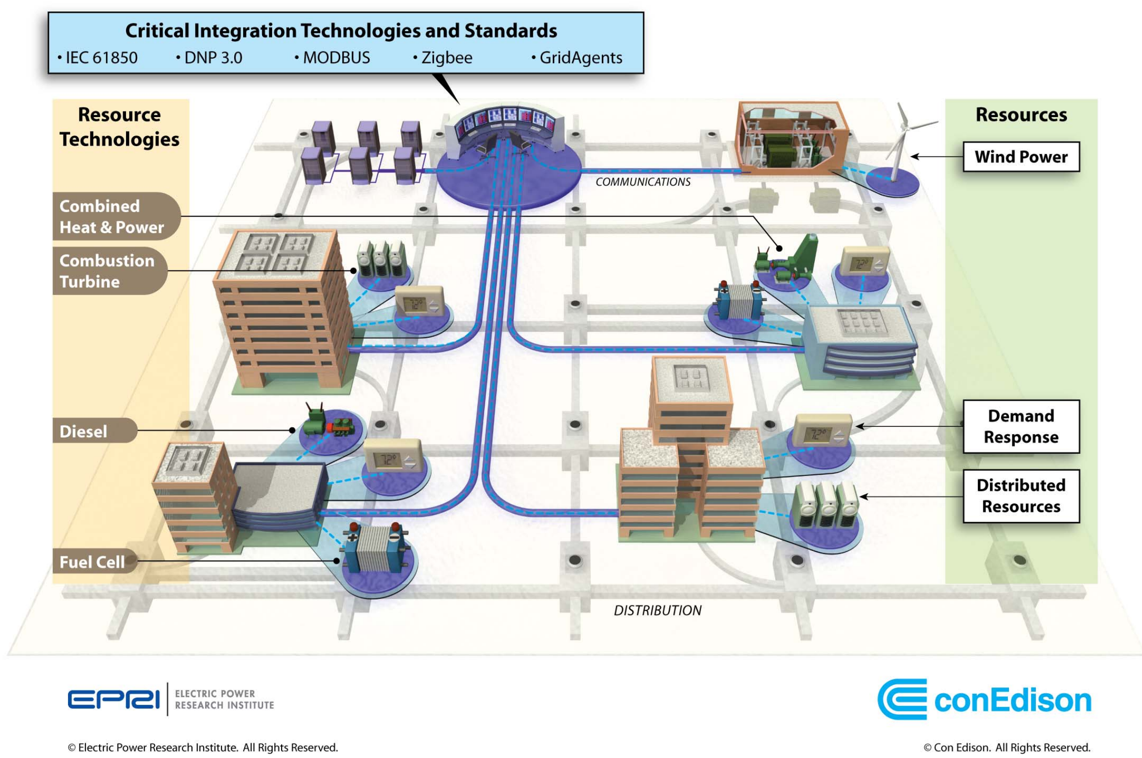
This project intends to address functionality and performance of a fully integrated and robust smart grid, from end-use to Regional Transmission Operator (RTO). It leverages a foundational system (South Bend, Indiana 10,000 customer pilot) that includes smart meters, communications, end-use tariffs and controls, and distribution automation and volt/var control with robust modeling and simulation platforms (e.g. GridLab-D and OpenDSS). Through these simulation platforms we are able to integrate other distributed and end-use technologies that are being evaluated by AEP, either in a real system environment or at our Dolan Technology Center, including four MW scale sodium sulfur battery installations, two 70-kW roof-top photovoltaic systems, a new 5.7 kW concentrating solar technology (with 1.2 kW electrical and 4.5 kW thermal outputs), three 60 kW natural gas fired reciprocating engines (with the potential for combined heat and power), two plug-in hybrid electric vehicles, one Ice Bear air conditioning system, two 10 kW wind turbines, and several 25 kW community energy storage systems (CES). Each of these individual demonstrations will be evaluated and reported separately as part of this EPRI project; however, the simulation platforms will enable us to virtually "install" these same systems on the South Bend system, utilizing real performance and temporal data as input to the simulations and to develop and validate system and component models. From a temporal perspective, we can simulate system operation as though it was integrated into a PJM market. In this way AEP can create a very robust representation of a "virtual power plant", leveraging real device and system information and data.



B.3 Con Edison Smart Grid Project Overview

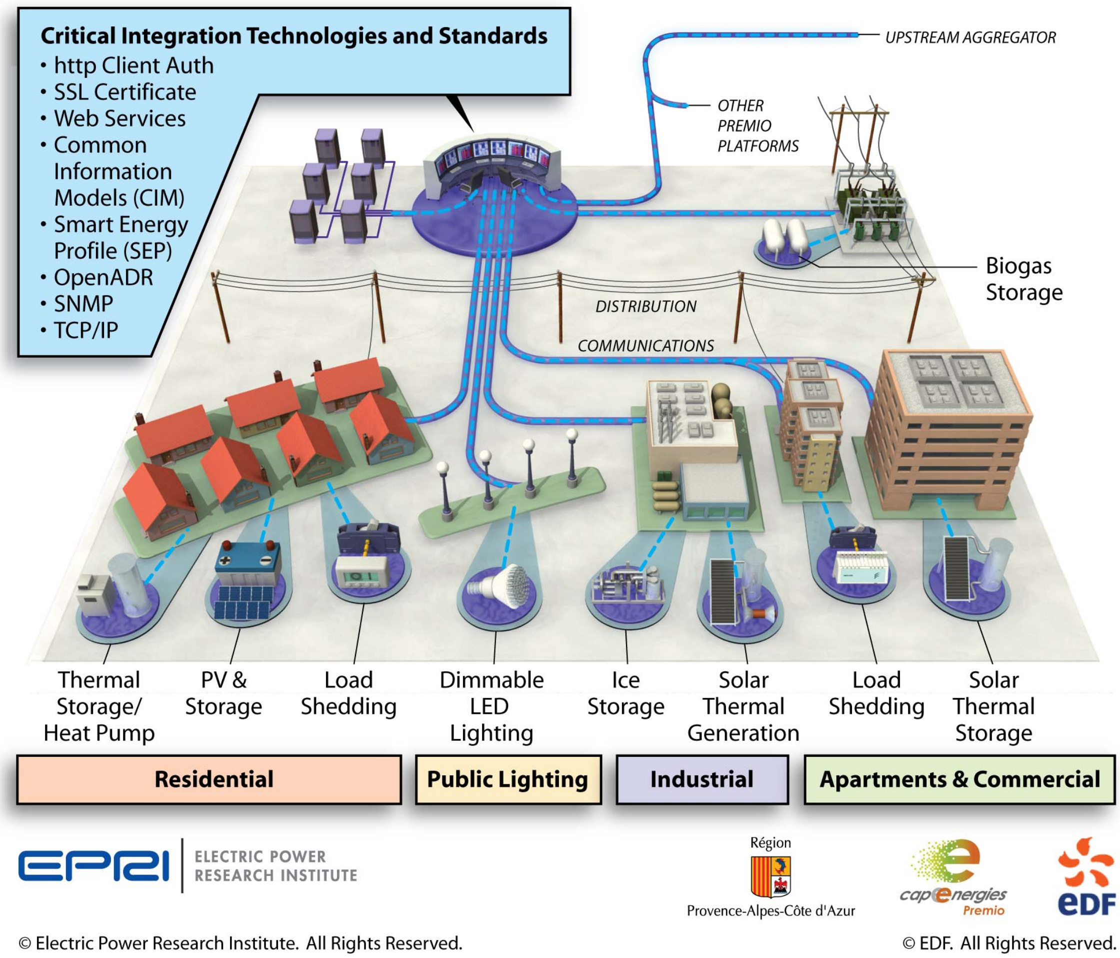
This project targets development of interoperability techniques including the development of protocols and software to leverage multiple types of customer owned distributed generation (DG) along with the integration of intermittent renewable generation and commercial building demand response. In order to achieve the project objective, interoperability between the delivery company and the demand response resources is important because Con Edison does not own or actively control the demand response resources. This project will demonstrate methodologies to enhance the ability of customer owned demand response resources to more effectively interface with electric delivery companies and demonstrate simple, safe, cost-effective methods of interconnection.

The primary business case for integrating customer owned distributed resources is related to a major reliability challenge of the Con Edison delivery system due to growth in demand, which has increased by 20% in the past decade and is projected to increase another 10% in the next decade. Given the large resident and working population and high infrastructure and load density, it is difficult to expand the delivery capacity. Therefore, increasing the ability to harness demand response resources is key to enabling Con Edison to maintain and enhance its high level of reliability. While enhancing the use of demand response is critical, it is also a great challenge to harness such a resource, which traditionally has not been under the complete control of the delivery company.



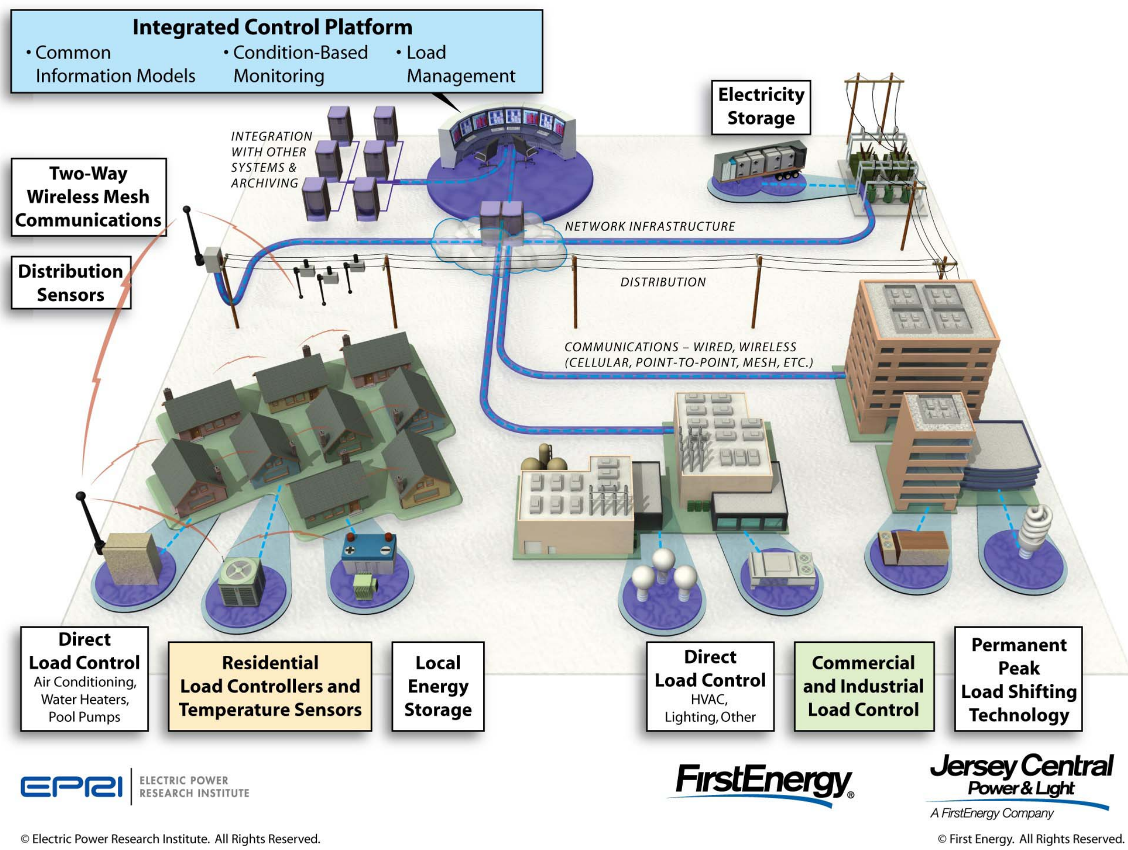
B.4 Electricité de France (EDF) Smart Grid Project Overview

The project objective is to demonstrate an innovative, open and repeatable architecture aimed at optimizing the integration of distributed generation, storage, renewable energy resources, demand response and energy efficiency measures in order to provide load relief, local network support and reduce CO_2 emissions in the PACA region (South East of France). The project includes deploying and integrating 9 types of distributed energy resources. This region of France is an electric peninsula supplied by a unique 400kV transmission line to fulfill most of the electricity needs of the customers. In addition, local electricity generation covers less than half of the needs and this peninsula effect is aggravated by the distance between generation and consumption sites. During peak periods, congestions occur and the demand supply balance of the system becomes difficult to guarantee especially in periods of extreme weather conditions (heat waves or thunderstorms).



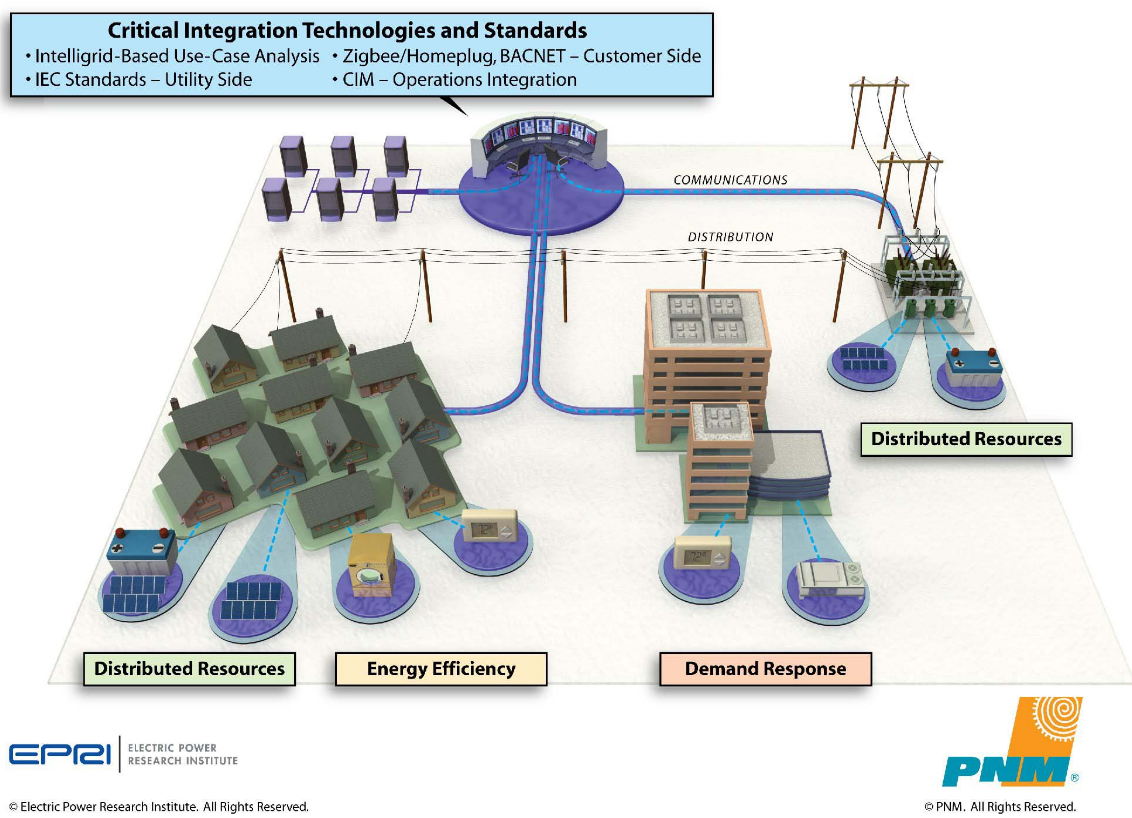
B.5 FirstEnergy Smart Grid Demonstration Project Overview

The Jersey Central Power & Light Integrated Distributed Energy Resource (IDER) management smart grid pilot will deliver operational and ISO program benefits by managing DER. Demand management with distributed resources is a primary focus and includes 8 MW of direct load control (DLC) equipment at 3,500 residential (5 MW) and 30-100 commercial & industrial (3 MW) customer locations. The Direct Load Control (DLC) technology will give the utility the ability to monitor and control non-critical customer electrical loads at a granular level via two-way communications architecture. The IDER architecture provides local distribution circuit monitoring via the DER Local Manager while the DER Master Control monitors wholesale energy market for price and/or capacity signals for market opportunities and for system reliability. The DER Master Control can aggregate DER from multiple Local Managers for optimal wide area management. Other DER technologies, including electricity storage and permanent peak load shift devices as well as electrical distribution equipment are expected to be added to the system once regulatory approval has been granted. The smart grid pilot is designed to provide utility operations with real-time system status based on pre-defined utility operational rules.



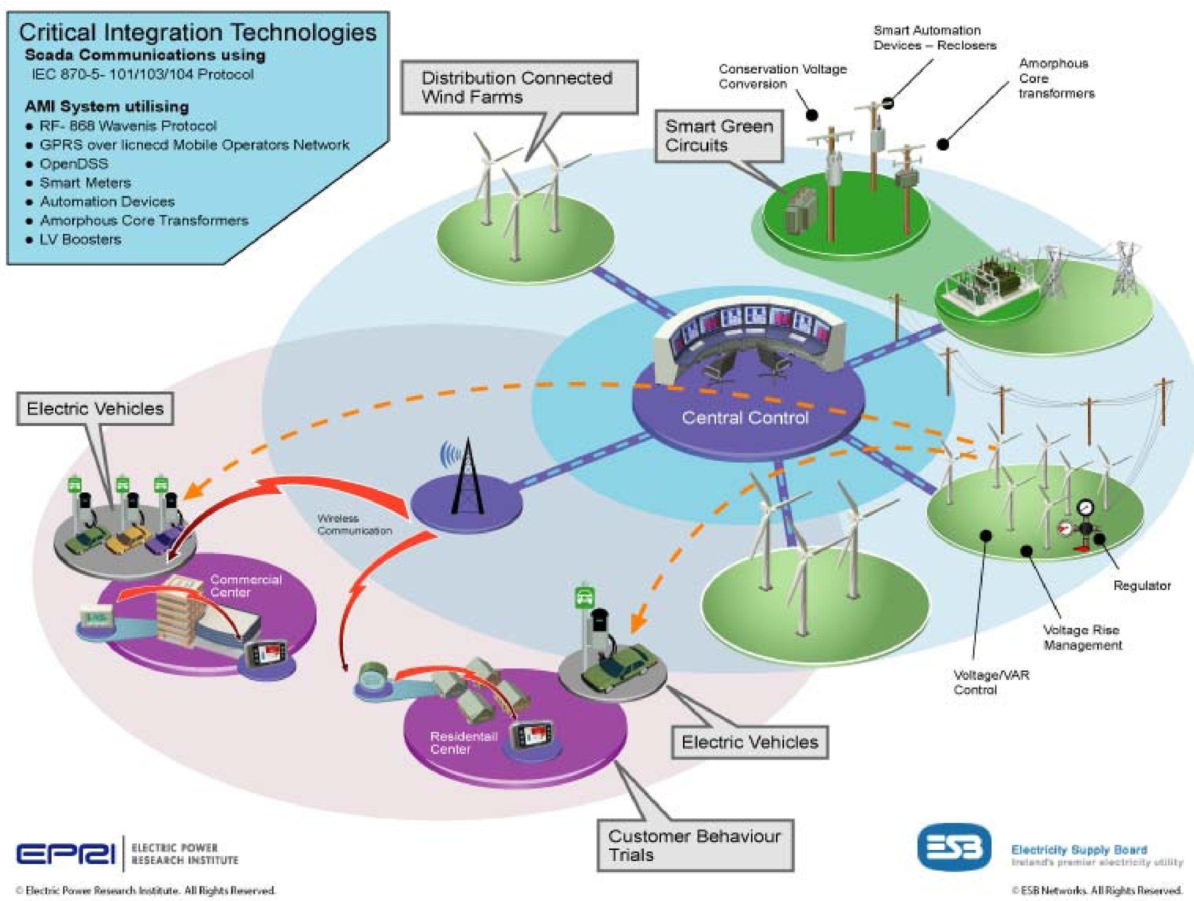
B.6 PNM Smart Grid Demonstration Project Overview

This project targets development and implementation of a real-world advanced distributed control and communication infrastructure to optimize renewable resource utilization and system benefits. The project will integrate distributed Photo Voltaic (PV) systems with high distribution circuit penetration levels, local storage, substation sited PV and storage with both local distribution system management and overall load management at the system level. Integration at the local level will consider smart inverter interface technologies to enhance system benefits, leveraging previous work done in the area of smart inverter interface software and applying it to residential and substation based PV systems. This project aims to match local loads with rate structures to identify and resolve technical issues related to high penetration of renewable generation at the utility distribution level. The project will investigate and analyze additional consumer-based demand response opportunities utilizing a modern communication infrastructure integrated with a Home Area Network (HAN), commercial building control systems and smart devices.



B.7 ESB Networks Smart Grid Demonstration Project Overview

ESB Networks' "Roadmap for Smart Grid Networks" project in Ireland intends to explore maximizing existing electricity networks, further developing and connecting wind farms, and increasing the effectiveness of customer response and interest in real-time demand and consumption management. ESB will maximize electricity usage by conducting customer behavior trials with smart meters and dynamic pricing, integrating electric vehicles and charging posts into its fleet, and installing "Smart-Green" circuits for remote control and system management. This project will also seek to increase the amount of wind energy connected to the system through management of voltage, reactive power, and demand. The customer behavior trial involves 6,000 customers in association with smart networks facilitated by multi tariff options, Demand-Side Management (DSM) and an interface with home area networks.



C

INITIAL APPROACH TO QUANTIFY AND MONETIZE BENEFITS

C.1 Optimized Generator Operation

The Optimized Generator Operation benefit can be realized through one functions and two Enabled Energy Resources (EERs):

- Wide Area Monitoring, Visualization, and Control
- Stationary Electricity Storage
- Plug-in Electric Vehicles

This benefit is composed of two pieces: avoided generator start-up costs and improved performance due to improved heat rate efficiency. In order to determine the value of the benefit, the project would have to track the annual generator dispatch avoided (MWh), along with the hourly cost of the generation ($/MWh).

For Wide Area Monitoring Visualization and Control:
Value ($) = $[\text{Annual Generation Cost (\$))}]_{\text{Baseline}}$ - $[\text{Annual Generation Cost (\$)}]_{\text{Project}}$

The net electricity cost[28] for charging Stationary Electricity Storage and PEVs ($/MWh) would also be tracked to calculate the benefit using the following formula:

Value ($) = $\{[\text{Hourly Generation Cost (\$/MWh) * Annual Generator Dispatch (MWh)}]_{\text{Baseline}}$ – $[\text{Hourly Generation Cost (\$/MWh) * Annual Generator Dispatch (MWh)}]_{\text{Project}}\}$* Energy Storage Efficiency(%)

Optimized generator operation could be very difficult to track and monetize because of the relatively small size of the project and the necessary coordination with the grid operator. The contribution to the optimized generator operation benefit will likely have to be estimated, rather than calculated. In this case, the value could be based on the reduction in marginal generation that could be realized if generators could follow load more closely or if electricity storage or PEVs could provide ancillary services so that conventional generators could operate at a more optimal level.

[28] The net electricity cost could include the difference between the charging price and the discharge price, as well as any energy losses associated with energy conversion and balance of systems for the energy storage technology.

C.2 Deferred Generation Capacity Investments

The Deferred Generation Capacity Investments benefit can be realized through one function and three EERs:

- Customer Electricity Use Optimization
- Distributed Generation
- Stationary Electricity Storage
- Plug-in Electric Vehicles

The impact of this benefit is determined by the capacity of the EER (MW) or the amount of load reduction from customer optimization (MW) and the price paid for capacity ($/MW), which represents the capital expenditures for conventional generation. The project would report when the EER was utilized during peak times. The cost savings could be accumulated based on the hourly savings. The monetary impact of this benefit is calculated using the following formula:

Value ($) = [Price of a Peaking Generator ($/MW) * EER Use or Customer Optimization at Annual Peak (MW)]$_{\text{Baseline}}$ - [Price of a Peaking Generator ($/MW) * EER Use or Customer Optimization at Annual Peak (MW)]$_{\text{Project}}$

Alternatively, the benefit could be monetized based on the value of deferring a central generating plant.

Value ($) = Capital Carrying Charge of New Generation ($/yr) * Time deferred (yrs)

This assumes the price of the marginal unit at peak and that generation deferral is based on reducing peak demand. If the project EER is not available during the peak time, no benefit is derived.

C.3 Reduced Ancillary Service Cost

The Reduced Ancillary Service Cost benefit can be realized through three functions and three EERs:

- Wide Area Monitoring and Visualization
- Automated Voltage and VAR Control
- Real-Time Load Measurement & Management
- Distributed Generation
- Stationary Electricity Storage
- Plug-in Electric Vehicles

These Smart Grid functions and EERs could enable grid operators to procure ancillary services from sources other than conventional generators at a reduced cost, or to reduce the amount required to operate the grid less expensively without sacrificing reliability. Value can be derived from reducing the cost of three types of ancillary services:

Value ($) = [Price of Ancillary Service ($/MW) * Purchases (MW)]$_{\text{Baseline}}$ - [Price of Ancillary Service ($/MW) * Purchases (MW)]$_{\text{Project}}$

This benefit will be extremely hard for a project to track because ancillary services vary significantly from year to year and are market based so it may be impossible to establish a baseline. It would also require coordination with the grid operators.

C.4 Reduced Congestion Cost

The Reduced Congestion Cost benefit can be realized through three functions and three EERs:

- Wide Area Monitoring, Visualization, and Control
- Dynamic Capability Rating
- Flow Control
- Distributed Generation
- Stationary Electricity Storage
- Plug-in Electric Vehicles

The project would report the hourly congestion relief provided by the function or EER along with the cost of congestion during the hours of operation as shown in Table 4-12. The project could multiply the relief (MW) by the typical congestion price. For example, assume a transmission line had a normal summer rating of 1,000 MW based on typical summer day air temperatures and wind speed. On a cooler than normal day, with breezy conditions, the rating of the line might be increased during a critical mid-day peak to 1,100 MW, potentially relieving congestion. The project could report that the dynamic rating relieved 100 MW of congestion for two hours. This congestion relief would be multiplied by the average or typical congestion price.

Value ($) = [Congestion (MW) * Price of Congestion ($/MW)]$_{\text{Baseline}}$ - [Congestion (MW) * Price of Congestion ($/MW)]$_{\text{Project}}$

Table C-1
Means of Congestion Relief

Function	Means of Congestion Relief
Dynamic Capability Rating	Increase in rating of congested system element
Flow Control	Avoidance of overloading congested system element
Distributed Generation	Reduction in loading on congested system element
Stationary Electricity Storage	Reduction in loading on congested system element
Plug-in Electric Vehicles	Reduction in loading on congested system element

C.5 Deferred Transmission Capacity Investment

The Deferred Transmission Capacity Investments benefit can be realized through five functions and three EER:

- Fault Current Limiting
- Wide Area Monitoring, Visualization, and Control
- Dynamic Capability Rating
- Flow Control
- Customer Electricity Use Optimization
- Distributed Generation
- Stationary Electricity Storage
- Plug-in Electric Vehicles

For Fault Current Limiting, a project could report the deferred cost of replacing or upgrading circuit breakers or other transmission and distribution equipment.

For Wide Area Monitoring, Visualization, and Control, a project could report the increase in transmission capability that resulted from better operating information. This increased capability could be related to a deferred upgrade.

For Dynamic Capability Rating, the project could report the dynamic hourly ratings of system elements and compare these to standard (fixed) ratings. In cases where the dynamic rating exceeded the standard rating, the project could multiply the additional capacity by the typical carrying charge and the time for which the upgrade could be deferred.

For Flow Control, the project would report the amount of power that impedance control diverted to another system element (e.g., 100 MW diverted to anther transmission line), and the estimated cost of the project that the additional capacity deferred ($/MW).

The use of customer optimization or EERs (DR, DG, ES, and PEV) could decrease the loading on transmission system elements and postpone the need for capital upgrades. The project would report the capacity (MW) of EERs used during peak times, which would lead to deferral of equipment or line upgrades.

Value ($) = Capital Carrying Charge of Upgrade ($/yr) * Time deferred (yrs)

For each these benefits, the deferred cost could be accumulated over time. For example, a project could be deferred for one year, and then the following year it could be deferred again, depending on loading and the dynamic rating.

C.6 Deferred Distribution Capacity Investment

The Deferred Transmission Capacity Investment benefit can be realized through four functions and three EERs:

- Dynamic Capability Rating
- Real-Time Load Measurement and Management
- Real-Time Load Transfer
- Customer Electricity Use Optimization
- Distributed Generation
- Stationary Electricity Storage
- Plug-in Electric Vehicles

For Dynamic Capability Rating, the project could report the dynamic hourly ratings of system elements and compare these to standard (fixed) ratings. In cases where the dynamic rating exceeded the standard rating, the project could multiply the additional capacity by the typical carrying charge and the time for which the upgrade could be deferred.

Real-Time Load Transfer and the use of EERs (DR, DG, ES, and PEV) could decrease the loading on distribution system elements and postpone the need for capital upgrades.

For Real-Time Load Measurement and Management, the project would report the capital upgrade schedule for infrastructure associated with the project. Based on better monitoring, they could identify projects that can be deferred as a result of being able to operate closer to the feeder limit.

The use of customer optimization or EERs (DR, DG, ES, and PEV) could decrease the loading on distribution system elements and postpone the need for capital upgrades. The project would report the capacity (MW) of EERs used during peak times, which would lead to deferral of equipment upgrades.

Value ($) = Capital Carrying Charge of Upgrade ($/yr) * Time deferred (yrs)

C.7 Reduced Equipment Failures

One of the greatest benefits of the Smart Grid technologies is the life extension of both central station generating equipment and T&D apparatus on older power systems. EPRI has identified Life Extension as being a major thrust in the 1990s as this allows reductions in overall capital equipment expenditures and permits operation of major equipment for periods of 1 to 10 years beyond normal life. The Reduced Equipment Failures benefit can be realized through four functions:

- Fault Current Limiting
- Dynamic Capability Rating
- Diagnosis and Notification of Equipment Condition
- Enhanced Fault Protection

For Fault Current Limiting, Dynamic Capability Rating, and Enhanced Fault Protection, projects will report the capital expenditures related to equipment failure within the project scope, and apply an estimate of the impact of fault current or overloading. The following formula will be used to calculate the monetary value of this benefit:

Value ($) = Capital Replacement of Failed Equipment ($) * Portion Caused by Fault Current or Overloaded Equipment (%)

For Diagnosis and Notification of Equipment Condition, the cost of the equipment that did not have to be replaced must be estimated. This could be done either by the project, or by the DOE. The estimate could be based on a utility's annual capital budget for equipment replacement, and the utility's estimate of how much of that capital budget is spent on replacing equipment that could have been prevented with timely diagnosis and maintenance. A portion of that cost could be allocated to the project on a pro rata basis. The value is calculated:

Value ($) = Capital Replacement of Failed Equipment ($) * Portion Caused by Lack of Condition Diagnosis (%)

C.8 Reduced Distribution Equipment Maintenance Cost

The Reduced Distribution Equipment Maintenance Cost benefit can be realized through one function:

- Diagnosis and Notification of Equipment Condition

To calculate this benefit, the project would track the cost of distribution equipment maintenance before and after the project. The monetary impact of this benefit is calculated using the following formula:

Value ($) = $[\text{Distribution Maintenance Cost (\$)}]_{\text{Baseline}} - [\text{Distribution Maintenance Cost (\$)}]_{\text{Project}}$

C.9 Reduced Distribution Operations Cost

The Reduced Distribution Operations Cost benefit can be realized through two functions:

- Automated Feeder Switching
- Automated Voltage and VAR Control

The project will track the cost associated with distribution operations after implementation of the Smart Grid project compared to the operations cost prior to implementing the project.

For Automatic Feeder Switching:

Value ($) = [Annual Cost for Feeder Switching ($)]$_{Baseline}$ - [Annual Cost for Feeder Switching ($)]$_{Project}$

For Automated Voltage and VAR Control:

Value ($) = [Annual Cost for Capacitor Switching ($)]$_{Baseline}$ - [Annual Cost for Capacitor Switching ($)]$_{Project}$

These costs can be tracked through an activity based costing system or Work Management System (WMS). If it is not possible for the project to track and report the necessary information, the impact of this benefit can be determined by estimating the percentage of a field crew's time is dedicated to switching, and then estimating the time saved by the field service personnel compared to before implementing the Smart Grid project.

C.10 Reduced Meter Reading Cost

The Reduced Meter Reading Cost benefit can be realized through one function:

- Real-Time Load Measurement & Management

The project would report number of meters to be read and the average cost to manually read a meter.

Value ($) = [Number of Meter Reading Operations (# of events) * Average Cost per Meter Reading Operation ($/event)]$_{Baseline}$ - [Number of Meter Reading Operations (# of events) * Average Cost per Meter Reading Operation ($/event)]$_{Project}$

Alternatively, the project could directly report the metering reading costs that were eliminated.

C.11 Reduced Electricity Theft

The Reduced Electricity Theft benefit can be realized through one function:

- Real-Time Load Measurement & Management

The project will report the number of electricity theft events detected, and the estimation of load not recorded (kWh/yr). The monetary impact of this benefit is calculated using the following formula:

Value ($) = [Estimated Cumulative Load Not Recorded (kWh/yr) * Retail Electricity Rate ($/kWh)]$_{\text{Baseline}}$ - [Estimated Cumulative Load Not Recorded (kWh/yr) * Retail Electricity Rate ($/kWh)]$_{\text{Project}}$

Projects will be responsible for reporting incidents of theft detected by AMI. Smart meters will log hourly usage, and an estimate of load not recorded may be provided by the project at the time of reporting. However, the probability of identifying electricity theft within a pilot project could be low.

C.12 Reduced Electricity Losses

The Reduced Electricity Losses benefit can be realized through four functions and three EERs:

- Automated Voltage and VAR control
- Real-Time Load Measurement & Management
- Real-Time Load Transfer
- Customer Electricity Use Optimization
- Distributed Generation
- Stationary Electricity Storage

The best approach for determining loss reductions for a project is to make coincident measurements on the portion of the delivery system incurring the losses. For example, if a project were seeking to demonstrate a loss reduction on a distribution feeder, the hourly load and voltage data from smart meters, as well as hourly load and voltage data from the head end of the feeder at the substation could be measured, and the data used to calculate the losses. The monetary impact of this benefit is calculated:

Value ($) = [Losses (kWh) * Price of wholesale energy ($/kWh)]$_{\text{Baseline}}$ - [Losses (kWh) * Price of wholesale energy ($/kWh)]$_{\text{Project}}$

Several functions can contribute to reducing losses, and projects demonstrating more than one of these functions at one time will see compounded effects.

C.13 Reduced Electricity Cost

The Reduced Electricity Cost benefit can be realized through one function and four EERs:

- Customer Electricity Use Optimization
- Distributed Generation

- Stationary Electricity Storage
- Plug-in Electric Vehicles

The project will monitor hourly customer electricity use[29] and apply either an estimated hourly rate, or an actual hourly rate, to each hour's usage using the following formula:

Value ($) = {[Energy (kWh) * (Energy Rate ($/kWh)] + [Demand (kW) * Demand Rate ($/kW)]}$_{\text{Baseline}}$ - {[Energy (kWh) * (Energy Rate ($/kWh)] + [Demand (kW) * Demand Rate ($/kW)]}$_{\text{Project}}$

Projects may not have tariff structures in place to charge customers in an hourly fashion, and they may not intend to put them in place in the near term. In these cases, the hourly rates could be constant throughout the day.

An hourly pricing schedule for each customer class should be reported. If the company can't provide one, a default schedule should be used. This approach also requires some assumption about time-of-use, hourly, or critical peak pricing, and how it might change over the next 20 years. Otherwise, some projects who do not have peak pricing, may report project benefits that are much smaller than those who do, particularly if the Smart Grid technologies are successful in enabling reductions in consumption and demand.

C.14 Reduced Sustained Outages

The Reduced Sustained Outages benefit can be realized through six functions and three EERs:

- Adaptive Protection
- Automated Feeder Switching
- Automated Islanding and Reconnection
- Diagnosis & Notification of Equipment Condition
- Enhanced Fault Protection
- Real-Time Load Measurement and Management
- Distributed Generation
- Stationary Electricity Storage
- Plug-in Electric Vehicles

Customer outage time could be logged by smart meters or outage management systems. This data could be compared with typical hourly loads to estimate the "load not served" during the outage. The value of the decreased load not served as a result of Smart Grid functions must be

[29] Net electricity use may include credit for energy or demand from demand response, distributed generation, or stored energy from stationary or PEV sources.

allocated based on the function's contribution to reducing outage minutes. By applying a value of service (VOS) metric (i.e., by customer class and geographic region), the value of the load not served can be estimated as follows:

Value ($) = [Outage Time (hr) * Load Not Served (kW estimated) * VOS ($/kWh)]$_{\text{Baseline}}$ - [Outage Time (hr) * Load Not Served (kW estimated) * VOS ($/kWh)]$_{\text{Project}}$

An estimate of the load not served may be provided by the project at the time of reporting, or could be obtained from the baseline estimate generated when the project is established. For example, if all customers that experience the outage are residential, the project can simply report total outage time, load not served, and a single VOS metric. In a case where a project has 100 customers, 75 of whom are residential and 25 of whom are commercial, the project could report the total residential outage time, load not served, and the residential VOS metric, plus the total commercial outage time, load not served, and the commercial VOS metric.

If estimating the load not served from baseline data prior to project implementation, the project will need to consider the affect of load control and energy efficiency on the load not served. For example, load not served could decrease after project implementation due to customers using less energy, without any change in reliability (outage minutes).

C.15 Reduced Major Outages

The Reduced Major Outages benefit can be realized through four functions:

- Wide Area Monitoring, Visualization, and Control
- Automated Islanding and Reconnection
- Real-Time Load Measurement and Management
- Real-Time Load Transfer

As with Reduced Sustained Outages, smart meters will log outage times and this will be multiplied by a VOS metric. An estimate of the load not served may be provided by the project at the time of reporting, or can be pulled from the baseline estimate generated when the project is established.

Value ($) = [Outage Time (hr) * Load Not Served (kW) * VOS ($/kWh)]$_{\text{Baseline}}$ - [Outage Time (hr) * Load Not Served (kW) * VOS ($/kWh)]$_{\text{Project}}$

C.16 Reduced Restoration Cost

The Reduced Restoration Cost benefit can be realized through five functions:

- Adaptive Protection
- Automated Feeder Switching
- Diagnosis & Notification of Equipment Condition

- Enhanced Fault Protection

The project could report and track the number of outages and the reduction in restoration costs achieved by being able to restore service more quickly. The cause of outages must be reported for the baseline and tracked during the project. For example, a utility could have 10% of all outages caused by equipment failure historically. Therefore, the baseline for outage history (or reliability index) would include the percentages for each type of outage. Over the course of the project, the utility would track outages and causes, and the result would be compared against the baseline.

Value ($) = [Restoration Cost ($)]$_{\text{Baseline}}$ - [Restoration Cost ($)]$_{\text{Project}}$

C.17 Reduced Momentary Outages

The Reduced Momentary Outages benefit can be realized through one function and one EER:

- Enhanced Fault Protection
- Stationary Electricity Storage

The value of this benefit is based on the VOS metrics which are typically determined by customer class (residential, commercial, industrial) and may vary geographically. The VOS is provided as part of the baseline information at the beginning of the project. Otherwise VOS for a similar utility/region is applied. The project should preferably track the momentary outage events, not simply the number of times the lights blink. For example, one event might cause two recloser operations to clear the fault, but only one event should be recorded (not two). The capability of fault location without reclosing must be clearly identified in the project, and a specific monitoring plan should be put in place. Customer momentary interruptions could be logged by smart meters or outage management systems. The metric for momentary interruptions would most likely be the Momentary Average Interruption Frequency Index x (MAIFI) for the project.

For Enhanced Fault Protection

Value ($) = [Momentary Interruptions (# of interruptions) * Portion Caused by Reclosing (%) * VOS ($ per interruption)]$_{\text{Baseline}}$ - [Momentary Interruptions (# of interruptions) * Portion Caused by Reclosing (%) * VOS ($ per interruption)]$_{\text{Project}}$

For Stationary Electricity Storage

Value ($) = [Momentary Interruptions (# of interruptions) * VOS ($ per interruption)]$_{\text{Baseline}}$ - [Momentary Interruptions (# of interruptions) * VOS ($ per interruption)]$_{\text{Project}}$

C.18 Reduced Sags and Swells

The Reduced Sags and Swells benefit can be realized through one function and one EER:

- Enhanced Fault Protection

- Stationary Electricity Storage

The project would track the number of high impedance faults that were cleared without causing voltage sags. Feeder monitoring will most likely be required to determine the number and severity of voltage sags since customers do not always detect these events, and most probably go unreported.

Value ($) = [Number of High Impedance Faults Cleared (# of events) * VOS ($/event)]$_{\text{Baseline}}$ - [Number of High Impedance Faults Cleared (# of events) * VOS ($/event)]$_{\text{Project}}$

VOS would be for power quality events (voltage), and is probably most applicable to customers with sensitive loads. The project or DOE will estimate the VOS associated with voltage variations, and could refer to IEEE 1159[30] or a similar guideline to determine the technical impact of these events and calculate the value.

C.19 Reduced CO_2 Emissions

The Reduced CO_2 Emissions benefit can be realized through five functions and four EERs:

- Flow Control
- Automated Feeder Switching
- Automated Voltage and VAR Control
- Real Time Measurement and Management
- Customer Electricity Use Optimization
- Distributed Generation
- Stationary Electricity Storage
- Plug-in Electric Vehicles

For Automated Feeder Switching, Automated Voltage & VAR Control, and Real Time Load Measurement and Management, the impact of this benefit is based on reducing truck rolls for operations and maintenance, and meter reading. The project could estimate the percentage of a field crew's time that is dedicated to switching, and then estimate fuel consumed by the field service fleet. Alternately, the number and distance of truck rolls for typical distribution operations activities could be used. The emissions associated with using gasoline for truck rolls would then be determined.[31] The project would report this for each of the activities, and the average fuel efficiency of the vehicle would be incorporated by DOE.

[30] IEEE Std 1159-1995 IEEE Recommended Practice for Monitoring Electric Power Quality

[31] EPA reports 19.4 lbs CO2 per gallon of gasoline.

Value ($) = {Operation (# of events) * Average Miles Travelled per Event (miles/event) *Average Fuel Efficiency for Service Vehicle (gallons/mile) * CO_2 emissions per gallon (tons/gallon) * Value of CO_2 ($/ton)}$_{\text{Baseline}}$ - {Operation (# of events) * Average Miles Travelled per Event (miles/event) *Average Fuel Efficiency for Service Vehicle (gallons/mile) * CO_2 emissions per gallon (tons/gallon) * Value of CO_2 ($/ton)}$_{\text{Project}}$

For Enhanced Load Following, Flow Control and EERs the reduction is due to fewer line losses. The reduction in emissions is associated with reducing peak demand and the use of central generation. Therefore, the emissions associated with central generation would have to be determined for each project based on the generation mix in the service territory of the project.

Value ($) = [Line losses (MWH) * CO_2 emissions (tons/MWH) * Value of CO_2 ($/ton)]$_{\text{Baseline}}$ - [Line losses (MWH) * CO_2 emissions (tons/MWH) * Value of CO_2 ($/ton)]$_{\text{Project}}$

For renewable DG, CO_2 reductions are associated with using renewable vs. fossil energy. Currently, CO_2 emissions are monetized assuming $20/ton. The monetary impact of this benefit is calculated using the following formula:

Value ($) = [$CO_2$ Emissions (tons) * Value of CO_2 ($/ton)]$_{\text{Baseline}}$ - [CO_2 Emissions (tons) * Value of CO_2 ($/ton)] $_{\text{Project}}$

C.20 Reduced SO_X, NO_X, and PM-10 Emissions

The benefit of reducing SO_X, NO_X and PM-10 emissions benefit can be realized through five functions and four EERs:

- Flow Control
- Automated Feeder Switching
- Automated Voltage and VAR Control
- Real Time Measurement and Management
- Customer Electricity Use Optimization
- Distributed Generation
- Stationary Electricity Storage
- Plug-in Electric Vehicles

As with CO_2 reductions, the impact of this benefit for Automated Feeder Switching, Automated Voltage & VAR Control, and Real Time Load Measurement and Management is based on reducing truck rolls for operations and maintenance. The project could estimate the percentage of a field crew's time that is dedicated to switching, and then estimate fuel consumed by the field service fleet. Alternately, the number and distance of truck rolls for typical distribution operations activities can be used. The emissions associated with using gasoline for truck rolls would then be determined. The project would report this for each of the activities, and the average fuel efficiency of the vehicle would be incorporated by DOE.

Value ($) = {Operation (# of events) * Average Miles Travelled per Event (miles/event) *Average Fuel Efficiency for Service Vehicle (gallons/mile) * emissions per gallon (tons/gallon) * Value of emission($/ton)}$_{\text{Baseline}}$ - {Operation (# of events) * Average Miles Travelled per Event (miles/event) *Average Fuel Efficiency for Service Vehicle (gallons/mile) * emissions per gallon (tons/gallon) * Value of emission ($/ton)}$_{\text{Project}}$

For Enhanced Load Following, Flow Control and EER, the reduction in emissions is associated with fewer line losses. This can be due to reducing peak demand and the use of central generation. Therefore, the emissions associated with central generation would have to be determined for each project based on the generation mix in the service territory of the project.

Value ($) = [Line losses (MWH) * emissions (tons/MWH) * Value of CO_2 ($/ton)]$_{\text{Baseline}}$ - [Line losses (MWH) * emissions (tons/MWH) * Value of emission ($/ton)]$_{\text{Project}}$

For renewable DG, emission reductions are associated with using renewable vs. fossil energy. Polluting emissions are monetized based on the 2007 market value. The monetary impact of this benefit is calculated using the following formula:

Value ($) = [Emissions (tons) * Value of emission ($/ton)]$_{\text{Baseline}}$ - [Emissions (tons) * Value of emission ($/ton)] $_{\text{Project}}$

C.21 Reduced Oil Usage

The Reduced Oil Usage benefit can be realized through two functions and one EER:

- Automated Feeder Switching
- Diagnosis & Notification of Equipment Condition
- Real Time Load Measurement and Management
- Plug-in Electric Vehicles

To determine the impact of this benefit, an estimate of the fuel consumed per truck roll is used. For Automated Feeder Switching, the project will report the typical number of switching operations performed per feeder or region as a baseline and estimate the fuel consumed per switching operation. For Diagnosis & Notification of Equipment Condition, the project will report the typical number of trips to perform maintenance per feeder or region as a baseline and estimate the fuel consumed per maintenance operation. The project will track the number of switching and maintenance operations that are performed during the project, and estimate the fuel savings by not rolling a truck to perform them manually.

For Automated Feeder Switching, Diagnosis & Notification of Equipment Condition, and Real Time Load Measurement and Management:

Value ($) = {Operation (# of events) * Average Miles Travelled per Event (miles/event) *Average Fuel Efficiency for Service Vehicle (gallons/mile) * Oil Conversion Factor (barrels of oil/gallon of gasoline)}$_{\text{Baseline}}$ - {Operation (# of events) * Average Miles Travelled per Event (miles/event) *Average Fuel Efficiency for Service Vehicle (gallons/mile) * Oil Conversion Factor (barrels of oil/gallon of gasoline)}$_{\text{Project}}$

For PEVs, the electrical energy used by PEVs displaces the equivalent amount of gasoline. However, PEVs may not be individually metered. The project may be required to estimate how much electricity is used to charge them.

Value ($) = {Electricity consumed (kWh) * Gasoline Conversion Factor (gallons of gasoline/kWh) * Oil Conversion Factor (barrels of oil/gallon of gasoline)}$_{\text{Baseline}}$ - {Electricity consumed (kWh) * Gasoline Conversion Factor (gallons of gasoline/kWh) * Oil Conversion Factor (barrels of oil/gallon of gasoline)}$_{\text{Project}}$

C.22 Reduced Wide-scale Blackouts

The Reduced Wide-scale Blackouts benefit can be realized through three functions:

- Wide Area Monitoring and Visualization
- Dynamic Capability Rating
- Enhanced Fault Detection

The value of this benefit is estimated by calculating the number of blackouts that would be avoided and the cost of each event. The project would report instances where conditions were detected that could have put the system at great risk in the past. These could be considered an "event", and then the expected cost of the event is applied by the DOE. The monetary impact of this benefit is calculated using the following formula:

Value ($) = [Number of Events (# of events) * Estimated Cost per Event ($/event)]$_{\text{Baseline}}$ - [Number of Events (# of events) * Estimated Cost per Event ($/event)]$_{\text{Project}}$

It is highly unlikely that an event will occur during the project, and it is almost impossible to estimate the cost of the avoided impact. To estimate this, the tool would need to refer to a set of blackout studies for an estimate.

Table C-2
Monetization Calculations

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Optimized Generator Operation	• Wide Area Monitoring, Visualization, and Control • Stationary Electricity Storage • Plug-in Electric Vehicles	• Hourly Generation Cost ($/MWh) • Annual Generator Dispatch (MWh) • Annual Energy Storage Efficiency (%)	For Wide Area Monitoring, Visualization, & Control: **Value ($)** = $[\text{Annual Generation Cost (\$)}]_{Baseline}$ - $[\text{Annual Generation Cost (\$)}]_{Project}$ For Stationary Electricity Storage and PEV: **Value ($)** = $\{[\text{Hourly Generation Cost (\$/MWh)} * \text{Annual Generator Dispatch (MWh)}]_{Baseline} – [\text{Hourly Generation Cost (\$/MWh)} * \text{Annual Generator Dispatch (MWh)}]_{Project}\}$* Energy Storage Efficiency (%)
Deferred Generation Capacity Investments	• Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• Price of Capacity at Annual Peak ($/MW), • EER Use At Annual Peak (MW) • Capital Carrying Charge of New Generation ($/yr) • Time deferred (yrs)	**Value ($)** = $[\text{Price of Capacity at Annual Peak (\$/MW)} * \text{EER Use or Customer Optimization at Annual Peak (MW)}]_{Baseline}$ - $[\text{Price of Capacity at Annual Peak (\$/MW)} * \text{EER Use or Customer Optimization at Annual Peak (MW)}]_{Project}$ Or **Value ($)** = Capital Carrying Charge of New Generation ($/yr) * Time deferred (yrs)

Table C-2 (continued)
Monetization Calculations

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Reduced Ancillary Service Cost	• Wide Area Monitoring Visualization and Control • Automated Voltage and VAR Control • Real-Time Load Measurement & Management • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• Price of Reserves ($/MW) • Reserves Purchased (MW) • Price of Regulation ($/MW) • Regulation Purchases (MW) • Price of Voltage Control ($/MVAR) • Voltage Control Purchases (MVAR)	**Value ($)** = [Price of Ancillary Service ($/MW) * Purchases (MW)]$_{Baseline}$ - [Price of Ancillary Service ($/MW) * Purchases (MW)]$_{Project}$
Reduced Congestion Cost	• Wide Area Monitoring, Visualization, & Control • Dynamic Capability Rating • Flow Control • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• Congestion (MW) • Price of Congestion ($/MW)	**Value ($)** = [Congestion (MW) * Price of Congestion ($/MW)]$_{Baseline}$ - [Congestion (MW) * Price of Congestion ($/MW)]$_{Project}$

Table C-2 (continued)
Monetization Calculations

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Deferred Transmission Capacity Investments	• Fault Current Limiting • Wide Area Monitoring, Visualization, & Control • Dynamic Capability Rating • Flow Control • Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• Capital Carrying Charge of Upgrade ($/yr) • Time Deferred (yrs)	**Value ($)** = Capital Carrying Charge of Upgrade ($/yr) * Time deferred (yrs) Note: this should only be calculated once since all years of deferral are included

Table C-2 (continued)
Monetization Calculations

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Deferred Distribution Capacity Investments	• Dynamic Capability Rating • Real-Time Load Measurement & Management • Real-Time Load Transfer • Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• Capital Carrying Charge of Upgrade ($/yr) • Time deferred (yrs)	**Value ($)** = Capital Carrying Charge of Upgrade ($/yr) * Time deferred (yrs) Note: this should only be calculated once since all years of deferral are included
Reduced Equipment Failures	• Fault Current Limiting • Dynamic Capability Rating • Diagnosis & Notification of Equipment Condition • Enhanced Fault Protection	• Capital Replacement of Failed Equipment ($) • Portion Caused by Fault Current or Overloaded equipment (%) • Portion Caused by Lack of Condition Diagnosis (%)	For Fault Current Limiting, Dynamic Capability Rating, & Enhanced Fault Protection: **Value ($)** = Capital Replacement of Failed Equipment ($) * Portion Caused by Fault Current or Overloaded Equipment (%) For Diagnosis & Notification of Equipment Condition: **Value ($)** = Capital Replacement of Failed Equipment ($) * Portion Caused by Lack of Condition Diagnosis (%)

Table C-2 (continued)
Monetization Calculations

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Reduced Distribution Equipment Maintenance Cost	• Diagnosis & Notification of Equipment Condition	• Distribution Maintenance Cost ($)	**Value ($)** = [Distribution Maintenance Cost ($)]$_{Baseline}$ – [Distribution Maintenance Cost ($)]$_{Project}$
Reduced Distribution Operations Cost	• Automatic Feeder Switching • Automated Voltage and VAR Control	• Cost for Feeder Switching for the Project ($) • Cost for Capacity Switching for the Project ($)	For Automatic Feeder Switching: **Value ($)** = [Annual Cost for Feeder Switching ($)]$_{Baseline}$ - [Annual Cost for Feeder Switching ($)]$_{Project}$ For Automated Voltage and VAR Control: **Value ($)** = [Annual Cost for Capacitor Switching ($)]$_{Baseline}$ - [Annual Cost for Capacitor Switching ($)]$_{Project}$
Reduced Meter Reading Cost	• Real-Time Load Measurement & Management	• Number of Meter Reading Operations (# of events) • Average Cost per Meter Reading Operation ($/event)	**Value ($)** = [Number of Meter Reading Operations (# of events) * Average Cost per Meter Reading Operation ($/event)]$_{Baseline}$ - [Number of Meter Reading Operations (# of events) * Average Cost per Meter Reading Operation ($/event)]$_{Project}$
Reduced Electricity Theft	• Real-Time Load Measurement & Management	• Estimated Load Not Recorded (kWh/yr) • Retail Electricity Rate ($/kWh)	**Value ($)** = [Estimated Cumulative Load Not Recorded (kWh/yr) * Retail Electricity Rate ($/kWh)]$_{Baseline}$ - [Estimated Cumulative Load Not Recorded (kWh/yr) * Retail Electricity Rate ($/kWh)]$_{Project}$

Table C-2 (continued)
Monetization Calculations

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Reduced Electricity Losses	• Automated Voltage and VAR Control • Real-Time Load Measurement & Management • Real-Time Load Transfer • Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage	• Losses (kWh) • Price of wholesale energy ($/kWh)	**Value ($)** = [Losses (kWh) * Price of wholesale energy ($/kWh)]$_{\text{Baseline}}$ - [Losses (kWh) * Price of wholesale energy ($/kWh)]$_{\text{Project}}$
Reduced Electricity Cost	• Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• Energy (kWh) • Energy Rate ($/kWh) • Demand (kW) • Demand Rate ($/kW)	**Value ($)** = {[Energy (kWh) * (Energy Rate ($/kWh)] + [Demand (kW) * Demand Rate ($/kW)]}$_{\text{Baseline}}$ - {[Energy (kWh) * (Energy Rate ($/kWh)] + [Demand (kW) * Demand Rate ($/kW)]}$_{\text{Project}}$

Table C-2 (continued)
Monetization Calculations

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Reduced Sustained Outages	• Adaptive Protection • Automatic Feeder Switching • Automated Islanding and Reconnection • Diagnosis & Notification of Equipment Condition • Enhanced Fault Protection • Real-Time Load Measurement & Management • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• Outage Time (hr) • Load Not Served (kW estimated) • Value of Service ($/kWh)	**Value ($)** = [Outage Time (hr) * Load Not Served (kW estimated) * VOS ($/kWh)]$_{\text{Baseline}}$ - [Outage Time (hr) * Load Not Served (kW estimated) * VOS ($/kWh)]$_{\text{Project}}$

Table C-2 (continued)
Monetization Calculations

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Reduced Major Outages	• Wide Area Monitoring, Visualization & Control • Automated Islanding and Reconnection • Real-Time Load Measurement & Management • Real-Time Load Transfer	• Outage Time (hr) • Load Not Served (kW) • Value of Service ($/kWh)	**Value ($)** = [Outage Time (hr) * Load Not Served (kW) * VOS ($/kWh)]$_{Baseline}$ - [Outage Time (hr) * Load Not Served (kW) * VOS ($/kWh)]$_{Project}$
Reduced Restoration Cost	• Adaptive Protection • Automatic Feeder Switching • Diagnosis & Notification of Equipment Condition • Enhanced Fault Protection	• Number of Outage Events (# events) • Restoration Cost per Event ($/event)	**Value ($)** = [Restoration Cost ($)]$_{Baseline}$ - [Restoration Cost ($)]$_{Project}$

Table C-2 (continued)
Monetization Calculations

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Reduced Momentary Outages	• Enhanced Fault Protection • Stationary Electricity Storage	• Momentary Interruptions (# of interruptions) • Portion Caused by Reclosing (%) • Value of Service ($ per interruption)	For Enhanced Fault Protection **Value ($)** = [Momentary Interruptions (# of interruptions) * Portion Caused by Reclosing (%) * VOS ($ per interruption)]$_{Baseline}$ - [Momentary Interruptions (# of interruptions) * Portion Caused by Reclosing (%) * VOS ($ per interruption)]$_{Project}$ For Stationary Electricity Storage **Value ($)** = [Momentary Interruptions (# of interruptions) * VOS ($ per interruption)]$_{Baseline}$ - [Momentary Interruptions (# of interruptions) * VOS ($ per interruption)]$_{Project}$
Reduced Sags and Swells	• Enhanced Fault Protection • Stationary Electricity Storage	• Number of High Impedance Faults Cleared (# of events) • Value of Service ($/event)	**Value ($)** = [Number of High Impedance Faults Cleared (# of events) * VOS ($/event)]$_{Baseline}$ - [Number of High Impedance Faults Cleared (# of events) * VOS ($/event)]$_{Project}$

Table C-2 (continued)
Monetization Calculations

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Reduced CO_2 Emissions	• Flow Control • Automatic Feeder Switching • Automated Voltage and VAR Control • Real-Time Load Measurement & Management • Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• Operation (# of events) • Average Miles Travelled per Event (miles/event) • Average Fuel Efficiency for Service Vehicle (gallons/mile) • CO_2 emissions per gallon (tons/gallon) • Line losses (MWH) • CO_2 emissions (tons/MWH) • CO_2 Emissions (tons) • Value of CO_2 ($/ton)	**Value ($)** = [$CO_2$ Emissions (tons) * Value of CO_2 ($/ton)]$_{Baseline}$ - [CO_2 Emissions (tons) * Value of CO_2 ($/ton)] $_{Project}$

Table C-2 (continued)
Monetization Calculations

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Reduced SO_x, NO_x, and PM-10 Emissions	• Flow Control • Automatic Feeder Switching • Automated Voltage and VAR Control • Real-Time Load Measurement & Management • Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• Operation (# of events) • Average Miles Travelled per Event (miles/event) • Average Fuel Efficiency for Service Vehicle (gallons/mile) • Emissions per gallon (tons/gallon) • Line losses (MWH) • Emissions (tons/MWH) • Emissions (tons) • Value of Emission ($/ton)	**Value ($)** = [Emissions (tons) * Value of emission ($/ton)]$_{Baseline}$ - [Emissions (tons) * Value of emission ($/ton)]$_{Project}$

Table C-2 (continued)
Monetization Calculations

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Reduced Oil Usage	• Automated Feeder Switching • Diagnosis & Notification of Equipment Condition • Real-Time Load Measurement & Management • Plug-in Electric Vehicles	• Number of Switching or Maintenance Operations Completed (# of events) • Average Miles Travelled per Operation (Baseline miles/operation) • Average Fuel Efficiency for Service Vehicle (gallons/mile) • kWh consumed (kWh) • Electricity to Fuel Conversion Factor	For Automated Feeder Switching, Diagnosis & Notification of Equipment Condition, & Real-Time Load Measurement & Management: **Value ($)** = {Operation (# of events) * Average Miles Travelled per Event (miles/event) *Average Fuel Efficiency for Service Vehicle (gallons/mile) * Oil Conversion Factor (barrels of oil/gallon of gasoline)}$_{\text{Baseline}}$ - {Operation (# of events) * Average Miles Travelled per Event (miles/event) *Average Fuel Efficiency for Service Vehicle (gallons/mile) * Oil Conversion Factor (barrels of oil/gallon of gasoline)}$_{\text{Project}}$ For PEVs: **Value ($)** = {Electricity consumed (kWh) * Gasoline Conversion Factor (gallons of gasoline/kWh) * Oil Conversion Factor (barrels of oil/gallon of gasoline)}$_{\text{Baseline}}$ - {Electricity consumed (kWh) * Gasoline Conversion Factor (gallons of gasoline/kWh) * Oil Conversion Factor (barrels of oil/gallon of gasoline)}$_{\text{Project}}$
Reduced Wide-scale Blackouts	• Wide Area Monitoring & Visualization • Dynamic Capability Rating • Enhanced Fault Detection	• Number of Events (# of events) • Estimated Cost per Event ($/event)	**Value ($)** = [Number of Events (# of events) * Estimated Cost per Event ($/event)]$_{\text{Baseline}}$ - [Number of Events (# of events) * Estimated Cost per Event ($/event)]$_{\text{Project}}$

Program:

PDU Demonstrations

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